# Exhibit N
# Need

# Boardman to Hemingway Transmission Line Project

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*Amended Preliminary Application for Site Certificate*

*June 2017*

# TABLE OF CONTENTS

1.0 INTRODUCTION ..... N-1
2.0 APPLICABLE RULES AND AMENDED PROJECT ORDER PROVISIONS ..... N-1
2.1 Need Standard for Nongenerating Facilities ..... N-1
2.1.1 Need for a Facility ..... N-1
2.1.2 Least-Cost Plan Rule ..... N-1
2.1.3 System Reliability Rule for Electric Transmission Lines ..... N-1
2.2 Site Certificate Application Requirements ..... N-2
2.2.1 General Requirements ..... N-2
2.2.2 Contents of Application ..... N-2
2.3 Amended Project Order Provisions ..... N-4
3.0 ANALYSIS ..... N-5
3.1 Rules under which IPC Will Demonstrate Need ..... N-5
3.2 Demonstration of Need Under the Least-Cost Plan Rule ..... N-5
3.2.1 Least-Cost Plan Rule ..... N-5
3.2.2 Application Content Requirements ..... N-5
3.3 Demonstration of Need under the System Reliability Rule ..... N-10
3.3.1 System Reliability Rule ..... N-10
3.3.2 Application Content Requirements ..... N-11
3.3.3 Firm Resources to be Used to Meet Demands ..... N-14
3.3.4 Retirement or Displacement of Resources ..... N-14
3.3.5 Assumed Annual Capacity Factors ..... N-15
3.3.6 Reliability Criteria Demonstrating Need for the Project ..... N-15
3.3.7 The Project is an Economically Reasonable Alternative ..... N-16
3.3.8 Required Alternatives Evaluated ..... N-18
3.3.9 Earliest and Latest Expected In-Service Dates ..... N-19
4.0 CONCLUSION ..... N-19
5.0 COMPLIANCE CROSS-REFERENCES ..... N-19

# LIST OF TABLES

Table N-1. Expected-Case Total Portfolio Cost (2015-2034) ..... N-17
Table N-2. Comparison of Transmission Line Capacity Scenarios..... N-19
Table N-3. Compliance Requirements and Relevant Cross-References..... N-20

# LIST OF ATTACHMENTS

Attachment N-1. Idaho Power Company's 2009 Integrated Resource Plan (Docket LC 50)
Attachment N-2. Idaho Power Company's 2011 Integrated Resource Plan (Docket LC 53)
Attachment N-3. Idaho Power Company's 2013 Integrated Resource Plan (Docket LC 58)
Attachment N-4. Idaho Power Company's 2015 Integrated Resource Plan (Docket LC 63)
Attachment N-5. Order No. 10-392 in Docket LC 50
Attachment N-6. Order No. 12-177 in Docket LC 53
Attachment N-7. Order No. 14-253 in Docket LC 58
Attachment N-8. Order No. 16-160 in Docket LC 63
Attachment N-9. Annual Capacity Factors

# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| Amended Project Order | First Amended Project Order, Regarding Statutes, Administrative Rules and Other Requirements Applicable to the Proposed Boardman to Hemingway Transmission Line (December 22, 2014) |
| aMW | average megawatt |
| ATC | available transmission capacity |
| DOE | United States Department of Energy |
| EFSC or Council | Energy Facility Siting Council |
| IPC | Idaho Power Company |
| IRP | Integrated Resource Plan |
| IRPAC | Integrated Resource Plan Advisory Council |
| kV | kilovolt |
| kWh | kilowatt-hour |
| LOLE | Loss of Load Expectation |
| MW | megawatt |
| NERC | North American Electric Reliability Corporation |
| OAR | Oregon Administrative Rules |
| OPUC | Public Utility Commission of Oregon |
| Project | Boardman to Hemingway Transmission Line Project |
| SAE | Statistically Adjusted End-use |
| TPL | Transmission Planning |
| WECC | Western Electricity Coordinating Council |

# Exhibit N
# Need

## 1.0 INTRODUCTION

Exhibit N establishes the need for the Boardman to Hemingway Transmission Line Project (Project) under the least-cost plan rule, Oregon Administrative Rule (OAR) 860-023-0020, and the system reliability rule for transmission lines, OAR 345-023-0030.

## 2.0 APPLICABLE RULES AND AMENDED PROJECT ORDER PROVISIONS

### 2.1 Need Standard for Nongenerating Facilities

#### *2.1.1 Need for a Facility*

OAR 345-023-0005 provides that Idaho Power Company (IPC) shall demonstrate the need for the Project as follows:

> *(1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act;*

#### *2.1.2 Least-Cost Plan Rule*

The least-cost plan rule, OAR 345-023-0020(1), states:

> *(1) The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans . . . .*
>
> *(2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.*

#### *2.1.3 System Reliability Rule for Electric Transmission Lines*

The system reliability rule, OAR 345-023-0030, provides:

> *The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that:*
>
> > *(1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility;*
> >
> > *(2) The facility is consistent with the applicable mandatory and enforceable North American Reliability Corporation (NERC) Reliability Standards in effect as of*

*September 18, 2015 as they apply either internally or externally to a utility system; and*

*(3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.*

## 2.2 Site Certificate Application Requirements

### *2.2.1 General Requirements*

OAR 345-021-0000(8) provides the following:

*If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, in addition to the application for a site certificate described in OAR 345-021-0010, the applicant shall submit to the Department three copies of each energy resource plan or combination of plans on which the applicant relies to demonstrate need under 345-023-0020, unless the applicant chooses to incorporate copies of the plan(s) as part of the application for a site certificate. The applicant shall submit the plan(s) to the Department with the site certificate application. The Department may not find the site certificate application to be complete before receiving copies of the plan(s). The plan or plans described in this section are part of the decision record for the Department's proposed order, described in 345-015-0230.*

### *2.2.2 Contents of Application*

OAR 345-021-0010(1)(n) provides Exhibit N must include the following Information about the need for the Project:

*(A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need.*

*(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:*

*(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need.*

*(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i).*

*(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:*

*(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or*

*(II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record.*

*(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility.*

*(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s).*

*. . .*[1]

*(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:*

*(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.*

*(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:*

*(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;*

*(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;*

*(III) Conservation that results from responses to price; and*

*(IV) Retail customer fuel choice;*

*(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately.*

*(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements.*

[1] Subsections (C) and (E) of OAR 345-021-0010(1)(n) are relevant to energy projects that rely on an energy resource plan not acknowledged by the Public Utility Commission of Oregon to demonstrate need. Here, because IPC is not relying on a resource plan not acknowledged by the Commission, subsections (C) and (D) are not applicable to the Project. Further, subsection (D) is not applicable because it relates to natural gas pipeline or storage facility projects and not transmission line projects.

*(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii).*

*(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility.*

*(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:*

*(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility.*

*(II) Construction and operation of electric generating facilities as a substitute for the proposed facility.*

*(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility.*

*(IV) Adding standard sized smaller or larger transmission line capacity.*

*(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.*

*. . . .*[2]

## 2.3 Amended Project Order Provisions

The Amended Project Order includes the following discussion:

*The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a "National Interest Electric Transmission Corridor" designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23.*

(Amended Project Order, Section III(n)).

[2] Subsection (G) of OAR 345-021-0010(1)(n) is not applicable to the Project, because subsection (G) relates to natural gas pipeline or storage facility projects and not transmission line projects.

# 3.0 ANALYSIS

## 3.1 Rules under which IPC Will Demonstrate Need

> OAR 345-021-0010(1)(n)(A): Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need.

IPC chooses to demonstrate the need for the Project under the least-cost plan rule and system reliability rule. The Energy Facility Siting Council (EFSC or Council) may find the Project need is sufficiently demonstrated under one or both of those rules.

## 3.2 Demonstration of Need Under the Least-Cost Plan Rule

The following analysis addresses the requirements of the least-cost plan rule, OAR 345-023-0020, and the application content requirements of OAR 345-021-0010(n) regarding the same.

### *3.2.1 Least-Cost Plan Rule*

> OAR 345-023-0020(2): The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.

Under OAR 345-023-0020(2), the Council shall find IPC has demonstrated the Project need if the capacity of the Project or a facility substantially similar to the Project is identified for acquisition in the short-term plan of action of an Integrated Resource Plan (IRP) acknowledged by the Oregon Public Utilities Commission (OPUC). Here, the development of the Project has been acknowledged by the OPUC in the 2009, 2011, 2013, and 2015 IRPs (Attachments N-1, N-2, N-3, and N-4; see Section 3.2.2.3 below). Therefore, EFSC must find that the need standard has been satisfied.

### *3.2.2 Application Content Requirements*

#### *3.2.2.1 Relevant Integrated Resource Plans*

> OAR 345-021-0010(1)(n)(B)(i): Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need.

IPC relies on its 2009, 2011, 2013, and 2015 IRPs (Attachments N-1, N-2, N-3, and N-4) to demonstrate the Project need. The 2009, 2011, 2013, and 2015 IRPs were acknowledged by the OPUC and are attached as Attachment N-1, Attachment N-2, Attachment N-3, and Attachment N-4, respectively. The Project was included as a supply-side resource in the preferred portfolio for each of the IRPs.

#### *3.2.2.2 Person Responsible for Preparing the Integrated Resource Plans*

> OAR 345-021-0010(1)(n)(B)(ii): The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i).

The person responsible for preparing IPC's IRPs is:

Rick Haener, Integrated Resource and Operations Plan Manager
1221 West Idaho Street
Boise, Idaho 83702
(208) 388-5862

### *3.2.2.3 IPC's Acknowledged Integrated Resource Plans*

> OAR 345-021-0010(1)(n)(B): (iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including: (I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or (II) . . . .[3]
>
> (iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility.
>
> (v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s).

The OPUC's IRP process is "an approach to utility planning which requires consideration of all known resources for meeting the utility's load."[4] These resources include both supply-side resources (such as generation plants) and demand-side resources (such as conservation and load management). The OPUC has adopted guidelines that govern the development and acknowledgement of utility IRPs. As relevant here, the IRP process must include significant public involvement in the preparation of the plan.[5] Substantively, the plan must:

- Evaluate all resources on a consistent and comparable basis;
- Consider uncertainty;
- Include as its primary goal the least cost to the utility and ratepayers, consistent with the long-run public interest; and
- Be consistent with Oregon's energy policy.[6]

The IRP process requires a utility to identify several portfolios of different combinations of resources that can be used to meet the utility's load over a 20-year planning horizon. The portfolios are analyzed and a preferred portfolio is identified, representing the best combination of costs and risks. Next, an action plan is developed to explain how the utility will obtain the resources identified in the preferred portfolio.

OPUC's acknowledgement of an IRP means that the IRP is "reasonable, based on information available at the time."[7] IRP guidelines recognize that all utility planning encompasses uncertainty and requires only that utilities consider the uncertainties in their planning and that the preferred portfolio represent the best combination of expected costs, associated risks, and uncertainties.[8]

#### *IPC's 2009 IRP*

IPC filed its 2009 IRP with the OPUC on December 30, 2009 (Attachment N-1). The filing was docketed as LC 50. IPC provided notice of the filing to all parties that had participated in IPC's

[3] Subsection (II) of OAR 345-021-0010(1)(n)(B)(iii) applies to applicants relying on energy resource plans reviewed by agencies other than the OPUC. Because IPC is relying on OPUC energy plans and not plans reviewed by other agencies, Subsection (II) does not apply to the Project.
[4] OPUC Order No. 89-507, p. 8 (Apr. 20, 1981).
[5] OPUC Order No. 07-002, p. 1 (Jan. 8, 2007).
[6] Order No. 07-002, p. 2.
[7] Order No. 07-002, p. 10.
[8] Order No. 07-002, p. 5 (defining "uncertainty" as a "measure of the quality of information about an event or outcome").

previous IRP docket, LC 41.

In developing the 2009 IRP, IPC engaged in an extensive public process, including the creation of an IRP Advisory Council (IRPAC), which included major stakeholders including representatives of political organizations, environmental groups, customer representatives, and others. The IRPAC generally met monthly and all meetings were open to the public. The meetings allowed stakeholders to provide input to IPC on all aspects of the planning process, including the development of the portfolios that were ultimately included in the IRP.

The 2009 IRP divided the 20-year planning period into two 10-year periods. IPC then developed different portfolios for each of those 10-year periods. The portfolios each represented the resources that IPC planned to obtain during each of the 10-year periods. For the first period, 2010 to 2019, IPC developed four different resources portfolios. For the second period, 2019 to 2029, IPC developed five different resource portfolios.

To analyze the portfolios, IPC used an electric market model. The tool enabled IPC to model resource operations and determine operating costs for the entire 20-year planning horizon. The analysis was based on the application of economic principles and dispatch simulation to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources was based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. The modeling simulated the regional electrical system to determine how utility generation and transmission resources operate to serve load. The analysis included multiple electricity markets, zones, and hubs. IPC modeled the entire Western Electricity Coordinating Council (WECC) system when evaluating the resource portfolios.

IPC's analysis also included detailed assessment of risk, both quantitative and qualitative. The analysis identified portfolios that performed well in a variety of possible future scenarios. The risk analysis identified six risk variables that were then included in IPC's modeling—carbon risk, natural gas price risk, capital cost risk, risk associated with demand side management variability, risk caused by load variability, and risk associated with renewable energy certificate price changes. The stochastic modeling was used to estimate the distribution of the incremental portfolio costs. Based on the modeling and analysis, IPC selected a preferred portfolio for each 10-year period.

The 2009 IRP's preferred portfolio for the first 10-year period included the Project as a supply-side resource. IPC's analysis demonstrated that the preferred portfolio represented the best combination of cost and risk for IPC and its ratepayers. The IRP also included IPC's action plan, which described the specific actions IPC intended to take to implement its preferred portfolio. That action plan included the construction of the Project.[9] Chapter 10 of the 2009 IRP described the modeling and risk analysis of each of the identified portfolios and identified the selection of the portfolio including the Project as the preferred portfolio.

The OPUC's analysis and public process on the 2009 IRP were both extensive and thorough. The IRP was the subject of discussion at two separate OPUC public meetings. In addition, there was a public hearing held in Ontario, Oregon. The hearing allowed members of the public to submit both oral and written comments for the OPUC's consideration. The OPUC's process also allowed parties that formally intervened in the docket to submit written comments on two separate occasions. Over 25 individuals and organizations submitted written comments that were considered by the OPUC in the IRP process.

[9] OPUC Order No. 10-392 (Attachment N-5), p. 5 (Oct. 11, 2010).

In addition to public comment, the staff of the OPUC undertook a comprehensive and independent review of the 2009 IRP. As part of that process, the staff issued to IPC 69 data requests to which IPC responded with additional analysis and explanation. OPUC staff ultimately concluded that IPC's preferred portfolio, which included the Project, represented the "best combination of expected costs and associated risks and uncertainties for IPC and its customers."[10] OPUC staff concluded that IPC's analysis demonstrated the "robustness of the Preferred Portfolio." As OPUC staff noted, for the next best portfolio to break even with the preferred portfolio (meaning only that the two portfolios' cost assumptions become comparable), the Project's capital costs would have to increase by 40 percent and the subscription rates would have to decrease by 15 percent.[11] This demonstrated that not only was the preferred portfolio the most cost effective and lowest risk, the preferred portfolio also tolerated a great deal of uncertainty before the next best alternative became competitive.

On October 11, 2010, the OPUC issued Order No. 10-392, which acknowledged IPC's 2009 IRP. The OPUC concluded that it is "reasonable to proceed with [the Project] based on the information available now and acknowledge it as part of [IPC's] 2009 IRP."[12] Order No. 10-392 is included as Attachment N-5 to this Exhibit.

### *IPC's 2011 IRP*

On June 30, 2011, IPC filed its 2011 IRP (Attachment N-2) with the OPUC. It was docketed as LC 53. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009 IRP (Attachment N-1), IPC's 2011 IRP also included extensive public participation through the IRPAC process, which allowed for significant input into the portfolios included for analysis in the 2011 IRP. The IRPAC held nine monthly meetings, all of which were open to the public. In addition, IPC hosted a field trip covering wind, hydroelectric, and natural gas resources and held two resource portfolio-design workshops. Several of the portfolios included in the 2011 IRP were developed during these workshops.

The 2011 IRP again utilized two 10-year planning periods to develop its resource portfolios. For the first 10-year period, 2011 to 2020, IPC developed and analyzed nine different portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, and the Project. For the second 10-year period, 2020 to 2030, IPC developed and analyzed 10 different resource portfolios.

IPC's analysis in the 2011 IRP was largely the same as that used in the 2009 IRP, although the 2011 IRP included significantly more resource portfolios. As a result, the analysis in the 2011 IRP was more robust, and compared the Project against a greater range of potential alternatives.

Based on the analysis and modeling in the 2011 IRP, IPC selected for the first 10-year period a preferred portfolio that included the Project. This selection was based on the expected low costs and the limited risk spread provided by this portfolio. Because the Project was included in the preferred portfolio, it was also included in the 2011 IRP's Action Plan, which is described in Chapter 10 of the 2011 IRP.

[10] *See* Final Comments and Recommendations, p. 6, and Appendix A, p. 1 (Comments); Order No. 07-002 at 5 ("The primary goal [of the IRP process] must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").
[11] LC 50, Staff Proposed Order, p. 6.
[12] Order No. 10-392, p. 9.

On September 20, 2011, IPC presented its IRP to the OPUC at a public meeting. Thereafter, the OPUC held a technical workshop for parties in the docket. Staff and intervenors filed initial comments on October 18, 2011, followed by several additional rounds of comments from IPC and other parties. Staff filed its report and proposed order on January 24, 2012, recommending acknowledgement of the Project. Staff noted its general agreement "regarding the benefits [the Project] brings," and the fact that the Project was "proposed and justified as the primary resource in a portfolio representing the best combination of cost and risk for Idaho Power and its ratepayers."[13]

At the OPUC's February 14, 2012 public meeting, the OPUC reviewed and acknowledged IPC's 2011 IRP. On May 21, 2012, the OPUC confirmed its acknowledgement of IPC's 2011 IRP in a written order (Order No. 12-177), including acknowledging the Project in the near-term action plan.[14] Order No. 12-177 is included as Attachment N-6 to this Exhibit.

### *IPC's 2013 IRP*

On June 28, 2013, IPC filed its 2013 IRP with the OPUC (Attachment N-3), which was docketed as LC 58. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009 and 2011 IRPs (Attachments N-1 and N-2), IPC's 2013 IRP included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2013 IRP. The IRPAC held 11 meetings, including a resource portfolio design workshop, and hosted a field trip covering the distribution and transmission system and natural gas power generation.

Prior to performing the portfolio analysis, IPC performed a resource alternatives analysis, which allowed a direct comparison of the major resource types considered in the 2013 IRP. This analysis informed the selection of resources to include and evaluate in the subsequent portfolio analysis.

The 2013 IRP utilized one 20-year planning period to develop its nine resource portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, and the Project.

Based on the analysis and modeling in the 2013 IRP, IPC selected the Project portfolio as the preferred portfolio. This selection recognized the expected low costs and the limited risk spread provided by this portfolio.

The OPUC's analysis and public process for the 2013 IRP was similarly extensive and thorough as that described for the 2009 and 2011 IRPs. On December 2, 2013, IPC presented its IRP to the OPUC at a public meeting. Staff and intervenors filed initial comments on January 15, 2014, followed by several additional rounds of comments from IPC and other parties. Staff filed its recommendations in its Staff Report dated March 7, 2014. In that Report, Staff recommended that the OPUC acknowledge the action item calling for "ongoing permitting, planning studies and regulatory filings" for the Project.[15] Staff stated that it did not recommend acknowledgement of the action item calling for the construction of Project because "it is beyond the two to four year timeframe for an IRP action plan."[16] At its March 17, 2014, public meeting, the OPUC reviewed

[13] LC 53, Staff Proposed Order, pp. 9-10.
[14] Attachment N-6, Order No. 12-177, Appendix A, p. 2 (May 21, 2012).
[15] LC 58, Staff Report, p. 8.
[16] LC 58, Staff Report, p. 8.

and acknowledged portions of IPC's 2013 IRP. On July 8, 2014, the OPUC confirmed its acknowledgement in Order No. 14-253, included as Attachment N-7 to this Exhibit. Specifically regarding the Project, as recommended by Staff, the Commission acknowledged the near-term action plan items for ongoing permitting, planning studies, and regulatory filings for the Project.[17] Also as recommended by Staff, the Commission declined to acknowledge the completion of the Project as falling outside the appropriate time period for IRP action plans.[18] Importantly, the Commission's decision not to acknowledge the construction action item was based only on its policy of approving action items to be completed within the 2- to 4-year time period, and does not reflect any concerns regarding the merit of the IPC's plans to construct the resource.

### *IPC's 2015 IRP*

On June 30, 2015, IPC filed its 2015 IRP with the OPUC (Attachment N-4), which docketed the filing as LC 63. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009, 2011, and 2013 IRPs (Attachments N-1, N-2, and N-3), IPC's 2015 IRP included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2015 IRP. The IRPAC held 12 meetings, including a resource portfolio design workshop, and hosted a field trip covering the distribution and transmission system and hydroelectric power generation.

Prior to performing the portfolio analysis, IPC performed a resource alternatives analysis, which allowed a direct comparison of the major resource types considered in the 2015 IRP and informed the selection of resources to include and evaluate in the subsequent portfolio analysis.

The 2015 IRP utilized one 20-year planning period to develop its nine resource portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, ice-based thermal energy storage, and the Project.

Based on the analysis and modeling in the 2015 IRP, IPC selected its preferred portfolio, which included the Project. The preferred portfolio represented the portfolio of resources with the best combination of expected costs and associated risks and uncertainties.

The OPUC's analysis and public process for the 2015 IRP was as extensive and thorough as that described for the 2009, 2011, and 2013 IRPs. On April 28, 2016, the OPUC acknowledged IPC's 2015 IRP in Order No. 16-160, attached hereto as Attachment N-8.

## 3.3 Demonstration of Need under the System Reliability Rule

This section addresses the requirements of the system reliability rule, OAR 345-023-0030, and the relevant application content requirements of OAR 345-021-0010(n).

### *3.3.1 System Reliability Rule*

> OAR 345-023-0030: The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that: (1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that

[17] Attachment N-7, OPUC Order No. 14-253, p. 5 (July 8, 2014); *see also id.,* Appendix A.
[18] *Id.*

are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility; (2) The facility is consistent with the applicable mandatory and enforceable North American Electric Reliability Corporation (NERC) Reliability Standards in effect as of September 18, 2015 as they apply either internally or externally to a utility system; and (3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.

The system reliability rule requires a showing that the Project is: (1) needed to allow IPC to meet its projected firm capacity demands or firm annual sales; (2) consistent with applicable North American Reliability Corporation (NERC) reliability standards; and (3) an economically reasonable method of meeting these requirements as compared to other alternatives.

First, the Project is required to meet projected loads. Without additional supply-side resources or the inclusion of demand response programs, the 2015 IRP projects a resource deficiency (unmet load) of up to 14 megawatts (MW) in 2025, 324 MW in 2026, 399 MW in 2027, 438 MW in 2028, and up to 786 MW by 2034. Moreover, additional transmission capacity is also needed to meet IPC's minimum operating criteria for reliability and to provide transmission service to wholesale customers.

Second, the Project is consistent with the applicable mandatory and enforceable NERC Reliability Standards in effect as of September 18, 2015.

Third, the Project is an economically reasonable approach to meeting IPC's projected firm capacity demands. As discussed in Section 3.2.2.3 above, the Project has been part of IPC's preferred portfolio in each of the last four IRPs, demonstrating that the Project is an economic alternative for meeting IPC's needs to serve its native load, satisfy minimum reliability standards, and provide service to wholesale transmission customers. Accordingly, the Project meets the requirements of the system reliability rule and the Council must find that IPC has demonstrated the need for the Project.

### *3.3.2 Application Content Requirements*

#### *3.3.2.1 Load-Resource Balance Tables*

OAR 345-021-0010(1)(n)(F): If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule: (i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

The load-resource balance tables for the area to be served by the Project are included in IPC's 2015 IRP, Appendix C – Technical Report, at pages 29 through 70 (attached hereto as Attachment N-4). The monthly average energy load-resource balance values are reported on pages 29 through 48, and the monthly peak hour load-resource balance values are reported on pages 50 through 70. These tables include annual firm capacity demands and existing and committed firm resources for a 20-year period beginning in 2015.

### *3.3.2.2 Firm Capacity Demand and Firm Annual Electricity Sales Forecasts*

OAR 345-021-0010(1)(n)(F)(ii): Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. . . .

The load-resource balance tables in IPC's 2015 IRP (Attachment N-4, Appendix C) are based on a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the Project. As explained below, (1) the firm capacity demands for electricity or firm annual electricity sales are those reasonably expected to occur within 5 years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year; and (2) IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins, and each wholesale contract for firm sales.

The sales and load forecast values are reported in IPC's 2015 IRP at Attachment N-4, Appendix C – Technical Report, pages 10 through 28. The expected-case (or 50th percentile) load forecast is shown on pages 11 through 19 of the Technical Report. The expected-case load forecast is based on median forecast data. The load forecast values for IPC's planning cases are shown on pages 20 through 28 of the Technical Report. The planning case load forecast is based on 70th percentile average energy and 95th percentile peak forecast data. IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers and system losses. Reserve or planning margins deserve special discussion. IPC does not explicitly include a planning margin in its IRP; instead, IPC uses 70th percentile planning criteria as discussed on pages 131 and 132 of IPC's 2015 IRP:

> *Idaho Power discussed planning criteria with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.*
>
> *As part of preparing the 2015 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected-case (50th-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case (50th-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.*

IPC maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to IPC's share of two units at the Jim Bridger coal facility or the loss of Langley Gulch. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows IPC to import energy during an emergency via the Northwest Power Pool. A 330-MW reserve margin is also roughly equivalent to a Loss of Load

Expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.6 of the 2015 IRP (Attachment N-4). The 95th percentile means that 95 percent of the time, the peak load is expected to be less than the peak load value used for planning, and five percent of the time the peak load is expected to be greater than the peak load value used in the planning analysis. The 95th percentile peak load distribution is based on observations of the IPC peak load and the historical probability distribution of the peak load. The 95th percentile calculations for peak load mean that the peak load has approximately a 5 percent probability of occurrence.

IPC has calculated the capacity planning margin resulting from the resource planning process. The capacity planning margin calculations are for the month of July, the month of IPC's peak load. The capacity planning margin calculations are shown on pages 133 and 134 of IPC's 2015 IRP.

#### *3.3.2.3 Reductions in Firm Capacity Demand and Firm Annual Electricity Sales*

> OAR 345-021-0010(1)(n)(F)(ii): . . . In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from: (I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility; (II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010; (III) Conservation that results from responses to price; and (IV) Retail customer fuel choice;

The forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from the factors set forth in OAR 345-021-0010(1)(n)(F)(ii)(I)-(IV).

First, IPC's forecast reflects "Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(I). IPC's forecasting process integrates conservation through the Statistically Adjusted End-use (SAE) methodology.[19] This approach incorporates the most recent codes and standards of the U.S. Department of Energy (DOE) National Energy Modeling System. The regionally based data are conformed to the IPC service territory data through incorporating building characteristics and equipment installation shares associated with the territory. The intensity of the conservation is developed through product efficiency and equipment shipment data into the region from manufacturers and suppliers.

In addition, large industrial and irrigation customer code-related conservation is typically tied to large process/operational investments that integrate IPC efficiency engineering as part of the process. The conservation reductions are recognized by virtue of integrating the results from the engineering measurement and validation process for codifying energy savings (both code-impacted and utility-incentivized installations) and are discussed in the following paragraphs responding to OAR 345-021-0010(1)(n)(F)(ii)(II).

Second, IPC's forecast reflects "Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(II). Conservation programs provided by energy suppliers are integrated into the SAE conservation curve. To ensure IPC is capturing internal conservation program acquisition, individual utility energy reports of conservation acquisition to DOE for the region are compared to IPC acquisition to

[19] The SAE model is designed for developing long-term energy and demand forecasts and entails integrating end-use information into an econometric modeling framework. It is designed to explicitly capture the impact of end-use saturation and efficiency trends as well as economic conditions on long-term residential and commercial energy demand. SAE models can also be used for developing long-term peak demand forecasts.

validate assumptions used in the regional model. IPC adjusts model output for deviations of IPC program savings from the DOE model.

Large industrial and irrigation customer conservation is modeled by utilizing survey data from individual customers and directly subtracting it from the forecast output. For aggregated sector forecasts, IPC analyzes historical conservation data for marginal impact (rate of change) and compares this to future conservation to establish trend reductions of forecast model output. Implied trends of improvement in industrial and irrigation equipment are integrated into the utility conservation forecasts applied to the total energy forecasts. As part of the internal forecasting methodology monitoring and evaluation process, IPC evaluates analytical methods for explicitly segregating code impacts that are presently captured in aggregated fashion for these sectors.

Third, IPC's forecast reflects "Conservation that results from responses to price" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(III). Price impacts on energy sales are captured in the regression models for each sector as an independent variable. IPC utilizes the most recent IRP preferred-portfolio rate impact in developing the price variable.

Fourth, IPC's forecast reflects "Retail customer fuel choice" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(IV). For SAE-based models, fuel switching is integrated via the consumption and equipment stock manufacturer shipments data from DOE. For example, these data capture usage of electric versus gas space heating appliances and fuel price differentials to capture the impacts of fuel choice dynamics on the forecast.

### *3.3.3 Firm Resources to be Used to Meet Demands*

> OAR 345-021-0010(1)(n)(F)(iii): Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately.

As discussed in Section 3.3.1, the load-resource balance tables for the area to be served by the Project are included in IPC's 2015 IRP, Appendix C – Technical Report, at pages 29 through 70 (Attachment N-4). The monthly sales and load forecast data are reported on pages 29 through 48, and the monthly peak hour load-resource balance values are reported on pages 50 through 70 (summary chart provided on page 70). The load-resource balance tables provide a forecast of IPC's existing and committed firm resources used to meet its forecast demands. IPC has included its existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. IPC has listed each resource separately.

### *3.3.4 Retirement or Displacement of Resources*

> OAR 345-021-0010(1)(n)(F)(iv): A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements.

Of the IPC resources included in the load-resource tables in IPC's 2015 IRP (Attachment N-4, Appendix C), two reflect an expected early retirement or displacement. IPC is a 10 percent owner of the Boardman coal plant, which typically provides IPC with 55 average megawatts

(aMW)[20] of generation per year. This facility is expected to cease coal-fired operations in 2020 in compliance with an Oregon Environmental Quality Commission plan approved in December 2010. IPC is a 50 percent owner of the North Valmy coal plant, which typically provides IPC with 262 aMW of generation per year. The preferred resource portfolio in the 2015 IRP contemplates ceasing coal-fired operations for Valmy Units 1 and 2 in 2025.

### *3.3.5 Assumed Annual Capacity Factors*

OAR 345-021-0010(1)(n)(F)(v): A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii).

The assumed annual capacity factors for IPC generation resources by resource type are set forth in the tables in Attachment N-9. The annual capacity factor calculations are based on the average annual forecasted MW for hydro, coal, and gas facilities in IPC's 2015 IRP (see Attachment N-4, Appendix C – Technical Report, Monthly Average Energy Load and Resource Balance, pages 29 through 48, and Hydro Modeling Results [PDR580], pages 135 through 164). For informational purposes, the capacity factors of IPC's hydroelectric resources are presented under 50th percentile, 70th percentile, and 90th percentile water assumptions. IPC's 2015 IRP assumes a 70th percentile water condition for energy-based resource adequacy assessments, and 90th percentile water condition for peak-hour resource adequacy assessments.

### *3.3.6 Reliability Criteria Demonstrating Need for the Project*

OAR 345-021-0010(1)(n)(F)(vi): A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility.

The Project is needed for IPC to satisfy reliability criteria enforced by NERC and WECC. These standards require IPC to: (a) reliably serve customer demand; (b) operate the system within facility limits; (c) maintain voltage through reactive power control; and (d) maintain contingency reserves—i.e., operate the system such that the most severe single contingency does not result in loss of load or instability.

NERC Transmission Planning (TPL) standards provide the criteria for reliably serving future load and system performance under normal and outage conditions. These standards require that system facilities operate within NERC accepted operating limits for a wide range of system conditions, including loss of generator units and transmission facilities. The Project has been evaluated annually as part of NERC TPL compliance requirements. With the Project modeled in-service, IPC has demonstrated through assessments that IPC can meet NERC TPL criteria for the planning horizon.

As part of the WECC Project Coordination, Path Rating and Progress Report Process, IPC organized a regional project review group composed of western utility representatives to study the addition of the Project to the western grid. Through the WECC Rating Process, the Project was determined to meet regional performance criteria.

NERC Transmission Operations Standards require that transmission schedules across WECC transmission paths do not exceed system operating limits. Currently, IPC's intertie lines are constrained with little or no available transmission capacity (ATC). In the past, IPC has needed to utilize nearly 100 percent of ATC to purchase resources from the Northwest in order to serve

[20] An "average megawatt" or "aMW" is defined as one megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8760 hours/year = 8,760 MWh = 8,760,000 kilowatt-hour (kWh).

load while maintaining necessary contingency reserves and capacity margins. Because IPC maintains contingency reserves on the Idaho–Northwest intertie transmission lines, without ATC, serving load with transmission reserves could put IPC's native load at risk if the most severe single contingency were to occur. The Project will increase IPC's transmission import capability and will allow IPC to maintain a margin between actual flow and facility limits.

Heavily loaded transmission lines consume large amounts of reactive power. In order to prevent voltage collapse and regional blackouts, IPC maintains reactive power margin at critical locations on the IPC system. Certain outages on the IPC system have historically driven reactive margins near the margin limits. The Project's transmission connectivity to the Northwest will reduce previously heavily loaded transmission lines and greatly increase the reactive margin across the IPC system, making it even more unlikely that a system event could lead to voltage collapse.

IPC utilizes reactive power/voltage stability adequacy criteria contained in WECC Standard *TPL-001-WECC-RBP-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events*. IPC has demonstrated through its Ten-Year Transmission Reliability Assessments that the future transmission system, with the addition of Project, provides sufficient reactive power resources to ensure system performance as defined in TPL-001-WECC-RB2.

IPC's 2015 IRP analysis also supports the need for the Project for reliability purposes, demonstrating that the resource adequacy and reliability margins requirements will be met with the Project. LOLE analysis is conducted as part of the IRP (refer to pages 139-140 in Attachment N-4). IPC used a spreadsheet model to calculate the LOLE for the resource portfolios identified in the 2015 IRP. The analysis in IPC's 2015 IRP concludes that the Project provides the requisite LOLE performance and thus sufficient resource adequacy for IPC's projected customer demands.

### *3.3.7 The Project is an Economically Reasonable Alternative*

> OAR 345-021-0010(1)(n)(F)(vii): A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. . . .

The preferred portfolio in the 2009, 2011, 2013, and 2015 IRPs (Attachments N-1, N-2, N-3, and N-4), which includes the Project, represents the portfolio of resources with the best combination of expected costs and associated risks and uncertainties to meet IPC's growing load and to maintain its system in a safe, reliable, and economic manner. The Project portfolio was selected on the basis of, among other things, extensive cost analysis, considering the discounted sum of all monetary costs as described in OAR 345-001-0010(16) (providing the definition of "direct cost").

Chapter 8 of the 2015 IRP describes the 23 portfolios considered (see Attachment N-4). The total cost for each portfolio is shown in Chapter 9 and Table 9.3 on page 117 of the 2015 IRP. Financial assumptions for the 2015 IRP portfolio cost analysis are provided in table form in IPC's 2015 IRP, Attachment N-4, Appendix C – Technical Report. An overview of the IRP methodology for evaluating resource portfolios is provided in Chapter 1 of this document. The results of the expected-case portfolio analysis are presented in Table N-1 below.

## Table N-1. Expected-Case Total Portfolio Cost (2015-2034)

| Portfolio | | | | Variable Costs | Fixed Costs | Summary | |
|---|---|---|---|---|---|---|---|
| Portfolio Index | Portfolio Description | B2H | Coal Capacity Retirement | Operating (AURORA) | Total Fixed Costs | Total Fixed + Variable Costs | Lowest Cost Rank |
| P1 | Status quo w/B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions) | ✓ | | $4,306,018 | $110,689 | $4,416,707 | 1 |
| P9* | Valmy19_25 w/DR, recips, B2H_25, SCCT | ✓ | ✓ | $4,489,655 | $30,933 | $4,520,588 | 2 |
| P11* | Bridger23_32 w/ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,418,783 | $130,594 | $4,549,377 | 3 |
| P2(a)* | B2H_25, recips, (no coal capacity retirement) | ✓ | | $4,461,356 | $110,689 | $4,572,046 | 4 |
| P8* | Valmy19_25 w/ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,445,028 | $129,423 | $4,574,450 | 5 |
| P10* | Bridger23_32 w/SCCT, B2H_25, CCCT | ✓ | ✓ | $4,505,955 | $75,219 | $4,581,175 | 6 |
| P2(b) | B2H_23, recips, (no coal capacity retirement) | ✓ | | $4,456,215 | $136,570 | $4,592,785 | 7 |
| P6(b)* | Valmy25_25 w/B2H_25, DR, ice TES, CCCT | ✓ | ✓ | $4,492,228 | $102,944 | $4,595,171 | 8 |
| P6 | Valmy25_25 w/B2H_25, CCCT | ✓ | ✓ | $4,492,934 | $111,303 | $4,604,237 | 9 |
| P13* | Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,507,342 | $100,935 | $4,608,277 | 10 |
| P2(c) | B2H_21, recips, (no coal capacity retirement) | ✓ | | $4,452,737 | $164,124 | $4,616,861 | 11 |
| P3* | Valmy19_19 w/ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,311,661 | $309,467 | $4,621,128 | 12 |
| P12 | Bridger23_28 w/SCCT, B2H_25, CCCT | ✓ | ✓ | $4,541,071 | $100,730 | $4,641,800 | 13 |
| P18* | Valmy 21_25 w/res PV, B2H_25, CHP, geotherm, hydro, recips | ✓ | ✓ | $4,464,898 | $179,429 | $4,644,327 | 14 |
| P4(c) | Valmy19_19 w/battery, recips, B2H_21 | ✓ | ✓ | $4,539,309 | $105,904 | $4,645,213 | 15 |
| P4(b) | Valmy19_19 w/battery, recips, B2H_23 | ✓ | ✓ | $4,528,608 | $180,442 | $4,709,050 | 16 |
| P4(a) | Valmy19_19 w/battery, recips, B2H_25 | ✓ | ✓ | $4,521,759 | $188,424 | $4,710,183 | 17 |
| P17* | Bridger23_32 w/ice TES, PV, CHP, recips, geothermal, CCCT, SCCT | | ✓ | $4,380,138 | $332,652 | $4,712,790 | 18 |
| P16* | Valmy19_25 w/DR, recips, CCCT, SCCT | | ✓ | $4,518,985 | $197,652 | $4,716,637 | 19 |
| P14 | Ice TES, recips, CCCT, SCCT, (no coal capacity retirement) | | | $4,477,547 | $263,236 | $4,740,783 | 20 |

| Portfolio | | | | Variable Costs | Fixed Costs | Summary | |
|---|---|---|---|---|---|---|---|
| **Portfolio Index** | **Portfolio Description** | **B2H** | **Coal Capacity Retirement** | **Operating (AURORA)** | **Total Fixed Costs** | **Total Fixed + Variable Costs** | **Lowest Cost Rank** |
| P5 | Valmy19_19 w/CCCT, B2H_25 | ✓ | ✓ | $4,482,891 | $281,412 | $4,764,303 | 21 |
| P15 | Valmy19_19 w/battery, recips, SCCT, CCCT | | ✓ | $4,493,671 | $311,829 | $4,805,500 | 22 |
| P7 | Valmy25_25 w/B2H_25, pumped storage | ✓ | ✓ | $4,509,228 | $487,899 | $4,997,127 | 23 |

Source: IPC 2015 IRP (Attachment N-4)
aMW – average megawatt; B2H – Boardman to Hemingway Transmission Line Project; CAA – Clean Air Act; CHP – combined heat and power; CCCT – combined-cycle combustion turbine; MW – megawatt; PV – photovoltaic; SCCT – simple-cycle combustion turbine; TES – thermal energy storage

### *3.3.8 Required Alternatives Evaluated*

> OAR 345-021-0010(1)(n)(F)(vii): . . . The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to: (I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility. (II) Construction and operation of electric generating facilities as a substitute for the proposed facility. (III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility. (IV) Adding standard sized smaller or larger transmission line capacity.

First, IPC's economic analysis of alternatives included evaluation of "Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(I). In the IRP process, IPC has committed to implementing all cost-effective, demand-side management measures prior to considering supply-side alternatives, including the Project. Further description of the analyses and assumptions associated with demand-side measures is included in Attachment N-4, Chapter 4 of the 2015 IRP and Attachment N-4, Appendix B – Demand-Side Management Annual Report.

Second, IPC evaluated "Construction and operation of electric generating facilities as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(II). The portfolios considered in the 2015 IRP include a variety of generation resources. Based on the IRP analysis, portfolios containing these resources were expected to result in higher direct costs (as defined by OAR 345-001-0010(16)) than the Project preferred portfolio.

Third, IPC evaluated "Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(III). Natural gas, solar, and geothermal resources were included in four alternative portfolios considered for the 2015 IRP. As an example, portfolio 14 contains 548 MW of combined-cycle combustion turbine resources, ice-based thermal energy storage, and single-cycle combustion turbine resources. The IRP cost analysis indicated that the costs associated with this alternative portfolio were expected to be greater than those for the Project preferred portfolio.

Fourth, IPC evaluated "Adding standard sized smaller or larger transmission line capacity," as required by OAR 345-021-0010(1)(n)(F)(vii)(IV). A number of factors impact the transfer

capability of transmission lines, including distance, source/sink capabilities, relative location in the bulk electric system, etc. IPC's analysis assumed a 300-mile line between a station in the Northwest and the Hemingway station in southwestern Idaho. Table N-2 contains a summary of relative capacities, anticipated ratings, and losses. Only the scenarios including 500-kilovolt (kV) line capacity or greater are capable of providing the service capacity needed, including existing transmission service requests. The 2011 IRP (Attachment N-2) analysis demonstrates the cost-effectiveness of the 500-kV single circuit design, as opposed to those with lesser or greater capacity.

**Table N-2. Comparison of Transmission Line Capacity Scenarios**

| Scenario | Line Capacity[1] | Potential Rating[2] | Losses[3] |
|---|---|---|---|
| a. 230-kV single circuit | 956 MW | 538 MW | 3.7% |
| b. 230-kV double circuit | 2,199 MW | 866 MW | 2.4% |
| c. 500-kV single circuit | 3,585 MW | 1,300 MW | 1.3% |
| d. 500-kV – two separate lines | 7,170 MW | 2,600 MW | 1.3% |
| e. 500-kV double circuit | 7,170 MW | 1,300 MW | 1.3% |
| f. 765-kV single circuit | 4,770 MW | 1,300 MW | 0.5% |

Source: IPC 2011 IRP (Attachment N-2)

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies which were to be initiated in 2009.

[3] Estimated Losses are percent losses at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

### *3.3.9 Earliest and Latest Expected In-Service Dates*

> OAR 345-021-0010(1)(n)(F)(viii): The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.

IPC's 2015 IRP (Attachment N-4) evaluated an in-service date range of 2021 to 2025 for the Project. Current estimates based on IPC's updated assessment of siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions and factors conclude the Project is not expected to be in-service any earlier than 2021.

## 4.0 CONCLUSION

Exhibit N includes the application information provided for in OAR 345-021-0010(1)(n). Additionally, the evidence provided in Exhibit N demonstrates the need for the Project under both the least-cost plan rule (OAR 345-023-0020) and the system reliability rule for transmission lines (OAR 345-023-0030).

## 5.0 COMPLIANCE CROSS-REFERENCES

Table N-3 identifies the location within the application for site certificate of the information responsive to the need standard for non-generating facilities, OAR 345-0023-0005, the

application submittal requirements in OAR 345-021-0000(8) and OAR 345-021-0010(n), and the relevant Amended Project Order provisions.

**Table N-3. Compliance Requirements and Relevant Cross-References**

| Requirement | Location |
|---|---|
| **OAR 345-023-0005** | |
| This division applies to nongenerating facilities as defined in ORS 469.503(2)(e), except nongenerating facilities that are related or supporting facilities. To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility. The Council may adopt need standards for other nongenerating facilities. This division describes the methods the applicant shall use to demonstrate need. In accordance with ORS 469.501(1)(L), the Council has no standard requiring a showing of need or cost-effectiveness for generating facilities. The applicant shall demonstrate need:<br>(1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act; | Exhibit N, Section 3.2 and Section 3.3 |
| **OAR 345-023-0020(1)** | |
| (1) The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans . . . .<br>(2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan. | Exhibit N, Section 3.2 Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4 |
| **OAR 345-023-0030** | |
| The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that:<br>(1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility;<br>(2) The facility is consistent with the applicable mandatory and enforceable North American Reliability Corporation (NERC) Reliability Standards in effect as of September 18, 2015 as they apply either internally or externally to a utility system; and<br>(3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate. | Exhibit N, Section 3.3 |

| Requirement | Location |
|---|---|
| **OAR 345-021-0000(8)** | |
| If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, in addition to the application for a site certificate described in OAR 345-021-0010, the applicant shall submit to the Department three copies of each energy resource plan or combination of plans on which the applicant relies to demonstrate need under 345-023-0020, unless the applicant chooses to incorporate copies of the plan(s) as part of the application for a site certificate. The applicant shall submit the plan(s) to the Department with the site certificate application. The Department may not find the site certificate application to be complete before receiving copies of the plan(s). The plan or plans described in this section are part of the decision record for the Department's proposed order, described in 345-015-0230. | Exhibit N, Section 3.2, Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4 |
| **OAR 345-021-0010(1)(n)** | |
| Exhibit N. If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, information about the need for the facility, providing evidence to support a finding by the Council as required by OAR 345-023-0005, including: | |
| (A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need; | Exhibit N, Section 3.1 |
| (B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule: | Exhibit N, Section 3.2.1 |
| (i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need; | Exhibit N, Section 3.2.2.1, Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4 |
| (ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i); | Exhibit N, Section 3.2.2.2 |
| (iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including: | Exhibit N, Section 3.2.2.3 |
| (I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or | Exhibit N, Section 3.2.2.3 |
| (II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record; | Not Applicable |
| (iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility; and | Exhibit N, Section 3.2.2.3 |

| Requirement | Location |
|---|---|
| (v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s); | Exhibit N, Section 3.2.2.3 |
| (C) In addition to the information described in paragraph (B), if the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon . . . . | Not Applicable |
| (D) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed natural gas pipeline or storage facility for liquefied natural gas under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (G) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (G), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information; | Not Applicable |
| (E) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0020(1), the least-cost plan rule and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (F) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (F), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information; | Not Applicable |
| (F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule: | Exhibit N, Section 3.3 |
| (i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility. | Exhibit N, Section 3.3.2.1 and Attachment N-4 |

| Requirement | Location |
|---|---|
| (ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from: | Exhibit N, Section 3.3.2.2 and Attachment N-4 |
| (I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility; | Exhibit N, Section 3.3.2.3 |
| (II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010; | Exhibit N, Section 3.3.2.3 |
| (III) Conservation that results from responses to price; and | Exhibit N, Section 3.3.2.3 |
| (IV) Retail customer fuel choice; | Exhibit N, Section 3.3.2.3 |
| (iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately; | Exhibit N, Section 3.3.3 and Attachment N-4 |
| (iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements; | Exhibit N, Section 3.3.4 |
| (v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii); | Exhibit N, Section 3.3.5 and Attachment N-9 |
| (vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility; and | Exhibit N, Section 3.3.6, Attachment N-1, and Attachment N-2 |
| (vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to: | Exhibit N, Section 3.3.7 and Table N-1 |
| (I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility; | Exhibit N, Section 3.3.8 |
| (II) Construction and operation of electric generating facilities as a substitute for the proposed facility; | Exhibit N, Section 3.3.8 |

| Requirement | Location |
|---|---|
| (III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility; and | Exhibit N, Section 3.3.8 |
| (IV) Adding standard sized smaller or larger transmission line capacity; | Exhibit N, Section 3.3.8, Table N-2 |
| (viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates; and | Exhibit N, Section 3.3.9 |
| (G) If the applicant chooses to demonstrate need for a proposed natural gas pipeline or a proposed facility for storing liquefied natural gas under OAR 345-023-0040, the economically reasonable rule: . . . | Not Applicable |
| **Amended Project Order, Section III(n)** | |
| The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a "National Interest Electric Transmission Corridor" designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23. | Exhibit N, Section 3.2 and Section 3.3 |

# ATTACHMENT N-1
# IDAHO POWER COMPANY'S 2009 INTEGRATED RESOURCE PLAN (DOCKET LC 50)



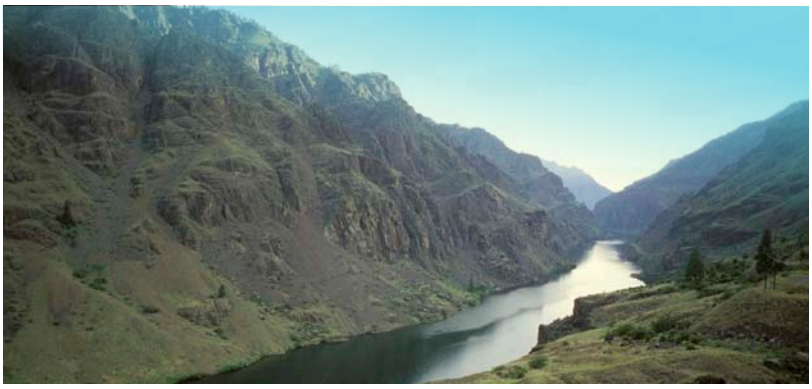
# *2009 Integrated Resource Plan*

December 2009

IDAHO POWER®
An IDACORP Company

# 2009 Integrated Resource Plan

December 2009



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## Acknowledgement

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power prepares and publishes a resource plan every two years and expects the experience gained over the next few years will lead to modifications in the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2009 Integrated Resource Plan* (IRP). Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council, and the comments provided by other concerned citizens and customers.

In recognition of the amount of time and effort expended by the IRP Advisory Council, members discussed the possibility of including a statement in the IRP indicating the advisory council's support of the IRP. Because the advisory council represents such a diverse set of stakeholders, the members determined it would not be possible for the group to unanimously support all aspects of the IRP. However, the members were supportive of the public process and asked Idaho Power to include the following statement in the 2009 IRP: "The members of the IRP Advisory Council support the public process Idaho Power Company conducted as part of preparing the 2009 IRP."

Idaho Power looks forward to continuing the resource planning process with its customers and other interested parties. You can learn more about Idaho Power's resource planning process at www.idahopower.com.

**Safe Harbor Statement**

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

# TABLE OF CONTENTS

List of Tables ..... v
List of Figures ..... vi
List of Appendices ..... vii
Glossary of Abbreviations ..... viii
1. Summary ..... 1
Introduction ..... 1
Public Advisory Process ..... 2
IRP Methodology ..... 3
Demand-Side Management ..... 3
Supply-Side Resource Costs ..... 4
Risk Management ..... 4
Greenhouse Gas Emissions ..... 5
Preferred Resource Portfolio ..... 6
Near-Term Action Plan ..... 7
Public Policy Issues ..... 8
New Large Loads ..... 8
Asset Ownership ..... 8
Renewable Energy Credits ..... 8
Emission Offsets ..... 9
Technology Risk and Joint Development Opportunities ..... 9
Solar Pilot Project ..... 9
2. Political, Regulatory, Operational, and Technology Issues ..... 11
Political and Regulatory Issues ..... 11
Idaho Energy Plan ..... 11
Idaho Strategic Energy Alliance ..... 12
Idaho State Legislature—Senate Bill 1123 ..... 12
Oregon Renewable Portfolio Standard ..... 12
Proposed Federal Energy Legislation ..... 13
Renewable Energy Credits (Green Tags) ..... 14
FERC Relicensing ..... 15
Idaho Water Issues ..... 16
Fixed Cost Adjustment ..... 17

Operational and Technology Issues ..... 18
Wind Integration ..... 18
Clean Coal Technologies ..... 19
Storage Technologies ..... 20
3. Idaho Power Today ..... 23
Customer and Load Growth ..... 23
Existing and Committed Resources ..... 25
2008 Energy Sources ..... 25
Existing Supply-Side Resources ..... 26
Committed Supply-Side Resources ..... 36
4. Demand-Side Management ..... 41
DSM Potential Study ..... 41
Residential Efficiency Potential ..... 42
Commercial Efficiency Potential ..... 42
Industrial Efficiency Potential ..... 42
Irrigation Efficiency Potential ..... 43
Appliance Standard Assessment ..... 43
Demand-Side Management Analysis ..... 44
Energy Efficiency Cost Effectiveness ..... 44
Demand Response Cost Effectiveness ..... 45
Energy Efficiency Programs ..... 45
Residential Program Planning ..... 46
Commercial Program Planning ..... 46
Demand Response Resources ..... 47
5. Planning Period Forecasts ..... 49
Load Forecast ..... 49
Weather Impacts ..... 50
Economic Impacts ..... 50
Peak-Hour Load Forecast ..... 52
Average-Energy Load Forecast ..... 53
Additional Firm Load ..... 55
Planning Scenarios ..... 56
Existing Resources ..... 56
Hydro ..... 57

Thermal ..... 59
Transmission Resources ..... 60
Natural Gas Price Forecast ..... 60
Cost of Carbon Emissions ..... 62
6. Supply-Side Resources ..... 63
Renewable Resources ..... 63
Geothermal ..... 63
Wind ..... 64
Hydro ..... 64
Solar ..... 65
Biomass ..... 66
River In-stream Generation ..... 66
Natural Gas-Fired Resources ..... 67
Combined-Cycle Combustion Turbines ..... 67
Simple-Cycle Combustion Turbines ..... 67
Conventional Coal Resources ..... 68
Advanced Nuclear ..... 69
Resource Advantages and Disadvantages ..... 69
Resource Cost Analysis ..... 69
Emission Adders for Fossil Fuel-Based Resources ..... 72
Production Tax Credits for Renewable Generating Resources ..... 72
Levelized Capacity (Fixed) Cost ..... 72
Levelized Cost of Production ..... 73
7. Transmission Resources ..... 77
Transmission Interconnections ..... 77
Brownlee-East Path ..... 80
Oxbow-North Path ..... 80
Northwest Path ..... 80
Montana Path ..... 80
Transmission Planning ..... 81
Transmission Adequacy ..... 81
Northern Tier Transmission Group ..... 81
Proposed Transmission Projects ..... 82
Boardman to Hemingway ..... 83

Gateway West ....85
8. Planning Criteria and Portfolio Selection ....87
Planning Scenarios and Criteria ....87
Load and Resource Balance ....87
Average Monthly Energy Planning ....88
Peak-Hour Planning ....89
Portfolio Design and Selection ....91
9. Modeling Approach and Assumptions ....95
AURORA Setup Enhancements ....96
Carbon Modeling Approach ....96
Renewable Energy Credits ....97
Transmission and Market Purchases ....98
Regional Transmission Planning (from the NTTG Plan) ....99
Market Purchase Assumptions ....100
Economic Evaluation Components and Assumptions ....101
10. Modeling Results and Risk Analysis ....103
Portfolio Modeling Results ....103
Risk Analysis and Results ....105
Quantitative Risk Analysis ....105
Qualitative Risk Analysis ....111
Preferred Portfolio Selection ....114
2010–2019 (Portfolio 1-4 Boardman to Hemingway) ....114
2020–2029 (Portfolio 2-4 Wind and Peakers) ....114
Developing Alternate Portfolios ....115
Capacity Planning Margin ....118
Loss of Load Expectation ....119
11. Action Plan ....123
Near-Term Action Plan ....123
Long-Term Action Plan ....123
Conclusion ....125

# LIST OF TABLES

Table 1.1 Preferred Portfolio ....6
Table 1.2 Near-Term Action Plan Milestones ....7
Table 2.1 Phase I Measures....16
Table 3.1 Historical Capacity, Load, and Customer Data ....24
Table 3.2 Electricity Delivered to Customers (2008) ....26
Table 3.3 Existing Resources....27
Table 4.1 Analyzed Appliances and Code Implementation Status....43
Table 4.2 Appliance Standard Potential Savings—Idaho Statewide ....44
Table 4.3 New Energy Efficiency Cost Effectiveness Summary ....45
Table 4.4 Demand Response Cost-Effectiveness Summary....45
Table 5.1 Load Forecast—Peak-Hour (MW) ....53
Table 5.2 Load Forecast—Average Monthly Energy (aMW) ....54
Table 5.3 Planning Criteria for Average Load and Peak-Hour Load ....56
Table 6.1 Supply-Side Resources Advantages and Disadvantages ....70
Table 6.2 Emissions Adder Assumptions ....72
Table 6.3 Emission Adders (lbs/MWh) ....72
Table 7.1 Transmission Interconnections ....78
Table 9.1 Financial Assumptions....102
Table 10.1 AURORA Results and Capital Costs Used in Portfolio Evaluation (2010–2019) ....103
Table 10.2 AURORA Results and Capital Costs Used in Portfolio Evaluation (2020–2029) ....104
Table 10.3 Market Purchases and Sales Summary (2010–2019)....113
Table 10.4 Market Purchases and Sales Summary (2020–2029)....113
Table 10.5 Preferred and Alternate Portfolios (2010–2019)....116
Table 10.6 Preferred and Alternate Portfolios (2020–2029)....116
Table 10.7 Carbon Legislation Costs (2010–2019) ....117
Table 10.8 Carbon Legislation Costs (2020–2029) ....117
Table 10.9 Capacity Planning Margin (2010–2019)....120
Table 10.10 Capacity Planning Margin (2020–2029)....121
Table 11.1 Near-Term Action Plan....123
Table 11.2 Long-Term Action Plan ....124
Table 11.3 Alternate Portfolio Near-Term Action Plan....124

# LIST OF FIGURES

Figure 1.1 Cost of Existing and New Supply-Side Resources ....4
Figure 3.1 Historical Capacity, Load, and Customer Data ....24
Figure 3.2 2008 Energy Sources ....26
Figure 3.3 2008 Long-Term Power Purchases by Resource Type ....26
Figure 5.1 Peak-Hour Load Growth Forecast ....52
Figure 5.2 Average Monthly Load Growth Forecast ....54
Figure 5.3 Brownlee Historical and Forecast Inflows ....58
Figure 5.4 Fuel Price Forecast ....61
Figure 6.1 30-Year Levelized Capacity (Fixed) Costs ....74
Figure 6.2 30-Year Levelized Cost of Production (at Stated Capacity Factors) ....75
Figure 7.2 Boardman to Hemingway Line Project Map ....84
Figure 8.1 Monthly Average Energy Surpluses and Deficits with Existing Resources (70th Percentile Water and 70th Percentile Load) ....88
Figure 8.2 Monthly Average Energy Surpluses and Deficits with Existing and Committed Resources and New DSM (70th Percentile Water and 70th Percentile Load) ....88
Figure 8.3 Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources (70th Percentile Water and 70th Percentile Load) ....89
Figure 8.4 Peak-Hour Deficits with Existing Resources (90th Percentile Water and 95th Percentile Load) ....89
Figure 8.5 Peak-Hour Deficits with Existing and Committed Resources and New DSM (90th Percentile Water and 95th Percentile Load) ....90
Figure 8.6 Peak-Hour Deficits with 2009 IRP Resources (90th Percentile Water and 95th Percentile Load) ....90
Figure 8.7 Initial Resource Portfolios (2010–2019) ....91
Figure 8.8 Initial Resource Portfolios (2020–2029) ....92
Figure 9.1 Average Annual Generation from Coal Resources ....97
Figure 9.2 Waxman–Markey RES Requirements and Portfolio RECs ....98
Figure 9.3 Northern Tier Transmission Group Planned Transmission Additions ....100
Figure 10.1 REC—Forward Price Curve ....106
Figure 10.2 Natural Gas Price Forecast ....107
Figure 10.3 Boxer–Kerry Carbon Allowance Price Cap and High Case Scenario ....108
Figure 10.4 Average Monthly Load Growth Forecast ....109
Figure 10.5 Cumulative Portfolio Risk (2010–2019) ....110
Figure 10.6 Cumulative Portfolio Risk (2020–2029) ....111

Figure 10.7 2019 Supply-Side Resources ..... 115
Figure 10.8 2029 Supply-Side Resources ..... 115
Figure 10.9 Carbon Allowance Cost and Portfolio Costs ..... 118
Figure 10.10 Loss of Load Expectation ..... 119

## LIST OF APPENDICES

Appendix A–Sales and Load Forecast
Appendix B–Demand-Side Management 2008 Annual Report
Appendix C–Technical Appendix

# GLOSSARY OF ABBREVIATIONS

AC–Alternating Current

A/C–Air Conditioning

ADI–Ace Diversity Interchange

AFUDC–Allowance for Funds Used During Construction

AMPS–Associated Mountain Power System

aMW–Average Megawatt

B2H–Boardman to Hemingway Transmission Project

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

Btu–British Thermal Unit

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

$CO_2$–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DG–Distributed Generation

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EA–Environmental Assessment

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

EPRI–Electric Power Research Institute

ESA–Endangered Species Act

ESPA–Eastern Snake River Plain Aquifer

F–Fahrenheit

FCA–Fixed-Cost Adjustment

FCP–Formal Consultation Package

FCRPS–Federal Columbia River Power System

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

GHG–Greenhouse Gas

GW–Gigawatt

HRSG–Heat Recovery Steam Generator

ICIP–Industrial Customers of Idaho Power

IDWR–Idaho Department of Water Resources

IGCC–Integrated Gasification Combined Cycle

INL–Idaho National Laboratory

IOER–Idaho Office of Energy Resources

IPUC–Idaho Public Utilities Commission

IRP–Integrated Resource Plan

IRPAC–IRP Advisory Council

kV–Kilovolt

kW–Kilowatt

kWh–Kilowatt Hour

lbs–Pounds

LED–Light-Emitting Diode

LOLE–Loss of Load Expectation

LT–Long Term

MIT–Massachusetts Institute of Technology

mm–Millimeter

MMBTU–Million British Thermal Units

MSA– Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NiCd–Nickel Cadmium

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

NOx–Nitrogen Oxide

NOI–Notice of Intent

NPV–Net Profit Value

NREL–National Renewable Energy Laboratories

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCC–Planning Coordination Council

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PTC–Production Tax Credit

PURPA–Public Utility Regulatory Policies Act of 1978

PV–Photovoltaic

QF–Qualifying Facility

REC–Renewable Energy Credit

RES–Renewable Electricity Standard

RFP–Request for Proposal

RISEC–River In-Stream Energy Conversion

RPS–Renewable Portfolio Standard

SAR–Surrogate Avoided Resource

SCCT–Simple Cycle Combustion Turbine

SMES–Superconducting Magnetic Energy Storage

$SO_2$–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

U.S. Army COE–United States Army Corps of Engineers

USFWS–United States Fish and Wildlife Service

USFS–United States Forest Service

VRB–Vanadium Redox Battery

WACC–Weighted Average Cost of Capital

WAQC–Weatherization Assistance for Qualified Customers

WECC–Western Electricity Coordinating Council

# 1. SUMMARY

## Introduction

The *2009 Integrated Resource Plan* (IRP) is Idaho Power's ninth resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2009 IRP assumes that during the planning period (2010–2029), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and that the company will continue to operate as a vertically integrated electric utility. In developing this plan, Idaho Power has worked with the IRP Advisory Council (IRPAC), comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. There are four primary goals of Idaho Power's planning process.

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period
2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns
3. Give equal and balanced treatment to both supply-side resources and demand-side measures
4. Involve the public in the planning process in a meaningful way

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, and to construct and place in service sufficient transmission capacity to reliably deliver resources to network customers[1] and native load customers[2]. The 2009 IRP only evaluates the need for additional transmission capacity necessary to serve native load customers. The total capacity of proposed transmission line projects may be larger than identified in the IRP in order to accommodate third-party requests and network customer obligations for capacity on the same transmission path.

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC Tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

### Highlights

- The 2009 IRP load forecast projects peak-hour load will grow at an average annual rate of 53 MW (1.5 percent) and average system load will grow at 13 aMW (0.7 percent) over the 20-year planning period.
- By 2012, Idaho Power's demand response programs are expected to reduce peak–hour load by 380 MW.
- Existing and new energy efficiency programs are forecasted to reduce average annual system load by 382 aMW by 2029.

The number of customers in Idaho Power's service area is expected to increase from around 486,000 in 2008 to over 680,000 by the end of the planning period in 2029. Even with the current recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base.

With hydroelectric generation as the foundation of its energy production, Idaho Power has an obligation to serve customer loads regardless of the water conditions that may occur. In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, Idaho Power will continue to emphasize a resource plan based upon a worse-than-median level of water. The IRP uses more conservative planning criteria than median water planning, but the criteria are less conservative than critical water planning. Further discussion of Idaho Power's planning criteria can be found in Chapter 8.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Prior Idaho Power IRPs used a 10-year planning horizon, but with the increased need for baseload resources with long construction lead times along with the need for a 20-year resource plan to support Public Utilities Regulatory Policies Act (PURPA) contract negotiations, Idaho Power and the IRPAC decided to extend the planning horizon of the 2006 and future resource plans to 20 years.

Planning for the future is necessary to meet the needs of Idaho Power's customers today and tomorrow. While the 2009 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term through the *Energy Risk Management Policy* that was collaboratively developed in 2002 between Idaho Power, the IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). While the IRP has a planning horizon of 20 years and is updated every two years, the *Energy Risk Management Policy* focuses on an 18-month period and is updated every month.

## Public Advisory Process

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. In earlier years, the public forum was called the Technical Advisory Panel. Idaho Power revised the public involvement process and formed the IRPAC when preparing the 2004 IRP and has continued working with the council in the preparation of the 2006 and 2009 resource plans.

The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public interest groups. A list of the IRPAC members can be found in *Appendix C—Technical Appendix*. Idaho Power continued the public involvement process for the 2009 IRP and the IRPAC meetings served as an open forum for discussions related to the development of the IRP. The IRPAC members and the public have made significant contributions to the 2009 IRP.

Idaho Power has found that working with members of the IRPAC and the public has been very rewarding and the company believes the 2004, 2006, and the 2009 IRPs are better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the 2009 IRP are made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2009 IRP and the planning process in general.

Following the filing of the final plan, Idaho Power presents the IRP at public meetings in various cities around the company's service area. In addition, Idaho Power staff presents the resource plan and discusses the planning process with various civic groups and at educational seminars as requested.

## IRP Methodology

The preparation of Idaho Power's 2009 IRP begins with updating the forecast of future customer demand. Existing resources, the ability to import electricity, and the performance of existing demand-side management (DSM) programs are then accounted for in the load and resource balance. The next step involves evaluating new DSM programs and the expansion of existing programs. Idaho Power is committed to implementing all cost-effective DSM programs and the impact of the new programs is accounted for in the load and resource balance. Finally, Idaho Power evaluates portfolios of supply-side resources designed to eliminate any remaining deficits.

Idaho Power primarily uses a financial analysis to compare various resource portfolios in order to determine the preferred portfolio. Idaho Power attempts to financially value all of the resource costs and benefits. Traditional resources have both a fuel cost and a market value for the delivered energy and Idaho Power includes both the cost and the value when evaluating resources. Further, the value of renewable energy credits (REC) is also included in the financial analysis.

Each resource portfolio is designed to substantially meet the energy and capacity deficits identified in the load and resource balance. Idaho Power continues to face load and resource deficits during the next few years, but each resource portfolio meets the energy and capacity requirements after the 2013 time period.

Three resources identified in the 2006 IRP are considered committed resources in the 2009 IRP—1) the Langley Gulch combined-cycle combustion turbine (CCCT) that will be used as a dispatchable resource, 2) up to 150 megawatts (MW) of wind generation from the 2012 Wind Request for Proposals (RFP), and 3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

For the 2009 IRP, the 20-year planning period was divided into two 10-year segments. Dividing the planning period into these two segments prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years.

In the first 10-year period (2010–2019), four resource portfolios were examined. The preferred resource portfolio from the first 10-year period was coupled with a variety of portfolios containing advanced technologies in the second 10-year period. Using the preferred portfolio from the first 10-year period insures that all of the advanced technologies are considered equally in the second 10-year period. It is not necessary for Idaho Power to commit to a single advanced technology at the present time. Idaho Power anticipates discussing its preferred long-term portfolio options with other Pacific Northwest utilities over the next several years and is contemplating forming a regional partnership to further explore some of the more promising advanced technologies.

## Demand-Side Management

New energy efficiency programs included in the 2009 IRP are forecast to reduce average load by 127 aMW by 2029, which represents a 53 percent increase over the measures included in the 2006 IRP. New energy efficiency measures come from a combination of new Idaho Power programs, new measures recommended in the 2009 potential study performed by Nexant, Inc., and a review of measures included in the Northwest Power and Conservation Council's (NPCC) *Draft 6th Power Plan*.

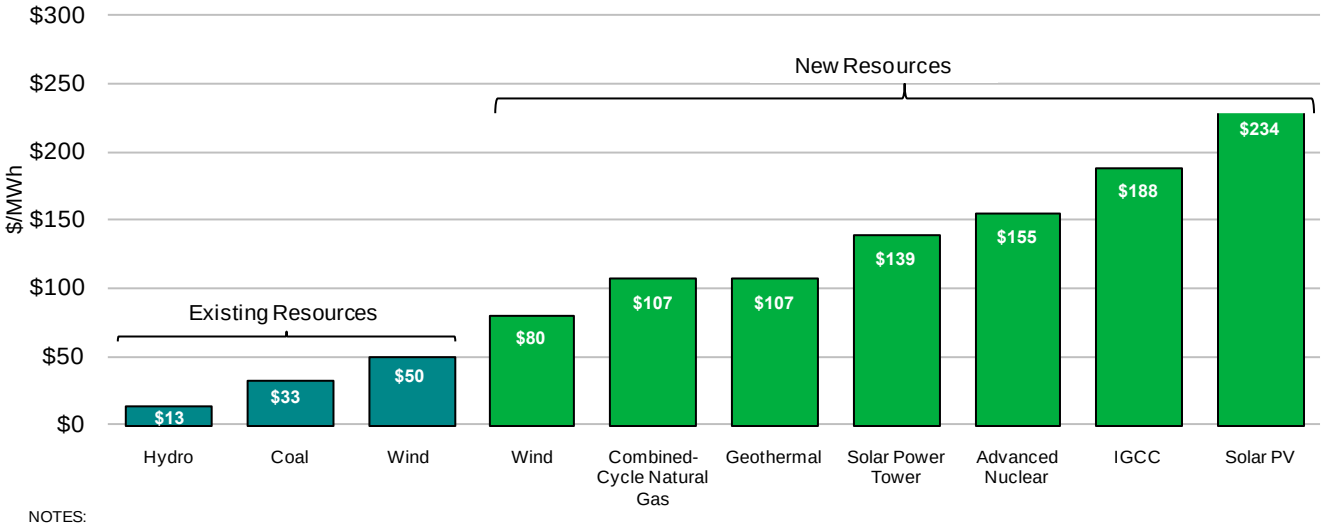
New and expanded demand response programs developed as part of the 2009 IRP are expected to reduce peak summer load by 323 MW by 2012 when the programs mature. This reflects tremendous growth over 2006 IRP forecasts where demand response programs were estimated to provide 78 MW of peak reduction by 2026. The large increase comes from the introduction of the FlexPeak Management program which targets commercial and industrial customers and also the transition of the Irrigation Peak Rewards program into a dispatchable, direct load control program.

Chapter 4 contains details on Idaho Power's existing and proposed DSM programs, and *Appendix A–Sales and Load Forecast* contains the forecast performance of energy efficiency and demand response programs by customer class.

## Supply-Side Resource Costs

The 2009 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future needs of customers. Recent cost increases have significantly impacted the cost of new supply-side resources, especially when compared to the cost of the existing resources in Idaho Power's generation portfolio. Figure 1.1 shows the 2008 costs in dollars per megawatt hour (MWh) for Idaho Power's existing hydroelectric resources, coal generation facilities, and power purchased from the Elkhorn Valley Wind Project. In addition, Figure 1.1 shows the estimated cost of new resources considered in the 2009 IRP. Existing resource costs are based on 2008 actual costs of capital, fuel, and non-fuel operating and maintenance (O&M). New resource costs are 30-year levelized estimates (based on expected annual generation), which include capital, fuel, non-fuel O&M, plus a cost of $43 per ton for carbon-emitting resources.

**Figure 1.1 Cost of Existing and New Supply-Side Resources**




NOTES:
1) Cost of existing resources based on 2008 costs
2) Cost of new resources based on 30-year levelized cost estimates
3) Cost of existing wind is for the Elkhorn Wind Project only (Elkhorn produced approximately 80 percent of the wind generation purchased by Idaho Power during 2008).

In 2008, 78 percent of Idaho Power's electricity came from existing, low-cost hydroelectric and coal resources. These resources are the primary reason Idaho Power has historically had some of the lowest retail electric rates in the country. As Idaho Power adds new resources in the future, either due to load growth or reduced generation from coal facilities, power supply expenses and customer rates are going to increase. Additional discussion regarding new resources and associated costs is presented in Chapter 6 of the 2009 IRP.

## Risk Management

Long-term resource planning requires many assumptions regarding future conditions. Forecasts for load growth, DSM program performance, fuel prices, and many other factors are required as part of the planning process. Due to the amount of uncertainty in preparing these forecasts, risk factors are evaluated in the 2009 IRP as part of determining the preferred portfolio. Risk factors are evaluated by performing sensitivity analyses on each portfolio.

The load forecast used for the 2009 IRP reflects the current economic recession as well as the potential impact of carbon regulation on future energy rates charged to Idaho Power customers. Both of these factors resulted in a load forecast substantially lower than seen in recent years. To evaluate the risk associated with higher-than-expected load growth, the 2009 IRP includes an analysis of a high load growth scenario where projected load growth continues at historical levels.

In the 2009 IRP, considerable energy efficiency measures and demand response programs are expected to reduce future load growth. In the event these programs do not develop and perform as planned, a low conservation scenario was analyzed as part of the 2009 IRP risk analysis.

Natural gas prices are highly correlated to market energy prices in the Pacific Northwest as gas resources typically represent the marginal resource in the region. Natural gas price volatility, as well as higher than forecast prices, have been analyzed in Idaho Power's previous IRPs. The natural gas price analysis is also included in the 2009 IRP.

Idaho Power believes some form of carbon regulation will be enacted in the near future. However, there is still a great deal of uncertainty on how the regulation will be implemented and what the costs will be. In the 2009 IRP, Idaho Power has attempted to quantify the impact of a carbon tax scenario as well as a cap-and-trade scenario based on the provisions contained in the Waxman–Markey bill (H.R. 2454). In addition to the Waxman–Markey bill passed by the U.S. House of Representatives in June 2009, the Boxer–Kerry bill (S. 1733) was introduced in the U.S. Senate in September 2009.

Renewable portfolio standards (RPS) have been passed by many states, including Oregon. In addition, a federal renewable electricity standard (RES) is included in the provisions of the Waxman–Markey bill. RECs, which are needed to comply with RPS (or RES) requirements, are valued according to a forward price curve developed for the 2009 IRP. Although a market for RECs has developed recently, there is uncertainty associated with the future market value of RECs and potential limitations on the quantity of RECs that may be purchased to meet state RPS requirements or a federal RES. As part of the risk analysis, the 2009 IRP analyzes a high REC price scenario and estimates the effect on each portfolio.

Idaho Power believes that maintaining a diverse resource portfolio is the best way to mitigate risk given the amount of uncertainty in the planning process. As part of this strategy and in addition to the quantitative analyses previously discussed, the 2009 IRP contains a qualitative discussion of the potential risk associated with carbon regulation, developing technologies, resourcing siting, and relying on market purchases. This discussion can be found in the Qualitative Risk Analysis section in Chapter 10.

## Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, two natural gas-fired plants, one diesel-powered generator, and shares ownership in three coal-fired facilities. Idaho Power's carbon dioxide ($CO_2$) emission levels have historically been well below the national average for the 100 largest electric utilities in the United States, both in terms of total $CO_2$ emissions (tons) and $CO_2$ emissions intensity (pounds [lbs]/MWh), based on the report of 2006 $CO_2$ emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, released May 2008 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and PG&E Corporation.

In September 2009, Idaho Power's Board of Directors approved guidelines to establish a goal to reduce the $CO_2$ emission intensity of the company's utility operations. The guidelines are intended to prepare the company for potential legislative and/or regulatory restrictions on greenhouse gas (GHG) emissions, while minimizing the cost of complying with such reductions on Idaho Power's customers.

The guidelines establish a goal to reduce Idaho Power's resource portfolio's average $CO_2$ emission intensity for the 2010 through 2013 time period to a level of 10 percent—15 percent below the company's 2005 $CO_2$ emission intensity of 1,194 lbs/MWh. Since Idaho Power's $CO_2$ emission intensity fluctuates with stream flows and the production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal, to be achieved over several years.

Generation from company-owned resources and any renewable resources under contract, for which Idaho Power has long-term rights to RECs, will be included in the denominator of the intensity calculation. The company's progress toward achieving this intensity reduction goal, as well as additional information on Idaho Power's $CO_2$ emissions, will be reported on the company's Web site at www.idahopower.com. Information related to Idaho Power's $CO_2$ emissions is also available through the Carbon Disclosure Project at www.cdproject.net.

The guidelines are intended to reduce Idaho Power's near-term $CO_2$ emission intensity levels in a manner that minimizes the costs of the reductions on the company's customers. The 2009 IRP attempts to quantify the cost and longer term impacts of carbon regulations proposed in the Waxman–Markey bill (H.R. 2454). Additional details regarding the analysis are presented in Chapter 10 of the 2009 IRP.

## Preferred Resource Portfolio

The preferred portfolio for the 2009 IRP presented in Table 1.1 was constructed by combining the preferred portfolio for the first 10 years of the planning horizon (2010–2019) with the preferred portfolio for the second 10-year period (2020-2029). In addition to the committed resources previously discussed, the preferred resource portfolio includes 250 MW of market purchases beginning in 2015 with an additional 175 MW in 2017. These purchases rely on the completion of the Boardman to Hemingway Transmission Project (Boardman to Hemingway) in 2015. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 425 MW. The first 10-year period also includes the Shoshone Falls Upgrade Project in 2015.

The preferred portfolio for the second 10-year period (2020–2029) represents a strategy of adding wind resources sufficient to provide energy and RECs along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation. The preferred portfolio also assumes the completion of the Gateway West Transmission Project (Gateway West) by 2022 in order to add the additional wind resources to the portfolio. Due to existing transmission constraints, all portfolios analyzed for the 2020–2029 timeframe assume capacity is available on the Gateway West transmission project.

**Table 1.1 Preferred Portfolio**

| 1–4 Boardman to Hemingway (2010–2019) | | | 2–4 Wind & Peakers (2020–2029) | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2012 | Wind* | 150 | 2020 | SCCT (Large Aero) | 100 |
| 2012 | CCCT (Langley Gulch)* | 300 | 2022 | Wind | 100 |
| 2012 | Geothermal* | 20 | 2024 | SCCT (Large Aero) | 200 |
| 2015 | Shoshone Falls | 49 | 2025 | Gateway West | 100 |
| 2015 | Boardman to Hemingway | 250 | 2026 | SCCT (Large Aero) | 200 |
| 2016 | Geothermal* | 20 | 2027 | Wind | 400 |
| 2017 | Boardman to Hemingway | 175 | 2028 | SCCT (Large Aero) | 400 |
| | | | 2029 | SCCT (Large Aero) | 500 |

*Committed resource

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2011 IRP and subsequent plans as more certainty regarding carbon regulation and a federal RES become available. Future uncertainty requires alternate portfolios be considered in the resource planning process. Further details regarding the preferred portfolio and the alternate portfolios can be found in Chapter 10.

## Near-Term Action Plan

Idaho Power has completed the competitive procurement process for the Langley Gulch CCCT and has nearly completed the RFP process for the 2012 wind resource. Both resources are expected to be on-line in 2012. Idaho Power anticipates expanding both the irrigation and commercial demand response programs in 2010 and 2011 to address expected growth in peak-hour loads. Idaho Power anticipates beginning construction of the Shoshone Falls Upgrade Project in 2012 with the project being completed by 2015. Idaho Power is also continuing to work with federal and state agencies, FERC, other transmission providers, and the public on the Boardman to Hemingway and Gateway West transmission projects. Major milestones associated with these resources and programs are presented in Table 1.2.

**Table 1.2 Near-Term Action Plan Milestones**

| Year | Action |
|---|---|
| 2010 | Present and gain acceptance of 2009 IRP with regulatory commissions |
| | File wind contract resulting from the 2012 Wind RFP with the IPUC |
| | File geothermal contract with the IPUC (approximately 20 MW) |
| | Irrigation Peak Rewards program increases from 160 MW to 220 MW |
| | FlexPeak Management program increases from 20 MW to 40 MW |
| | Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins |
| | Langley Gulch CCCT construction continues |
| | Irrigation Peak Rewards demand response program increases from 220 MW to 250 MW |
| | FlexPeak Management program increases to from 40 MW to 45 MW |
| | File 2011 IRP with regulatory commissions |
| 2012 | Wind project on-line (approximately 150 MW) |
| | Langley Gulch CCCT on-line (300 MW) |
| | Geothermal project on-line (approximately 20 MW) |
| 2013 | Boardman to Hemingway construction begins |
| | Shoshone Falls Upgrade Project construction begins |
| | File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls Upgrade Project construction continues |
| | Boardman to Hemingway construction continues |
| 2015 | Shoshone Falls Upgrade Project on-line (49 MW) |
| | Boardman to Hemingway completed (250 MW) |
| | File 2015 IRP with regulatory commissions |
| 2016 | Geothermal project on-line (approximately 20 MW) |
| 2017 | Boardman to Hemingway additional capacity for market purchases (175 MW) |
| | File 2017 IRP with regulatory commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with regulatory commissions |

# Public Policy Issues

The 2009 IRP was completed using computer modeling and other analytical methods. However, certain public policy questions exist that cannot be directly examined through analytical methods. Idaho Power has presented these issues to the IRPAC for discussion, but the nature of the issues typically precludes a strong majority opinion from the IRPAC members. The public policy issues presented to the IRPAC are discussed below.

## *New Large Loads*

Locally, Idaho Power and its customers face internal conflicts created by traditional rate determination and the cost difference between existing resources and future resources. New customers that connect to Idaho Power's system benefit from energy rates based on the low-cost of existing resources that are embedded in current rates. However, Idaho Power's existing resources and transmission system are fully used and new customers require the addition of generation, transmission, and distribution resources. Each new customer dilutes the existing resource base and increases the cost to all customers. The question of rate determination based on embedded resources is a significant public policy issue and Idaho Power senses a desire by some parties to discuss the existing rate determination principles.

Idaho Power's ability to serve new large loads is limited. Previously existing surplus energy and capacity have been consumed by load growth over the past several years. Idaho Power's ability to serve new large loads has an impact on Idaho's economy. New businesses are attracted to southern Idaho in part due to Idaho Power's low rates which have consistently been some of the lowest in the nation.

## *Asset Ownership*

Idaho Power can develop and own generation assets, rely on power purchase agreements (PPAs) and market purchases to supply the electricity needs of its customers, or use a combination of the two ownership strategies. Idaho Power expects to continue participating in the regional power market and enter into mid-term and long-term PPAs. However, when pursuing PPAs, Idaho Power must be mindful of imputed debt and its potential impact on Idaho Power's credit rating. In the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate of return advantages inherent in a regulated electric utility. Idaho Power's preference is to own the generation assets necessary to serve its customer load.

## *Renewable Energy Credits*

In late 2008, Idaho Power filed an application with the IPUC asking to retire RECs received as part of the long-term PPAs for generation from the Elkhorn Valley Wind Project and the Raft River Geothermal Project. Because the state of Idaho does not have an RPS, these RECs could be either voluntarily retired or sold. Idaho Power's application pointed out that these RECs needed to be retired in order for Idaho Power to represent to its customers that they were receiving renewable energy from these projects.

In May 2009, the IPUC issued Order No. 30818 which required Idaho Power to sell the eligible 2007 and 2008 RECs from these projects. The order also instructed Idaho Power to file a business plan addressing the disposition of future RECs by the end of 2009. When this issue was presented to the IRPAC, environmental representatives felt future RECs should be retired while customer representatives generally felt they should be sold so that the value could be returned to customers.

Idaho Power believes a federal RES requiring Idaho Power to retire RECs for compliance will be passed by Congress in the near future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented. Because of recent increases in costs and customer rates, along with feedback from the IPUC, Idaho Power feels it would be

prudent to sell the RECs until they are required by a federal RES. Additional information on RECs and the proposed federal legislation can be found in Chapter 2.

## Emission Offsets

Depending on market conditions and future regulations, it may be possible to purchase emission or carbon offsets for less than the cost of a carbon allowance. Some members of the IRPAC have suggested it would be prudent for Idaho Power to hedge carbon emission risk by purchasing emission offsets prior to the formal passage of carbon legislation. However, there are differing opinions among IRPAC members. The principal reason cited for not purchasing offsets today is the uncertainty associated with whether or not carbon offsets purchased today will meet future carbon control requirements and regulations. In addition, draft federal legislation limits the amount of offsets that may be used to meet reduction targets.

Idaho Power believes it should investigate purchasing either emission offsets or options to acquire future carbon offsets. Idaho Power could potentially reduce the large financial exposure of possible carbon regulation for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emission offset options as well as the cost of any emission offsets purchased.

## Technology Risk and Joint Development Opportunities

In the 2009 IRP, several resource options dependent on developing technology have been evaluated in various portfolios. Carbon capture and sequestration, integrated gasification combined-cycle (IGCC), advanced nuclear, and numerous storage technologies are not yet commercially available; however, the technology may become available during the 20-year planning horizon evaluated in the IRP. This raises the question of whether Idaho Power should participate in development efforts related to any of these technologies prior to them becoming commercially available.

Idaho Power believes that as a medium-sized utility it would be impractical to lead the development work on any particular technology. However, as certain technologies are identified that show promise as being beneficial to Idaho Power and its customers, the company may chose to participate in development efforts. Idaho Power's participation would most likely be part of a larger group effort to develop a technology jointly with other utilities with similar needs.

Similarly, certain existing and emerging resource technologies are available only in large sizes—larger than what Idaho Power could or would consider developing alone. If opportunities become available to jointly develop large resources, Idaho Power would evaluate them on a case-by-case basis. A similar strategy has been used in the past and resulted in Idaho Power's joint ownership of three coal-fired resources.

## Solar Pilot Project

For the 2009 IRP, Idaho Power hired Black & Veatch to prepare a feasibility study to assess the performance and associated costs of various solar technologies in southwest Idaho. While solar technology continues to be more expensive than other alternatives, the cost of solar resources has come down in recent months during a time when the cost of most other resource options has increased substantially. In addition to providing RECs, solar resources provide the benefit of delivering energy during the time of day when Idaho Power's customer demand is peaking.

Several possibilities exist for the structure of a solar pilot project. One option Idaho Power is interested in pursuing would be to develop a photovoltaic (PV) project at a substation near existing load. This concept would not require the addition of new transmission resources and would have economy-of-scale advantages over distributed rooftop installations. The cost of the project could be

subsidized by allowing customers to buy the output from the project as a means of investing in renewable energy.

A solar resource at a company substation would provide customers a physical asset they could identify with as the source of their electricity, and commercial customers would also be able to advertise their use of renewable energy. The level of customer subscription in this type of project would also provide an indication of customers' willingness to pay a premium for renewable energy. This concept was generally well received and supported when it was presented and discussed at a recent IRPAC meeting.

# 2. Political, Regulatory, Operational, and Technology Issues

## Political and Regulatory Issues

Idaho Power is a regulated utility. On the federal level, Idaho Power is subject to the rules and regulation of FERC. On the state level, Idaho Power has customers in both Idaho and Oregon, with approximately 95 percent of Idaho Power's customers being located in the state of Idaho. The following sections describe some of the federal and state regulatory issues facing Idaho Power.

### *Idaho Energy Plan*

In 2006, the Idaho State Legislature directed an Interim Committee on Energy, Environment, and Technology to develop a state energy plan that provides for the state's power generation needs and protects the health and safety of the citizens of Idaho. In January 2007, the committee completed the Idaho Energy Plan and concluded that all Idaho energy systems have performed very well with retail electric and natural gas prices that remain some of the lowest in the country.



The Idaho Legislature sets state energy policy in Idaho.

The committee also recognized that Idaho's reliance on low-cost coal plants may become a source of risk in the future due to the economic impact of potential federal regulation of carbon and mercury emissions. To address these concerns, the committee recommended increasing investments in energy conservation and in-state renewable resources. In a resource priority policy statement, the committee stated, "When acquiring resources, Idaho and Idaho utilities should give priority to: 1) conservation, energy efficiency and demand response; and 2) renewable resources; recognizing that these alone may not fulfill Idaho's growing energy requirements." The committee further stated, ". . . energy suppliers must continue to have access to conventional energy resources to keep Idaho's energy costs as low as possible."

**Highlights**

- The Idaho Energy Plan recommends increasing investments in energy conservation and in-state renewable resources.
- Proposed federal energy legislation would establish greenhouse gas (GHG) reduction goals and require a percentage of electricity supplied to customers to come from renewable resources.
- Idaho Power continues to operate the Hells Canyon Complex under annual licenses issued by FERC until a new license is issued.
- The 2009 IRP explores clean coal technologies and carbon capture and sequestration as well as storage technologies that could aid in the integration of renewable resources.

The committee also expressed support for the "25x25" vision, which states "By 2025, America's farms, forests, and ranches will provide 25 percent of the total energy consumed in the United States, while continuing to produce safe, abundant, and affordable food, feed and fiber." Additional information regarding the "25x25" vision can be found at www.25x25.org.

## Idaho Strategic Energy Alliance

In 2007, Governor C.L. "Butch" Otter established the Idaho Office of Energy Resources (IOER) to oversee energy planning, policy and coordination in Idaho. Under the umbrella of this office, the Idaho Strategic Energy Alliance (the alliance) was established to respond to rising energy costs and other energy challenges facing the state. The governor's philosophy is that there should be a joint effort between all stakeholders in developing options and solutions for Idaho's energy future.

The purpose of the alliance is to enable the development of a sound energy portfolio for Idaho that diversifies energy resources and provides stewardship of the environment. The alliance consists of a board of directors and twelve volunteer task forces working in the following areas:

- Conservation and energy efficiency
- Wind
- Geothermal
- Hydropower
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

Idaho Power representatives serve on many of these task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council, a group of the governor's cabinet members.

## Idaho State Legislature—Senate Bill 1123

Recent economic conditions have increased the cost of financing new capital projects—generation, transmission, and distribution. The electric utility business is a capital-intensive industry with significant financing requirements. Idaho Power has worked with the Idaho State Legislature to address some of the capital issues by proposing legislation to allow the authorization of capital recovery to occur prior to project construction rather than after the project is completed.

As a result of these efforts, the Idaho State Legislature passed Senate Bill 1123 in April 2009. The bill became law in July 2009 when it was signed by Governor Otter. Idaho Power recognizes that the policy change will require cost-containment commitments from the company, but Idaho Power anticipates that the legislation will lower the cost to finance new capital projects and, ultimately lower the capital costs included in customer rates. In September 2009, the IPUC issued an order granting a certificate of public convenience and necessity (CPCN) for the Langley Gulch combined-cycle combustion turbine (CCCT) project. The CPCN included provisions for ratemaking treatment as provided in the new Idaho law.

## Oregon Renewable Portfolio Standard

The state of Oregon's Renewable Portfolio Standard (RPS) requires utilities and electricity service suppliers serving Oregon load to include in their portfolio of power sold to retail customers a percentage of electricity generated from qualifying renewable energy sources. Like most states, Oregon's RPS is phased-in over a number of years, with final targets set for the year 2025. The Oregon RPS also includes

a tiered system based on the amount of load a utility serves in Oregon. Larger utilities have higher RPS requirements and interim targets while smaller utilities have less rigorous requirements and no interim targets.

Under the Oregon RPS, Idaho Power is categorized as a "smaller utility" because the percentage of the company's retail electric sales in Oregon are between 1.5 and 3 percent of the total retail sales in the state (approximately 5 percent of Idaho Power's total load is in Oregon). As a "smaller utility" Idaho Power is not subject to interim targets; however, by 2025 at least 10 percent of Idaho Power's retail sales in Oregon must come from qualifying renewable energy sources.

## Proposed Federal Energy Legislation

Congress is developing comprehensive federal energy legislation that addresses two important factors in resource planning—greenhouse gas (GHG) emission reductions and a federal renewable electricity standard (RES). Proposed GHG regulations target the reduction of carbon and other GHG emissions nationwide and a federal RES would require a percentage of electricity supplied to customers to come from renewable resources.

In June 2009, the U.S. House of Representatives narrowly passed H.R. 2454, the American Clean Energy and Security Act sponsored by Representatives Henry A. Waxman and Edward J. Markey. The Waxman-Markey bill proposes a cap-and-trade system that establishes a limit or cap on the total amount of GHG emissions. Under a cap-and-trade system, utilities would be allocated emission allowances that would be decreased over time in order to achieve a total emission reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society. Details of the Waxman-Markey bill related to GHG reduction include:

- **Reduction Goals**–Three percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and 83 percent by 2050. Average annual emissions calculation based upon data from 2006 through 2008, or any three consecutive calendar years between 1999 and 2008.
- **Allocation of Allowances**–From 2011 through 2028, 50 percent of allowances are allocated on the basis of a utility's share of emissions associated with retail sales and 50 percent are allocated based on a utility's annual average electricity deliveries.
- **Carbon Offsets**–Allows the use of some forms of carbon offsets in lieu of allowances for compliance.

The Waxman–Markey bill also includes provisions for a federal RES that would require a percentage of electricity supplied to customers come from renewable resources. Details of the RES in the Waxman–Markey bill include:

- **Required Annual Percentage**–Starts at 6 percent in 2012 and escalates to 20 percent by 2020.
- **Resources Eligible to Meet RES**–Wind, solar, geothermal, renewable biomass, biogas and biofuels derived exclusively from renewable biomass, marine, hydrokinetic, and qualified hydropower (efficiency improvements or capacity additions since January 1, 1992). Utilities can also meet up to 25 percent of their requirements through energy efficiency savings.
- **Treatment of Existing Hydro**–Generation from existing hydroelectric resources would be subtracted from the sales base used to calculate RES requirements. While this does not fully recognize the renewable aspect of hydropower, it does provide a benefit to utilities with existing hydroelectric facilities that do not qualify for renewable energy credits (REC).

In September 2009, Senators Barbara Boxer and John Kerry jointly released the Clean Energy Jobs and American Power Act which addresses climate change. The draft bill includes a GHG emission reduction goal of 20 percent below 2005 levels by 2020. The Boxer-Kerry bill (S. 1733) does not include a federal RES provision; however, a separate proposal by Senator Jeff Bingaman does include a federal RES that includes the following provisions:

- **Required Annual Percentage**–Starts at 3 percent in 2011 and escalates to 15 percent by 2021.
- **Resources Eligible to Meet RES**–Wind, solar, geothermal, ocean, biomass, landfill gas, incremental hydropower (efficiency improvements or capacity additions), hydrokinetic, and new hydropower at existing dams with no generation. Utilities can also meet up to 26.67 percent of their requirements through energy efficiency savings.
- **Treatment of Existing Hydro**–Excluded from the sales base used to calculate the RES.

Idaho Power has incorporated elements of the Waxman–Markey bill in the 2009 IRP to quantify the impact of the proposed GHG reduction goals. Idaho Power also anticipates that some form of a federal RES will be passed in the near future; therefore all portfolios analyzed in the 2009 IRP are designed to meet the requirements proposed in the Waxman–Markey bill.

## *Renewable Energy Credits (Green Tags)*

To promote the construction of renewable resources, a system was created that separates renewable generation into two parts 1) the electrical energy produced by a renewable resource and 2) the renewable attributes of that generation. These renewable attributes are referred to as RECs or green tags. The entity that holds a REC has the right to make claims about the environmental benefits associated with the renewable energy from the project. One REC is issued for each megawatt hour (MWh) of electricity generated by a qualified resource. Electricity that is split from the REC is no longer considered renewable and cannot be marketed as renewable by the entity that purchases the electricity.

A REC must be retired once it has been used for regulatory compliance and once a REC is retired, it cannot be sold or transferred to another party. The same REC may not be claimed by more than one entity, including any environmental claims made pursuant to electricity coming from renewable energy resources, environmental labeling, or disclosure requirements. State RPS requirements also typically specify a "shelf life" for RECs so they cannot be banked indefinitely.

Idaho Power is currently receiving all of the RECs from the 101 megawatt (MW) Elkhorn Valley Wind Project in northeast Oregon. The Elkhorn wind project is expected to provide approximately 300,000 RECs to Idaho Power annually throughout the term of the power purchase agreement (PPA) that expires in 2027.

Idaho Power is also receiving RECs from the 13 MW Raft River Geothermal Project. For the first 10 years of the agreement (2008 –2017), Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds a monthly average of 10 MW. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the RECs generated by the project.

Idaho Power expects a federal RES will be enacted in the near future, and, in the 2009 IRP, the portfolios being analyzed are designed to substantially comply with the federal RES contained in the Waxman–Markey bill. Idaho Power also anticipates RECs generated from both the Elkhorn Valley Wind Project and the Raft River Geothermal Project will be needed to meet federal RES requirements once implemented.

## FERC Relicensing



Idaho Power's Hells Canyon Project is licensed by FERC.

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex and the Swan Falls Hydroelectric Projects.

Idaho Power's most significant ongoing relicensing effort is the Hells Canyon Complex. The Hells Canyon Complex provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 40 percent of the company's total generating capacity. The current license for the Hells Canyon Complex expired at the end of July 2005. Until the new multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The Hells Canyon Complex license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the Federal Power Act (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the Endangered Species Act (ESA); and other applicable federal laws.

The license for the Swan Falls project expires in June 2010. In March 2005, Idaho Power issued a Formal Consultation Package (FCP) to the public relating to environmental studies designed to determine project effects for the relicensing of the project. In September 2007, Idaho Power submitted a draft license application to FERC for public review and comment. The draft application was based on the results of environmental studies along with agency and public consultation. Idaho Power filed a final license application for the Swan Falls hydroelectric project with FERC in June 2008, and anticipates NEPA consultation to initiate in early 2010.

Failure to relicense any of the existing hydropower projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) measures imposed as a condition for relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed was assumed as part of the 2009 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

## Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin stream flows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to be able to maintain generation from these projects. The company is dedicated to the vigorous defense of its water rights. None of the pending water management issues are expected to impact Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water rights proceedings. Idaho Power's ongoing participation in water rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process commenced in 1987 to define the nature and extent of water rights in the Snake River Basin. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984. The purpose of the agreement was to resolve litigation related to the company's water rights at the Swan Falls project. Idaho Power has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights.

Idaho Power has also actively participated in proceedings associated with the Comprehensive Aquifer Management Plan (CAMP) of the Eastern Snake River Plain Aquifer (ESPA). Remedial actions identified in CAMP are intended to address persistently declining aquifer conditions. Given the high degree of interconnection between ESPA and the Snake River, Idaho Power recognizes the importance of aquifer management planning in promoting the long-term sustainability of the Snake River.

The company is hopeful the implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. For the 2009 IRP, it is assumed that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations consist of a combination of ground water to surface water conversions, managed aquifer recharge, demand reduction programs, and weather modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre-feet. Further discussion of the ESPA CAMP is included in *Appendix C—Technical Appendix*. The Phase I measures with associated target water volumes are shown in Table 2.1.

**Table 2.1 Phase I Measures**

| Measure | Target (acre-feet) |
|---|---|
| Ground Water to Surface Water Conversions | 100,000 |
| Managed Aquifer Recharge | 100,000 |
| Demand Reduction | |
| Surface Water Conservation | 50,000 |
| Crop Mix Modification | 5,000 |
| Rotating Fallowing, Dry-Year Lease, Conservation Reserve Enhancement Program (CREP) | 40,000 |
| Weather Modifications | 50,000 |

## Fixed Cost Adjustment




The IPUC regulates Idaho Power in Idaho.

In January 2006, Idaho Power filed an application with the IPUC requesting to implement a fixed-cost adjustment (FCA) mechanism similar to the Power Cost Adjustment (PCA), which accounts for changes in power supply expenses. The FCA is designed to separate fixed cost rate recovery from energy sales. The FCA adjusts rates downward or upward to recover fixed costs independent of the volume of the company's energy sales. The filing was a continuation of a 2004 case that was opened by Idaho Power to investigate energy efficiency investments and financial disincentives. Idaho Power recognizes that energy efficiency improvements lower the company's energy sales, which then reduce the company's income. Like most utilities, Idaho Power recovers a portion of fixed costs through variable energy sales—the fixed costs to serve customers are much larger than customers' fixed fees, and a significant portion of the fixed costs are included in customers' kilowatt hour (kWh) energy charges.

Idaho Power and IPUC staff agreed in concept to a three-year pilot program and a stipulation was filed in December 2006 indicating the pilot program would begin in January 2007. The stipulation called for the implementation of the FCA mechanism pilot program as proposed by Idaho Power in the original application, with additional conditions and provisions related to customer count and weather normalization methods, recording of the FCA deferral amount in reports to the IPUC, and detailed reporting of demand-side management (DSM) activities. The IPUC approved the stipulation in March 2007. The pilot program retroactively began in January 2007 and runs through December 2009. The first rate adjustment occurred in June 2008, the second in June 2009, and the final adjustment will occur in June 2010.

Idaho Power believes the FCA removes an inherent disincentive to utility-sponsored DSM programs. In response to implementation of the FCA, Idaho Power has committed to enhancing the efforts promoting DSM and energy efficiency in several key areas, including a broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, continued expansion of DSM programs beyond peak-shaving and load-shifting programs, and third-party verification of program effectiveness. Additional details on Idaho Power's DSM programs and results can be found in Chapter 4.

Idaho Power has been successful in achieving its previously established DSM targets and the company continues to pursue additional cost-effective DSM resource options through the IRP planning process. Furthermore, in response to the FCA, Idaho Power has further reduced any financial bias toward supply-side resource alternatives by removing "earnings neutrality" from the criteria for assessing the viability of DSM resource options in the 2009 IRP analysis.

In October 2009, Idaho Power submitted an application to the IPUC (Case No. IPC-E-09-28) requesting authorization for the company to convert the FCA from a pilot program to an ongoing and permanent program.

# Operational and Technology Issues

Supply-side resources have different characteristics that impact how they ultimately perform. Renewable resources tend to be variable and intermittent and present operational issues. Many forms of storage technology aimed at addressing these issues are under development. Likewise, significant effort is being made to develop technologies such as carbon capture and sequestration, to allow the continued use of coal as a fuel. These topics are all relevant to resource planning, and the following sections provide details on the operational and technology issues associated with various resources.

## *Wind Integration*

In February 2007, Idaho Power filed a wind integration study with the IPUC. Idaho Power also filed a petition requesting removal of the temporary restriction on the size of Public Utilities Regulatory Policies Act (PURPA) wind projects and an adjustment to the avoided cost rates to compensate for the increase in system costs due to wind variability. In March and June 2007, public workshops were held to present and discuss the results of the wind integration study.

Following negotiations, Idaho Power entered into a settlement stipulation in October 2007. The settlement stipulation prescribed a methodology for calculating a wind integration charge to be applied to new PURPA wind projects, as well as other provisions to account for the characteristics of wind generation. The integration charge is calculated as a percentage of the current 20-year, levelized, avoided-cost rate and is subject to a cap of $6.50 per MWh. In February 2008, the IPUC issued an order approving the settlement stipulation and returned the PURPA cap to 10 average megawatts (aMW). In compliance with the terms of the settlement stipulation, Idaho Power held a follow-up public workshop in August 2008 during which further analysis results were presented along with the operational strategies being used to integrate wind.

Idaho Power currently has 192 MW (nameplate) of wind generation on-line. Signed PURPA contracts exist for 266 MW of wind generation that is expected to be on-line by the end of 2010. The 2012 Wind RFP is also expected to add up to 150 MW by 2012, which will put the total wind generation on Idaho Power's system in excess of 600 MW. Given this projected increase, it is critical that integration methodologies in practice continue to evolve through ongoing operational experience and further study. Idaho Power plans to update its wind integration study in the first half of 2010 during the time between filing the 2009 IRP and starting the 2011 IRP process in July 2010. The updated study will incorporate planned increases in wind generation as well as the capability of the new Langley Gulch CCCT to provide additional operating reserves.

Along with other regional balancing authorities, Idaho Power shares the belief that improvements in wind forecasting are necessary as wind resources continue to be built in the Pacific Northwest. As a consequence, the company is currently developing a wind forecasting tool to forecast production from PURPA wind projects. Data collection and testing of the new system is being performed to determine whether this low-cost, in-house approach offers comparable performance to services offered by third-party forecasting companies. A status report on this effort will be included in the updated wind integration study to be released in 2010.

Idaho Power continues to explore potential changes in operating practices to aid in the integration of wind resources. Included among these efforts are two programs designed to collaborate with surrounding balancing authorities to manage balancing issues due to the variable and intermittent nature of wind generation. ACE Diversity Interchange (ADI) and the concepts of dynamic and intra-hour scheduling are based on the principle that sub-hour imbalances between generation and load will impact system reliability less if balancing authorities are able to efficiently transfer and account for energy moving between balancing authority areas within the hour.

## Clean Coal Technologies

### Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC), is a process that converts low-value fuels such as coal, petroleum coke, orimulsion, biomass, and municipal wastes into a high-value, low-British thermal unit (Btu), environmentally friendly natural gas type fuel, also called "synthesis gas" or simply "syngas." When used to fuel a CCCT, coal-based syngas fuel produces electricity more efficiently and with lower emissions of sulfur dioxide ($SO_2$), particulates, and mercury than traditional direct-fire coal boilers.

A significant amount of work continues worldwide on IGCC research and development. IGCC technology is already being demonstrated at several plants around the world, and there are at least five IGCC plants being planned in the United States. More than 40 IGCC projects with a combined capacity of over 20 gigawatts (GW) have been announced globally. Major power generation equipment suppliers, including Siemens and GE Energy, are investing substantial amounts of capital in IGCC research and development. Idaho Power will continue to monitor the activities and results of IGCC research and development and will continue to evaluate this technology in future IRPs.

### Sequestration

Carbon capture and sequestration begins with the separation and capture of carbon dioxide ($CO_2$) from power plant flue gas and other stationary $CO_2$ sources. At present, the process is costly and energy intensive, accounting for the majority of the cost of sequestration. Post-combustion, pre-combustion, and oxy-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas $CO_2$.

After separating the $CO_2$, the next step is to sequester or store the $CO_2$ by injecting it into geologic formations or using terrestrial applications. Geologic sequestration involves taking the $CO_2$ that has been captured from power plants and other stationary sources and storing it deep underground. Geologic formations, such as oil and gas reservoirs, un-mineable coal seams, and underground saline formations are potential options for storing $CO_2$. Storage in basalt formations and organic-rich shales is also being investigated.

Terrestrial sequestration involves the net removal of $CO_2$ from the atmosphere by plants and microorganisms that use $CO_2$ in their natural cycles. Terrestrial sequestration requires the development of technologies to quantify, with a high degree of precision and reliability, the amount of carbon stored in a given ecosystem. Program efforts in this area are focused on increasing carbon uptake on mined lands and evaluation of no-till agriculture, reforestation, rangeland improvement, wetlands recovery, and riparian restoration.

Research and development continues on carbon capture and sequestration with the U.S. Department of Energy (DOE) in a lead role. The DOE is pursuing evolutionary improvements in existing $CO_2$ capture systems and exploring new capture and sequestration concepts. Additional research is being performed in the private sector with companies such as Alstom and with utility-affiliated organizations, such as the Electric Power Research Institute (EPRI). Idaho Power will continue to monitor the activities and results of carbon capture and sequestration research and development and will modify future portfolios as appropriate.

### Carbon Recycling Using Algae

Carbon recycling using algae is an emerging technology and an alternative method for reducing $CO_2$ emissions. Algae "farms" rely on the capture of $CO_2$ from coal plant flue gases, which is then used to accelerate algae growth and eventually produce a biofuel that is similar to natural gas.

To create the biofuel, algae (biomass) is harvested and then gasified in a highly efficient, catalytic, hydrothermal gasifier to produce a fuel that can be either injected into a natural gas pipeline or burned in a combustion turbine to produce electricity. Compared with other methods of gasifying biomass, this process is 400 times faster than anaerobic digestion and gives higher yields according to the DOE's Pacific Northwest National Laboratory. Currently, funding is being solicited to construct a commercial demonstration project next to an existing coal-fired facility.

## Storage Technologies

In order to keep the electric power system balanced, generation must match system load at all times. Intermittent renewable resources, such as wind and solar, present a problem because they are not dispatchable. The advent of large-scale storage technologies may help utilities address this issue because surplus energy could be stored and used at a later time. Energy storage technologies convert electrical power into potential or kinetic energy, which can then be converted back into electrical energy when needed, in effect making it dispatchable. The following sections present an update on the status of various storage technologies.

### Pumped Storage

Pumped storage technology has existed for some time, and Idaho Power has evaluated the technology in numerous IRPs. The economics of pumped storage has always relied on a significant differential between peak and off-peak market prices because the value is realized by storing water during off-peak times and generating electricity with it during peak load periods. Historically, the differential between peak and off-peak market prices in the Pacific Northwest has not been enough to justify the economics of pumped storage.

Pumped storage recovers about 75 percent of the energy consumed, and is currently one of the most cost-effective technologies for power storage. Pumped storage requires two nearby reservoirs at considerably different elevations, linked with a pipeline or penstock. Because of the required facilities and equipment, pumped storage typically requires considerable capital expenditures.

A relatively new concept in pumped storage is using wind power or other intermittent renewable resources to pump water to the upper reservoir instead of relying on off-peak, baseload generation. However, the capital cost of this pumped storage concept is still considerable because of the required equipment and facilities.

### Batteries

Battery technology has existed for a long time; however, utility-scale battery storage technologies are still under development. Batteries are generally expensive and have a limited lifespan, but they also have a relatively high efficiency, as high as 90 percent or better. To date, the most common use of batteries has been in small off-grid domestic systems.

A nickel cadmium (NiCd) battery uses nickel oxide hydroxide and metallic cadmium as electrodes. The world's largest NiCd installation is in Fairbanks, Alaska and is used to stabilize voltage at the end of a long transmission line. This battery system has a capacity of 27 MW for a duration of 15 minutes.

A Vanadium Redox Battery (VRB) is a type of rechargeable flow battery that employs vanadium redox couples in both half cells. The King Island Wind Farm in Tasmania is connected to a VRB that allows up to 800 kWh of surplus electricity to be stored. The battery has an output of 200 kW and is used to help stabilize and improve the reliability of the local power system.

As the adoption of plug-in hybrid electric vehicles increases, batteries could be used for energy storage. Vehicle-to-grid technology would turn each vehicle into a 20 to 50 kWh distributed, load-balancing device or emergency power source. For example, during peak daytime hours when people tend to be at

work and their vehicles are parked, utilities could draw power from the batteries. During off-peak nighttime hours when people and their cars are at home, the batteries would be recharged.

### Compressed Air

Compressed air technology typically involves compressing and storing air in underground geological features. During times of peak electricity demand, the compressed air is heated with a small amount of natural gas and run through a turbine to generate electricity. A proposed hybrid power plant using compressed air is currently under consideration in Iowa. This project also proposes a 75 to 150 MW wind project to generate the electricity needed for air compression.

### Thermal

Thermal storage technology typically uses molten salt to store heat collected by a solar thermal generation plant. Heat from the molten salt is then used to generate electricity for a few hours after the sun sets or during cloudy periods when normal generation is reduced. Molten salt technologies can provide three to seven hours of energy storage. Solar Millennium and Abengoa are constructing two 50 MW solar thermal plants in Spain with seven hours of thermal storage.

### Flywheel

Mechanical inertia is the basis of the flywheel storage technology where energy is stored in the kinetic motion of a rotating mass. A heavy, rotating disc is typically accelerated by an electric motor, which also functions as a generator when reversed. Friction loss must be kept to a minimum to extend the relatively short storage time. Because of the limited storage time, flywheel technology is best suited for back-up applications during brief outages.

Flywheel storage technology is currently being used for uninterruptible power supply systems in large data centers. The flywheel provides generation during transfer, which is the relatively brief time between loss of power and the start up of an alternate source, such as a diesel generator. In addition, flywheels can be used to minimize minor power disturbances and improve power quality.

### Hydrogen

The concept of hydrogen as a storage technology involves using electricity from intermittent renewable resources to extract hydrogen through the electrolysis of water. The resulting hydrogen is stored and later burned as fuel to generate electricity. A pilot project using wind turbines and hydrogen generators was undertaken in 2007 on Ramea Island in Newfoundland, Canada. Wind energy is also currently being used to extract hydrogen through the electrolysis process at a small facility southeast of Boise, Idaho. The hydrogen generated at the Idaho facility is sold commercially.

### Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) systems store energy in the magnetic field created by the flow of direct current in a superconducting coil that has been cryogenically cooled to a temperature below its superconducting critical temperature. A typical SMES system includes three parts, 1) a superconducting coil, 2) the power conditioning system, and 3) a cryogenically cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely. The stored energy can then be released back into the electric system by discharging the coil.

SMES systems are highly efficient, greater than 95 percent; however, the high cost of superconductors limits the commercial application of this technology. The SMES technology would most likely be useful to utilities as a diurnal storage device where less expensive, off-peak energy could be used to charge the system which would then be discharged during the peak-load hours the following day. SMES is

currently being used in a utility application in northern Wisconsin where a string of distributed SMES units are deployed to enhance the reliability of a transmission loop.

### Fuel Conservation

The concept of fuel conservation combines an intermittent renewable resource with a dispatchable fossil fuel generation resource. Under this concept, generation from the intermittent resource is combined with an appropriate amount of generation from the fossil fuel resource to maintain a constant level of output from the combined resources. While the concept is not specifically a storage technology, fuel conservation does provide a means of firming the generation from a renewable resource. Other benefits of this concept include reduced fossil fuel consumption and better use of available transmission capacity.

# 3. IDAHO POWER TODAY

## Customer and Load Growth

In 1990, Idaho Power had approximately 290,000 general business customers. Today, Idaho Power serves more than 486,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 megawatts (MW) in 1990 to over 3,000 MW in 2006, 2007, 2008, and 2009. In June 2008, the peak-hour load reached 3,214 MW, which was a new system peak-hour record. Average firm load (excluding Astaris/FMC) has increased from nearly 1,200 average megawatts (aMW) in 1990 to over 1,800 aMW in 2008. Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.



Idaho Power commercial customers in downtown Boise.

Simple calculations using the data in Table 3.1 suggest that each new customer adds approximately 5.9 kilowatts (kW) to the peak-hour load and about 3.1 average kilowatts to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,276 MW. This includes Idaho Power's newest supply-side resource, a 170 MW simple-cycle combustion turbine (SCCT) at the Danskin Project that was completed in April 2008. The 641 MW increase in capacity represents enough generation to serve approximately 108,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

### Highlights

- Idaho Power had over 486,000 retail customers at the end of 2008.
- Idaho Power expects to add almost 10,000 retail customers per year through 2029.
- In June 2008, Idaho Power set a new peak-hour system load record of 3,214 MW.
- The 300 MW Langley Gulch natural gas-fired combined-cycle combustion turbine (CCCT) is expected to begin operating in July 2012.
- In May 2009, Idaho Power released an RFP for up to 150 MW of wind generation.

Since 1990, Idaho Power has added more than 195,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 195,000 customers require over 1,100 MW of additional peakhour capacity and about 600 aMW of energy.

**Figure 3.1 Historical Capacity, Load, and Customer Data**

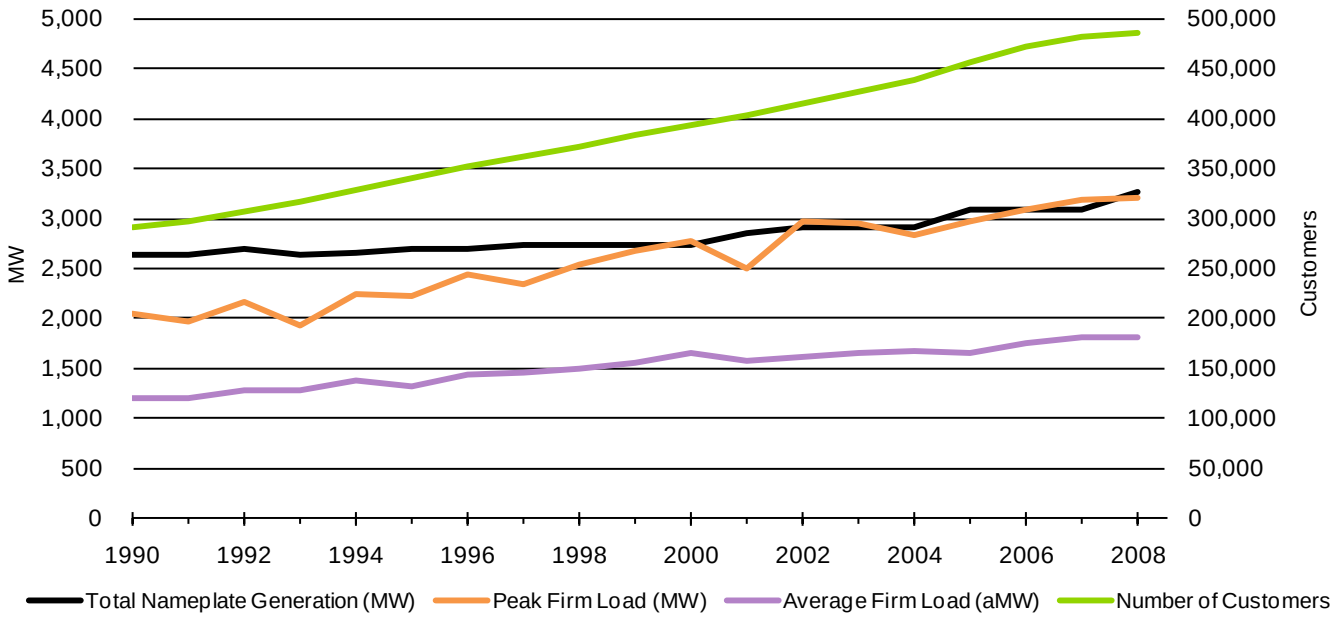



**Table 3.1 Historical Capacity, Load, and Customer Data**

| Year | Total Nameplate Generation (MW) | Peak Firm Load (MW) | Average Firm Load (aMW) | Customers |
|---|---|---|---|---|
| 1990 | 2,635 | 2,052 | 1,205 | 290,492 |
| 1991 | 2,635 | 1,972 | 1,206 | 296,584 |
| 1992 | 2,694 | 2,164 | 1,281 | 306,292 |
| 1993 | 2,644 | 1,935 | 1,274 | 316,564 |
| 1994 | 2,661 | 2,245 | 1,375 | 329,094 |
| 1995 | 2,703 | 2,224 | 1,324 | 339,450 |
| 1996 | 2,703 | 2,437 | 1,438 | 351,261 |
| 1997 | 2,728 | 2,352 | 1,457 | 361,838 |
| 1998 | 2,738 | 2,535 | 1,491 | 372,464 |
| 1999 | 2,738 | 2,675 | 1,552 | 383,354 |
| 2000 | 2,738 | 2,765 | 1,653 | 393,095 |
| 2001 | 2,851 | 2,500 | 1,576 | 403,061 |
| 2002 | 2,912 | 2,963 | 1,622 | 414,062 |
| 2003 | 2,912 | 2,944 | 1,657 | 425,599 |
| 2004 | 2,912 | 2,843 | 1,671 | 438,912 |
| 2005 | 3,085 | 2,961 | 1,660 | 456,104 |
| 2006 | 3,085 | 3,084 | 1,745 | 470,950 |
| 2007 | 3,093 | 3,193 | 1,808 | 480,523 |
| 2008 | 3,276 | 3,214 | 1,815 | 486,048 |

Idaho Power anticipates adding nearly 10,000 customers each year throughout the planning period. The expected-case load forecast predicts that peak-hour load requirements are expected to grow at about 57 MW per year and average energy is forecast to grow at approximately 11 aMW per year. More detailed customer and load forecast information is presented in Chapter 4 and in *Appendix A–Sales and Load Forecast*.

The simple peak-hour load growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 173 MW Bennett Mountain plant every three years throughout the entire planning period. However, this calculation does not include the expected impact demand response programs will have on peak-hour load. The near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 11.

The generation costs per kW included in Chapter 6 help put forecast customer growth in perspective. Load research data indicate the average residential customer requires about 1.5 kW of baseload generation and 5.0 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $2,000 per kW for wind resources, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT. These capital costs do not include fuel or any other operation and maintenance expenses.

Based on these capital cost estimates, each new residential customer requires about $3,000 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5.0 to 5.5 kW of peak-hour capacity for a total generation capital cost of $7,000. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $7,000 capital generation requirement. The forecasted residential customer growth rate of 10,000 new customers per year translates into over $70 million of new generation plant capital per year to serve new residential customers.

## Existing and Committed Resources

Idaho Power primarily relies on company-owned hydroelectric and coal-fired generation facilities and long-term power purchase agreements (PPAs) to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River and market purchases and sales used to balance supply and demand throughout the year. The next sections provide specific details on Idaho Power's sources of energy in 2008 followed by a description of Idaho Power's existing and committed resources.

### *2008 Energy Sources*

In 2008, 79 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.2 shows Idaho Power's electricity sources for 2008, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

Long-term power purchases are electric power contracts with independent power producers and firm PPAs 3with other utilities and can typically be identified by resource type. In 2008, Idaho Power purchased 1,194,087 megawatt hours (MWh) of electricity through long-term PPAs that are shown by resource type in Figure 3.3. Long-term power purchases that cannot be identified by resource type are shown as "other" in the chart.

**Figure 3.2 2008 Energy Sources**

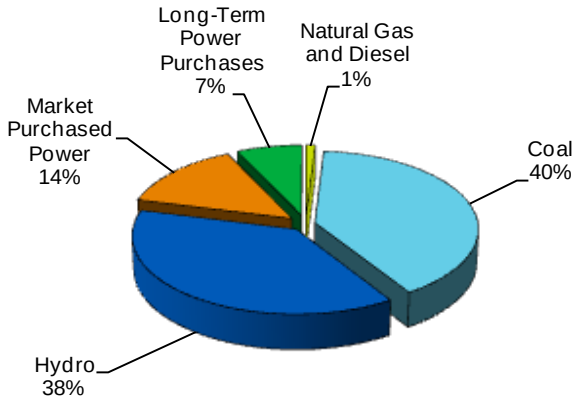
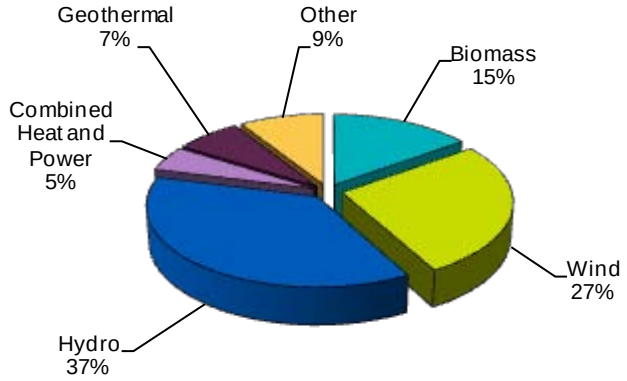



**Figure 3.3 2008 Long-Term Power Purchases by Resource Type**




Electricity delivered to retail customers includes both electricity generated by Idaho Power-owned facilities and energy purchased from others. Electricity produced by resources typically considered to be renewable, such as wind, biomass, geothermal, etc., is not counted as renewable energy delivered to retail customers in a given year, unless Idaho Power holds and retires an equivalent number of renewable energy credits (REC) in that year. Energy for which Idaho Power holds and retires an equivalent number of RECs will be counted as renewable energy delivered to customers in the year the RECs are retired.

Idaho Power has been directed by the IPUC to sell its eligible 2007 and 2008 RECs. The IPUC also has directed Idaho Power to file by December 31, 2009, a report explaining how the company intends to manage its RECs on an ongoing basis. Table 3.2 represents the electricity Idaho Power delivered to customers in 2008. Because Idaho Power sells electricity to other utilities and to retail customers, not all electricity purchased or generated by Idaho Power is delivered to its retail customers. Table 3.2 assumes that all 2008 RECs will be sold. If any of the 2008 RECs are retained and retired, the actual amount of renewable energy delivered to retail customers could be higher than what is presented in Table 3.2.

**Table 3.2 Electricity Delivered to Customers (2008)**

| Resource by Type | MWh |
|---|---|
| Hydroelectric | 6,908,211 |
| Coal | 7,278,844 |
| Natural Gas & Diesel | 217,152 |
| Purchased Power | 3,716,429 |
| **Total** | **18,120,636** |

## *Existing Supply-Side Resources*

In order to identify the need and timing of future resources, Idaho Power prepares a load and resource balance which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are presented in *Appendix C–Technical Appendix*. Table 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

**Table 3.3 Existing Resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydro | 92.3 | Upper Snake |
| Bliss | Hydro | 75.0 | Mid-Snake |
| Brownlee | Hydro | 585.4 | Hells Canyon |
| C.J. Strike | Hydro | 82.8 | Mid-Snake |
| Cascade | Hydro | 12.4 | North Fork Payette |
| Clear Lake | Hydro | 2.5 | South Central Idaho |
| Hells Canyon | Hydro | 391.5 | Hells Canyon |
| Lower Malad | Hydro | 13.5 | South Central Idaho |
| Lower Salmon | Hydro | 60.0 | Mid-Snake |
| Milner | Hydro | 59.4 | Upper Snake |
| Oxbow | Hydro | 190.0 | Hells Canyon |
| Shoshone Falls | Hydro | 12.5 | Upper Snake |
| Swan Falls | Hydro | 27.2 | Mid-Snake |
| Thousand Springs | Hydro | 8.8 | South Central Idaho |
| Twin Falls | Hydro | 52.9 | Mid-Snake |
| Upper Malad | Hydro | 8.3 | South Central Idaho |
| Upper Salmon A | Hydro | 18.0 | Mid-Snake |
| Upper Salmon B | Hydro | 17.0 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| Valmy | Coal | 283.5 | North Central Nevada |
| Bennett Mountain | Natural Gas | 172.8 | Southwest Idaho |
| Danskin | Natural Gas | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | East Idaho |
| *Total Existing Nameplate Capacity* | | *3,276.4* | |

The following sections describe Idaho Power's existing supply-side resources and long-term PPAs.

## Hydro Facilities

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 970 aMW, or 8.5 million MWh under median water conditions.

### *Hells Canyon Complex*

The backbone of Idaho Power's hydroelectric system is the Hells Canyon Complex in the Hells Canyon reach of the Snake River. The Hells Canyon Complex consists of the Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation and approximately 35 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the Hells Canyon Complex projects to provide the major portion of Idaho Power's peaking and load-following capability.



High runoff at Idaho Power's Hell's Canyon Dam.

Idaho Power operates the Hells Canyon Complex to comply with the existing FERC license, as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall Chinook plan, voluntarily adopted by Idaho Power in 1991 to protect spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the Endangered Species Act (ESA).

Brownlee Reservoir is the only one of the three Hells Canyon Complex reservoirs—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used for flood control, recreation, and for the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams that are coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood control directions received from the United States Army Corps of Engineers (U.S. Army COE) as outlined in Article 42 of the existing FERC license.

After flood control requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The U.S. Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish

migrate past the Federal Columbia River Power System (FCRPS) projects. The periodic releases are part of the flow augmentation implemented by the 2000 FCRPS biological opinion. The flow augmentation water travels through Idaho Power's Mid-Snake projects and eventually through the Hells Canyon Complex before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the fall Chinook plan adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook plan operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

Maintaining constant flows to protect the fall Chinook spawning contributes to the need for additional generation resources during the fall months. The fall Chinook operations result in lower reservoir elevations in Brownlee Reservoir, which reduces the power production capability of the project. The reduced power production may necessitate Idaho Power to acquire power from other sources to meet customer load.

#### *Mid-Snake Projects*

Idaho Power's hydroelectric facilities upstream from the Hells Canyon Complex include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls, and Cascade projects. Although the Mid-Snake projects of Upper and Lower Salmon, Bliss, and C.J. Strike, typically follow run-of-river operations, the Lower Salmon, Bliss, and C.J. Strike plants do provide a limited amount of peaking and load-following capability. When possible, the projects are operated within FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants are operated as run-of-river projects.



Idaho Power's C.J. Strike project on the Mid-Snake.

Idaho Power has entered into a settlement agreement with the U.S. Fish and Wildlife Service (USFWS) that provides for a study of the ESA listed snails and their habitat. The objective of the research study is to determine the impact of load-following operations on the Bliss Rapids snail and the Idaho Springsnail. The study required Idaho Power to operate the Bliss and Lower Salmon facilities under varying operational constraints to facilitate the Idaho Springsnail research. Run-of-river operations during 2003 and 2004 serve as the baseline, or control, for the study. These facilities were again operated as run-of-river plants during 2004 and 2005 and then were used to follow load during 2006, 2007, 2008, and 2009. Idaho Power is developing, in consultation with the USFWS, a snail protection plan that will be completed in March 2010. The plan will define how the Bliss and Lower Salmon hydroelectric facilities will be operated in the future.

#### *Water Lease Agreements*

Idaho Power views the lease of water for delivery through its hydroelectric system as a potentially cost-effective power supply alternative. This approach is particularly attractive for water lease agreements allowing the company to request delivery as needed. Water lease agreements in 2008

included the release of 41,620 acre-feet of water from the Idaho Water District No.1 rental pool and 45,716 acre-feet from the Shoshone–Bannock Tribal Water Supply Bank. The water released under both of these agreements was delivered through the company's entire system of main stem Snake River hydroelectric projects.

The company also signed agreements with two irrigation districts on the Boise and Payette River systems to lease approximately 16,400 acre-feet of storage water released in December 2008 and January 2009. Because of high carryover storage levels in the Boise River reservoir system, the lease agreement for the Boise system water (approximately 10,500 acre-feet) has been renewed for the winter of 2009-2010.

In August 2009, the company also entered into a five year (2009–2013) water lease agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. Under the terms of this agreement, Idaho Power can schedule the releases of the water in order to maximize the value of the generation. The company plans to schedule delivery of the water between July and October of each year during the term of the lease. The Shoshone–Bannock agreement was executed in part to offset the impact of drought and changing water use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Acquiring water through leases also helps the company to improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex. Idaho Power intends to continue to pursue water lease opportunities as part of its regular operations.

#### *Cloud Seeding*

In 2003, Idaho Power implemented a winter cloud-seeding program for snowpack augmentation. The program initially focused on increasing snow accumulation in the south fork of the Payette River watershed. In 2008 it was expanded to enhance an existing program operated by a coalition of counties and other entities (coalition) in the Upper Snake River system above Milner Dam. Cloud seeding, as practiced by Idaho Power, extracts additional precipitation from passing storm systems. Storms with an abundance of super-cooled liquid water vapor provide optimal conditions to increase precipitation.

To seed clouds, ground generators located near mountain tops, or special flares attached to modified airplanes, release silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide and eventually grow and fall to the ground in the form of snow. Silver iodide has been used as a seeding agent in numerous western states for decades, and there are no known harmful effects. Analysis conducted since the program began in 2003 suggests consistent enhancement of annual snowpack in the Payette River between 5 and 15 percent, which is estimated to provide an additional 120,000 to 180,000 acre-feet of water. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of the program.

For the 2009–2010 winter season, the program consists of 10 remote–controlled, ground-based generators and one airplane for the Payette Basin operations. The Upper Snake Basin cloud seeding program consists of nine remote-controlled ground-based generators operated by Idaho Power and 25 manual ground-based generators operated by the coalition. Idaho Power provides the coalition with meteorological data and forecasting to guide their operations.

## Thermal Facilities

### *Jim Bridger*

Idaho Power owns a one-third share of the Jim Bridger coal-fired plant located near Rock Springs, Wyoming. The plant consists of four nearly identical generating units. Idaho Power's one-third share of the generator nameplate capacity of the Jim Bridger plant currently is 771 MW. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, efficiency upgrades, and transmission losses, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.



The Jim Bridger Plant is located near Rock Springs, Wyoming.

### *Valmy*

Idaho Power owns a 50 percent share, or 284 MW, of the 568 MW (nameplate) Valmy coal-fired plant located east of Winnemucca, Nevada. The plant is owned jointly with NV Energy, which performs operation and maintenance services. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy generating capability of Idaho Power's share of the Valmy plant is approximately 230 aMW.

### *Boardman*

Idaho Power owns a 10 percent share, or 64 MW, of the 642 MW (nameplate) coal-fired plant near Boardman, Oregon, operated by Portland General Electric Company (PGE). After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW.

Because of concerns regarding the future of the Boardman plant and pending legal action, PGE analyzed two scenarios in its 2009 IRP regarding the future of the Boardman plant. First, shutting down the plant in 2014 and, second, adding pollution control equipment required to continue operating the plant until the year 2040. Due to uncertainty in the ability to find alternate sources of replacement energy, PGE indicated the best option was to invest in the pollution control equipment and continue to operate the plant.

While Idaho Power has not specifically modeled either of PGE's scenarios in the 2009 IRP, significant reductions in generation from all of Idaho Power's coal resources, including Boardman, have been modeled in the 2009 IRP. If PGE continues to operate the plant beyond 2014, Idaho Power will evaluate the required additional capital cost and the associated risk when more details are known. If the project is shut down in 2014, the existing transmission capacity from the Pacific Northwest currently used to deliver Boardman's generation to Idaho Power's system would be available to import energy from other resources.

## Peaking Facilities

### *Danskin*

Idaho Power owns and operates the Danskin plant, a 271 MW natural gas-fired project. The plant consists of one 179 MW Siemens 501F simple-cycle combustion turbine and two 46 MW Siemens W251B12A combustion turbines. The 12-acre facility was initially constructed during 2001 and is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001 and the larger turbine was recently installed in 2008. The Danskin plant operates as needed to support system load.



The 45-MW combustion turbines at Danskin are used to meet peak customer load.

### *Bennett Mountain*

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173 MW Siemens–Westinghouse 501F simple-cycle, natural gas-fired combustion turbine located near the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant also operates as needed to support system load.

### *Salmon Diesel*

Idaho Power owns and operates two diesel generation units located in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are primarily operated during emergency conditions.

## Solar Facilities

In 1994, a 25 kW photovoltaic (PV) array with 90 individual panels was installed on the rooftop of Idaho Power's corporate headquarters in Boise, Idaho. The company also maintains a remote off-grid 80 kW PV array for the U.S. Air Force near Grasmere, Idaho.




25 kW PV array on top of Idaho Power's corporate headquarters.

Idaho Power uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring stream flows, and for operating cloud seeding equipment. In addition to these PV installations, Idaho Power participates in the *Solar 4R Schools Program*; has a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events and has a 200 watt solar water pump that is used for demonstrations and the promotion of PV technology.

Idaho Power's net metering program also allows customers to install small-scale, renewable generation projects on their property and connect to Idaho Power's system. Under the program, net energy generated beyond what the customer uses is sold back to Idaho Power. A majority of the program's

participants are solar projects. Currently there are 77 PV installations under this program with a total capacity of 227 kW.

## Power Purchase Agreements

### *Elkhorn Valley Wind Project*

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn wind project was constructed during 2007 and began commercial operations in December 2007.



The Elkhorn Valley Wind Project in northeast Oregon.

Under the PPA, Idaho Power receives the RECs from the project. However, in May 2009 the IPUC issued Order No. 30818, which required Idaho Power to sell 2007 and 2008 RECs and to submit a business plan by the end of 2009 addressing the disposition of future RECs from this project. This issue is discussed further in the public policy section in Chapter 1 and the renewable energy credits section in Chapter 2.

### *Raft River Geothermal Project*

The 2006 IRP identified a need for Idaho Power to acquire geothermal generation resources and a request for proposals (RFP) for geothermal energy was released in June 2006. In March 2007, Idaho Power identified U.S. Geothermal, Inc. as the successful bidder based on their proposal to supply 45.5 MW of geothermal energy. In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a Public Utilities Regulatory Policies Act (PURPA) contract with Idaho Power that was subsequently canceled when the new PPA was approved by the IPUC.

For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the RECs generated by the Raft River Geothermal Project. These RECs are also subject to IPUC Order No. 30818, as discussed above.

### *Neal Hot Springs Geothermal Project*

After extensive discussions with U.S. Geothermal, it was mutually agreed that development of the additional 32.5 MW of geothermal generation units originally proposed in the 2006 RFP process was not feasible within the terms and conditions as specified in the RFP. However, over the past two years Idaho Power continued discussions with U.S. Geothermal regarding the development of the Neal Hot Springs project in eastern Oregon. During much of 2009, Idaho Power negotiated a PPA with U.S. Geothermal. In December 2009, Idaho Power submitted a PPA to the IPUC for approval for approximately 20 MW of geothermal energy from the Neal Hot Springs project.

### *Clatskanie Energy Exchange*

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the newly constructed 18 MW power plant at Arrowrock Dam on the Boise River, and in exchange Idaho Power provides Clatskanie PUD energy of equivalent value

delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account will be maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project is expected to begin generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

## Public Utility Regulatory Policies Act

In 1978, Congress passed PURPA requiring investor–owned electric utilities to purchase the energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined within the FERC regulations as a small renewable generation project or small cogeneration project. Individual states were given the task of establishing the PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in both Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities not located in the state of Oregon, and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar, but not identical, for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.



The Bennett Creek and Hot Springs PURPA wind projects are located in Elmore County.

Idaho Power currently has 96 contracts with independent developers for over 560 MW of nameplate capacity. The PURPA generation facilities consist of low head hydro projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities and various other small renewable power projects. Of the 96 contracts, 80 are on-line as of November 2009 with a cumulative nameplate rating of approximately 300 MW. Of the remaining contracts, 15 are expected to be on-line in late 2010 and one in late 2012.

### *Published Avoided Costs*

A key component of the PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided costs. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost that Idaho Power is required to include in the PURPA contracts.

### *Idaho PURPA Contracts and Published Avoided Costs*

- The term of the agreements cannot exceed 20 years.
- For projects up to 10 aMW, energy prices are based on the published avoided cost.
- For projects greater than 10 aMW, energy prices and other contract terms and conditions are negotiated.
- The published avoided costs are based upon a surrogate avoided resource (SAR) model and both non-firm and firm contracts are available:
  - Firm contracts have a specific term and contain published avoided cost energy pricing.

- Non-firm contracts contain no specific term and energy pricing is based on market prices.

***Oregon Published Avoided Costs***

OPUC docket UM 1129 established PURPA PPA rules and regulations for projects located in Oregon. In UM 1129, the OPUC adopted the basic published avoided cost concepts used in Idaho for Idaho Power agreements. One exception is that Oregon QF projects also have the option of selecting energy pricing that is based on monthly natural gas prices. Idaho Power's Oregon Schedule 85 is the direct result of OPUC docket UM 1129.

***Oregon PURPA Contracts and Published Avoided Costs***

- The term of the agreements cannot exceed 20 years.
- For projects up to 10 MW nameplate rating, energy prices are based on the published avoided cost. Idaho Power is required to use standard contracts that have been pre-approved by the OPUC (Oregon Schedule 85).
- For projects greater than 10 MW nameplate rating, energy prices and other contract terms and conditions are negotiated. The starting point for the negotiations are the terms and conditions of the Oregon Schedule 85 standard contract and there are three pricing options available:
  - **Fixed Price Option**–The energy price is fixed for all energy deliveries.
  - **Deadband Option**–The deadband option contains a fixed price component plus a variable price component that is based on monthly natural gas prices. The calculated gas price is then confined between a cap and floor creating the "deadband".
  - **Gas Index Option**–The gas price option contains a fixed price component plus a variable price component that is based on monthly natural gas prices.

## Wholesale Contracts

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. Since the 2006 IRP was published, the term of the contract has been renewed annually and is expected to continue to be renewed each year until the contract expires at the end of September 2011.

The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. The agreement was established as a full-requirements contract after being approved by FERC and the Public Utilities Commission of Nevada.

The contract requiring Idaho Power to supply 6 aMW to the City of Weiser expired at the end of 2006 and was not renewed. The expiration of the City of Weiser contract was anticipated in the 2006 IRP.

Idaho Power and Montana's NorthWestern Energy negotiated a load-following agreement in which Idaho Power provided NorthWestern Energy 30 MW of load-following service. Idaho Power did not renew the load-following agreement at the end of 2007 because of concerns regarding the integration of new wind generation anticipated to be interconnected on Idaho Power's system.

NorthWestern has provided load-following services for the Salmon, Idaho area which is located in the NorthWestern Balancing Authority Area. Idaho Power and NorthWestern are currently working together to move the Salmon area load into the Idaho Power Balancing Authority Area. Idaho Power continues to use its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during summertime, heavy-load hours from PPL EnergyPlus, LLC. Although the purchase agreement expires in 2012, Idaho Power plans to continue to use the available transmission capacity during the summer months.

### Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity. Idaho Power is especially dependent on the regional markets and the existing transmission system used to import these purchases during peak periods. Reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the power cost adjustment (PCA).

## *Committed Supply-Side Resources*

### Langley Gulch

The need for a new baseload power plant was identified in Idaho Power's 2004 and 2006 IRPs. The initial decision was to construct a coal-fired baseload resource, but regulatory, price, and environmental issues led Idaho Power to reconsider the coal resource and instead select a natural gas-fired combined-cycle combustion turbine (CCCT). Idaho Power completed the competitive bidding process in early 2009 and selected a 300 MW CCCT project near New Plymouth, Idaho to meet the resource need.

The Langley Gulch project is expected to begin delivering energy in time to meet summer peaking needs in July 2012. The Langley Gulch project will require the construction of short segments of 138-kV and 230-kV transmission lines to connect to the existing system in order to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon. The Langley Gulch resource is included when calculating the energy and capacity deficits discussed later in the IRP.

### Wind RFP

Idaho Power's acknowledged 2006 IRP included a 150 MW wind generation resource to be added in 2012. With the passage of the American Recovery and Reinvestment Act of 2009 (the economic stimulus package), Idaho Power believed it would be advantageous to accelerate the timing of this resource acquisition. In May 2009, Idaho Power released an RFP for up to 150 MW of wind generation. Proposals were received in June 2009; however, the evaluation process was delayed due to the analysis of transmission constraints impacting all of the proposed projects. In October 2009, the company initiated contract negotiations which are anticipated to be completed by the end of 2009. Idaho Power expects to have a signed contract to submit for regulatory approval during the first quarter of 2010.

### Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric Project from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single 50 MW unit which will result in a net upgrade of 49 MW.

In March 2007, Idaho Power received a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis from FERC that provided a 60-day comment period for interested parties. FERC issued a supplemental EA in December 2007 and Idaho Power expects a license amendment will be issued during 2010. For the 2009 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in October 2015. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal renewable electricity standard (RES) requirements.

The Shoshone Falls Upgrade Project has been included in previous Idaho Power IRPs as a committed resource. For the 2009 IRP, the project was treated as an uncommitted resource; however, it was included in all the portfolios analyzed because it is the most cost-effective new supply-side resource

available. In order to quantify the value of the project, the preferred portfolio was subsequently analyzed without the upgrade project included. The results of this analysis indicate the project adds approximately $11.5 million of value (excluding capital cost and REC value) to the portfolio each year (average annual nominal dollars for 2016–2019), and $15 million with RECs using the expected-case REC price curve.

In the 2009 IRP, the expected levelized cost of energy from the upgrade (without RECs) is $73 per MWh under median water assumptions, which makes the project the least expensive of all the supply-side options analyzed in the 2009 IRP. The project becomes even more economically attractive depending on the assumed future value of RECs. While the evaluation of the Shoshone Falls upgrade was done under median water conditions, some uncertainty exists regarding future Snake River streamflows that would not only impact the Shoshone Falls project, but all of Idaho Power's Snake River hydroelectric projects. Additional details regarding water issues can be found in Chapter 2.

Because of the benefits and additional value provided by the Shoshone Falls Upgrade Project, it remains in the 2009 IRP preferred portfolio. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the state of Idaho.

### Geothermal, Combined Heat and Power, and Small Hydro

The preferred portfolio in Idaho Power's 2006 IRP included 50 MW of geothermal energy in 2009 and 50 MW of energy from Combined Heat and Power (CHP) in 2010. In June 2006, Idaho Power released a geothermal RFP that resulted in a long-term PPA with U.S. Geothermal, Inc. for approximately 13 MW of generation from the Raft River Geothermal Project. In January 2008, Idaho Power released another RFP for up to 100 MW of geothermal energy; however, by the time the evaluation process was completed all the bidders had withdrawn their proposals.

Although the results of the geothermal RFP processes have been disappointing, Idaho Power has continued to work with project developers capable of delivering energy to the company's service area. Idaho Power has included two 20 MW increments of geothermal energy in 2012 and 2016 in the 2009 IRP as a committed resource. While there is still uncertainty regarding the development of geothermal projects, ongoing contract negotiations warrant the inclusion of a small amount of geothermal energy in the IRP. Idaho Power will continue to monitor geothermal project development and is hopeful geothermal energy will become an economic and readily available resource for its customers.

The 2006 IRP also included 50 MW of CHP coming on-line in 2010. In April 2008, Idaho Power solicited large industrial customers to determine the level of interest in CHP development. Because the level of interest in CHP development was far less than anticipated in the 2006 IRP, CHP is not shown as a committed resource in the 2009 IRP. However, Idaho Power continues to work with parties to explore CHP projects and will pursue opportunities as they develop.

Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in November 2009 with the Idaho Office of Energy Resources (IOER) and Amalgamated Sugar, one of Idaho Power's large industrial customers. The agreement establishes the framework for a CHP feasibility study to be performed at Amalgamated Sugar's Nampa, Idaho facility that could be as large as 100 MW. Under the agreement, IOER will allocate up to $20,000 of DOE grant funds and Idaho Power will contribute up to an additional $20,000 to fund the study.

Idaho Power believes the development of new large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

Because small hydro, in particular, run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydro, the IRP Advisory Council (IRPAC) expressed an interest in including small hydro in the 2009 IRP. The potential for new small hydro projects was recently studied by the Idaho Strategic Alliance's Hydropower Task Force. The results of this evaluation are presented in a draft report available on the IOER's Web site at www.energy.idaho.gov. Idaho Power and others also continue to evaluate pumped storage opportunities and the state of Idaho is examining possible large water storage projects for flow augmentation and the potential for hydropower.

Due to potential regulation of carbon emissions and the associated costs, new small hydro may be a feasible resource option for Idaho Power. However, uncertainty exists in the level of available sites and the likelihood the sites would be developed as PURPA projects. Therefore, Idaho Power has not included small hydro as a committed resource in the 2009 IRP. Similar to geothermal and CHP resources, Idaho Power will evaluate small hydro development opportunities as they emerge.

### Distributed Generation

In 2006, Idaho Power renewed its investigation of a dispatchable customer generation program. As initially conceptualized by the company, the program would use non-residential customers' standby generators for up to 400 hours a year to help meet system peak power demands. Customer generators would operate parallel with Idaho Power's generation resources during times of peak energy demand and also provide back-up for the customer's facility when needed. The customers' generators would be started remotely by Idaho Power's dispatch center.

Idaho Power performed a feasibility analysis of the concept, examining the various costs involved in the interconnection of backup generators as well as the resulting operations and maintenance costs. Both initial generator installations and existing retrofits were considered. The analysis concluded that Idaho Power would have to make a significant infrastructure investment.

Idaho Power determined that it was necessary to do an in-depth analysis of the interconnection costs, targeting generators of different sizes, ages, and locations. Five Idaho Power customers committed to the detailed analysis and allowed the company to perform an on-site interconnection analysis. The on-site analysis provided a more detailed cost estimate and determination of the program's potential viability. Idaho Power concluded that it may be economical to operate customers' generators during short periods of high energy demand.

Following the detailed analysis, Idaho Power began investigating air quality and permitting issues. If a customer generation program was implemented, Idaho Power would most likely dispatch customers' generators, almost all of which use diesel fuel, at times of peak system demand, which occurs most often on hot, summer afternoons—the times when air quality may already be compromised. In addition, Idaho Power has received concerns from the environmental community regarding air quality issues associated with operating diesel generators.

In April 2008, Idaho Power filed an updated status report on the investigation with the IPUC. In late 2008, Idaho Power held several meetings with the Industrial Customers of Idaho Power (ICIP) and the IPUC staff to discuss the research and findings related to a dispatchable generation program. However, none of the meetings resulted in sufficient support to file a dispatchable generation program at that time. Idaho Power did agree to further analyze a dispatchable generation resource option targeting new generator installations that are fueled by natural gas as part of the company's 2009 IRP.

Both natural gas- and diesel-fueled distributed generation (DG) options were analyzed as part of the 2009 IRP. Because of air quality concerns the potential programs were analyzed at a lower capacity factor of 0.69 percent (60 hours-per-year), which more closely matches the capacity factor of demand response programs. At a capacity factor of 0.69 percent, the results of the analysis indicated a natural gas

option would have a 30-year, levelized cost of $519 per MWh and $808 per MWh for diesel. The cost estimate for a natural gas-fired peaking resource (SCCT) is $234 per MWh at a 6 percent capacity factor and $1,165 per MWh at a capacity factor of 0.69 percent. Because the cost estimates for the DG options fall within the range of costs for a SCCT, Idaho Power has committed to work with the ICIP to determine if a cost-effective program can be established.

Several questions remain to be answered regarding air quality issues and whether the backup generators can qualify as operating reserves. Based on Idaho Power's survey of industrial customers, the initial size of the program is expected to reach approximately 15 MW; however, the ICIP is more optimistic and believes the program could reach 80 MW. Idaho Power will continue to work with the ICIP to resolve outstanding issues and is optimistic a program can be developed that will benefit all of Idaho Power's customers.

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# 4. DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with its customers to promote energy efficiency and produce the same output or provide the same level of service with lower energy consumption. Through demand response programs, Idaho Power provides incentives to customers to identify applications where a short-term load reduction can be timed to coincide with peak energy consumption when purchased power is most expensive. Energy efficiency and demand response programs address all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power collaborates with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities. *Appendix B—Demand-Side Management 2008 Annual Report* shows a detailed description of Idaho Power's energy efficiency program portfolio.

During each Integrated Resource Plan (IRP) planning period, Idaho Power uses various resources, including current program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, NEEA, and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill electricity resource needs from demand-side resources. Idaho Power adopts new demand-side resources when determined cost-effective, indicating the benefits of avoided power generation costs exceed the costs of offering an energy efficiency program. Energy efficiency resources are usually one of the least-cost resources available for Idaho Power's resource stack. Figures 6.1 and 6.2 in Chapter 6 compare demand response and energy efficiency program costs with Idaho Power's supply-side resource options.

## DSM Potential Study

In August 2007, Idaho Power contracted with Nexant, Inc. to conduct a DSM potential study to identify cost-effective new programs and opportunities to expand existing programs. The study took place during 2008, with a draft report delivered in September 2008. The DSM potential study included a comprehensive report detailing forecast reductions from Idaho Power's existing programs and the forecast reductions from new programs. In early 2009, Idaho Power requested a revision to the study methodology to make the models used for the study more adaptable and useful for the IRP process.

**Highlights**

- Idaho Power conducted a DSM potential study as part of preparing the 2009 IRP.
- Idaho Power implements all cost-effective DSM measures prior to analyzing the need for new supply-side resources.
- Existing and new energy efficiency programs are forecast to reduce average annual system load by 382 aMW by 2029.
- Demand response programs are forecast to reduce Idaho Power's summer peak load by 380 MW in 2012 and by nearly 500 MW in 2029.

Interactive models were provided by Nexant, which allowed Idaho Power to change the inputs based on new DSM avoided costs, market penetration, and other factors affecting energy savings potential. The overall potential assessment for Idaho Power's DSM programs was determined by characterizing a baseline profile for energy consumption by customer class, defining a list of applicable measures within each customer class, and calculating the achievable potential.

The achievable potential for energy efficiency programs was calculated by determining the technical and economic potential. Technical potential describes the possible savings if all baseline equipment stock in a program is replaced. Economic potential is a calculation of savings when all cost-effective measures are installed. Achievable potential is determined by applying expected market penetration rates to the economic potential. Achievable potential represents the savings Idaho Power expects to achieve from energy efficiency programs.

Forecast program savings were determined using the results of the DSM potential study and analyzing cost effectiveness with calculated avoided costs. The following sections provide additional details of the DSM potential study. Analysis for the IRP focused solely on new cost-effective measures that are currently not part of existing programs for the residential and commercial sectors and potential expansion over existing program performance for industrial efficiency.

## Residential Efficiency Potential

Residential efficiency potential focused on increased savings by expanding weatherization measures for homes. Expansion potential included program measures similar to existing low income weatherization programs that would be available to all residential homes in Idaho Power's service area. Other measures included adding high efficiency water heating and freezers to the Home Products program, which promotes and incents the purchase and use of ENERGY STAR® products. As new products receive ENERGY STAR certification, the products will be reviewed for possible inclusion in the program. In addition, potential new savings could come from expanding Idaho Power's ENERGY STAR Homes Northwest program to non-owner occupied multi-family housing units. Savings from these new measures are forecast to start out at approximately 0.3 average megawatts (aMW) in 2010 and grow to 16 aMW by 2029.

## Commercial Efficiency Potential

Nexant provided recommendations focused on the existing Easy Upgrades program, which was adopted as part of the 2006 IRP. The program targets commercial energy efficiency retrofit projects and offers a menu of measures. Nexant recommended several measures, including the expansion of high-efficiency motor offerings and various measures that would benefit commercial dairies, a growing industry in Idaho Power's service area. Savings from these new measures are forecast to be 0.8 aMW in 2010 and grow to 31 aMW by 2029.

## Industrial Efficiency Potential

The primary driver for industrial efficiency potential is customer adoption rates, which are correlated to the incentive levels being offered. Nexant provided four tracks of achievable potential: low, moderate, aggressive, and maximum, correlating to incentives levels of 25, 50, 75 and 100 percent of customer costs, respectively. Idaho Power chose the aggressive potential level to model potential expansion to the current Custom Efficiency program, which pays industrial and large commercial customers proportionally to the electrical savings achieved on a per-project basis. With the adoption of the aggressive potential level, it is anticipated that 1 aMW of additional industrial energy efficiency can be obtained in 2010, which will increase to 67 aMW by 2029.

### *Irrigation Efficiency Potential*

DSM potential research of Idaho Power's irrigation efficiency program offerings looked at energy savings relative to irrigation load, annual customer participation, turnover, and the list of measures available in the program for customers relative to other similar programs. In 2007, savings from the 819 completed projects under the Irrigation Efficiency Rewards program totaled 12,304 megawatt hours (MWh), representing 0.76 percent of the sector energy sales for the year. The present level of savings is at the high end of the range of results of similar programs offered by other utilities (0.1 to 0.8 percent). Considering the number of systems that might be replaced on an annual basis, Idaho Power's program may be reaching 80 percent of the potential customers. Because of the current success of the existing program, Nexant did not recommend implementation of any new energy efficiency programs for the irrigation sector.

## Appliance Standard Assessment

Idaho Power contracted with Quantec, LLC, in 2007 to conduct a study of the potential energy savings and costs associated with enacting appliance energy efficiency standards in Idaho similar to the standards enacted in Oregon during 2007. The intent of the evaluation was to provide information regarding the costs and potential for energy savings that would occur if the appliance standards enacted by Oregon were applicable in Idaho. In addition, the evaluation provided information and an analytical base to promote new or additional appliance standards in Idaho. The study also addressed the concern that higher standards already in place in Washington and Oregon would increase the potential of less-efficient equipment being marketed and sold to Idaho residents.

Unlike a potential study, Idaho Power's Appliance Standards Assessment did not address the creation of corresponding cost-effective utility programs that would capture the savings discussed in the report. Some basic qualitative information about the level and type of effort required to conduct an appliance standards development program were considered as part of the report, while detailed programmatic recommendations were beyond the scope of the report. The energy savings shown in the report are similar in methodology to the technical potential savings defined in a typical energy efficiency potential study, where it is assumed that every available measure or appliance is replaced. Table 4.1 shows the 10 appliances that were considered for the study and their status in neighboring states. Table 4.2 summarizes the total savings forecast if standards were enacted, adopted, and allowed to penetrate the marketplace over 20 years throughout Idaho.

**Table 4.1 Analyzed Appliances and Code Implementation Status**

| | | Oregon | | Neighboring States | |
|---|---|---|---|---|---|
| Appliance | Sector | Enacted | Effective | Washington | California |
| Metal halide lamps/fixtures | Commercial | 2005 | 2008 | Enacted | Enacted |
| Incandescent reflector lamps | Commercial | 2005 | 2007 | Enacted | Enacted |
| External power supplies | Commercial/Residential | 2005 | 2007 | Enacted | Enacted |
| Bottle-type water dispensers | Commercial | 2007 | 2009 | | Enacted |
| Hot food holding cabinets | Commercial | 2007 | 2009 | | Enacted |
| Walk-in refrigerators and freezers | Commercial | 2007 | 2009 | | Enacted |
| Compact audio products (CD players) | Residential | 2007 | 2009 | | Enacted |
| DVD players and recorders | Residential | 2007 | 2009 | | Enacted |
| Portable electric spas/hot tubs | Residential | 2007 | 2009 | | Enacted |
| Residential furnace fans | Residential | 2007 | 2009 | | |

**Table 4.2 Appliance Standard Potential Savings—Idaho Statewide**

| Sector | Total estimated Energy Savings (MWh) | Total Estimated Demand Savings (MW) |
|---|---|---|
| Commercial | 56,916 | 12 |
| Residential | 221,893 | 31 |
| Overall | 278,809 | 43 |

Based on the findings, Quantec recommended that Idaho Power consider developing and adopting Idaho appliance standards for the first nine appliances shown in Table 4.1. In addition, Quantec recommended specific alternatives be investigated for the possibility of increasing the efficiency of furnace fans. Quantec also recommended Idaho Power examine the options and monitor progress in setting standards for general service incandescent and metal halide fixtures.

To support the development of efficiency standards, Quantec also recommended that Idaho Power and other entities in Idaho identify priorities for conducting research and develop the data needed for such efforts. Expanding current collaborative efforts would leverage existing resources and minimize the need for additional resources.

At the state level, Quantec recommended the State of Idaho invest in the capability required to research and adopt standards for the appliances analyzed in the study. In addition, the state could investigate the option of developing a regulatory framework similar to California's that would recognize utilities' efforts dedicated to efficiency standards; similar to how utility energy efficiency acquisition programs are treated.

## Demand-Side Management Analysis

Prior to the final portfolio selection, the current working portfolio of supply-side resources is used to model the value of avoided supply-side generation and market purchases that are being avoided through the implementation of DSM. The value of avoided generation is then balanced against program costs and costs incurred by customers in programs to create benefit-cost ratios.

Tables 4.3 and 4.4 summarize the analysis for the new energy efficiency and demand response resources forecasted for the 2009 IRP planning period. Each column represents the net present value of the 20-year stream of energy, utility costs, and resource costs. Utility costs are the direct expenses Idaho Power incurs in planning, implementing, and evaluating a DSM program, while the total resource cost is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. *Appendix C–Technical Appendix* describes Idaho Power's methodology of calculating cost effectiveness.

### *Energy Efficiency Cost Effectiveness*

Table 4.3 demonstrates the new energy efficiency program measures and expansions adopted for resource planning in the 2009 IRP. The new energy efficiency programs are estimated to be effective with a total resource benefit-to-cost ratio of 3.2. The ratio indicates that the benefits of avoided power generation due to the energy efficiency programs exceed the costs to the utility and its customers by more than three times. The highest total resource benefit-to-cost ratio is the industrial efficiency programs with a benefit-to-cost ratio of 4.9 and levelized cost of 2.6 cents per kilowatt hour (kWh). Cost effectiveness screening for the residential and commercial sectors yielded benefit-to-cost ratios of 2.8 and 2.1, respectively.

The 20-year levelized total resource cost of each saved kWh is 4.0 cents; the programs save energy at a cost of $41 per MWh. For all of the energy efficiency programs, the combined net present value of the 20-year stream of avoided generation costs is over $587 million.

**Table 4.3 New Energy Efficiency Cost Effectiveness Summary**

| | Impact | | 20-Year NPV Costs | | | Utility Costs | | Total Resource Costs | |
|---|---|---|---|---|---|---|---|---|---|
| | 2029 Load (aMW) | 20-Year Energy (MWh) | Utility | Resource | Avoided Energy | Benefit/Cost Ratio | Levelized ($/kWh) | Benefit/Cost Ratio | Levelized ($/kWh) |
| Residential | 29 | 1,097,000 | $42,647,000 | $51,412,000 | $142,492,000 | 3.3 | $0.039 | 2.8 | $0.047 |
| Commercial | 31 | 1,043,000 | 15,207,000 | 68,482,000 | 143,366,000 | 9.4 | 0.015 | 2.1 | 0.066 |
| Industrial | 67 | 2,391,000 | 46,583,000 | 61,693,000 | 301,075,000 | 6.5 | 0.019 | 4.9 | 0.026 |
| Total | 127 | 4,531,000 | 104,437,000 | 181,587,000 | 586,933,000 | 5.6 | 0.023 | 3.2 | 0.040 |

## *Demand Response Cost Effectiveness*

Table 4.4 summarizes the cost-effectiveness analysis for all demand response programs, existing or new, that were considered for the 2009 IRP. The overall 20-year levelized cost for the demand response portfolio of programs is estimated at $46 per kW, with a peak forecasted demand reduction of 367 megawatts (MW) during the planning period. The benefit-to-cost ratio for the portfolio of programs is 1.5, with an estimated net present value of $258 million in avoided generation capacity costs over 20 years, relative to the estimated $176 million dollars to administer the programs.

**Table 4.4 Demand Response Cost-Effectiveness Summary**

| | Impact | | 20-Year NPV Costs | | | Total Resource Costs | |
|---|---|---|---|---|---|---|---|
| | 2029 Load (MW) | 20-Year Energy (MWh) | Utility | Resource | Avoided Energy | Benefit/Cost Ratio | Levelized ($/kW) |
| Residential | 51 | 555 | $21,020,000 | $21,020,000 | $33,418,000 | 1.6 | $38 |
| Commercial/Industrial | 56 | 574 | 35,339,000 | 35,339,000 | 39,982,000 | 1.1 | 62 |
| Irrigation | 260 | 2,749 | 120,389,000 | 120,389,000 | 185,239,000 | 1.5 | 44 |
| Total | 367 | 3,878 | 176,748,000 | 176,748,000 | 258,639,000 | 1.5 | 46 |

# Energy Efficiency Programs

During the preparation of the IRP, Idaho Power analyzes various DSM options, including current program expansion and new program development. Idaho Power also uses potential studies, NPCC research, NEEA, and the EEAG to determine the best methods of designing and implementing DSM programs. Idaho Power is committed to adopting all cost-effective DSM, which is determined by comparing the cost of DSM programs to the cost of supply-side resource options. Table 6.2 compares the cost of DSM options to various supply-side alternatives that were also evaluated in the 2009 IRP. The methodology used to screen the cost effectiveness of DSM programs is discussed later in this chapter and in greater detail in *Appendix C–Technical Appendix.*

In addition to the new program identification resulting from the DSM potential study, internal program development identified an additional four new energy efficiency programs and one demand response program for the 2009 IRP. One existing demand response program, Irrigation Peak Rewards, was redesigned as a dispatchable program with significantly more peak reduction capability. The additional peak reduction potential from the program was modeled as a new resource for the

2009 IRP, along with the other new programs. No new industrial or irrigation efficiency programs were planned as new resources for the 2009 IRP.

By 2029, existing and committed energy efficiency programs are forecast to provide 255 aMW of system load reduction and 289 MW of peak-hour load reduction. The energy and capacity effects from the company's existing and committed energy efficiency programs are accounted for in Idaho Power's sales and load forecast. However, peak-hour load reduction due to demand response programs is not included in the forecast, but is accounted for in the peak-hour load and resource balance. *Appendix A– Sales and Load Forecast* includes the annual forecast impact of existing and committed DSM programs by customer class for each year of the IRP planning horizon.

New energy efficiency measures are forecast to offset 127 aMW of average annual load by 2029 at an estimated total resource cost of 4.0 cents per kWh. Industrial efficiency program expansion identified in the potential study will provide more than 50 percent of the reduction, or almost 67 aMW at a cost of 2.6 cents per kWh. The next lowest cost energy efficiency acquisition is from residential programs which include new weatherization program measures and an expansion of the Home Products Program that provides incentives for customers to purchase ENERGY STAR qualified appliances. The combined contribution is forecast to reduce load by 29 aMW at a total resource cost of 4.7 cents per kWh. For the commercial customer class, the new energy efficiency portfolio from the potential study includes higher cost measures, such as higher efficiency motors and agricultural measures along with one new small commercial Holiday Lighting program. The commercial sector is forecast to provide 31 aMW of load reduction by 2029 at a total resource cost of 6.6 cents per kWh.

## Residential Program Planning

Three new efficiency programs were implemented during 2009. The Home Improvement Program offers customer incentives for attic insulation retrofits into existing residential homes. The Weatherization Solutions for Eligible Customers program provides increased home weatherization opportunities for families that do not qualify for the long standing Weatherization Assistance for Qualified Customers (WAQC) program. The See Ya Later Refrigerator program incents customers to recycle secondary refrigerators and freezers. The combined forecasted impact for these three new programs in 2010 is 2,440 MWh in annual energy savings, or 0.28 aMW of system load reduction, growing to an estimated impact of 82,113 MWh in 2029 or 9.4 aMW of reduced average system load.

## Commercial Program Planning

The Holiday Lighting program enables commercial customers to recycle old incandescent holiday lights and replace them with light-emitting diode (LED) bulbs. The seasonal program was added to the portfolio of existing commercial programs during 2009 and will result in savings of approximately 0.1 aMW in 2010, growing to 0.5 aMW at the end of the IRP planning period. While relatively small, the Holiday Lighting program provides a unique opportunity for educating all customers about the energy savings potential of LED technologies.

## Demand Response Resources



Irrigation customers make significant contributions to Idaho Power's DSM programs.

The goal of demand response programs at Idaho Power is to reduce the summer peak electric load during periods of high demand and minimize or delay the need to build new supply-side alternatives, such as gas-turbine peaking resources.

Two major demand response program changes occurred in 2009 that expanded the dispatch capability of Idaho Power to reduce system demand during critical summer peak load events. The Irrigation Peak Rewards program, originally identified as a resource in 2004, was changed to a direct load control or dispatchable program. In prior years, demand reduction through the program was controlled with programmed timers that provided demand reduction from irrigation pumping systems from 4:00 p.m. to 8:00 p.m. on weekdays in June, July, and August. Options added to the program in 2009 allowed direct load control or dispatch capabilities to match demand response resources with actual system peaks. While fixed timers remain an option, the dispatchable change in the program will increase the program's peaking resource capacity from its previous range of 34 to 37 MW to a forecasted impact of 260 MW at program maturity in 2012. Actual demand reductions from the revised program will depend on the level of irrigation customer participation, drought conditions, and agricultural business cycles. Details on the approved Irrigation Peak Rewards tariff changes are listed as part of Case No. IPC-E-08-23 on the IPUC Web site.

Another demand response program that emerged for the 2009 IRP planning period was the FlexPeak Management program. The program is offered to commercial and industrial customers through a third-party demand response aggregator. FlexPeak Management is expected to provide nearly 40 MW of peak demand reduction in 2010 and over 56 MW by 2012, as part of a five-year contract. For details corresponding to the program addition, view Case No. IPC-E-09-02, Order No. 30805 on the IPUC Web site.

As part of the 2009 IRP process, Idaho Power prepared an updated forecast of the A/C Cool Credit program. Using communication hardware and software, Idaho Power cycles participants' central air conditioners on and off during summer peak load events. The A/C Cool Credit program is forecast to exceed 50 MW in potential reduction with continued growth in the Treasure Valley and planned expansion into Twin Falls, Mountain Home, and Pocatello, Idaho. Through the life of the planning period, combined total impact of the three programs is forecast to be 310 MW in 2010 and 367 MW in 2012. Table 4.4, in the Demand Response Cost Effectiveness section of this chapter shows expected program performance and associated costs.

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# 5. Planning Period Forecasts

The Integrated Resource Plan (IRP) process requires the preparation of numerous forecasts which can be grouped into three main categories—load forecasts, a generation forecast, and financial assumptions. The load and generation forecasts, including supply-side resources, demand-side management (DSM), and transmission import capability, are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are then used to develop resource portfolios which are evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2009 IRP.



Idaho Power has served Idaho and Oregon customers for almost 100 years.

## Load Forecast

Historically, Idaho Power has been a summer peaking utility, with peak loads driven by irrigation pumps and air conditioning in the months of June, July, and August. In recent years, the growth rate of peak-hour load has exceeded the growth of average monthly load. However, both measures are important in planning for future resources and are part of the load forecast prepared for the 2009 IRP.

The expected-case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not exactly follow the path suggested by the expected-case forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather.

### Highlights

- The 2009 IRP load forecast projects peak-hour load will grow at an average annual rate of 53 MW (1.5 percent) and average system load at 13 aMW (0.07 percent) over the 20-year planning period.
- Idaho Power expects the number of residential customers to increase 1.7 percent annually to more than 550,000 by the end of the planning period in 2029.
- The 2009 IRP sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices.
- Idaho Power's customers set a new, winter system peak record of 2,527 MW on December 10, 2009 during several days of below normal temperatures.

The high-growth and low-growth scenarios provide boundaries on each side of the expected-case forecast and historical load variability potential on future load due to demographic, economic, and other non-weather related influences. The 70th percentile and 90th percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced the 2009 IRP load forecast. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics are also used in developing the 2009 IRP load forecast. The forecast of the number of households and employment projections, along with customer consumption patterns, are used to develop customer forecasts and load projections.

## Weather Impacts

The expected-case load forecast assumes median temperatures and median precipitation meaning that there is a 50 percent chance that loads will be higher or lower than the expected-case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios are analyzed to address load variability due to weather. Idaho Power has generated load forecasts for 70th percentile and 90th percentile weather. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1 in 10 likelihood that the load will be greater than the forecast.

Idaho Power's system load is highly dependent upon weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand the probabilities associated with the load forecasts apply to any given month and an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast over the long-term time horizon.

## Economic Impacts

The national recession that began in 2007 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the current recession has resulted in a reduction in new residential customer growth from an average of 2,000 new residential customers per month prior to the recession, to approximately 200 new customers per month at the present time. Commercial and industrial customer energy use has contracted and overall system energy use has declined by 3.6 percent in 2009 from the prior year; the first time that overall energy use has declined since the energy crisis of 2001.

Increased population in Idaho Power's service area due to migration to Idaho from other states is expected to continue throughout the planning period and has been included in the load forecast model. Idaho Power also continues to receive requests from prospective new large load customers that are

attracted to southern Idaho due to the relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.3 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual county specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with estimated consumption per household adjusted for DSM measures, results in a 0.7 percent residential load growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.7 percent annually from approximately 404,000 at the end of 2008 to over 563,000 by the end of the planning period in 2029.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A–Sales and Load Forecast*. For example, the expected annual average system load growth of 0.6 percent (over the period 2010 through 2029) is comprised of residential load growth of 0.7 percent, commercial load growth of 0.7 percent, declining irrigation load growth of -0.3 percent, industrial load growth of 1.0 percent, and additional firm load growth of 2.3 percent.

The 2009 IRP average system load forecast is lower than the 2006 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow significantly. In addition, the significant increase in assumed DSM combined with retail electricity price assumptions that incorporate estimates of assumed carbon legislation both serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include:

- For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. Retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C–Technical Appendix*.
- A collapse in the housing sector has significantly slowed the growth in the number of residential customers being added within Idaho Power's service area. The number of commercial customers being added has also slowed as a result of the economic downturn. Both forecasts of the number of residential and commercial customers were adjusted downward in the near term to reflect the current housing slowdown and credit crisis. By 2012, residential and commercial customer growth is expected to recover and customer additions are expected to be similar to the growth that occurred in the 1993–2003 timeframe, prior to the housing bubble.
- A somewhat higher irrigation sales forecast compared to recent years due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand lines to electrically operated pivots may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines has triggered the substitution of labor with electrically operated pivots.

- The uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contacted Idaho Power and expressed interest in locating production operations within Idaho Power's service area and the unknown magnitude of the energy and peak demand requirements. The current sales and load forecast reflects only those customers that have a high probability of locating in the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the number of large customers that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

## Peak-Hour Load Forecast

The firm peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), and the Raft River Rural Electric Cooperative wholesale agreement. Idaho Power uses the 95$^{th}$ percentile forecast as the basis for peak-hour planning in the IRP. The 95$^{th}$ percentile forecast is based on 95$^{th}$ percentile average peak day temperatures to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record is 3,214 MW, which was recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. Summertime peak-hour load growth has accelerated over the past 10 years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2009 IRP load forecast projects peak-hour load to grow by approximately 53 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance.

Figure 5.1 and Table 5.1 summarize three forecast outcomes of Idaho Power's estimate of annual system peak load considering median, 90$^{th}$ percentile and 95$^{th}$ percentile weather impacts on the expected (median) peak forecast. The 95$^{th}$ percentile forecast uses the 95$^{th}$ percentile peak-day average temperature to determine monthly peak-hour demand. The planning criteria for determining the need for peak-hour capacity assumes the 95$^{th}$ percentile peak-day temperature conditions.

**Figure 5.1 Peak-Hour Load Growth Forecast**

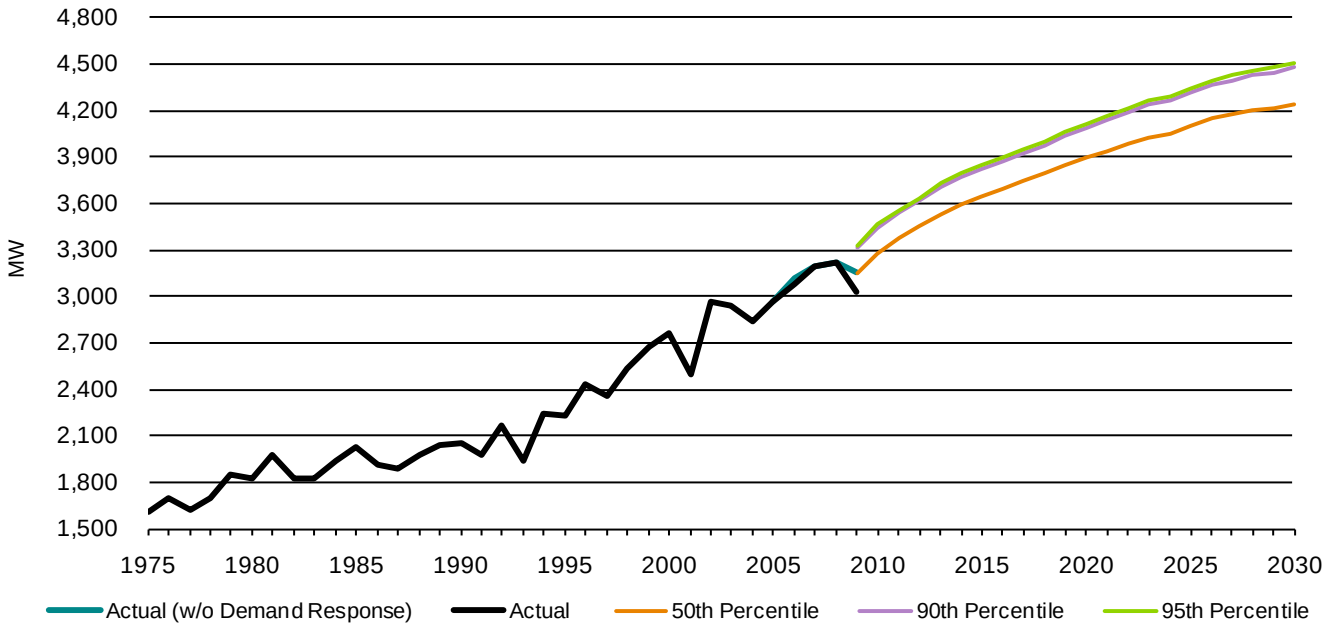


**Table 5.1 Load Forecast—Peak-Hour (MW)**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2009 (Actual) | 3,160 | 3,160 | 3,160 |
| 2010 | 3,279 | 3,439 | 3,460 |
| 2011 | 3,375 | 3,538 | 3,560 |
| 2012 | 3,447 | 3,614 | 3,636 |
| 2013 | 3,533 | 3,703 | 3,726 |
| 2014 | 3,592 | 3,766 | 3,789 |
| 2015 | 3,641 | 3,819 | 3,843 |
| 2016 | 3,689 | 3,871 | 3,895 |
| 2017 | 3,739 | 3,925 | 3,949 |
| 2018 | 3,790 | 3,978 | 4,003 |
| 2019 | 3,842 | 4,034 | 4,060 |
| 2020 | 3,895 | 4,091 | 4,118 |
| 2021 | 3,933 | 4,133 | 4,160 |
| 2022 | 3,980 | 4,183 | 4,210 |
| 2023 | 4,027 | 4,234 | 4,261 |
| 2024 | 4,052 | 4,262 | 4,290 |
| 2025 | 4,098 | 4,312 | 4,341 |
| 2026 | 4,146 | 4,364 | 4,393 |
| 2027 | 4,173 | 4,394 | 4,424 |
| 2028 | 4,204 | 4,430 | 4,460 |
| 2029 | 4,216 | 4,445 | 4,475 |
| Growth Rate *(2010–2029)* | 1.5% | 1.5% | 1.5% |

The median or expected-case peak-hour load forecast predicts peak-hour load will grow from 3,160 MW in 2009 to 4,216 MW in 2029, an average annual compound growth rate of 1.5 percent. The projected average annual compound growth rate of the 95th percentile peak forecast is also 1.5 percent. In the 95th percentile forecast, summer peak-hour load is expected to increase from 3,160 MW in 2009 to 4,475 MW in 2029. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 5.1.

Idaho Power's winter peak-hour load record was 2,527 MW, recorded on Thursday, December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to the variability of peak day temperatures in winter months which is far greater than the variability of peak day temperatures in summer months.

## *Average-Energy Load Forecast*

Potential monthly average energy use by customers in Idaho Power's service area is defined by a series of four load forecasts that reflect a range of load uncertainty resulting from differing economic growth and weather-related assumptions. Figure 5.2 and Table 5.2 show the results of the four forecasts used in the 2009 IRP to estimate the boundaries of annual system load growth over the planning period. There is approximately a 90 percent probability that Idaho Power's load growth will exceed the low-load growth forecast, a 50 percent probability of load growth exceeding the expected-case forecast, a 30 percent probability of load growth exceeding the 70th percentile forecast, and approximately a 10 percent probability that load growth will exceed the high-growth forecast. The projected 20-year average annual compound growth rate in the expected-load forecast is 0.7 percent.

Idaho Power uses the 70th percentile forecast as the basis for monthly average energy planning in the IRP. The 70th percentile forecast is based on 70th percentile weather to forecast average monthly load, 70th percentile water to forecast hydro generation, and 95th percentile average peak day temperature to forecast monthly peak-hour load.

**Figure 5.2 Average Monthly Load Growth Forecast**

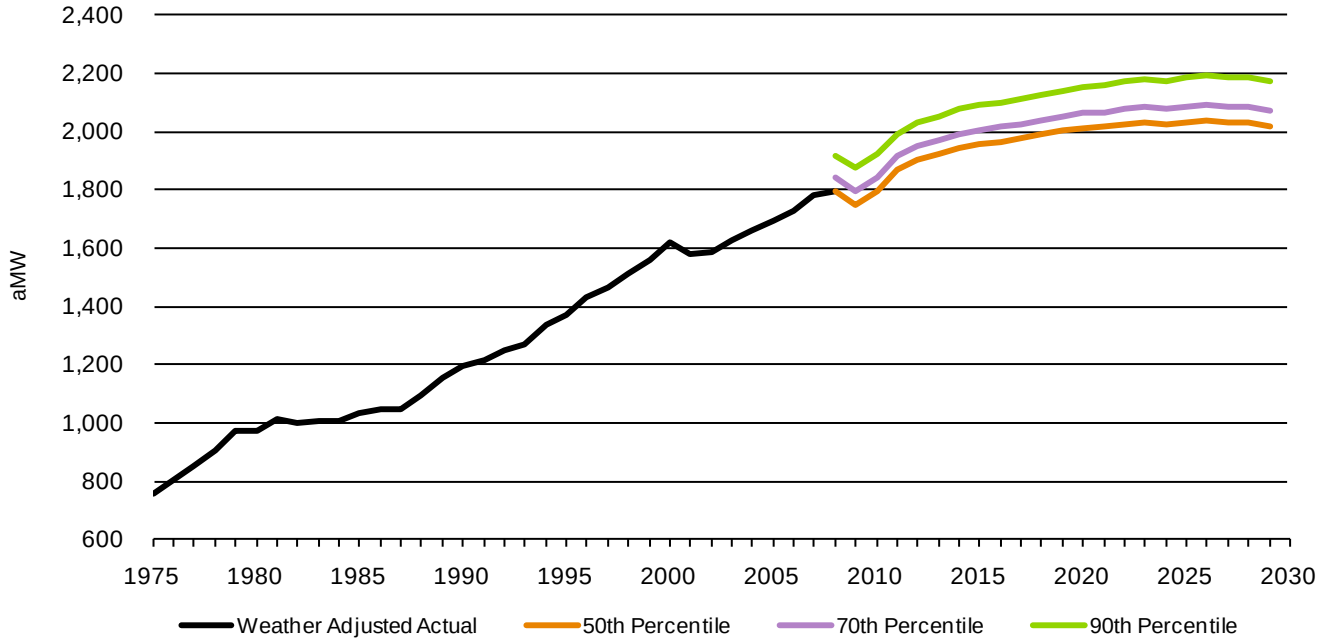



**Table 5.2 Load Forecast—Average Monthly Energy (aMW)**

| Year | Median | 70th Percentile | Low | High |
|---|---|---|---|---|
| 2010 | 1,797 | 1,842 | 1,796 | 1,863 |
| 2011 | 1,869 | 1,914 | 1,834 | 1,933 |
| 2012 | 1,906 | 1,952 | 1,851 | 1,974 |
| 2013 | 1,926 | 1,972 | 1,859 | 2,003 |
| 2014 | 1,947 | 1,994 | 1,857 | 2,020 |
| 2015 | 1,957 | 2,005 | 1,858 | 2,039 |
| 2016 | 1,967 | 2,015 | 1,858 | 2,055 |
| 2017 | 1,979 | 2,028 | 1,864 | 2,078 |
| 2018 | 1,991 | 2,040 | 1,857 | 2,085 |
| 2019 | 2,002 | 2,051 | 1,862 | 2,105 |
| 2020 | 2,013 | 2,063 | 1,867 | 2,125 |
| 2021 | 2,017 | 2,067 | 1,872 | 2,145 |
| 2022 | 2,026 | 2,077 | 1,886 | 2,174 |
| 2023 | 2,032 | 2,083 | 1,901 | 2,205 |
| 2024 | 2,024 | 2,077 | 1,917 | 2,237 |
| 2025 | 2,035 | 2,088 | 1,932 | 2,268 |
| 2026 | 2,041 | 2,094 | 1,947 | 2,297 |
| 2027 | 2,034 | 2,088 | 1,961 | 2,328 |
| 2028 | 2,030 | 2,084 | 1,977 | 2,359 |
| 2029 | 2,015 | 2,070 | 1,991 | 2,389 |
| Growth Rate | 0.7% | 0.7% | 0.6% | 1.6% |

## Additional Firm Load

Special contracts currently exist for five large customers that are recognized as firm load customers. The five customers are Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), Hoku Materials, and Raft River. Together, these customers make up the additional firm load category.

### Micron Technology

Micron Technology is currently Idaho Power's largest individual customer. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200 millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. Micron Technology will continue to operate its 300 mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility, at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on Moody's forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

### Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing sector for the Pocatello MSA.

### Idaho National Laboratory

The INL is a U.S. Department of Energy (DOE) research facility located in eastern Idaho. The INL is operated for the DOE by Battelle Energy Alliance, LLC which includes the Battelle Memorial Institute teamed with several institutions, including BWXT Services, Inc., Washington Group International, the Electric Power Research Institute, and the Massachusetts Institute of Technology (MIT). The laboratory employs about 8,000 people.

The DOE provided an energy consumption and peak demand forecast through 2029 for the INL. The DOE forecast calls for loads to increase through 2012, remain flat for six years, and then slowly decline throughout the remainder of the forecast period.

### Hoku Materials, Inc.

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2012.

## Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison. Table 5.3 provides a summary of six planning scenarios analyzed for the 2009 IRP and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2009 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2009 IRP are consistent with the criteria used in the 2006 IRP.

**Table 5.3 Planning Criteria for Average Load and Peak-Hour Load**

| | |
|---|---|
| **Average Load/Energy (aMW)** | 50th Percentile Water, 50th Percentile Average Load<br>**70th Percentile Water, 70th Percentile Average Load**<br>90th Percentile Water, 70th Percentile Average Load |
| **Peak-Hour Load (MW)** | 50th Percentile Water, 90th Percentile Peak-Hour Load<br>70th Percentile Water, 95th Percentile Peak-Hour Load<br>**90th Percentile Water, 95th Percentile Peak-Hour Load** |

The planning criteria used for energy or average load are 70th percentile water and 70th percentile average load. In addition, 50th percentile water and 50th percentile average load conditions are analyzed to represent a median condition, and 90th percentile water and 70th percentile average load are analyzed to examine the effects of low water conditions.

Peak-hour load planning criteria consist of 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system. A median condition of 50th percentile water and 50th percentile peak hour load are also analyzed, as well as 70th percentile water and 95th percentile peak-hour load. Peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods. Surpluses and deficiencies for the average and peak-hour load scenarios can be found in *Appendix C–Technical Appendix*.

## Existing Resources

In order to identify the need and timing of future resources, Idaho Power prepares a load and resource balance which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are shown in *Appendix C–Technical Appendix.* The following sections describe recent events or changes that are accounted for in the load and resource balance regarding Idaho Power's hydro, thermal, and transmission resources.

## Hydro



Idaho Power manages stream flows for energy and wildlife.

For the 2009 IRP, Idaho Power continues the practice of using 70th percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means that basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90th percentile streamflow conditions to project peak-hour hydroelectric generation. The 90th percentile means that streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse than median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50th percentile (median) streamflow conditions because the median streamflow condition is still used for rate setting purposes and other analyses.

The 50th, 70th, and 90th percentile streamflow forecasts used in the IRP are derived from a streamflow planning model developed by the Idaho Department of Water Resources (IDWR). The IDWR streamflow planning model is used by Idaho Power to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2005. The normalized model accounts for current hydro conditions and historical hydro development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

In the past, Idaho Power has assumed the representative streamflow conditions calculated from the normalized record are static through the IRP planning period. For example, the practice has been to assume that a 70th percentile year in 2010 is identical to a 70th percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the Eastern Snake Plain Aquifer (ESPA) is mirrored by downward trends in total surface water outflow from the river basin. The Comprehensive Aquifer Management Plan (CAMP) for the ESPA includes demand reduction and weather modification measures which will add new water to the basin water budget. However, it is the judgment of Idaho Power hydrologists that the positive effect of the new water associated with the new measures is likely to be temporary, and over time the water use practices driving the steady decline over recent years are expected to resume and result in a return to persistently declining basin outflows. For this reason, Idaho Power assumes that aside from a temporary increase in flows associated with the phasing in of demand reduction and weather modification measures, flows in the Snake River Basin are expected to decline year to year throughout the IRP planning period. The expected year to year decline in annual hydroelectric generation is less than 0.5 percent.

River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies have indicated a desire to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional

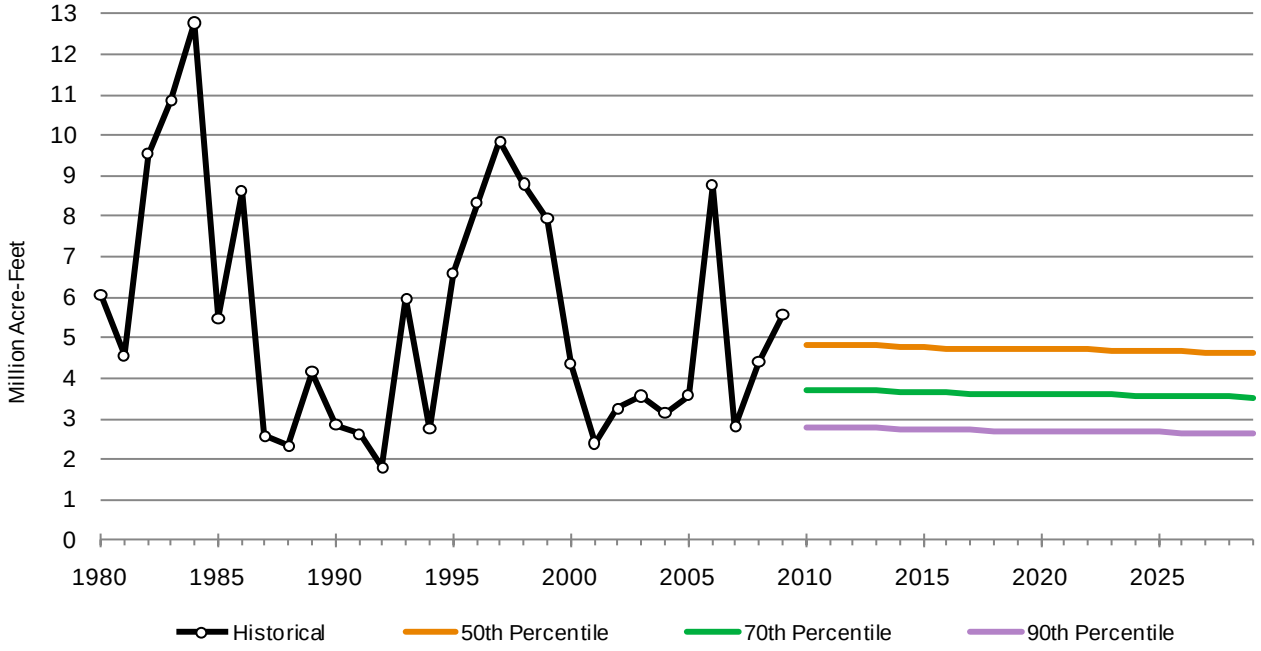
months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of the naturally occurring flow conditions. A federal study report indicates the shift in water delivery is most likely to take place during worse than median water years.

Because worse-than-median water is assumed in the IRP, and the importance of July as a resource constrained month, Idaho Power has incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on preliminary resource planning analyses, monthly average hydroelectric generation for July under the 70$^{th}$ percentile streamflow condition is projected to decline by approximately 115 aMW as a result of the water being shifted out of the month of July.

Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the Hells Canyon Complex as run-of-river plants. The generation model mathematically manages reservoir storage in the Hells Canyon Complex to meet the remaining system load, while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, an internally developed spreadsheet utilizing a commercial optimization routine is used to shape the monthly average generation for the Brownlee, Oxbow, and Hells Canyon projects into hourly generation profiles, while approximating compliance with Hells Canyon outflow ramp rate constraints, Brownlee Reservoir level constraints, and operating reserve obligations.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April–July runoff period. Figure 5.3 shows historical April–July Brownlee inflow as well as forecast Brownlee inflow for the 50$^{th}$, 70$^{th}$, and 90$^{th}$ percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability, but do include reductions related to declining base flows in the Snake River.

**Figure 5.3 Brownlee Historical and Forecast Inflows**



Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes that there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2009 IRP.

## Thermal

Idaho Power's thermal generation resources are comprised of coal and natural gas-fired facilities. The coal-fired resources generally operate 24 hours-per-day, every day, to provide baseload energy. The natural gas-fired resources are generally used to meet peak-hour load on certain days during the summer months.

Monthly average energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for regularly scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydro generation, seasonally low market prices, and moderate customer load.

Plant modifications that are required to maintain compliance with air-quality standards are projected for the Boardman plant in 2014 and 2018, for the Valmy plant in 2018, and for the Bridger plant in 2009, 2015, and 2016. The total effect of the air quality modifications is a reduction in coal-fired generation of less than one percent. Offsetting the modifications at the Jim Bridger plant are planned efficiency upgrades that will create a net increase in average generation of 17 aMW by 2016.

With respect to peak-hour output, the coal-fired projects are forecast to generate at the full rated maximum dependable capacity, minus six percent to account for forced outages. The gas-fired resources are projected to be fully available to meet extreme load conditions or during periods of transmission congestion. The peaking capability of the natural gas resources is adjusted seasonally to reflect the effect of ambient air temperature.

### Planned Upgrades at Thermal Facilities

Efficiency upgrades are planned for each of the four units at the Jim Bridger plant starting in 2010. The upgrades consist of replacing turbine components with higher efficiency designs for each unit's high pressure, intermediate pressure, and low pressure turbines. This project will start with the high pressure/intermediate pressure turbine upgrade on Unit 1 which will result in a generation increase of 2.1 MW. The low pressure turbines on Unit 1 will be replaced in 2018 which will increase output by another 4 MW for a total of 6.1 MW. Units 2, 3, and 4 will have all high pressure, intermediate pressure, and low pressure turbines replaced in 2016, 2017, and 2019. Idaho Power's share of the projected generation increase associated with each upgrade is a total of 6.1 MW per unit, with the increased output related solely to efficiency improvements with no additional fuel required. Idaho Power's share of the costs for the upgrades is expected to be approximately $11 million per unit.

### Coal Price Forecast

The expected coal price forecast for the 2009 IRP is an average of Idaho Power's coal forecasts for its Valmy and Jim Bridger thermal plants. The coal price forecasts were created using current coal and rail transportation market information and the Global Insight 2008 U.S. Power Outlook report. The resulting costs are shown in Figure 5.4 and represent the delivered cost of coal, including rail costs, and use taxes. A summary of the coal price forecast can also be found in *Appendix C–Technical Appendix*.

### Transmission Resources

Transmission constraints are an important factor in Idaho Power's ability to reliably serve peak-hour load. Idaho Power uses spot market purchases when the company's generating resources and firm purchases are inadequate to meet peak-hour load requirements and transmission constraints limit Idaho Power's ability to import additional energy.

For the IRP, the transmission analysis requires hourly forecasts for the entire 20-year planning period for both customer load and company generation. The hourly transmission analysis is used to quantify the magnitude of off-system market purchases necessary to serve forecast load, and to determine if adequate transmission capacity is available to deliver additional market purchases to load centers.

From the hourly load and generation forecasts, a determination can be made regarding the need for, and the magnitude of, the off-system market purchases needed to serve system load. The projected off-system market purchases are added to all other committed transmission obligations to determine if the additional imported energy will exceed the operational limits of the transmission system. The analysis assumes that all off-system market purchases will come from the Pacific Northwest.

Historically, during Idaho Power's peak-hour load periods, off-system market purchases from the east and south have proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power also experience a summer peak, and the weather conditions that drive Idaho Power's summer peak-hour load are often similar across the Intermountain Region. Therefore, Idaho Power does not typically rely on imports from the Intermountain Region for planning purposes.

For the 2009 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90$^{th}$ percentile streamflows, 70$^{th}$ percentile load, and 95$^{th}$ percentile peak-hour load. The 95$^{th}$ percentile peak-hour load planning criterion means that there is a one in twenty chance that Idaho Power will be required to initiate more drastic measures such as curtailing load if attempts to acquire energy and transmission access from the spot market are unsuccessful.

Idaho Power used the results of the transmission analysis to establish a capacity target for planning purposes. The capacity target identifies the amount of additional generation, demand response programs, or transmission resources that must be added to Idaho Power's system to avoid capacity deficits.

On a yearly basis, Idaho Power's transmission capacity is reserved for native load service based on annual load and resource forecasts. Although transmission resources are owned by Idaho Power, the unreserved transmission capacity may be purchased by other parties due to FERC's open access requirements. Idaho Power must reserve the use of its own transmission system under FERC's open access rules. Often, Snake River flow forecasts for the remainder of the year are not known with a high degree of accuracy until May or June and late spring is often too late to acquire firm transmission capacity for the summer months.

## Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2009 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The forecast sources include the Northwest Power and Conservation Council (NPCC), the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Global Insight.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness when compared with other forecasts, and the current forward price of actual contracts

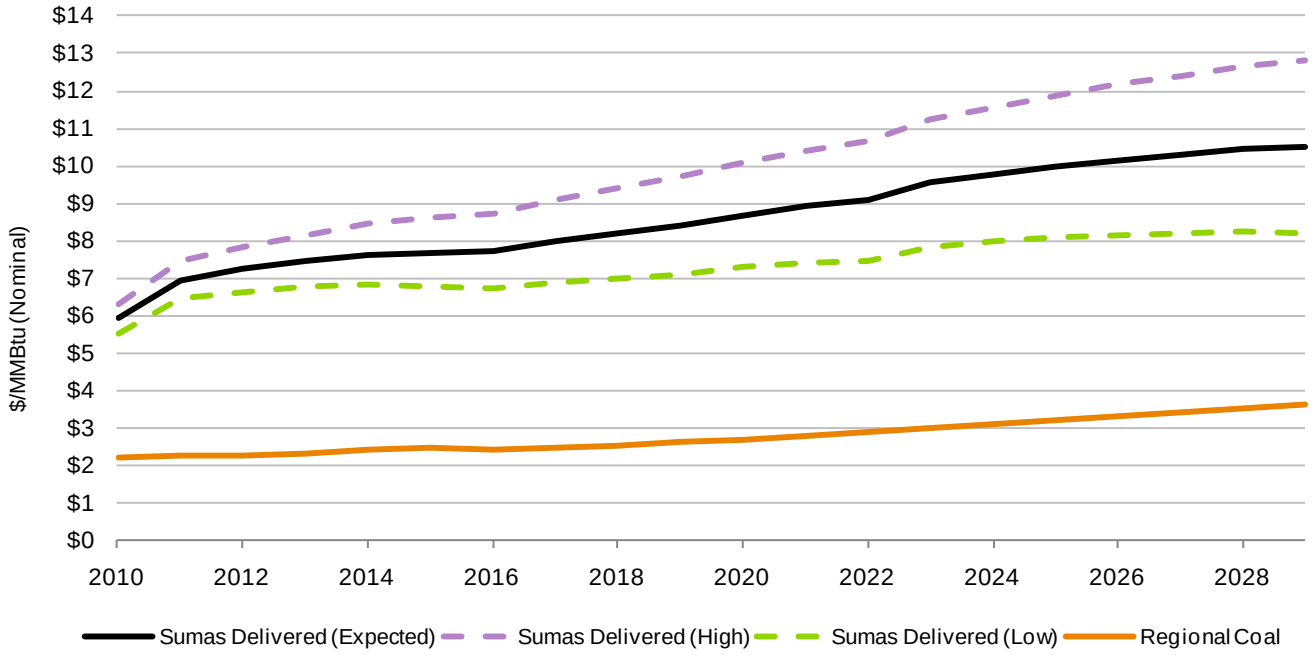
being executed on various exchanges. In the near-term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to the longer term forecast which is weighted more heavily towards projected prices without underlying financial trades (EIA, Global Insight).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2009 IRP assumes pipeline transport capacity will be available for future resources at the current tariff rate that is included in the natural gas price forecast.

The Henry Hub price including the Sumas adjustment is shaped by month to reflect the normal seasonal supply and demand price variation. The gas price forecast in all future years receives the same monthly price shaping. Sumas gas prices can have high spot seasonal price variability, especially in the winter months and the Sumas price volatility is not included in the regional adjustment. Idaho Power's geographic position between Sumas gas and Rockies gas allows Idaho Power to access two independent gas markets that may not have high price correlation. Also, Idaho Power expects the majority of the gas planned for use in the resource portfolios will be scheduled and purchased on longer term contracts which will diminish Idaho Power's exposure to spot price and seasonal price volatility.

In addition to an expected gas price forecast, high and low natural gas price forecasts are developed in order to analyze the risk associated with prices substantially different than the expected-case. Figure 5.4 shows the expected, high and low natural gas price forecasts used in the 2009 IRP.

**Figure 5.4 Fuel Price Forecast**



## Cost of Carbon Emissions

Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than has been done in previous IRPs. Historically, a "carbon adder" or tax has been used to account for the social costs of emitting carbon or other combustion byproducts. The purpose of a carbon adder is to account for all of the costs in the price of energy produced by carbon-emmitting resources. Both the Waxman–Markey bill (H.R. 2454) and the Boxer–Kerry bill (S. 1733) propose a cap-and-trade system for reducing carbon emissions and Idaho Power considers the implementation of a cap-and-trade system to be more likely than a carbon tax.

Although Idaho Power believes a cap-and-trade system is more likely, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has also done. However, the primary discussion in the 2009 IRP regarding carbon emissions is related to Idaho Power's attempt to model a cap-and-trade scenario under the provisions of the Waxman–Markey bill. To model the cap-and-trade scenario, Idaho Power has reduced the output from its coal facilities based on the number of allowances that are expected to be allocated to the company. The cost of resource portfolios with emissions in excess of the allocated amount of allowances are increased by purchasing additional allowances.

The primary reason for adopting the cap-and-trade analysis in the 2009 IRP is to quantify the effects of the proposed carbon legislation. Idaho Power's analysis indicated that a pure carbon tax increased portfolio costs but did not result in a substantial reduction of emissions. Since the purpose of the legislation is to reduce carbon emissions, Idaho Power selected a modeling approach that actually reduced carbon emissions. In addition, Idaho Power considers the cap-and-trade legislation the most likely to be implemented.

In order to quantify the cost of the proposed legislation, Idaho Power has also modeled a scenario where output from existing coal facilities has not been curtailed. A more thorough discussion of the analysis of carbon emissions is contained in Chapters 8, 9 and 10.

# 6. Supply-Side Resources

Supply-side facilities are traditional generation resources. Early integrated resource plan (IRP) utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. The company has done that and today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe all of the supply-side resources that were considered when Idaho Power developed the resource portfolios for the 2009 IRP. Not all of the supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described below was considered.

## Renewable Resources

Renewable resources are the foundation of Idaho Power and the company has a long history of renewable resource development and operation. In the 2009 IRP, renewable resources were included in all portfolios analyzed in order to meet proposed federal renewable electricity standard (RES) legislation. Renewable resources are discussed in general terms in the following sections.



The Raft River Geothermal Project is located in southern Idaho.

### *Geothermal*

Potential commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary-cycle technologies. Based on exploration to date in southern Idaho, binary-cycle geothermal development is more likely than flashed steam within Idaho Power's service area. Most of the optimal locations for potential geothermal development are believed to be in the southeastern part of the state. However, the potential for geothermal generation in southern Idaho is somewhat uncertain. In addition, the time required to discover and prove geothermal resource sites is highly variable and can take years, or even decades.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flash steam plants are applicable for geothermal resources where the fluid temperature is 300º Fahrenheit (F) or greater. Binary-cycle technology is used for lower temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed

**Highlights**

- Idaho Power expects to have over 600 MW of wind generation on its system by 2012.
- For the 2009 IRP, Idaho Power hired Black & Veatch to perform a feasibility study for solar technologies in southwest Idaho.
- Simple-cycle combustion turbines (SCCT) continue to be one of the lowest cost supply-side peaking resources because of low fixed costs.
- The dairy industry in southern Idaho has spurred the development of several biomass projects under the Public Utilities Regulatory Policies Act (PURPA).

through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters for binary cycle geothermal generation in the IRP are based on data from independent geothermal developers and information from the Geothermal Energy Association. Estimates for flashed steam geothermal generation are based on data from the Northwest Power and Conservation Council's (NPCC) Fifth Power Plan (2005).

## Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 megawatts (MW) each. The majority of the potential wind sites in southern Idaho lie between the south central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles-per-hour are prime locations for wind development.

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain Region, which is evidenced by the number of existing and planned projects. Wind resources present a problem for utilities due to the variable and intermittent nature of wind generation. Therefore, planning for new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2009 IRP, Idaho Power used an annual average capacity factor of 32 percent and a capacity factor of 5 percent for peak-hour planning.

Idaho Power currently has 192 MW (nameplate) of wind generation on-line. Signed PURPA contracts exist for 266 MW of wind generation that is expected to be on-line by the end of 2010. The 2012 Wind Request for Proposals (RFP) is also expected to add up to 150 MW by 2012, which will put the total wind generation on Idaho Power's system in excess of 600 MW. Given this projected increase, it is critical that integration methodologies in practice continue to evolve through ongoing operational experience and further study. Idaho Power plans to update its wind integration study in the first half of 2010 during the time between filing the 2009 IRP and starting the 2011 IRP process in July 2010. The updated study will incorporate planned increases in wind generation as well as the capability of the new Langley Gulch combined-cycle combustion turbine (CCCT) to provide additional operating reserves.

## Hydro

Hydropower is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants like fossil fuel based resources. Idaho Power believes the development of new large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

Because small hydro, in particular, run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydro, the IRP Advisory Council (IRPAC) expressed an interest in including small hydro in the 2009 IRP. The potential for new small hydro projects was recently studied by the Idaho Strategic Alliance's Hydropower Task Force. The results of this evaluation are presented in a draft report available on the Idaho Office of Energy Resources' (IOER) Web site at www.energy.idaho.gov. Idaho Power and others also continue to evaluate pumped storage opportunities and the state of Idaho is examining possible large water storage projects for flow augmentation and the potential for hydropower.

Due to the potential regulation of carbon emissions and associated costs, new small hydro may become a good resource option for Idaho Power. However, uncertainty exists in the level of available sites and the likelihood the sites would be developed as PURPA projects.

## Solar

There are two primary types of solar technology; solar thermal and photovoltaic (PV). Solar thermal technologies utilize mirrors to focus the sun's rays onto a central receiver or a "collector" to collect thermal energy that can be used to make steam and power a turbine, creating electricity. PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons creating an electric current.

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods, generally for three to seven hours. PV technology uses panels that convert the sun's rays directly to electricity. Even on cloudy days, a PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kilowatt hour (kWh)/$m^2$/day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratories (NREL) insolation charts show the Desert Southwest has the highest solar potential in the United States.

For the 2009 IRP, Idaho Power hired Black & Veatch to perform an independent, evaluation of the feasibility of using solar generation technology in southwest Idaho. The purpose of the study was to identify solar power generation technology options for southwest Idaho and to develop cost estimates associated for each technology. In the study, Black & Veatch concluded that during the summer, southwest Idaho's insolation is very similar to the desert Southwest. However, during winter months insolation values are approximately 50 percent lower than the Desert Southwest.

Black and Veatch modeled generation output of the various technologies using the Boise weather station because of its robust data set. Depending on the solar technology, capacity factors ranged from 17 to 28 percent, and for a 100 MW facility, land requirements ranged from 570–1,300 acres. The modeled generation for an entire year resulted in the highest production occurring in July and the lowest in January and February.

Idaho Power's peak demand occurs during July typically between 4:00 p.m. and 8:00 pm and is primarily due to air conditioning and irrigation load. Modeled July daily generation output from a parabolic trough or power tower with molten salt storage closely follows the system load curve on summer peak days. Additional details and the entire Black & Veatch study can be found on Idaho Power's Web site at www.idahopower.com. The cost estimates contained in the study were used in the 2009 IRP.

### Solar Generation Technologies

Black & Veatch analyzed various solar thermal and photovoltaic technologies in the study. The following sections contain details on each of the technologies.

#### *Parabolic Trough*

Parabolic trough technology is a closed looped system that consists of a solar field where single axis parabolic mirrors heat pipes containing a transfer fluid. The hot fluid returns from the solar field where heat energy is transferred to water, creating steam at 700 F. The steam is then used to drive a turbine and

generate electricity. In addition to heating water for steam, the hot fluid can also heat salt until the salt becomes molten. When the sun is not shining, the transfer fluid can be heated by the molten salt. After transferring the heat energy, the fluid returns to the solar field to be reheated.

#### *Power Tower*

Power tower technology uses thousands of small, flat, two-axis mirrors, called heliostats, to reflect the sun's rays onto a boiler at the top a central tower. The concentrated sunlight strikes the boiler's pipes, heating the water inside to 1,000°F. The high temperature steam is then piped from the boiler to a turbine where electricity is generated.

#### *Parabolic Dish Engine*

A two-axis parabolic dish focuses the sunlight striking the dish onto a collector placed above the dish. The collector is connected to a Stirling engine which uses the thermal energy to heat hydrogen in a closed-loop system. The expansion of the hydrogen gas creates a pressure wave on the pistons of the Stirling engine which turns a generator to create electricity.

#### *Photovoltaic*

PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons creating an electric current. The solar cells have one or more electric fields which force electrons to flow in one direction as a direct current (DC). The DC energy is passed through an inverter, converting it to alternating current (AC) which can then be used on-site, stored in a battery, or sent to the grid.

## Biomass

Biomass fuels, such as wood residues, organic components of municipal solid waste, animal manure, and wastewater treatment plant gas, can be used to power a turbine or reciprocating engine to produce electricity. Most of the biomass generating resources in the region are small-scale local cogenerating facilities operating under PURPA contracts. The use of biomass fuels has not proven to be economic for large scale commercial power production. Available fuel supply can vary as production from the industry fluctuates. The biomass fuel sources assumed in the resource cost analysis for the 2009 IRP are wood by-products from the forest and wood products industry. Because of the relatively small size of biomass projects and recent PURPA biomass project development, biomass resources were not included in the portfolios analyzed for the 2009 IRP.




Biomass energy is produced from agricultural waste in southern Idaho.

## River In-stream Generation

River in-stream generation is the conversion of the kinetic energy of water in free flowing rivers and channels to electricity. River in-stream energy conversion (RISEC) technology is still largely in a conceptual stage of development, with a few small vendors focused on the technology and limited operating experience in natural waters. The use of in-stream generation has not proven to be economic for large scale or commercial power production. The cost estimates and operating parameters for

in-stream generation are based on data from a feasibility study performed by the Electric Power Research Institute (EPRI) on two specific locations in Idaho Power's service area.

## Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine in order to generate electricity. CCCT are typically used for baseload energy, while less efficient SCCT are used to generate electricity during peak load periods. Additional details on the characteristics of both types of natural gas resources are presented in the following sections.

### *Combined-Cycle Combustion Turbines*

Until recently, CCCT plants have been the preferred choice for new commercial power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits less harmful emissions when compared to coal.




Natural gas-fired generation is an important component of Idaho Power's resource portfolio.

A traditional CCCT plant consists of a gas turbine/generator equipped with a heat recovery steam generator (HRSG) to capture waste heat from the turbine exhaust. The HRSG produces steam that drives a steam-turbine generator to produce electricity. In a CCCT plant, heat that would otherwise be wasted is used to produce additional power beyond that typically produced by a SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined cycle units.

Several CCCT plants, including Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. If natural gas supplies become constrained, efforts will have to be made to identify additional regional sources or off shore sources through the construction of liquefied natural gas terminals.

### *Simple-Cycle Combustion Turbines*

Simple-cycle natural gas turbine technology involves pressurizing air which is then heated by burning gas in fuel combustors. The hot pressurized air is expanded through the blades of the turbine which is connected by a shaft to the electric generator. Designs range from larger industrial machines at 80–200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are not typically economical to operate other than to meet peak-hour load requirements.

Several natural gas-fired SCCTs have been brought on-line in the region in recent years primarily in response to the regional energy crisis of 2000–2001. High electricity prices combined with persistent drought conditions during the 2000–2001 time period as well as continued summertime peak load growth created interest in generation resources with low capital costs and relatively short construction lead times.

Idaho Power currently has approximately 430 MW of SCCT resources. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been constructed to meet peak load during the critical high demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest. Like CCCTs, feasible sites and gas supply currently exist for future SCCT development. The SCCT resources studied in the 2009 IRP are assumed to be located in southwestern Idaho in close proximity to the mainline fuel supply and near Idaho Power's main load center in the Treasure Valley. Furthermore, in the 2009 IRP, natural gas pipeline capacity is assumed to be available. Given the limits of available natural gas pipeline capacity, Idaho Power may need to begin acquiring additional transport capacity.

## Conventional Coal Resources

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. Traditional pulverized coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,000 MW of pulverized coal generation in service. All of Idaho Power's pulverized coal generation is in neighboring states and is owned with other regional utilities.



The Boardman Plant in Oregon provides baseload energy to Idaho Power customers.

A pulverized coal facility uses coal that is ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine and generator. Emission controls at coal plants have become increasingly important in recent years and many units in the region have been upgraded to include the latest scrubber and low Nitrous Oxide (NOx) burner technology to help reduce harmful emissions and particulates. Coal has the highest ratio of carbon-to-hydrogen of all the fossil fuels and significant research is being done in hopes of developing carbon capture and sequestration technology that can be economically added to existing coal facilities.

Even though coal-fired power plants require significant capital commitments to develop, coal resources take advantage of a low-cost fuel and provide reliable and dispatchable energy. Coal supplies are abundant in the Intermountain Region and are sufficient to fuel Idaho Power's existing plants for many years to come.

In 2007, Idaho Power decided to not pursue the development of a coal-fired resource identified in the 2006 IRP. In addition to considering the cost of a coal-based resource, the company considered the uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly owned facilities as well as monitoring the development of clean coal technologies. However, due to the uncertainty regarding future carbon regulations, conventional coal resources were not included in any of the portfolios analyzed in the 2009 IRP.

## Advanced Nuclear

The *Energy Policy Act of 2005* authorized funds to be appropriated for the development of a next-generation nuclear power project at the Idaho National Laboratory (INL). The project would consist of the research and development, design, construction, and operation of a prototype plant, including a nuclear reactor used to generate electricity, produce hydrogen, or both. The target completion date for the prototype nuclear reactor is September 2021. For fiscal years 2006–2015, $1.25 billion has been authorized for appropriation. In addition, the act authorizes additional appropriations deemed necessary between fiscal years 2016–2021 to complete the project. Whether funds will actually be appropriated to develop the project is unknown at the present time.

The act also establishes tax credits for up to 6,000 MW of new advanced nuclear power development. Projects must be in service by January 2021 to qualify. Multiple projects in the southeastern states will likely make up the next 6,000 MW of development, and therefore qualify for the credits. The first of the new nuclear projects are expected to be on-line by 2014. Idaho Power will follow the progress of the projects in the coming years and special attention will be paid to the issues surrounding spent nuclear fuel disposal.

In the 2006 IRP, the preferred portfolio included a power purchase agreement (PPA) for a 250 MW share of the proposed Next Generation Nuclear Plant project beginning as early as 2022. Recent discussions with INL suggest the likelihood of the project being located in Idaho is less than when the 2006 IRP was prepared. Although the preferred portfolio for the 2009 IRP does not contain a nuclear resource, Idaho Power will continue to monitor the progress of the advanced nuclear research and development efforts as well as new modular nuclear designs that are being proposed and investigated by others.

## Resource Advantages and Disadvantages

Different resource types have specific characteristics that can be either an advantage or a disadvantage. In order to summarize the differences between the resource types, Idaho Power has prepared Table 6.1 which shows both the advantages and disadvantages of the resources analyzed in the 2009 IRP.

## Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2009 IRP. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources including, but not limited to, the NPCC, Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as:

- Levelized fixed cost-per-kilowatt (kW) of installed (nameplate) capacity per month, and
- Total levelized cost-per-megawatt hour (MWh) of expected plant output or energy saved, given assumed capacity factors and other operating assumptions.

The levelized costs for the various supply-side alternatives include the cost of capital, operating and maintenance (O&M) costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the cost of capital for the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system backbone upgrade costs were estimated by Idaho Power's transmission planning group. The cost of capital also includes Allowance for Funds Used During Construction (AFUDC–capitalized interest). The O&M portion of each resource's levelized cost

includes general estimates for property taxes and property insurance premiums. The value of renewable energy credits (RECs) is not included in the levelized cost estimates.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, annual incentive or rebate payments, and annual participant costs. The demand-side resource costs do not reflect the financial impact to Idaho Power as a result of these load reduction programs.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are shown in *Appendix C–Technical Appendix.*

**Table 6.1 Supply-Side Resources Advantages and Disadvantages**

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Geothermal** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk (once developed)<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• High exploration costs due to drilling risks<br>• Uncertainty surrounding future tax incentives |
| **Wind** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of good sites in southern Idaho<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Avian and aesthetic impacts<br>• Uncertainty surrounding future tax incentives |
| **Hydro** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of sites<br>• Future development is limited to small sites or at existing dams without power generation<br>• Fish and other environmental issues |
| **Solar** (General) | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs<br>• Generation would match well with summer peak loads. | • More expensive than other resource options<br>• Poor generation during winter months<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Limited utility scale projects exist |
| Parabolic Trough | • Can be built with thermal storage | • Utility scale production is limited |
| Power Tower | • By using molten salt, thermal storage can be built integrally into the system | • Utility scale production is unproven<br>• Requires land slope of 1 percent of less |
| Parabolic Dish | • Off-grid electricity production in remote areas | • Not suitable for storage options<br>• Unproven technology |
| Photovoltaic | • Proven & reliable technology<br>• Suitable for distributed generation | • Cloud cover creates a rapid power drop-off<br>• Utility scale projects are only practical up to 10 MW |
| **Biomass** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• Uncertainty surrounding future tax incentives<br>• Fuel supply risk |

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **In-stream Generation** | • Renewable resource<br>• No harmful emissions<br>• No fuel cost | • Small size, many sites would be required<br>• Environmental impact and permitting<br>• High maintenance cost |
| **Distributed Generation** | • Utilize existing backup generators at customer sites<br>• Dispatchable resource<br>• Provides operating reserves | • More expensive than other resource options<br>• Limited number of sites<br>• Fuel price risk and volatility<br>• Existing air quality permits may need to be modified<br>• Small size, many sites would be required |
| **Natural Gas** | | |
| Combined-Cycle Combustion Turbines (CCCT) | • Proven and reliable technology<br>• Dispatchable resource<br>• Provides operating reserves necessary for integration of renewable generation<br>• More efficient than a SCCT<br>• Greater than 50% reduction in $CO_2$ emissions per MWh of output compared to conventional pulverized coal technology | • Fuel price risk and volatility<br>• Potential fuel supply and transportation issues |
| Simple-Cycle Combustion Turbines (SCCT) | • Dispatchable resource<br>• Proven, reliable resource<br>• Low capital cost<br>• Short construction lead times<br>• Ideal for peaking service | • High variable operating cost<br>• Fuel price risk and volatility<br>• Less efficient than a CCCT |
| **Coal** | | |
| Pulverized | • Abundant, low cost fuel<br>• Less price volatility than natural gas<br>• Proven and reliable technology<br>• Dispatchable resource<br>• Well suited for baseload operations | • Potential lack of public acceptance<br>• Significant particulate and gas emissions, particularly $CO_2$<br>• Significant capital investment<br>• Long construction lead times<br>• Lengthy environmental permitting and siting processes |
| Advanced Technology | • Abundant, low cost fuel<br>• Potentially lower greenhouse gas emissions if $CO_2$ is sequestered<br>• Potential for financial incentives<br>• Dispatchable resource | • New, unproven technologies<br>• Higher capital costs than pulverized coal<br>• Long construction lead times |
| **Nuclear** | • Forecasted low fuel costs<br>• Forecasted adequate fuel availability<br>• Lack of greenhouse gas emissions<br>• Potential low cost of production<br>• Proven technology (existing reactor types) | • Lack of public acceptance<br>• Safety concerns<br>• Waste disposal<br>• Construction cost uncertainties and the potential for construction cost overruns<br>• Security concerns |

## Emission Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of the environmental and social costs. It is likely that further emissions regulations will be implemented during the period covered in the 2009 IRP.

In the analysis, Idaho Power incorporated estimates for the future costs of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emission adders for greenhouse gases (GHG), NOx, and mercury. The additional costs are assumed to begin in 2012. Table 6.2 provides the emission adder rates assumed in the analysis. Based on the assumptions in Table 6 2, Table 6.3 provides the emissions costs for the various fossil fuel-based resources that were analyzed.

**Table 6.2 Emissions Adder Assumptions**

| Adder | Cost in 2009 U.S. dollars | First Year Applied | Annual Escalation |
|---|---|---|---|
| GHG | $43 per ton | 2012 | 2.50% |
| $NO_x$ | 2,600 per ton | 2012 | 2.50% |
| Mercury | 1,443 per ounce | 2012 | 2.50% |

**Table 6.3 Emission Adders (lbs/MWh)**

| Adder | GHG | $NO_x$ | Hg |
|---|---|---|---|
| Pulverized Coal | 1,886 | 0.44 | 0.00 |
| IGCC | 1,797 | 0.21 | 0.00 |
| IGCC with Carbon Sequestration | 309 | 0.43 | 0.00 |
| Distributed Generation Diesel | 1,540 | 0.00 | 0.00 |
| SCCT | 1,127 | 0.11 | 0.00 |
| CCCT | 809 | 0.08 | 0.00 |

## Production Tax Credits for Renewable Generating Resources

Various federal tax incentives for renewable resources were extended and/or renewed within the Emergency Economic Stabilization Act of 2008. This legislation requires most projects to be on-line by December 31, 2016, to be eligible for the federal production tax credits (PTCs) identified in Section 45 of the Internal Revenue Code. The credit is earned on power produced by the project during the first 10 years of operation. The credit, which is adjusted annually for inflation is currently valued at $21 per MWh for wind and geothermal resources.

## Levelized Capacity (Fixed) Cost

The annual fixed revenue requirement in nominal dollars for each resource were summed and levelized over a 30 year operating life and are presented as dollars-per-kW of plant nameplate capacity per month. Included in these costs were the cost of capital and fixed O&M estimates. Figure 6.1 provides a combined ranking of all the various resource options, in order of lowest to highest levelized fixed cost-per-kW-per-month. The ranking shows that distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources do have high operating costs, but the operating costs are not as important when the resource is only used a limited number of hours per year to meet peak-hour demand.

## Levelized Cost of Production

Certain resource alternatives carry low-fixed costs and high-variable operating costs while other alternatives require significantly higher capital investment and fixed operating costs, but have low-variable operating costs. The levelized cost of production measurement represents the estimated annual cost-per-MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 6.2. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emission adders; however, no value for RECs was assumed in this analysis. Resources such as DSM measures, the Shoshone Falls upgrade, geothermal, wind, and certain types of thermal generation appear to be the lowest cost for meeting baseload requirements.

**Figure 6.1 30-Year Levelized Capacity (Fixed) Costs**

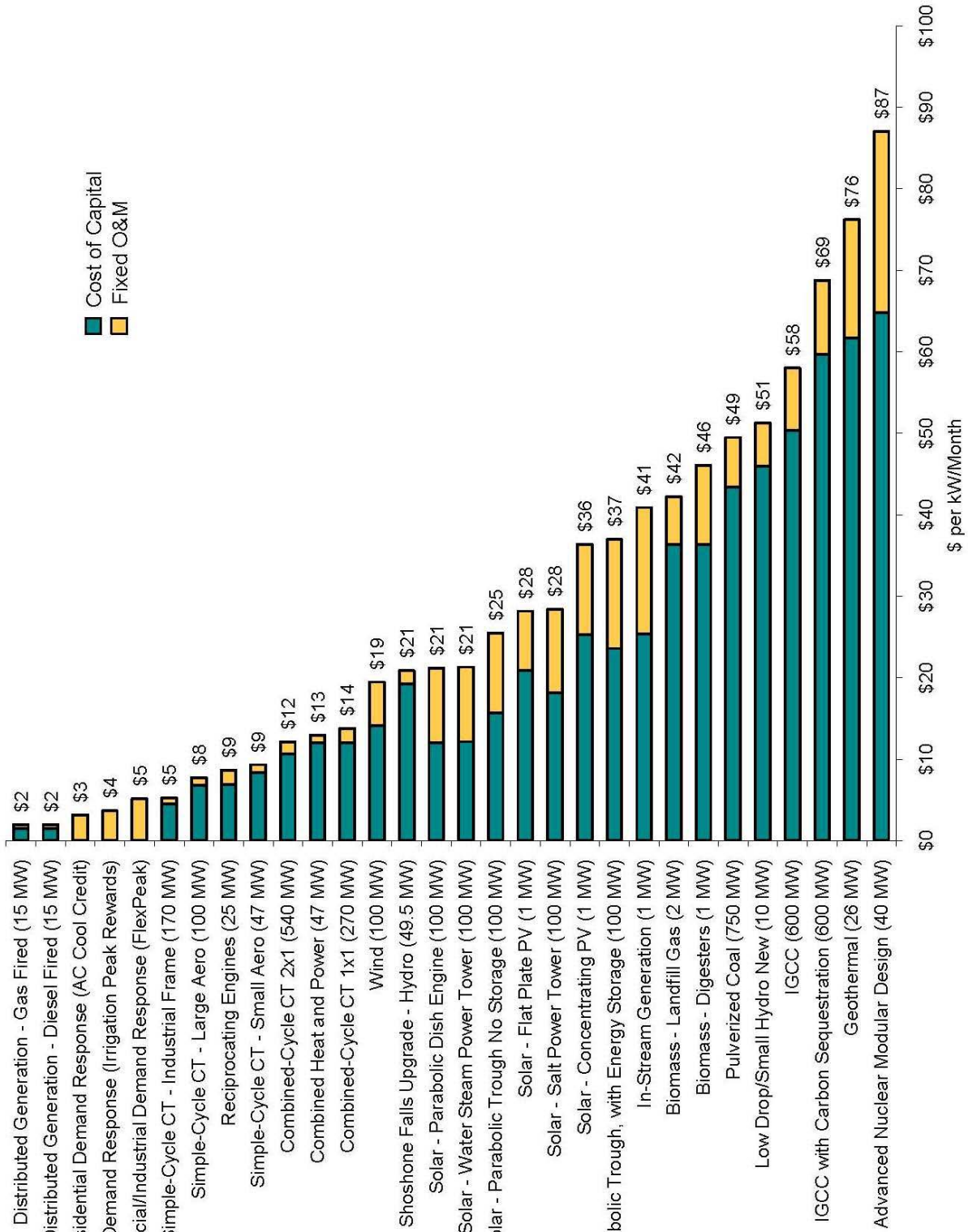
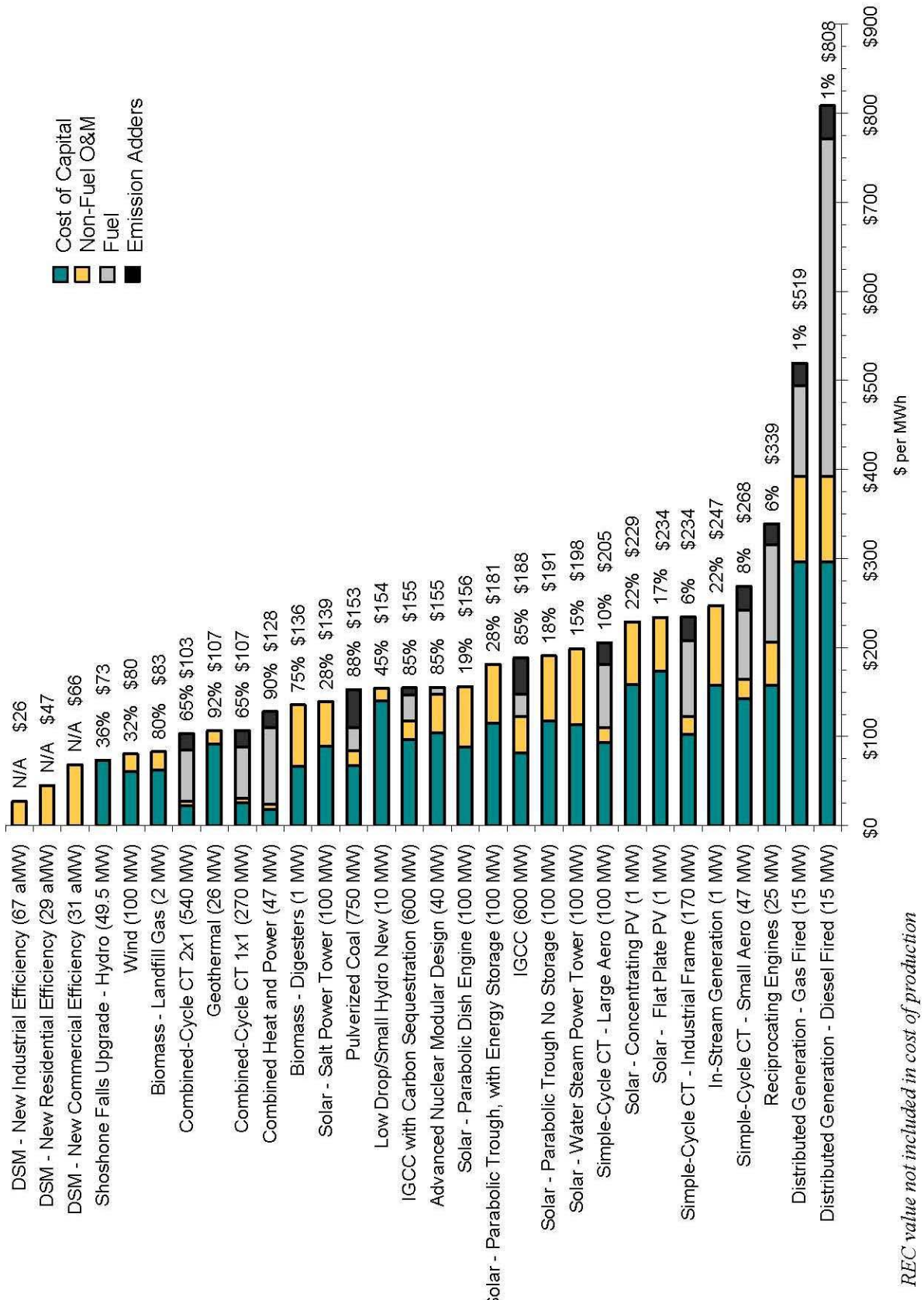


**Figure 6.2 30-Year Levelized Cost of Production (at Stated Capacity Factors)**



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# 7. TRANSMISSION RESOURCES



High-voltage transmission lines are necessary to interconnect with other regional utilities.

High-voltage transmission lines are a key element in operating Idaho Power's electrical system and are necessary for reliability, which makes them an essential part of Idaho Power's resource portfolio. In order to keep the electric power system balanced, generation must match system load at all times. Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities and also provide economic benefits from the ability to share operating reserves.

Historically, Idaho Power has been a "summer peaking" utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of this, Idaho Power is able to purchase energy from the Mid-Columbia market to meet peak summer load and sell excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits Idaho Power's customers because the construction of additional peaking resources is avoided and revenue from off-system sales is returned to customers through the power cost adjustment (PCA).

## Transmission Interconnections

While Idaho Power has added generation resources in the recent past to meet load growth, the ability to import additional amounts of energy from the Pacific Northwest has been, and continues to be, limited by constraints on the existing transmission system. Idaho Power's transmission system is shown in Figure 7.1 and the associated interconnections and capacities are shown in Table 7.1.

The rated capacity of a transmission path may be less than the sum of the individual circuit thermal capacities. The difference is due to a number of factors, including load distribution, potential outage impacts, and surrounding system limitations. In addition, not all of the transmission capacity identified in Table 7.1 is available for Idaho Power's use. Reliability reserve margins, ownership rights,

**Highlights**

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.
- Restrictions on the Brownlee-East and Northwest to Idaho transmission paths limit the import of Hells Canyon Complex generation and off-system purchases from the Pacific Northwest.
- The 500-kV Boardman to Hemingway project, expected to be in service in 2015, would be a major addition to the Brownlee-East and Northwest to Idaho paths and will remove the existing constraints.

contractual restrictions, and prior obligations commit much of the transmission capacity to other parties. In addition to the restrictions on interconnection capacities, other internal transmission constraints may limit Idaho Power's ability to access specific energy markets. The internal transmission paths needed to import resources from other utilities are shown in Figure 7.1 and Table 7.1. The following sections provide additional details on Idaho Power's primary interconnections and the constraints on each path.

Idaho Power regularly evaluates transmission improvements, such as the installation of reactive devices, to prove incremental transmission capacity increases on external interconnections and internal paths. When determined to be cost effective, Idaho Power commits capital resources to the improvements. Incremental transmission capacity increases are typically small and do not materially impact the Integrated Resource Plan (IRP) planning process.

**Table 7.1 Transmission Interconnections**

| Transmission Interconnections | Capacity | | Line or Transformers | Connects to Idaho Power |
|---|---|---|---|---|
| | To Idaho | From Idaho | | |
| Idaho to Northwest | 1,090–1,200 MW | 2,400 MW | Oxbow Lolo 230-kV | Avista |
| | | | Midpoint Summer Lake 500-kV | Pacific Power |
| | | | Hells Canyon Enterprise 230-kV | Pacific Power |
| | | | Quartz Tap LaGrande 230-kV | BPA |
| | | | Hines Harney 138/115-kV | BPA |
| Sierra | 262 MW | 500 MW | Midpoint Humboldt 345-kV | Sierra Pacific Power |
| Eastern Idaho[1] | | | Kinport Goshen 345-kV | Rocky Mountain Power |
| | | | Bridger Goshen 345-kV | Rocky Mountain Power |
| | | | Brady Antelope 230-kV | Rocky Mountain Power |
| | | | Blackfoot Goshen 161-kV | Rocky Mountain Power |
| Utah (Path C)[2] | 775–950 MW | 830–870 MW | Borah Ben Lomond 345-kV | Rocky Mountain Power |
| | | | Brady Treasureton 230-kV | Rocky Mountain Power |
| | | | American Falls Malad 138-kV | Rocky Mountain Power |
| Montana[3] | 79 MW | 58 MW | Antelope Anaconda 230-kV | NorthWestern Energy |
| | 87 MW | 70 MW | Jefferson Dillon 161-kV | NorthWestern Energy |
| Pacific (Wyoming) | 600 MW | 600 MW | Jim Bridger 345/230-kV | Rocky Mountain Power |

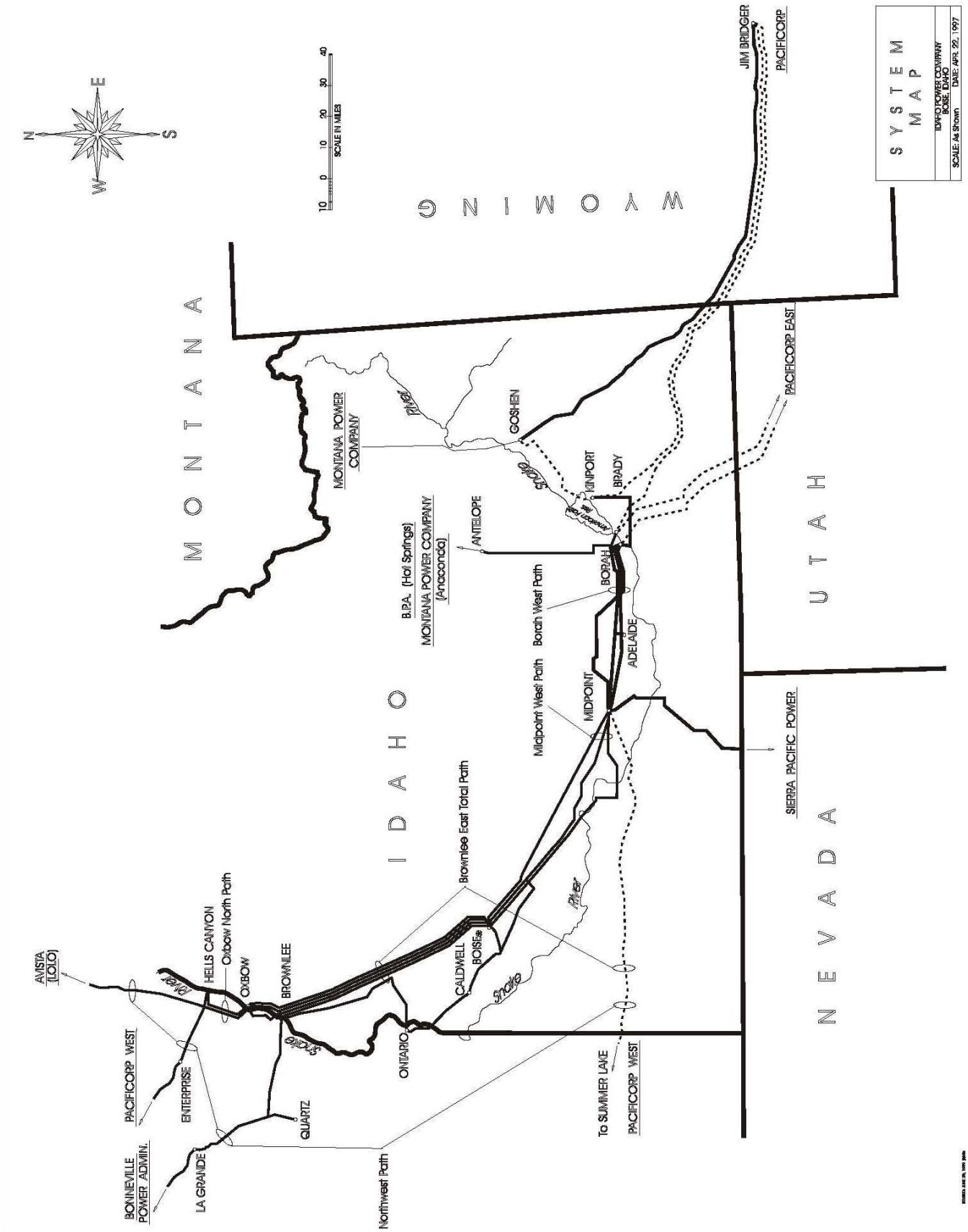
**Power Transfer Capacity for Idaho Power's Interconnections**

1 The Idaho Power-Rocky Mountain Power interconnection total capacities in eastern Idaho and Utah include Jim Bridger resource integration.

2 The Path C transmission path also includes the internal Rocky Mountain Power Goshen-Grace 161-kV line and the Three Mile Knoll 345/138-kV transformer.

3 The direct Idaho Power-Montana Power schedule is through the Brady-Antelope 230-kV line and through the Blackfoot-Goshen 161-kV line that are listed as an interconnection with Rocky Mountain Power. As a result, Idaho–Montana and Idaho–Utah capacities are not independent.

Figure 7.1 Idaho Power Transmission System Map



## Brownlee-East Path

The Brownlee–East transmission path is on the east side of the Northwest Interconnection shown in Table 7.1. Brownlee–East is comprised of the 230-kilovolt (kV) and 138-kV lines east of the Brownlee/Oxbow/Quartz area. When the Midpoint–Summer Lake 500-kV line is included with the Brownlee–East path, the path is typically referred to as the Brownlee–East Total path. The constraint on the Brownlee–East transmission path is within Idaho Power's main transmission grid and located in the area between Brownlee and Boise on the west side of the system.

The Brownlee–East path is most likely to face summer constraints during normal-to-high water years. The constraints result from a combination of Hells Canyon Complex hydro generation flowing east into the Treasure Valley, concurrent with transmission wheeling obligations and purchases from the Pacific Northwest. Transmission wheeling obligations also affect southeastern flow into and through southern Idaho. Significant congestion affecting southeast energy transmission flow from the Pacific Northwest may also occur during December. Restrictions on the Brownlee–East path limit the amount of energy Idaho Power can import from the Hells Canyon Complex, as well as off-system purchases from the Pacific Northwest.

The Brownlee–East Total constraint is the primary restriction on imports of energy from the Pacific Northwest during normal and high water years. If new resources are sited west of the constraint, additional transmission capacity will be required to remove the existing Brownlee–East transmission constraint to deliver the energy to the Boise/Treasure Valley load area. The Boardman to Hemingway project is a major addition to the Brownlee East Total Path and will remove the existing Brownlee–East constraint.

## Oxbow-North Path

The Oxbow–North path is a part of the Northwest Interconnection and consists of the Hells Canyon–Brownlee and Lolo–Oxbow 230-kV double-circuit line. The Oxbow–North path is most likely to face constraints during the summer months when high northwest-to-southeast energy flows and high hydro production levels coincide.

## Northwest Path

The Idaho to Northwest path consists of the 500-kV Midpoint–Summer Lake line, the three 230-kV lines between the Northwest and Brownlee, and the 115-kV interconnection at Harney. The Northwest path has different constrains than the Brownlee–East path. During summer months, the Northwest path is more constrained in low-to-normal water years due to transmission wheeling obligations and off-system purchases from the Pacific Northwest. The Boardman to Hemingway project is a major addition to the Idaho to Northwest path and will relieve constraints on the path.

## Montana Path

The Montana path consists of the Antelope–Anaconda 230-kV and Jefferson–Dillon 161-kV transmission lines. The Montana path is also constrained during the summer months. The Antelope–Anaconda 230-kV transmission line is one segment of the Associated Mountain Power System (AMPS) project which is owned by Idaho Power, NorthWestern Energy and PacifiCorp, collectively known as the AMPS participants. The AMPS participants have initiated the process to increase the path rating by installing reactive devices. The transmission capacity increase is subject to formalization of the agreement between the partners and the WECC rating process. Idaho Power would be allocated a portion of any capacity increase and plans for the capacity to be used for network and native load service.

# Transmission Planning

Idaho Power has discussed possible transmission upgrades linking the company's service area to the regional energy market in the Pacific Northwest since the 2000 IRP. Idaho Power discussed the Pacific Northwest transmission upgrades in general terms in both the 2000 and 2002 IRPs and identified 225 megawatts (MW) of capacity on the Boardman to Hemingway path, originally identified as the McNary to Boise transmission path, in the preferred portfolio of the 2006 Integrated Resource Plan (IRP). This chapter provides details regarding Idaho Power's existing transmission system, planning considerations, and proposed transmission projects. Details of the analysis methods and results are provided later in Chapters 9 and 10.

## *Transmission Adequacy*

Prior to 2000, Idaho Power was able to reasonably plan for the use of short-term power purchases to meet temporary water related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power is a summer peaking utility while the majority of other utilities in the Pacific Northwest region experience peak loads during the winter.

The transmission adequacy analysis reflects Idaho Power's contractual obligations to provide wheeling service to the Bonneville Power Administration (BPA) loads in southern Idaho. The BPA loads are typically served with a combination of energy and capacity from the Pacific Northwest and several Bureau of Reclamation (BOR) projects located in southern Idaho. BPA is a network transmission customer and Idaho Power's contractual obligations to BPA are detailed in four Network Service Agreements under the Idaho Power Open Access Transmission Tariff (OATT).

Although Idaho Power has transmission interconnections to the Southwest, the Pacific Northwest market is the preferred source of purchased power. The Pacific Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho Power's system tend to be smaller, less liquid, and have greater transmission distances. In addition, the markets south and east of Idaho Power's system can be very limited during summer peak conditions.

Prior to 2000, Idaho Power's IRPs often emphasized acquisition of energy rather than construction of generating resources to satisfy load obligations as transmission constraints were not a major impediment to Idaho Power's purchasing power to meet its service obligations. Transmission constraints began to place limits on purchased power supply strategies starting with the 2000 IRP. In addition to evaluating transmission alternatives in the IRP process, Idaho Power participates in regional transmission planning efforts as a member of the Northern Tier Transmission Group (NTTG).

## *Northern Tier Transmission Group*

The NTTG was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Portland General Electric (PGE), Rocky Mountain Power/PacifiCorp and the Utah Associated Municipal Power Systems (UAMPS).

Idaho Power is active in regional transmission planning through the NTTG, along with the Western Electricity Coordinating Council's (WECC) Transmission Expansion Planning Policy Committee (TEPPC) and Planning Coordination Committee (PCC). In addition to integrated resource planning requirements, coordinated regional and sub-regional planning studies are conducted and reviews of various transmission projects are evaluated through technical studies in the WECC rating process.

Through the NTTG planning process conducted in 2007, along with the 2008–2009 biennial planning process, a number of potential transmission projects, including the Boardman to Hemingway and Gateway West projects, have been identified. The public stakeholder process evaluates transmission needs as determined by state mandated integrated resource plans and load forecasts, proposed resource development and generation interconnection queues, and forecast uses of the transmission system by wholesale transmission customers.

By identifying potential resource areas and load center growth, the required transmission capacity expansions to safely and reliably provide service to customers are identified. The process considers not only Idaho Power's obligations to retail customers and network customers, such as BPA, but also provides for open access interstate wholesale obligations required by FERC's planning requirements under FERC Order No. 890's Attachment K planning process.

## Proposed Transmission Projects

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of FERC and is obligated to expand its transmission system to provide requested firm transmission service and to construct and place in service sufficient capacity to reliably deliver electrical resources to customers.

Because of the potential for renewable resource development in the region and the constraints on the existing transmission system, Idaho Power has considered two major transmission projects in the 2009 IRP—Boardman to Hemingway and Gateway West. These two projects were also evaluated in NTTG's regional, biennial planning process along with several other large projects. For the 2009 IRP, two portfolios requiring Boardman to Hemingway capacity were analyzed for the first 10 years of the planning horizon (2010–2019). In the second 10 years (2020–2029), the Gateway West project was included in every portfolio because current constraints require the addition of new transmission capacity for resources to be added in southern Idaho, east of the Treasure Valley load center. However, the amount of Gateway West capacity is different in each portfolio depending on other included resources.

Idaho Power will face increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including BPA's southern Idaho contracts and another 1,000 MW of energy that is expected to be wheeled through Idaho Power's system to other regional customers. The development of wind and other renewable resources in response to renewable portfolio standards (RPS) is anticipated to further increase the demand for transmission capacity between the Intermountain Region and the Pacific Northwest.

The concept of "right sizing" a transmission project, or building the project to an appropriate potential, has been carefully considered. There are many factors involved in the decision process prior to proposing a solution to the identified requirements, including planning horizon perspectives. The Boardman to Hemingway and Gateway West projects have been designed to appropriately size the transmission line, and allow phased construction to meet Idaho Power's needs as well as satisfy requests from third parties for capacity on the same path. A more detailed description of each project is presented in the following sections.

## Boardman to Hemingway




Public involvement is an important part of determining the route of proposed transmission lines.

The Boardman to Hemingway project is a new, 300 mile long, single-circuit, electric transmission line between northeast Oregon and southwest Idaho. The new line is intended to provide access to the Pacific Northwest electric market and is not intended to deliver energy from the Boardman coal facility to Idaho Power's service area.

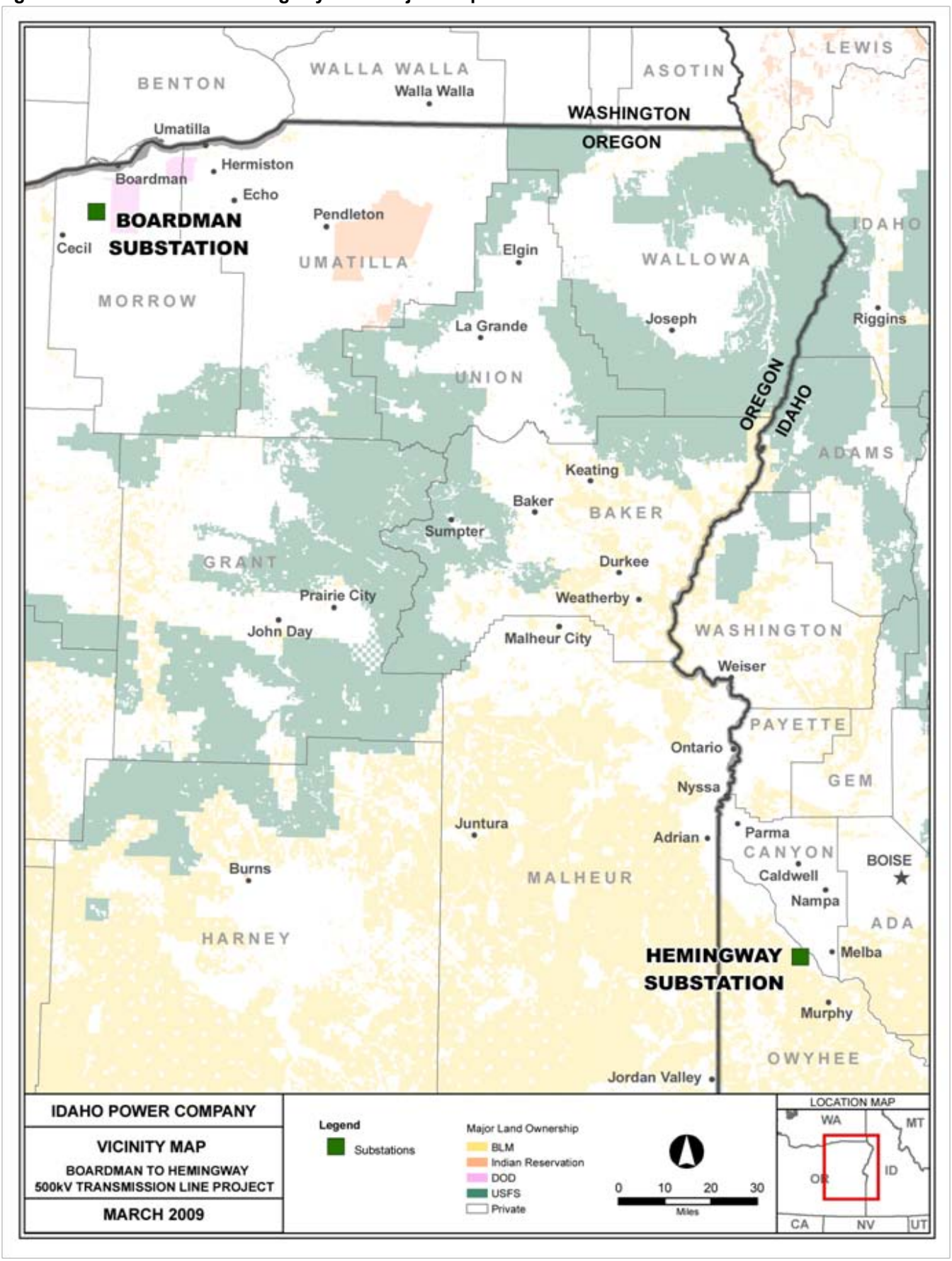
The project is expected to be completed and in service in 2015. The overhead, 500-kV, high-voltage transmission line will connect a switching yard at the Boardman Power Plant, near Boardman, Morrow County, Oregon to the Hemingway Substation, located in Owyhee County, Idaho. The proposed transmission line will connect with other transmission lines on either end of the project to convey electricity on a regional scale. Figure 7.2 shows a map of the region with the Boardman and Hemingway substation termination points.

The northern terminal of the project is expected to interconnect with the existing Boardman substation, which Idaho Power is a part owner. In the 2006 IRP, the new line was anticipated to interconnect at the McNary substation; however, there is insufficient room at the existing McNary substation for major transmission expansion options. A northeast Oregon (NEO) substation is also contemplated by a number of utilities, providing future interconnectivity of regional projects. The in-service date for the NEO substation is unknown at this time. The proposed Boardman to Hemingway project is not dependent upon completion of the NEO substation project, or any of the other transmission proposals to satisfy Idaho Power's need or other existing service requests.

The Boardman to Hemingway project is likely to utilize a bundled conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the WECC's rating process, the initial implementation of the Boardman to Hemingway project along with the Gateway West project is likely to result in an increased rating of approximately 1,400 MW from east to west (exports into the Pacific Northwest), and about 850 MW from west to east (imports into Idaho Power's balancing authority area). The ratings are subject to technical peer review and will be revisited as other regional projects continue to develop. As additional projects reinforce the transmission network, additional capacity rating increases of the Boardman to Hemingway project may occur.

The Boardman to Hemingway project capacity or sizing considerations and termination locations were developed in the public review process conducted by the NTTG and the project WECC phase 0 rating process (the regional planning phase). During the review process, it was determined a 230-kV project would be unable to meet Idaho Power's overall resource planning requirements and would underutilize a substantial transmission corridor. A project operating voltage of 500-kV was selected to match the existing Pacific Northwest transmission grid. A 765-kV line designed with a thermal capacity of approximately 7,000 MW would not achieve a greater rating that the proposed 500-kV project, but would be nearly twice the cost. Because of the higher cost, no further consideration was given to a 765-kV transmission line.

**Figure 7.2 Boardman to Hemingway Line Project Map**



Idaho Power has received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho-Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. There are currently active transmission service requests being studied that are expected to commence operations when the proposed Boardman to Hemingway project is completed. In the 2006 IRP, Idaho Power requested 225 MW of energy imports from the Pacific Northwest to Idaho Power's system. However, the 2009 IRP analyzed various levels of imports.

The Boardman to Hemingway project is important for the development of renewable resources as northeast Oregon has the potential for both wind and geothermal resource development. Idaho Power and Horizon Wind Energy recently developed the first phase of the 101 MW Elkhorn Valley Wind Project in Union County, Oregon. Firm transmission capacity existed for the first 66 MW of the wind project. The remaining 34 MW of output from the Elkhorn project may face curtailment during times of transmission congestion. Further renewable resource development in northeast Oregon will require additional transmission resources.

Idaho Power is committed to working with communities to identify proposed and alternate routes for the Boardman to Hemingway project. The initial process of identifying a route began in late 2007 when Idaho Power submitted documents to the Bureau of Land Management (BLM), the U.S. Forest Service (USFS), and the Oregon Department of Energy (DOE).

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power to conduct more extensive outreach as part of identifying a route for the new transmission line. In response, Idaho Power initiated the Community Advisory Process (CAP) to engage communities from Boardman, Oregon to Melba, Idaho in siting the Boardman to Hemingway project. The CAP enlists project advisory team members in three geographic regions within the project area. The members are familiar with the local areas and issues; the topography, recreation, wildlife and view shed issues; and work collaboratively with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009 and the process is expected to be completed in early 2010.

The results of the 2009 IRP analysis indicate the Boardman to Hemingway transmission line will be a well used resource that benefits customers and generators in both the Pacific Northwest and the Intermountain Region. The capital cost of the Boardman to Hemingway project, as measured on a dollar per kW of capacity basis, is estimated to be well below the capital cost of any supply-side resource alternative. Additional information about the Boardman to Hemingway project can be found at www.boardmantohemingway.gov.

## Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,150 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming to the Hemingway substation near Melba, Idaho. The project is being designed such that multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service as early as 2014.

The two transmission projects, Boardman to Hemingway and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah.

Significant resource development potential exists in Wyoming and southern and eastern Idaho. Idaho Power's transmission system is currently limited in the ability to transmit energy from new resources from the east to the major load centers in Idaho. Gateway West will provide new transmission capacity to integrate and deliver any such selected resources, in addition to meeting third-party transmission service requests under Idaho Power's Open Access Transmission Tariff (OATT).

The Gateway West project is currently undergoing a public involvement process regarding route selection, environmental studies, and permitting. The project as proposed in Idaho includes two separate 500-kV lines between the Populus substation in southeast Idaho, and the Hemingway substation in southwestern Idaho, with connections in central Idaho at the Midpoint and proposed Cedar Hill substations.

Phase 1 is expected to provide between 700 MW and 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide an additional 3,000 MW of transfer capacity. Similarly, the project extending east from Populus substation into eastern Wyoming is expected to provide Phase 1 capacity improvements of approximately 700 to 1,500 MW, with the full build out capacity increase being greater than 2,000 MW east of Jim Bridger, and 3,000 MW between the Populus substation and Jim Bridger.

The project cost and capacity is expected to be shared between Idaho Power and Rocky Mountain Power based upon load service requirements and third-party transmission service request obligations. Additional information about the Gateway West project can be found at www.gatewaywestproject.com.

# 8. PLANNING CRITERIA AND PORTFOLIO SELECTION

Many utilities plan to median, or expected, conditions and then include a reserve margin to cover the 50 percent of the time when conditions are less favorable than median. Idaho Power discussed planning criteria with commission staff members and the public criteria as part of the 2002 Integrated Resource Plan (IRP). Out of these discussions came the company's practice of using more stringent planning criteria than median conditions. The planning criteria and planning scenarios are discussed in the following section.

## Planning Scenarios and Criteria

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies for monthly average load and peak-hour load. The 20-year forecast is further divided into two 10-year periods that coincide with the near-term action plan and the long-term action plan.

The planning criteria for monthly average load planning are 70$^{th}$ percentile water and 70$^{th}$ percentile average load conditions. For peak-hour load conditions, the planning criteria used are 90$^{th}$ percentile water and 95$^{th}$ percentile peak-hour load. The peak-hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system. Peak-hour load planning criteria are more stringent than average-load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods. The median forecast is no longer used for resource planning although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings.

## Load and Resource Balance

Idaho Power has adopted the practice of assuming drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources, while using the conservative water and load conditions, is considered comparable to requiring capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having generating capacity in reserve for meeting day-to-day operating reserve requirements.

In order to identify the need and timing of future resources, Idaho Power prepares a load and resource balance which accounts for generation from all of the company's existing resources and planned purchases. The updated load and resource balance showing Idaho Power's existing and committed resources for average energy and peak-hour load are shown in *Appendix C–Technical Appendix.*

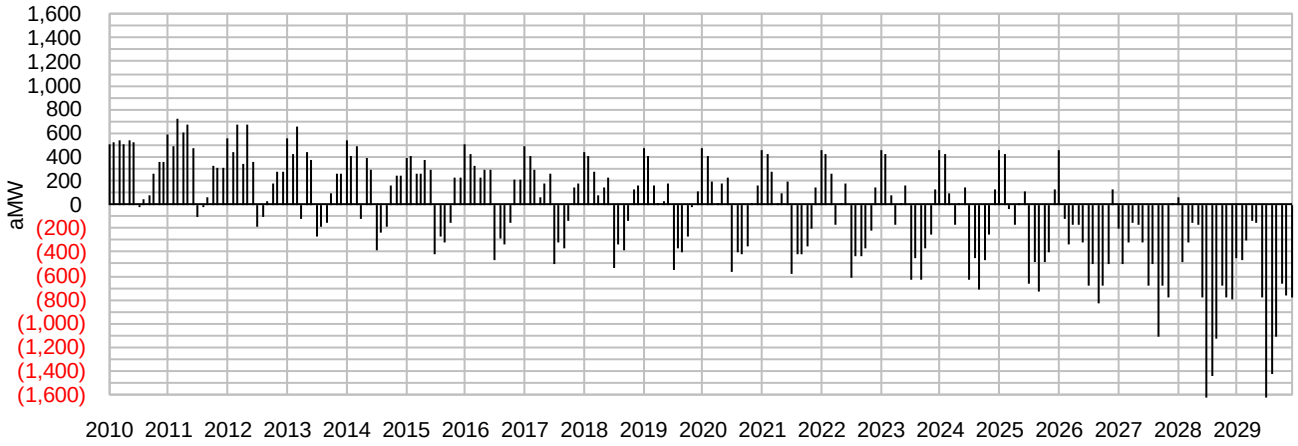
**Highlights**

- Idaho Power uses 70$^{th}$ percentile average load and 70$^{th}$ percentile water conditions for energy planning.
- For peak–hour capacity planning, Idaho Power uses 90$^{th}$ percentile water conditions and 95$^{th}$ percentile peak–hour loads.
- Peak–hour load deficiencies with 2009 IRP demand response and committed generating resources are close to 200 MW by 2014, and approximately 700 MW by 2025.

## Average Monthly Energy Planning

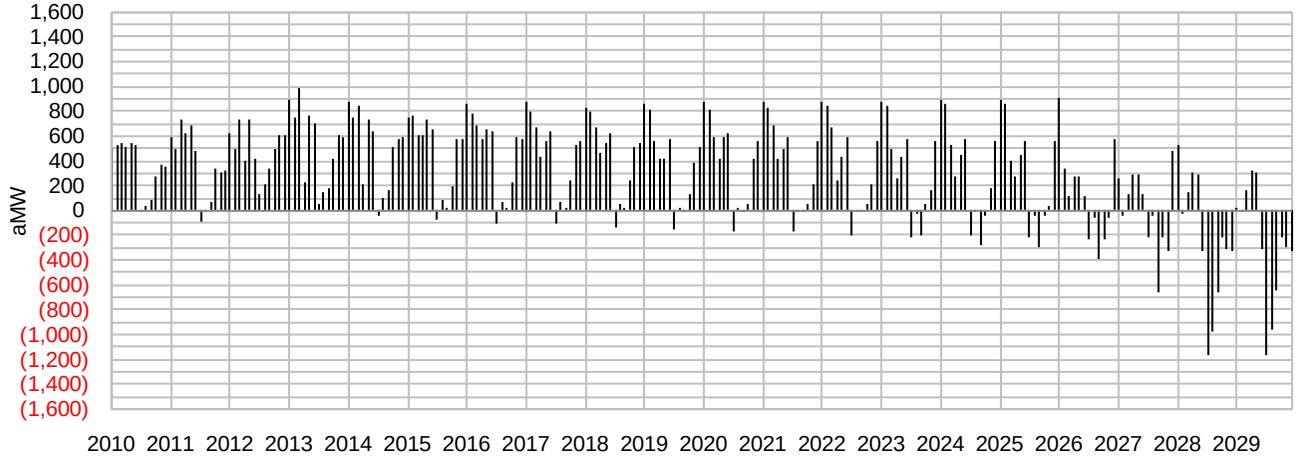
Average energy surpluses and deficiencies are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits with existing resources. The energy positions shown in Figure 8.1 include the forecast impact of existing demand-side management (DSM) programs, coal curtailment, the current level of Public Utilities Regulatory Act (PURPA) development, existing power purchase agreements (PPAs), firm Pacific Northwest import capability, and gas peaking unit output. Figure 8.1 illustrates that monthly average deficit positions grow steadily in magnitude and number of months affected. By 2014, four months are affected with deficits reaching nearly 400 aMW for the most deficit month and, near the end of the planning period, energy deficits become substantial as generation from Idaho Power's coal facilities is totally curtailed.

**Figure 8.1 Monthly Average Energy Surpluses and Deficits with Existing Resources (70th Percentile Water and 70th Percentile Load)**



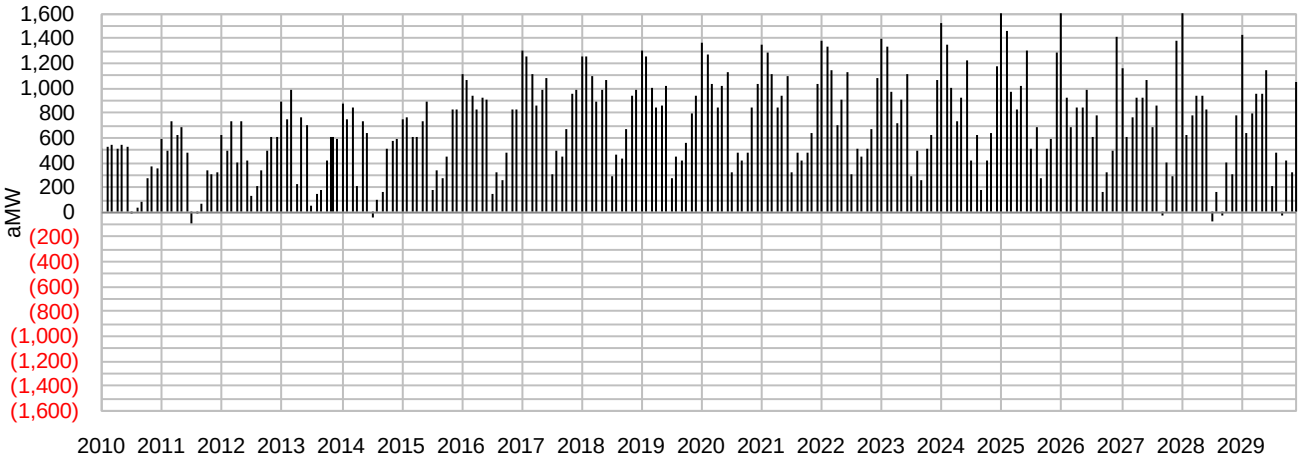

Resource deficits are substantially improved as shown in Figure 8.2 with the addition of committed resources from the 2006 IRP and the new DSM programs proposed in the 2009 IRP. The committed resources supply-side include the Langley Gulch combined-cycle combustion turbine (CCCT), the 2012 Wind Request for Proposal (RFP), and geothermal projects.

**Figure 8.2 Monthly Average Energy Surpluses and Deficits with Existing and Committed Resources and New DSM (70th Percentile Water and 70th Percentile Load)**



By design, the inclusion of generating and transmission resources in the 2009 IRP preferred portfolio substantially eliminates all energy deficits. Figure 8.3 shows the resulting positions for monthly average energy. The surpluses shown in Figure 8.3 are a result of the assumption that all resources are dispatched and operating.

**Figure 8.3 Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources (70th Percentile Water and 70th Percentile Load)**

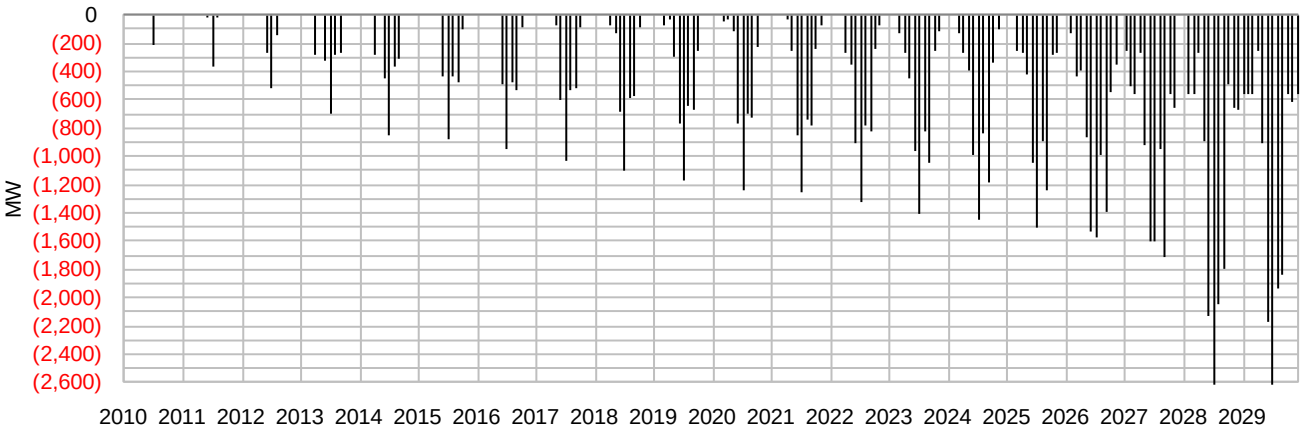



As shown in Figure 8.1, energy deficits of approximately 200 average megawatts (aMW) exist in July 2012 without the addition of the Langley Gulch project and the 2012 Wind RFP. As shown in Figure 8.2, with the addition of these two resources, deficiencies do not appear again until the 2014 to 2015 timeframe. Portfolios for the 2009 IRP were designed to eliminate the remaining deficits which were accomplished as shown in Figure 8.3. Additional details regarding the selection of the preferred portfolio are presented in Chapter 10.

## Peak-Hour Planning

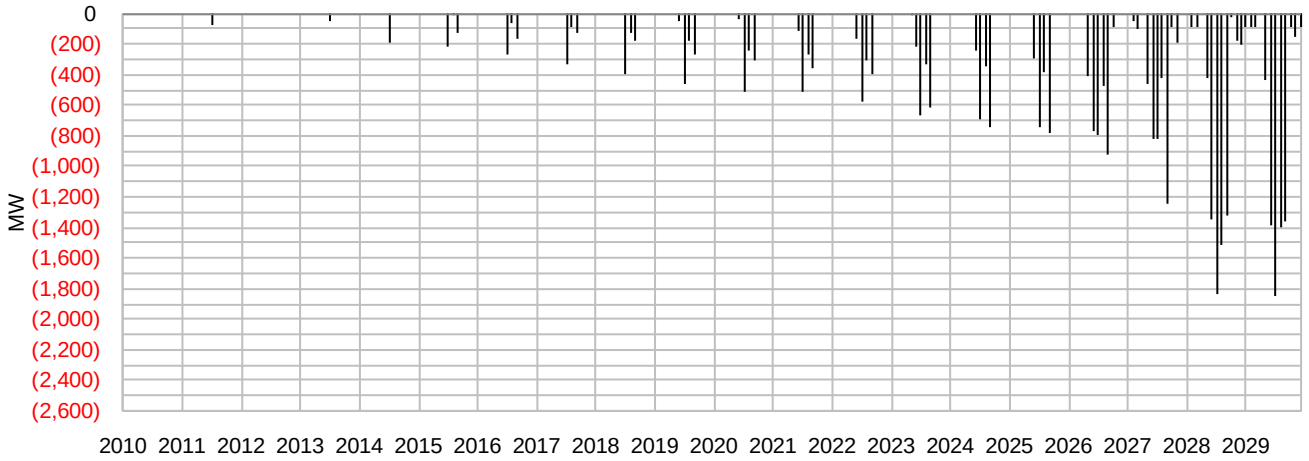
Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system to reduce any deficits. Monthly peak-hour deficits with existing resources are illustrated in Figure 8.4. Figure 8.4 illustrates considerable peak-hour deficits reaching in excess of 500 MW by 2012, and continuing to grow through the remainder of the 20-year planning period.

**Figure 8.4 Peak-Hour Deficits with Existing Resources (90th Percentile Water and 95th Percentile Load)**



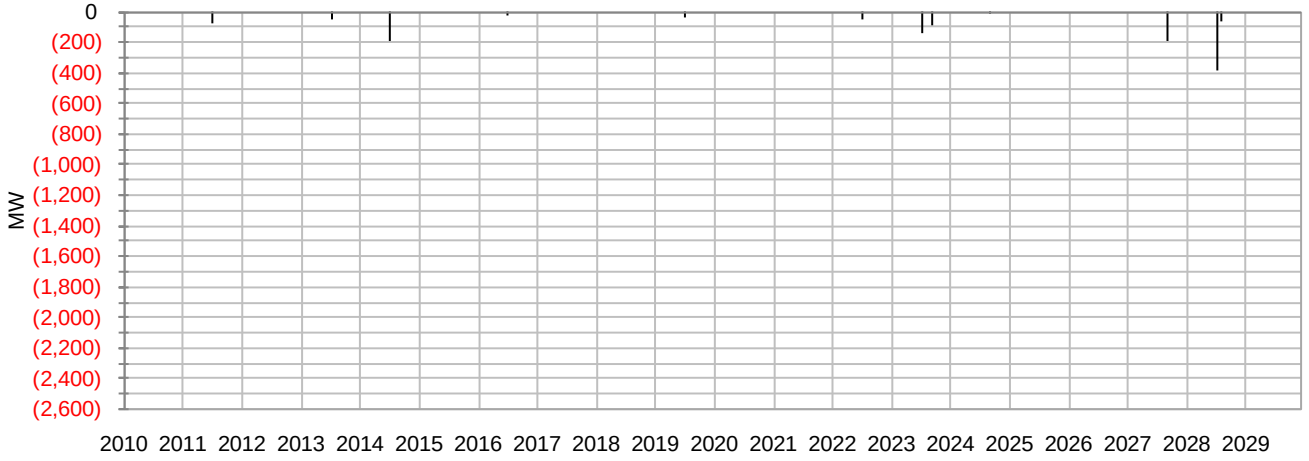
Peak-hour positions are substantially improved as shown in Figure 8.5 with the addition of committed resources from the 2006 IRP and the new demand response programs proposed in the 2009 IRP. The committed supply-side resources include the Langley Gulch CCCT, the 2012 Wind RFP, and geothermal projects.

**Figure 8.5 Peak-Hour Deficits with Existing and Committed Resources and New DSM (90th Percentile Water and 95th Percentile Load)**




Again by design, the inclusion of generation and transmission resources in the 2009 IRP preferred portfolio substantially eliminates all peak-hour deficits. Figure 8.6 shows the resulting monthly positions for peak-hour planning.

**Figure 8.6 Peak-Hour Deficits with 2009 IRP Resources (90th Percentile Water and 95th Percentile Load)**




Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficiencies. Peak-hour load planning criteria are more stringent than average energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

The deficits shown in Figure 8.5 account for the updated sales and load forecast, forecast performance of DSM programs, adjustments to the hydro generation forecast, the current level of PURPA development, the Langley Gulch CCCT, the 2012 Wind RFP and Idaho Power's natural gas-fired peaking resources. Similar to the deficits shown for average energy, the peak-hour analysis shows deficits beginning in 2014. With the addition of the 2009 IRP preferred portfolio, these deficits are

substantially eliminated as shown in Figure 8.6. Additional details regarding the selection of the preferred portfolio are presented in Chapter 10.

Idaho Power's customers reach a maximum energy demand in the summer. Idaho Power's existing and committed resources are insufficient to meet the projected peak-hour growth, and the company's customers in Oregon and Idaho face significant capacity deficits in the summer months if additional resources are not added.

At times of peak summer load, Idaho Power is fully using all available transmission capacity from the Pacific Northwest. If Idaho Power were to face a significant outage at one of its main generation facilities, or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power is unable to meet reserve requirements, then the company is required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

## Portfolio Design and Selection

The 2009 IRP portfolio development strategy divides the study period into two 10-year periods; 2010 - through 2019, and 2020 through 2029. Resource portfolios in each 10–year period are designed to satisfy the energy and peak-hour deficits shown in the load and resource balance. Idaho Power also believes a federal renewable electricity standard (RES) will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the Waxman–Markey bill.

The Shoshone Falls Upgrade Project has been included in numerous past IRPs as a committed resource. For the 2009 IRP, the project was included in all the portfolios analyzed. However, in order to quantify the value of the project, the preferred portfolio was also analyzed without including the Shoshone Falls upgrade project. The results of this analysis are presented in Chapter 10. A summary of the resource portfolios analyzed for the first 10 years of the planning horizon is shown below in Figure 8.7.

**Figure 8.7 Initial Resource Portfolios (2010–2019)**

| | 1-1 Solar | | 1-2 Gas Peaker | | 1-3 Gas Peaker & B2H[1] | | 1-4 B2H | |
|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | Resource | MW | Resource | MW | Resource | MW |
| 2012 | Wind* | 150 | Wind* | 150 | Wind* | 150 | Wind* | 150 |
| | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 |
| | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 |
| 2015 | Shoshone Falls | 49 | Shoshone Falls | 49 | Shoshone Falls | 49 | Shoshone Falls | 49 |
| | SCCT (Large Aero) | 200 | SCCT (Frame Peaker) | 170 | B2H | 250 | B2H | 250 |
| 2016 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 |
| 2017 | Solar PT w/St | 100 | SCCT (Frame Peaker) | 170 | SCCT (Large Aero) | 100 | B2H | 175 |
| 2019 | Solar PT w/St | 100 | | | SCCT (Large Aero) | 100 | | |

[1] B2H-Boardman to Hemingway
*Committed Resource

The first 10–year planning period has significant committed resources which are also shown in Figure 8.7. The committed resources included in all of the portfolios. The committed resources are not

included in the capital cost for comparison between portfolios. The new resources shown are designed to reduce previously discussed deficiencies and to meet proposed RES requirements. Because the identified deficiencies are not large and the list of possible resources is limited, it was not necessary to analyze a large number of portfolios for the first 10-year period. The limited number of resource options results in similar portfolios with regards to fuel and technology. A description of the major differences between each portfolio is presented below.

- **1–1 Solar**–Includes two, 100 MW solar power tower resources
- **1–2 Gas Peaker**–Includes two, 170 MW frame peaking units (simple-cycle combustion turbines [SCCT])
- **1-3 Gas Peaker and Boardman to Hemingway**–Includes a 250 MW market purchase on the Boardman to Hemingway transmission line and two, 100 MW aero derivative peaking units (SCCTs)
- **1-4 Boardman to Hemingway**–Includes two market purchases on the Boardman to Hemingway transmission line (250 MW and 175 MW)

In the second 10-year planning period, Idaho Power analyzed six portfolios and all portfolios were again designed to substantially meet the proposed RES requirements in the Waxman–Markey bill. In addition, advanced nuclear and integrated gasification combined cycle (IGCC) were included in separate portfolios to determine how they would impact portfolio performance. A summary of the resource portfolios analyzed for the second 10 years of the planning horizon is shown below in Figure 8.8.

**Figure 8.8 Initial Resource Portfolios (2020–2029)**

| | 2-1 Nuclear/Green | | 2-2 Gateway West | | 2-3 IGCC | | 2-4 Wind & Peakers | | 2-5 Limited Curtailment | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | Resource | MW | Resource | MW | Resource | MW | Resource | MW |
| 2020 | Solar PT w/St | 100 | | | | | SCCT (Large Aero) | 100 | | |
| 2021 | Wind | 100 | Wind | 100 | | | | | Wind | 100 |
| 2022 | Solar PT w/St | 100 | Gateway West | 200 | Solar PT w/St | 100 | Wind | 100 | SCCT (Large Aero) | 100 |
| 2023 | Nuclear | 270 | | | | | | | | |
| 2024 | Geothermal | 52 | | | IGCC w/Seq. | 600 | SCCT (Large Aero) | 200 | | |
| 2025 | Solar PT w/St | 100 | Gateway West | 200 | | | Gateway West | 100 | | |
| 2026 | | | Wind | 100 | | | SCCT (Large Aero) | 200 | SCCT (Large Aero) | 100 |
| 2027 | Geothermal | 52 | Gateway West | 400 | Solar PT w/St | 100 | Wind | 400 | Wind | 200 |
| | | | | | | | | | SCCT (Large Aero) | 100 |
| 2028 | Nuclear | 400 | Gateway West | 600 | SCCT (Large Aero) | 400 | SCCT (Large Aero) | 400 | | |
| 2029 | Gateway West | 250 | | | Solar PT w/St | 100 | SCCT (Large Aero) | 500 | | |

Portfolio 2-1 contains an advanced nuclear resource along with a mixture of renewable resources to meet RES requirements. Portfolio 2-2 relies heavily on market purchases and wind resources. Portfolio 2-3 includes an IGCC resource combined with solar power tower technology. Portfolio 2-4 relies on wind resources for energy and natural gas peaking units necessary for peak-hour loads and wind integration, and portfolio 2-5 includes limited curtailment of Idaho Power's coal resources with wind and natural gas peaking units. A description of each resource portfolio is presented below.

- **2-1 Nuclear/Green**–Includes a 270 MW nuclear resource in 2023 and another 400 MW nuclear resource in 2028. Renewable resources include wind, solar and geothermal

- **2-2 Market Purchases**–Includes 1,400 MW of purchases on the Gateway West transmission line and wind resources necessary to meet RES requirements
- **2-3 IGCC with Sequestration**–Includes 600 MW from an integrated gasification combined-cycle (IGCC) resource in 2024, 300 MW of solar for RES requirements, and 400 MW of natural gas peaking units
- **2-4 Wind and Peakers**–Includes 500 MW of wind resources and 1,400 MW of natural gas peaking units
- **2-5 Limited Curtailment**–Includes 300 MW of wind resources and 200 MW of natural gas peaking units. Portfolio 2-5 also includes limited curtailment of Idaho Power's existing coal resources

Chapter 9 provides details on how the portfolios were modeled and the assumptions used in the analysis. Chapter 10 presents a detailed discussion of the modeling results and risk analysis.

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# 9. MODELING APPROACH AND ASSUMPTIONS

Idaho Power uses the AURORAxmp® (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio costs for the 20-year integrated resource plan (IRP) planning horizon. AURORA uses a long-term (LT) study option to develop a future Western Electricity Coordinating Council (WECC) resource optimization scenario. In addition, AURORA modeling results provide detailed estimates on wholesale energy pricing, resource values under various market conditions, and electricity pricing and portfolio values.

The AURORA software applies economic principles and dispatch simulation to model the relationships of supply, transmission, and electricity demand in order to forecast market prices. The operation of existing and future resources are based on forecasts of key fundamental elements such as demand, fuel prices, hydro conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, pool pricing logic, and in the long-term capacity expansion capability. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Multiple electricity markets, zones, hubs, and operating pools can be modeled using AURORA. Idaho Power models the entire WECC when evaluating the various resource portfolios. Idaho Power does not maintain detailed data on all WECC resources in the AURORA model and the company relies on a database maintained and updated by EPIS, Inc. Idaho Power evaluates the AURORA database and makes changes based on available information prior to modeling the IRP portfolios.

Future WECC resources are determined in a two step process. The first step uses the AURORA LT module to optimize the WECC future resources per the AURORA LT process. Since the AURORA LT process does not account for state renewable portfolio standards (RPS), Idaho Power estimates RPS requirements for future years on a state-by-state basis and replaces some AURORA LT resources in the database with RPS qualifying resources. Enough RPS resources are added for compliance with the anticipated state requirements.

**Highlights**

- Idaho Power uses the AURORA Electric Market Model as the primary tool for determining future resource build-out of operations and portfolio cost impacts for the 20-year IRP planning period.
- The 2009 IRP evaluates proposed carbon reduction legislation differently than previous IRPs by specifically defining carbon reduction targets and curtailing coal units.
- The 2009 IRP incorporates anticipated federal renewable electricity standard (RES) legislation and plans for the resources necessary to comply with the legislation.
- Two categories of transmission, backbone and interstate transmission, are accounted for in the IRP.

## AURORA Setup Enhancements

Idaho Power incorporated several changes to the AURORA database which are designed to increase AURORA's operational modeling realism. The Idaho Power changes to the database generally add additional hourly operational detail and move away from flat generation output, de-rates, and fixed capacity factors over the term of the study. The 2009 IRP also incorporates detailed generating resource scheduling which results in a model that is more deterministic in character, and provides a more specific operational view of the WECC.

Several other enhancements to the LT model are included to incorporate the effects of legislated renewable energy requirements and specific WECC planned resources. The WECC resources are determined from the *2007 WECC Long Term Resource Adequacy* study.

## Carbon Modeling Approach

Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than has been done in previous IRPs. Historically, a carbon adder, or tax, has been used to account for the social costs of emitting carbon or other combustion byproducts. The purpose of a carbon tax is to account for all of the costs in the price of energy produced by carbon-emitting resources. Both the Waxman–Markey bill (H.R. 2454) and the Boxer–Kerry bill (S. 1733) propose a cap-and-trade system for reducing carbon emissions and Idaho Power considers the implementation of a cap-and-trade system to be more likely than a carbon tax.

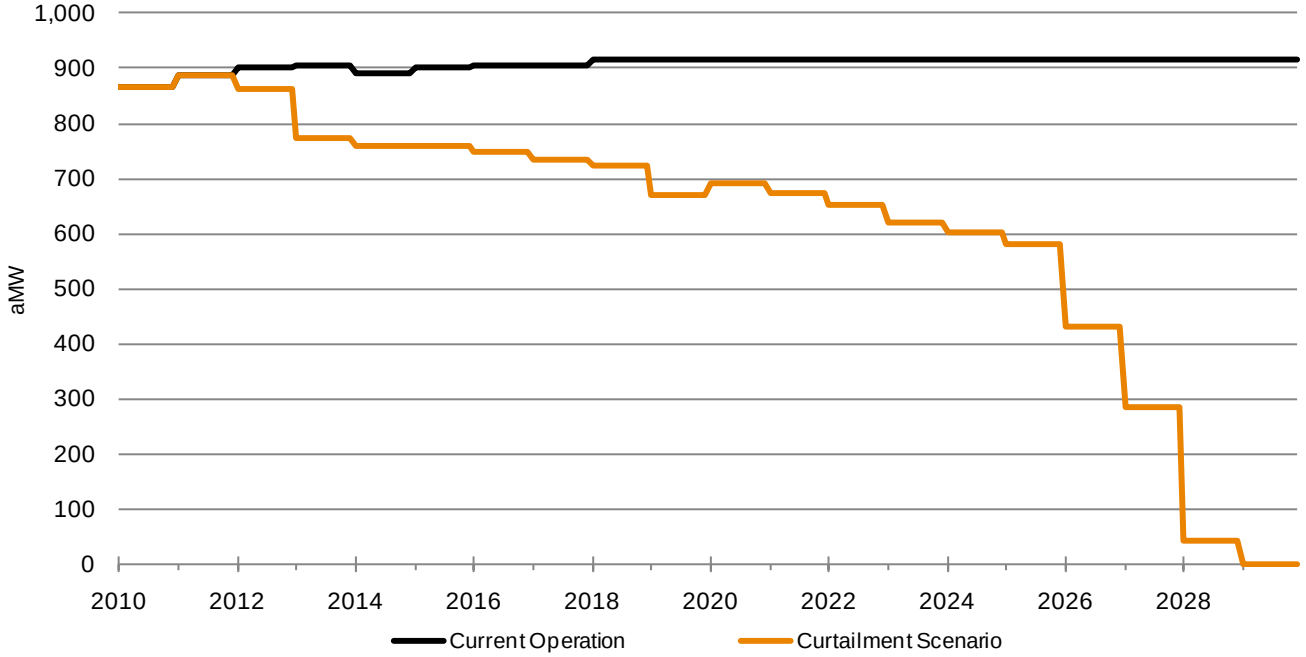
Although Idaho Power believes a cap-and-trade system is more likely, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has also done. However, the primary discussion in the 2009 IRP regarding carbon emissions is related to Idaho Power's attempt to model a cap-and-trade scenario under the provisions of the Waxman–Markey bill. To model the cap-and-trade scenario, Idaho Power has reduced the output from its coal facilities based on the number of allowances that are expected to be allocated to the company. The cost of resource portfolios with emissions in excess of the allocated amount are increased by purchasing additional allowances.

Idaho Power has also analyzed the effects of carbon legislation by modeling a $43 per ton carbon tax. The carbon tax analysis suggests that the $43 carbon adder significantly increases the portfolio costs, and increases the retail energy rates, but does not create a significant decrease in carbon emissions. The carbon tax appears to be less effective than the proposed cap-and-trade legislation.

In addition, the carbon adder approach does not appear to promote resource dispatch decisions that result in reduced emissions from existing resources. Coal curtailment forces the resource plan to replace the coal generation and quantifies the cost implications of the resource replacement. Figure 9.1 shows annual average megawatt (aMW) coal output under the existing operations and the annual aMW of coal-fired generation under the coal curtailment scenario. In this scenario, coal-fired generation is completely curtailed by the end of the planning period in 2029.

The emissions targets used to define the new total coal-fired generation are based on the limits proposed in the Waxman–Markey bill. The legislation was passed by the House of Representatives in June 2009, but has not yet been debated in the Senate. The assumed coal curtailment is the primary reason behind the resource needs in the second 10-year planning period. For additional details on the AURORA modeling comparisons, refer to the carbon allowance determination section of *Appendix C–Technical Appendix*.

**Figure 9.1 Average Annual Generation from Coal Resources**




An alternative to full coal curtailment is evaluated in Portfolio 2-5. Portfolio 2-5 reduces coal unit output to comply with 2020 target levels of emissions and then holds the 2020 carbon emission levels constant for years 2021–2029. In Portfolio 2-5, Idaho Power operates coal resources at the 2020 emission levels and acquires the necessary carbon emission allowances from the market. The required carbon emission allowances are valued at the price cap proposed in the Boxer–Kerry legislation. The total price of the coal curtailment portfolio 2-4 and the partial coal curtailment portfolio 2-5 are roughly equivalent assuming that the necessary carbon emission allowances can be acquired at costs equal to the proposed price cap.

The three distinct carbon futures are modeled in AURORA for all of the resource portfolios; 1) coal curtailment (as described above), 2) a $43 carbon adder without coal curtailment, and 3) continuation of present operations with no carbon adder and no coal curtailment. The results of the analysis are shown in *Appendix C–Technical Appendix* in the carbon futures comparison section.

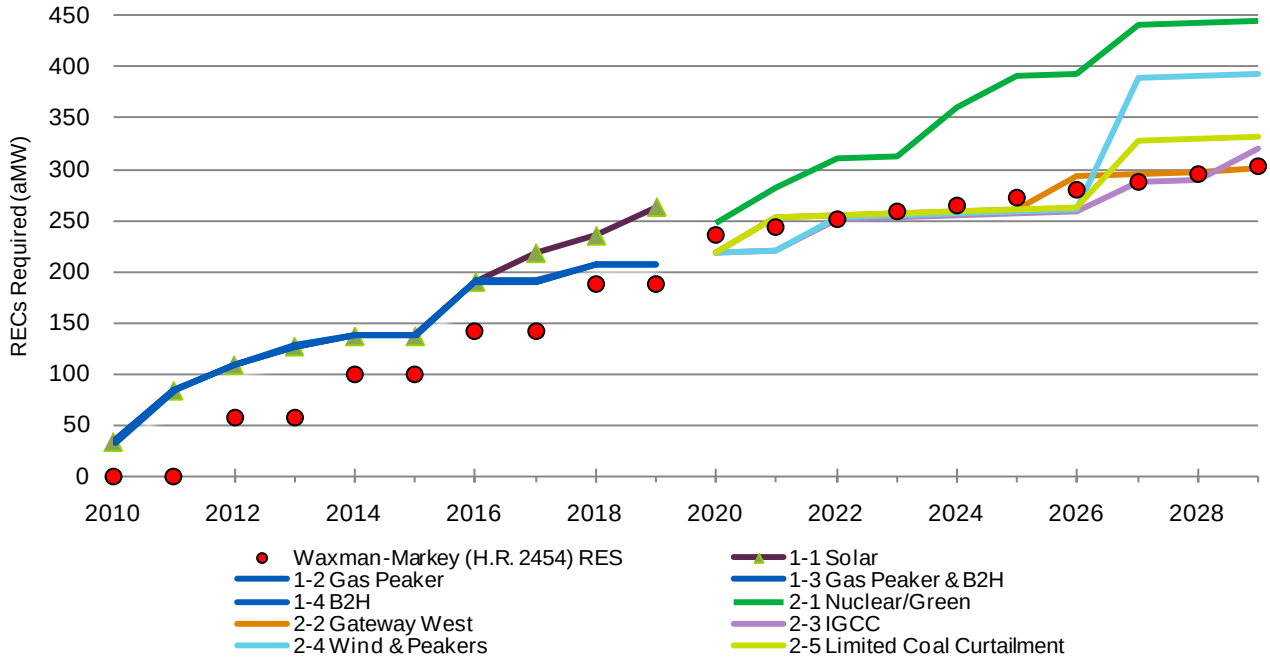
## Renewable Energy Credits

The 2009 IRP considers the proposed federal renewable electricity standard (RES) legislation and the resource plan includes the resources necessary to meet the proposed requirements. In addition, some neighboring states such as Washington, Oregon, Colorado, and California have already enacted significant RPS requirements. The state legislation has prompted the construction of renewable energy projects throughout the west even in states like Idaho without specific RPS requirements. Even if the renewable energy is not delivered to the specific state, the renewable energy credits (REC) have value and can be traded in a regional market.

Idaho does not have RPS and Idaho Power can meet the requirements of the Oregon RPS with a portion of the RECs from the Elkhorn Valley Wind Project. Idaho Power has not included defined RES planning criteria in previous resource plans. However, the increasing likelihood of a federal RES led Idaho Power to develop a formal plan to satisfy the expected future federal requirements. The planning goal in the 2009 IRP is to substantially satisfy the proposed federal RES targets with existing or new portfolio resources. Figure 9.2 shows the expected quantity of RECs Idaho Power would need under the Waxman–Markey bill along with the number of RECs each resource portfolio would provide. The

resource portfolios analyzed for the 2009 IRP meet the requirements in the first 10 years and substantially meet the requirements in the second 10-year period.

**Figure 9.2 Waxman–Markey RES Requirements and Portfolio RECs**




## Transmission and Market Purchases

The need for additional power from either new resources or market purchases will require additional transmission. Idaho Power faces severe transmission constraints when evaluating additional supply-side resources. Transmission constraints have been a major factor in evaluating each new supply-side resource; Bennett Mountain, Danskin 1, the Elkhorn Valley Wind Project, Langley Gulch, and the 2012 Wind Request for Proposals (RFP).



High-voltage transmission lines are an important part of delivering energy to customers.

Two categories of transmission are accounted for in the IRP. The first is backbone transmission which integrates resources and allows energy to flow from the gen

eration project to the load centers within a utility's own control area or service territory. Backbone transmission has a designated generating resource and is usually lower voltage and within the service territory. An example of backbone transmission is the transmission lines that deliver generation from the Hells Canyon Complex to the load center in the Treasure Valley.

Interstate transmission is the second transmission type and is generally higher voltage and covers greater distances. Interstate transmission is planned on a regional basis to meet the needs of electric utilities and the needs of third parties requesting transmission service. Very little interstate transmission has been constructed in the last 30 years. Examples of interstate transmission include the proposed Gateway West and Boardman to Hemingway projects.

The portfolios with market purchases in the first 10 years and all of the second 10-year portfolios include proposed interstate transmission projects. The Northern Tier Transmission Group (NTTG) is one entity that coordinates regional transmission plans in the Pacific Northwest. The NTTG annual report is the basis of the interstate transmission alternatives discussed in Idaho Power's 2009 IRP.
The transmission planning scenarios used in the 2009 IRP are taken from NTTG's *2008–2009 Biennial Plan Final Report-DRAFT* dated November 2, 2009.

Transmission costs are evaluated on an annual Network Transmission Revenue Requirement basis. The calculation is similar to the revenue requirement calculations used in Idaho Power's FERC formula rate. In determining the annual revenue requirement, the new transmission investment is calculated in two parts. The first part is based on a percentage of the total cost of an interstate transmission project subscribed to and the second part is the cost of backbone upgrades for planned new resources for each portfolio. The two parts are then added to arrive at the total transmission revenue requirement, which is included in the annual cost of a portfolio. Additional details showing the calculations can be found in *Appendix C–Technical Appendix*.

## Regional Transmission Planning (from the NTTG Plan)

NTTG's 2008-2009 biennial plan was produced through public processes in conjunction with related activities of the NTTG Cost Allocation Committee and the NTTG Transmission Use Committee. Technical studies have demonstrated the resulting plan to be capable of reliably meeting the identified regional transmission needs established in the study plan.

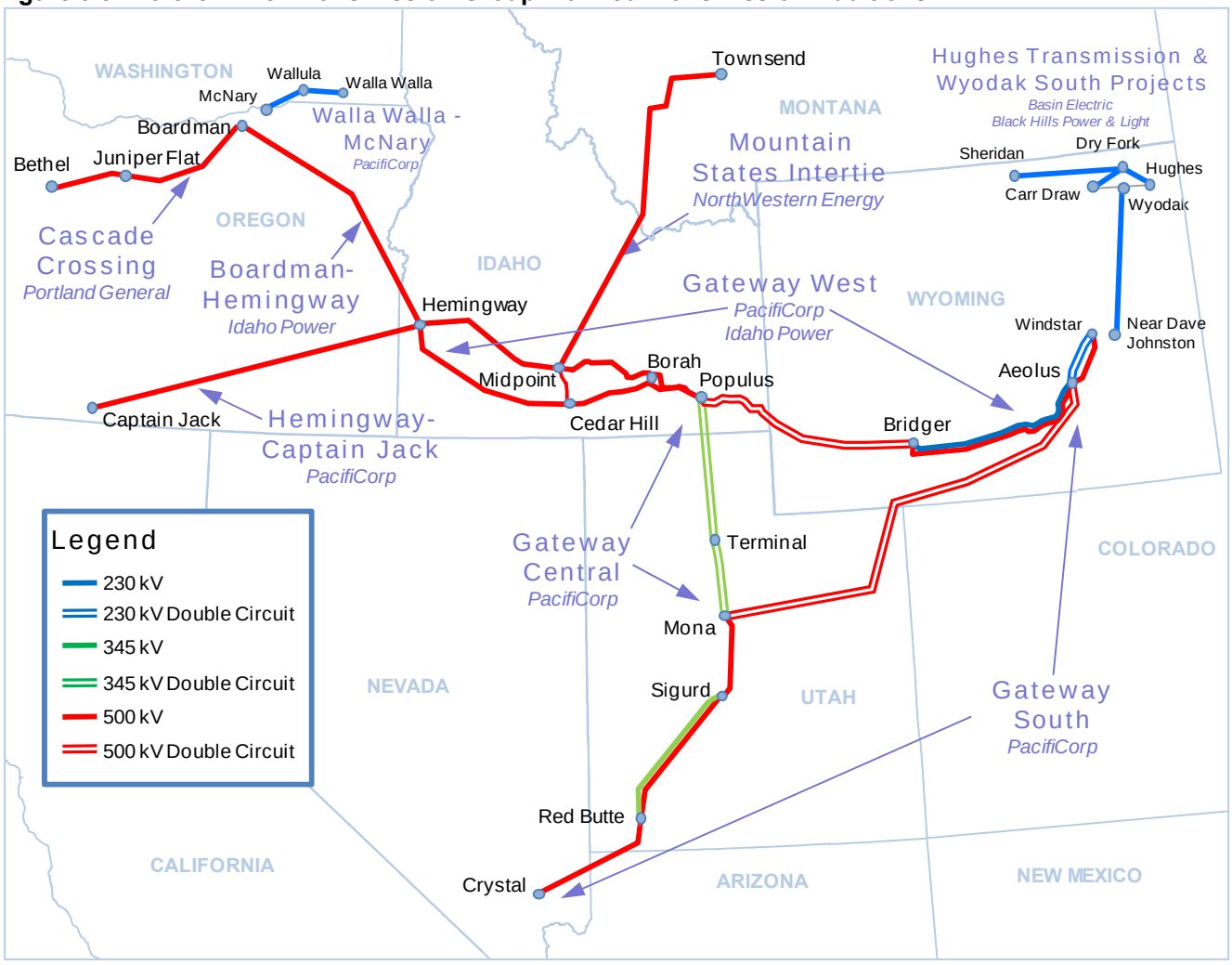
Planning is an iterative process and must work in concert with local transmission plans and IRPs, where they exist. The NTTG transmission plan is a result of a bottom-up load service process to ensure that the transmission planned for the NTTG footprint can reliably serve forecasted load growth and conditions established by data submittals and stakeholder input during the process. There may be broader regional needs outside of the NTTG footprint unmet by this plan. These unmet needs are expected to be addressed as part of regional, interconnection–wide efforts reconciling bottom-up and top-down study efforts.

The NTTG plan establishes the baseline main grid transmission configuration for the NTTG footprint for the planning horizon ending in 2018. The planned transmission should be used as a base plan to inform other planning processes. While Idaho Power cannot assure the NTTG regional plan will be implemented as designed, the plan represents the best information available during the current planning cycle. Changing needs or new information will be accommodated through appropriate data submittals during the next planning cycle.

The NTTG plan identifies a number of specific projects. However, the technical analysis was performed on the premise that the entire transmission plan is in service in 2018. Path and project ratings are determined separately through Western Electricity Coordinating Council (WECC) processes and are the responsibility of the projects' sponsors. Commercial subscription and capacity commitments are administered by each Transmission Provider under their Open Access Transmission Tariff (OATT).

Idaho Power evaluates both the Boardman to Hemingway project for the first 10-year period, and the Gateway West project for the second 10-year period. Figure 9.3 illustrates the identified transmission path upgrades for a variety of interstate transmission projects in the Pacific Northwest and Intermountain Region. The transmission paths shown in Figure 9.3 are for reference only. Actual transmission paths are being determines through public processes involving federal and state agencies and the general public.

**Figure 9.3 Northern Tier Transmission Group Planned Transmission Additions**




## Market Purchase Assumptions

The 2009 integrated resource plan uses different transmission assumptions for each of the 10-year periods. The assumption in the first 10-year period is that transmission capacity is increased only to the extent identified in each resource portfolio. Idaho Power has adopted a conservative approach for the first 10 years and only includes market energy purchases when the market need is specifically identified in a resource portfolio.

The second 10-year period increases the transmission based on the projects identified in the NTTG report discussed earlier. The uncertainty of the entire NTTG transmission expansion plan being completed as proposed is significant. Resource plans that rely heavily on market purchases over transmission that is beyond the reasonable scope of Idaho Power participation or control may not be prudent. The transmission risk is discussed further in Chapter 10.

The transmission upgrades modeled for the 2010-2019 period only increase the transmission capacity to the northwest (Boardman to Hemmingway). Idaho Power subscription on the Boardman to Hemingway project is determined by the capacity and timing of market purchases identified in each resource portfolio.

Transmission is expanded even further in the second 10–year period, 2020-2029 with the Gateway West project. As mentioned earlier, the 2020-2029 transmission expansion is defined by the NTTG plan. The results from the two time periods are evaluated independently.

The degree of Idaho Power's investment participation differs between the portfolios and the costs are included according to the transmission subscription in each resource portfolio. Each transmission subscription represents an Idaho Power equity investment in the project. Each equity investment translates into a revenue requirement and the revenue requirements for the transmission investments are estimated and included in the portfolio total cost comparisons. Idaho Power's investment defines the revenue requirement and the net present value (NPV) of the revenue requirement is included as part of the expected-case cost of each resource portfolio. The NPV of any possible transmission capacity sales to third parties are included in the risk analysis as project benefits.

## Economic Evaluation Components and Assumptions

The evaluation of the different resource portfolios incorporates the NPV of the items listed below.

- **AURORA Modeling (Total Portfolio Costing)**–Idaho Power uses the AURORA model to evaluate the variable cost of production for existing and committed resources along with any new resources proposed in the portfolios. Operational constraints are approximated along with energy purchases and sales in the regional market. Idaho Power used a base inflation rate of 3 percent per year discounted to 2010 dollars.
- **Capital Cost**–Idaho Power uses an internal financial analysis model to evaluate the capital cost of new resources and to estimate the associated revenue requirements. Estimated construction costs, including Allowance for Funds Used During Construction (AFUDC), have been escalated at the base inflation rate of 3 percent per year and included in the P-Worth Model. The estimated capital costs are translated into an annual revenue requirement which corresponds to the size and timing of the estimated dollar investment for each resource. The annual revenue requirement for each resource portfolio is then discounted and summed. The annual revenue requirement analysis has the benefit of matching the annual revenue requirements with the corresponding annual energy benefits. The annual revenue requirement analysis eliminates the need to estimate resource values beyond the study period because resource capital costs and resource benefits are matched annually within the study period.
- **Carbon Allowances**–Annual carbon emissions surpluses and deficits from 2012 onward are valued at the Boxer–Kerry allowance cap rate. As previously mentioned, each resource portfolio is designed to substantially comply with the proposed federal legislation. The annual allowance surplus or deficit is valued at the proposed legislative price cap and the total value is discounted and summed for the analysis.
- **Renewable Energy Credits**–Annual REC surpluses and deficits from 2012 forward are valued at the expected REC value. The annual value of the REC surplus or deficit is discounted and summed for the analysis.
- **Transmission Cost**–Idaho Power estimated the total transmission costs for each resource portfolio and the estimated transmission costs are used to determine the annual transmission revenue requirement. The NPV of the transmission revenue requirements are included in the portfolio evaluation. A more detailed presentation of the transmission assumptions for each portfolio can be found in *Appendix C–Technical Appendix.*
- **Financial Assumptions and Interest Rates**–A list of the IRP financial assumptions and interest rates is shown in Table 9.1.

**Table 9.1 Financial Assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount Rate (aka weighted average cost of capital [WACC]) | 6.98% |
| Composite Tax Rate | 39.10% |
| Deferred Rate | 35.00% |
| General O&M Escalation Rate | 3.00% |
| Emission Adder Escalation Rate | 2.50% |
| Annual Property Tax Escalation Rate (% of Investment) | 0.29% |
| Property Tax Escalation Rate | 3.00% |
| Annual Insurance Premium (% of Investment) | 0.31% |
| Insurance Escalation Rate | 2.00% |
| AFUDC Rate (Annual) | 7.00% |
| Production Tax Credit Escalation Rate | 3.00% |

# 10. Modeling Results and Risk Analysis

The AURORA modeling results form the basis for evaluating the operational and quantitative risk characteristics of the various resource portfolios. The portfolio resources include Idaho Power's existing and committed resources along with the new resources identified in the specific portfolio. The AURORA portfolio results are aggregated by the two 10-year time periods covered.

## Portfolio Modeling Results

Table 10.1 summarizes the market sales, market purchases, portfolio value, and capital costs used in the evaluation of the portfolios for the first 10-year period. The figures in Table 10.1 represent the results of the AURORA analysis, and total transmission and generation capital costs.

**Table 10.1 AURORA Results and Capital Costs Used in Portfolio Evaluation (2010–2019)**

| Year 1–10 Portfolio | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H* | 1-4 B2H |
|---|---|---|---|---|
| **AURORA Nominal ($000)** | | | | |
| Market Purchases | $478,000 | $511,000 | $507,000 | $510,000 |
| Market Sales | (1,264,000) | (1,210,000) | (1,229,000) | (1,209,000) |
| Portfolio Value | 3,436,000 | 3,485,000 | 3,473,000 | 3,483,000 |
| Total | 2,650,000 | 2,786,000 | 2,751,000 | 2,784,000 |
| **AURORA NPV ($000)** | | | | |
| Market Purchases | 361,000 | 382,000 | 378,000 | 381,000 |
| Market Sales | (926,000) | (890,000) | (905,000) | (889,000) |
| Resource Total | 2,528,000 | 2,562,000 | 2,549,000 | 2,561,000 |
| Total | 1,963,000 | 2,054,000 | 2,022,000 | 2,053,000 |
| **Capital Costs (2009 Dollars)** | | | | |
| Transmission Capital Costs | 27,000,000 | 22,000,000 | 87,000,000 | 111,000,000 |
| Generation Capital Costs | 1,264,000,000 | 267,000,000 | 250,000,000 | 97,000,000 |

*B2H–Boardman to Hemingway

The second 10-year planning period begins where Portfolio 1-4 ends in 2020. Portfolio 1-4 showed promise early on in the evaluation process as being a low-cost alternative, therefore Portfolio 1-4 was selected as the basis for designing the second-period portfolios. The load forecast for the second period is relatively flat. The primary driver for new resources in the second period is the carbon emission reduction to be compliant with the carbon allowance limits identified in the Waxman-Markey bill

### Highlights

- Quantitative risk factors analyzed include third-party transmission subscription, high renewable energy credit (REC) prices, high natural gas prices, high carbon emissions costs, high load growth, and low conservation.
- Qualitative risk factors analyzed include carbon regulation, technology, electric market prices, and resource siting.
- Idaho Power currently maintains a capacity reserve margin of approximately 10 percent.
- Loss of load expectation (LOLE) is based upon the utility industry standard metric of one day in 10 years.

(H.R. 2454). In fact, the base case assumption is that by the end of the integrated resource plan (IRP) planning period, virtually all of Idaho Power's existing coal resources are replaced with lower, or zero, carbon-emitting resources, or market purchases.

Portfolios 2-1 and 2-3 are the most capital intensive; each having over $5 billion dollars in generation resources and approximately $1.35 and $1.23 billion in transmission capital costs respectively (2009 dollars). Less costly, but still significant, is Portfolio 2-4 with almost $2 billion in new generating resources and $800 million in transmission projects. The least costly of the regular portfolios is portfolio 2-2 with $356 million in new resources and $2.25 billion in new transmission. Portfolio 2-5 (Limited Coal Curtailment) has $762 million in generating resources and $337 million in transmission projects. Portfolio 2-5 maintains, and continues to operate, the company's coal plants with limited curtailment.

The operational costs are included in the evaluation in addition to the generation and transmission capital costs. Operational value includes variable costs of operating the resources along with the net contribution of portfolio market purchases and sales. The net operational costs can be either negative or positive depending on the quantity of off-system market sales.

To a significant degree, an inverse correlation exists between the capital cost and the operational costs of the resource portfolios. The relationship is dependent on the exposure to market prices in both energy purchases and energy sales. For example, Portfolio 2-1 has the lowest portfolio operating cost of $2.3 billion (nominal dollars), but Portfolio 2-1 also has the most market sales at $2.2 billion. Because of the large quantity of market sales, portfolio 2-1 has the greatest market price risk.

Portfolio 2-2 has the highest total operating cost at $4.1 billion with over one-third of the total ($1.5 billion) being market purchases. The $1.5 billion gives Portfolio 2-1 a significant market purchases price risk. Table 10.2 summarizes the AURORA results and capital costs used in the portfolio evaluation.

**Table 10.2 AURORA Results and Capital Costs Used in Portfolio Evaluation (2020–2029)**

| Year 11–20 Portfolio | 2-1 Nuclear/Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| **AURORA Nominal ($000)** | | | | | |
| Market Purchases | $540,000 | $1,503,000 | $631,000 | $1,162,000 | $840,000 |
| Market Sales | (2,232,000) | (1,174,000) | (2,204,000) | (1,221,000) | (1,818,000) |
| Portfolio Value | 4,050,000 | 3,758,000 | 4,309,000 | 4,003,000 | 4,574,000 |
| Total | 2,358,000 | 4,087,000 | 2,736,000 | 3,944,000 | 3,596,000 |
| **AURORA NPV ($000)** | | | | | |
| Market Purchases | 214,000 | 527,000 | 250,000 | 423,000 | 323,000 |
| Market Sales | (823,000) | (473,000) | (818,000) | (484,000) | (669,000) |
| Portfolio Value | 1,559,000 | 1,465,000 | 1,644,000 | 1,540,000 | 1,717,000 |
| Total | 950,000 | 1,519,000 | 1,076,000 | 1,479,000 | 1,371,000 |
| **Capital Costs (2009 Dollars)** | | | | | |
| Transmission Capital Costs | 1,354,000,000 | 2,247,000,000 | 1,227,000,000 | 799,000,000 | 338,000,000 |
| Generation Capital Costs | 5,834,000,000 | 356,000,000 | 5,123,000,000 | 1,957,000,000 | 762,000,000 |

# Risk Analysis and Results

Idaho Power evaluated all of the resource portfolios identified in the 2009 IRP for both quantitative and qualitative risks. The objective of risk analysis is to identify resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

One of the major risks is load growth uncertainty associated with the present economic conditions. Economic growth has slowed considerably in Idaho Power's service area and there has been extensive speculation regarding the duration of the economic downturn. A quick return to the economic growth rates of the past 20 years will require additional generation resources to meet load. The present load forecast projects a relatively long period of diminished economic growth.

The other factor affecting the load growth is the effectiveness of Idaho Power's demand-side management (DSM) programs. Idaho Power is projecting continued success with DSM programs, but the success is dependent on overall economic conditions as well as program funding and consumer preferences. A lower realization factor for DSM programs will increase load and require additional generation resources.

Electric vehicles are another factor that has the potential to increase load. Idaho Power estimates that the total load from electric vehicles during the early part of the forecast period will not exceed 100 megawatt (MW) and that the load will occur primarily during off-peak-hours. Idaho Power determined the 100 MW estimate by assuming that each vehicle will be charged from a typical 220-volt residential circuit which creates approximately 3 kilowatt (kW) of load. It would take approximately 30,000 electric vehicles charging simultaneously to increase load by 100 MW. Electric vehicles may become a significant load affecting subsequent resource plans.

Many of the other risk factors are regulatory in nature. The electric utility industry, including Idaho Power, faces considerable regulatory risks. Idaho Power proposes to utilize the Boardman to Hemingway transmission line to meet part of its load. However, committed subscription to the Boardman to Hemingway line is not in place which creates uncertainty concerning allocation of the project costs.

In addition, Idaho Power faces regulatory uncertainty associated with carbon regulation and a federal RES. Idaho Power is planning for a resource future that restricts the quantity of carbon that can be released into the earth's atmosphere. The proposed carbon legislation is anticipated to restrict the quantity of carbon emissions and increase the price of renewable energy credits (REC). Limited, or ineffective, carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional fossil-fueled plants.

Natural gas prices are primarily affected by supply and demand; however, economic growth, load growth, carbon legislation, and transmission availability will also influence prices. Presently natural gas prices are relatively low. However, Idaho Power analyzed the portfolio costs under a scenario where natural gas is considerably more expensive.

## *Quantitative Risk Analysis*

For the 2009 IRP, Idaho Power quantitatively analyzed the risk associated with third party transmission subscription, high REC prices, high natural gas prices, high carbon emissions costs, high load growth, and low conservation. The change in expected cost for each portfolio forms the baseline for the risk comparison. Each portfolio is analyzed for the quantitative risk factors mentioned above, and the boundary costs are estimated for each scenario. The results of the quantitative risk analyses are presented in terms of net present value (NPV) resulting in a side-by-side comparison of the expected cost and range of potential risk for each resource portfolio.

## Transmission Subscription by Third Parties

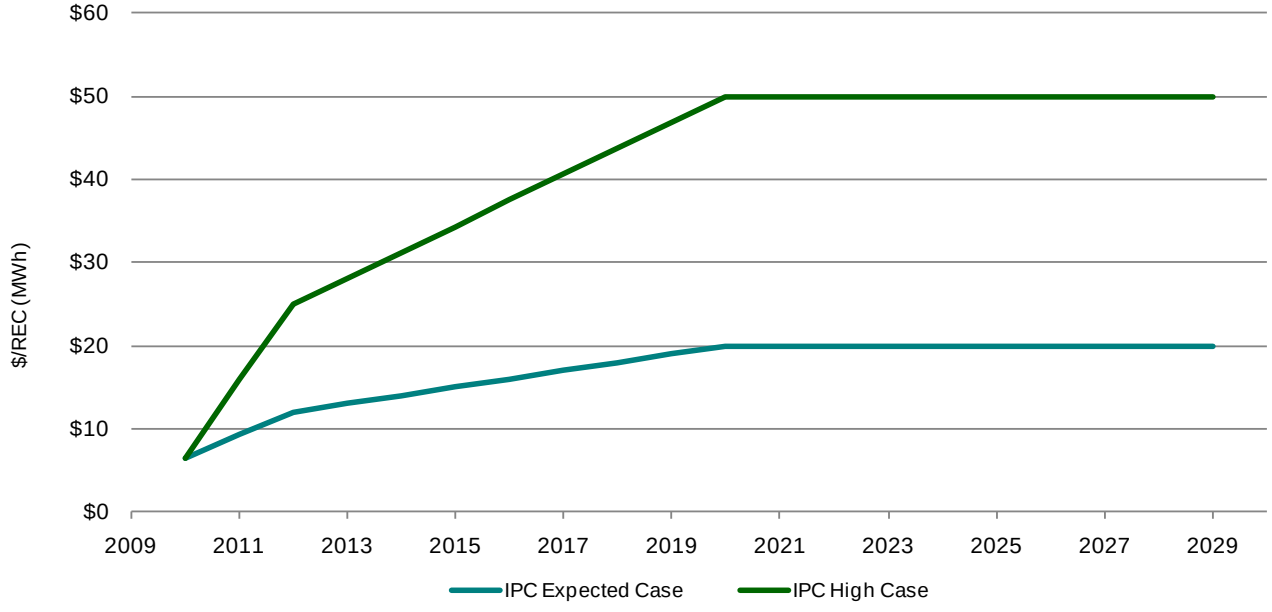
Interstate transmission projects are generally too expensive for a single utility to construct and regional utilities often form partnerships for large-scale transmission projects. Multiple parties commit to fund a portion of the project costs in return for a firm reservation of transfer capacity on the transmission line. Prior to signing the actual agreements, multi-party subscription to new transmission capacity creates significant uncertainty in evaluating actual project costs. At the present time, subscription to both the Boardman to Hemingway and the Gateway West transmission projects has not been determined. Transmission subscription is expected to be better defined in 2010 and will be discussed in the 2011 IRP.

When calculating the expected cost of a portfolio that includes new transmission, the bi-directional transfer capacity of the transmission project is included in the portfolio and is accounted for in the expected cost. For example, Idaho Power intends to use the Boardman to Hemingway transmission line to import energy into Idaho Power's system. Idaho Power's ability to sell transfer capacity from Idaho to the Pacific Northwest represents a possible cost reduction for any portfolio, which includes the Boardman to Hemingway transmission project. The risk analysis estimates that selling all of the unused transmission capacity would reduce the total expected portfolio cost by $46 million (NPV) in Portfolio 1-4 Boardman to Hemingway and by $16.7 million (NVP) in Portfolio 1-3 Gas Peaker and Boardman to Hemingway. Figure 10.5 in the quantitative risk analysis summary (2010-2019) section of this chapter shows the risk associated with third-party transmission subscription in all of the resource portfolios.

## Renewable Energy Credit Prices

All the portfolios analyzed in the 2009 IRP are designed to comply with the RES proposed in the Waxman–Markey bill (H.R. 2454). For any given year, the amount of RECs in the resource portfolio is valued based on the projected forward price curve for RECs. For the risk analysis, a high REC price scenario was analyzed using the price cap included in the Boxer–Kerry bill. Portfolios exceeding the Waxman–Markey REC requirement have lower total risk because a high REC price adds additional value to the portfolio. Likewise, portfolios with insufficient RECs are subject to additional REC price risk. Figure 10.1 shows the two REC forward price curves used in the 2009 IRP.

**Figure 10.1 REC—Forward Price Curve**



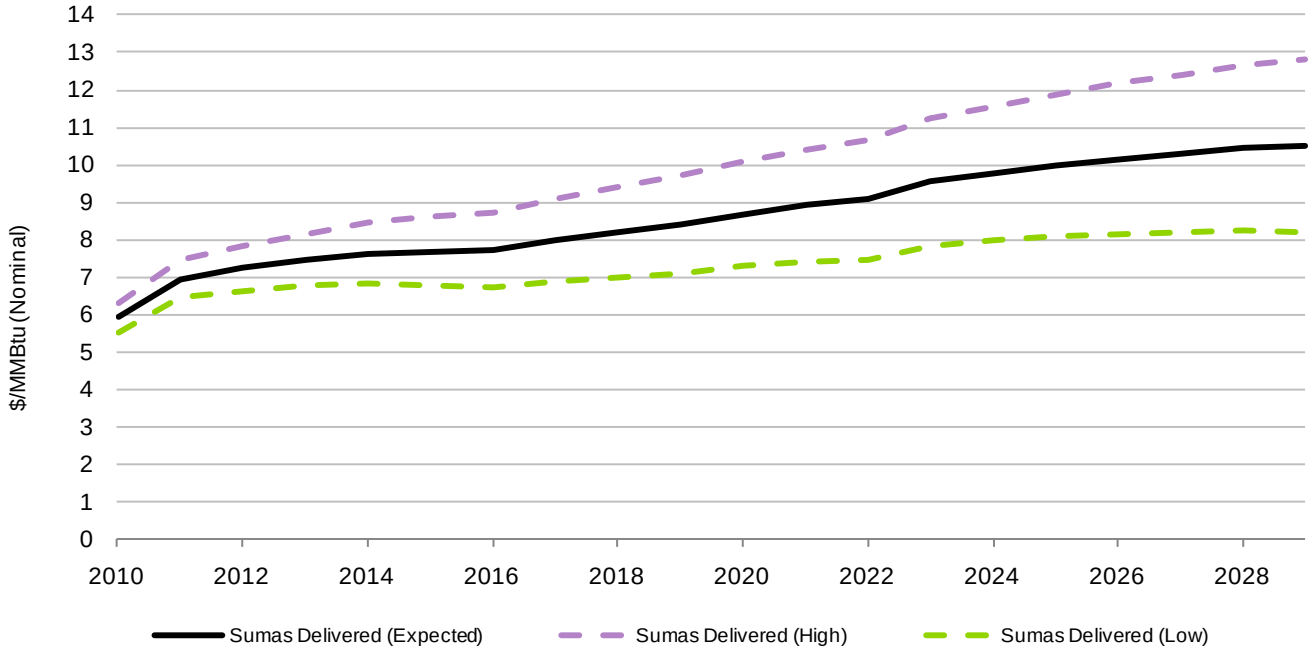
As shown in Figure 9.2 in Chapter 9, all of the resource portfolios considered in the 2009 IRP exceed the Waxman–Markey RES requirements for the first 10-year period. Portfolio 1-1 Solar generates the most RECs. Figure 10.5 shows the REC price risk for each of the portfolios.

During the second 10-year period, all of the proposed resource portfolios substantially meet the Waxman–Markey RES requirements. Portfolio 2-1 Nuclear/Green generates the most RECs during the second 10-year time period. Figures 10.5 and 10.6 show the REC price risk for each of the resource portfolios.

### High Natural Gas Prices

The effects of high natural gas prices were analyzed by subtracting the total portfolio cost determined with the expected natural gas prices from the total portfolio cost using high natural gas prices. Figure 10.2 shows the natural gas prices used for the analysis.

**Figure 10.2 Natural Gas Price Forecast**




High natural gas prices tend to increase the total portfolio value for Idaho Power. During much of the year, natural gas generation is the marginal resource in the Pacific Northwest and natural gas prices indirectly set electricity prices in the regional market. Even though Idaho Power uses natural gas fuel for a portion of its generation, the entire generation output is valued at market cost, and market cost is determined substantially by natural gas generation. High natural gas prices increase the portfolio value for all of the Idaho Power resource portfolios.

During the first 10 years, risk analysis for high gas prices showed that Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the least reduction in expected portfolio costs with portfolios 1-1 Solar, 1-2 Gas Peaker and 1-3 Gas Peaker and Boardman to Hemingway being very similar. Figure 10.5 shows the risk of high gas prices for each of the portfolios.

The risk analysis for the second 10 years showed that high gas prices would increase the expected portfolio cost for Portfolio 2-2 Gateway West and Portfolio 2-4 Wind and Peakers, with the Gateway West portfolio being exposed to market purchases and the Wind and Peakers portfolio containing a significant amount of natural gas resources. Portfolio 2-1 Nuclear/Green, Portfolio 2-3 and Portfolio 2-5 would benefit high gas prices and the resulting high energy prices because these portfolios

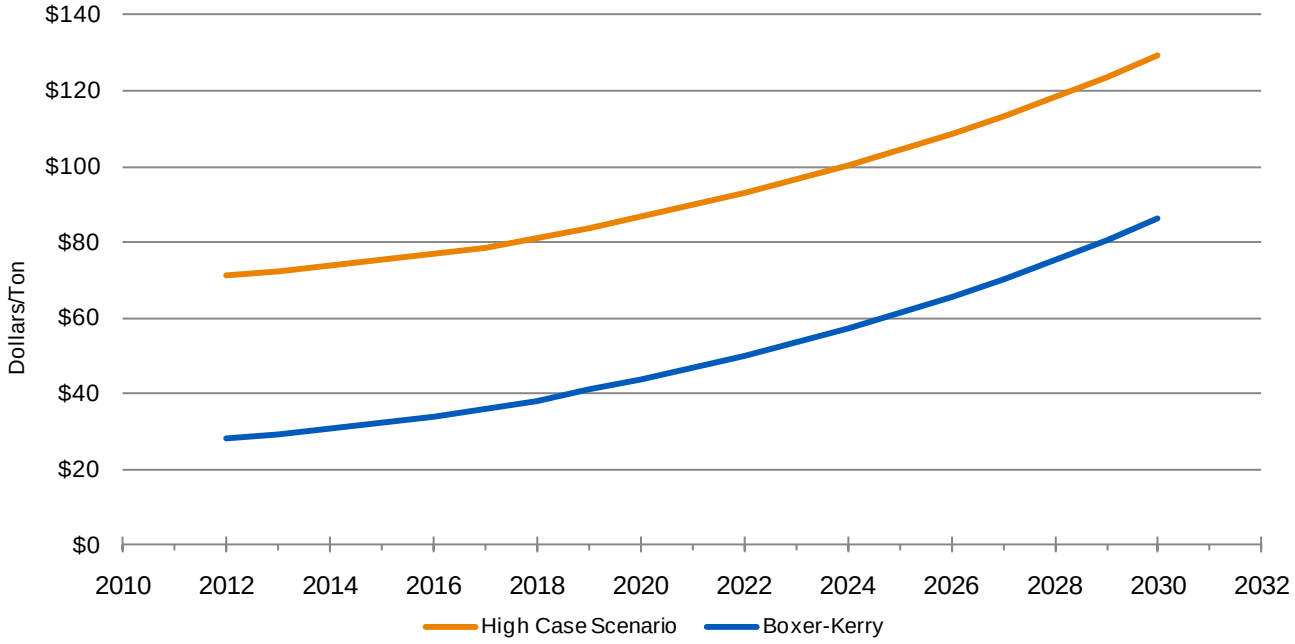
do not rely on a significant amount of natural gas resources. Figure 10.6 shows the risk of high gas prices in all of the portfolios.

### $CO_2$ Allowance Prices

The IRP base case curtails coal production to closely meet the carbon allowances Idaho Power would expect to receive under the Waxman–Markey bill (H.R. 2454). The Boxer–Kerry price cap proposal also sets a price cap on the cost of carbon allowances. Emissions associated with each of the resource portfolios were valued using the Boxer–Kerry price cap curve.

It is important to also understand the portfolio risk with high emission allowance prices. Idaho Power performed a risk analysis to estimate the effect of a $43 per ton carbon tax added to the Boxer–Kerry price cap curve. Figure 10.3 shows the expected case allowance price (Boxer–Kerry cap) and the high price case used for the risk analysis.

**Figure 10.3 Boxer–Kerry Carbon Allowance Price Cap and High Case Scenario**



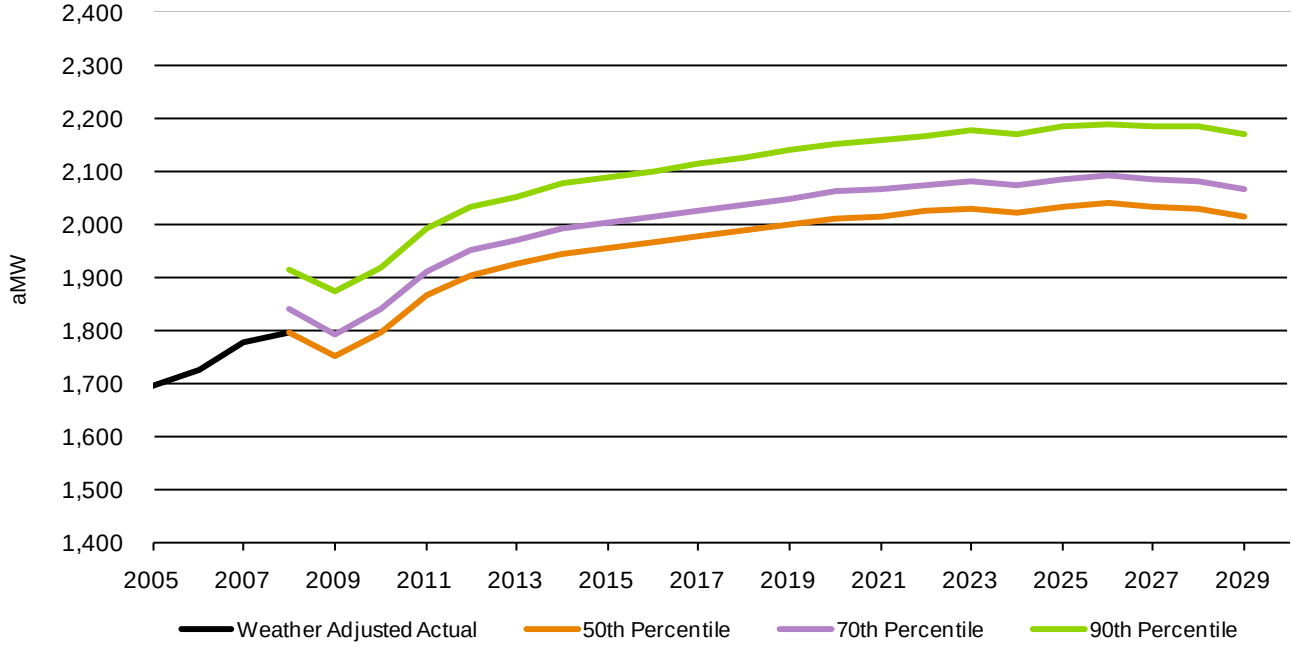

As expected, the high price case risk analysis resulted in a cost increase in all of the resource portfolios. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the greatest increase in costs and Portfolio 1-1 Solar had the lowest increase. Figure 10.5 shows the risk of high carbon allowance prices in all of the portfolios.

In the second 10 years, Portfolio 2-5 Limited Coal Curtailment showed the greatest cost increase and Portfolio 2-1 Nuclear/Green showed the lowest increase. Figure 10.6 shows the risk of high carbon allowance prices in all of the portfolios.

### High Load Growth

The current load growth forecast departs significantly from the historical trend line. The general consensus during the company's IRP Advisory Council (IRPAC) meetings was that Idaho Power faces the risk that loads may be higher than forecast. Figure 10.4 shows the various load forecasts used in the 2009 IRP, including the high load growth case used to assess the load forecast risk.

**Figure 10.4 Average Monthly Load Growth Forecast**




High load growth increased the costs in all resource portfolios as additional energy purchases were required to meet customer load. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the highest increase in costs and Portfolio 1-2 Gas Peaker had the lowest increase. Figure 10.5 shows the risk of high load growth in all of the portfolios.

In the second 10 years, Portfolio 2-4 Wind and Peaker had the highest increase in costs with Portfolio 2-5 Limited Coal Curtailment having the lowest increase. Figure 10.6 shows the risk of high load growth in all of the portfolios.

## Low Conservation

Energy efficiency, conservation, and demand response programs are forecast to significantly reduce the need for future generation resources. However, there is some uncertainty and risk associated with the forecast if the expected level of DSM is not achieved. Idaho Power evaluated a low conservation case where only 50 percent of the forecast DSM program performance is achieved to assess the DSM program realization risk.

The low conservation risk analysis showed an increase in costs to all of the portfolios which is similar to the high load growth analysis presented above. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the highest increase in costs and Portfolio 1-2 Gas Peaker had the lowest increase. Figure 10.5 shows the risk of low conservation in all of the portfolios.

In the second 10 years, Portfolio 2-4 Wind and Peakers had the highest increase in costs with Portfolio 2-5 Limited Coal Curtailment having the lowest increase in costs. Figure 10.6 shows the risk of low conservation in all of the portfolios.

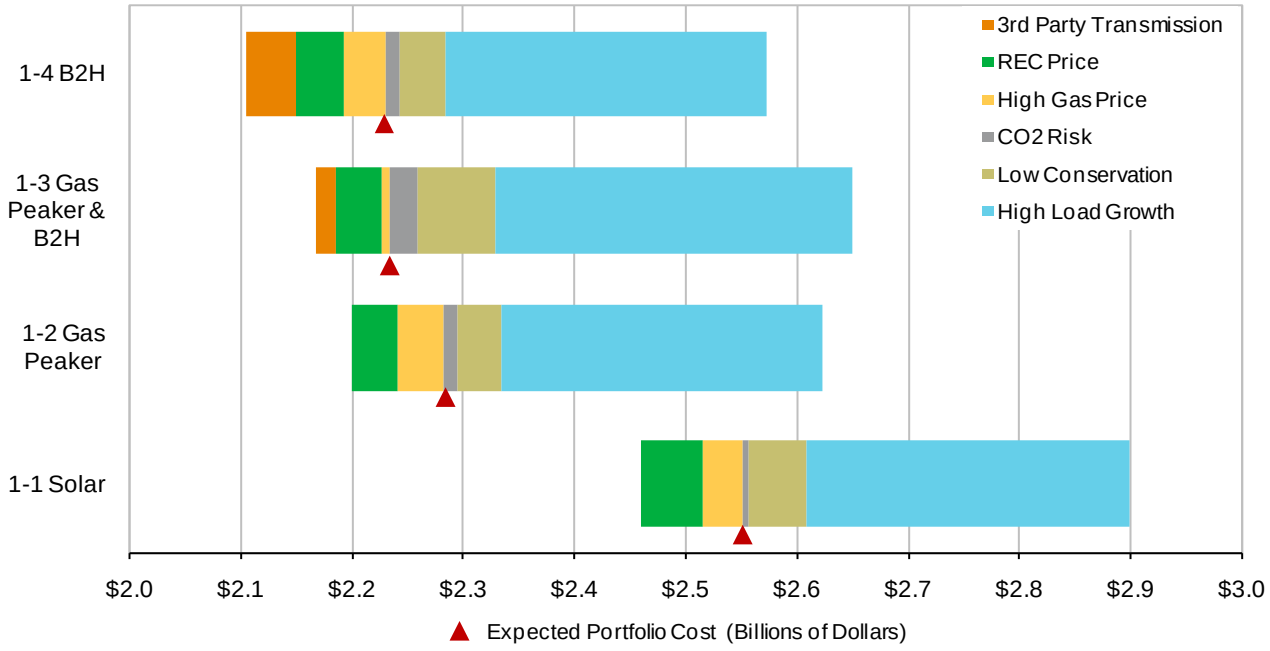
## Quantitative Risk Analysis Summary (2010–2019)

The summary conclusions of the quantitative risk analyses are:

- The high load growth and low conservation analyses do not provide significant differentiation between the different resource portfolios, but do quantify the potential for increased costs.
- Additional generation benefits some portfolios due to additional operational flexibility.
- Natural gas prices are correlated with market power prices and high gas prices increase the value of Idaho Power's existing portfolio.
- Portfolios that include the Boardman to Hemingway transmission project have the potential to cost less depending on actual third-party subscription.
- Carbon risk is a significant factor if emission costs exceed the anticipated allowance allocations.

Portfolio 1-4 Boardman to Hemingway has the lowest expected portfolio cost and the potential for the lowest risk. Figure 10.5 shows the expected total portfolio cost and the cumulative risk for each portfolio analyzed for the 2010-2019 time period.

**Figure 10.5 Cumulative Portfolio Risk (2010–2019)**



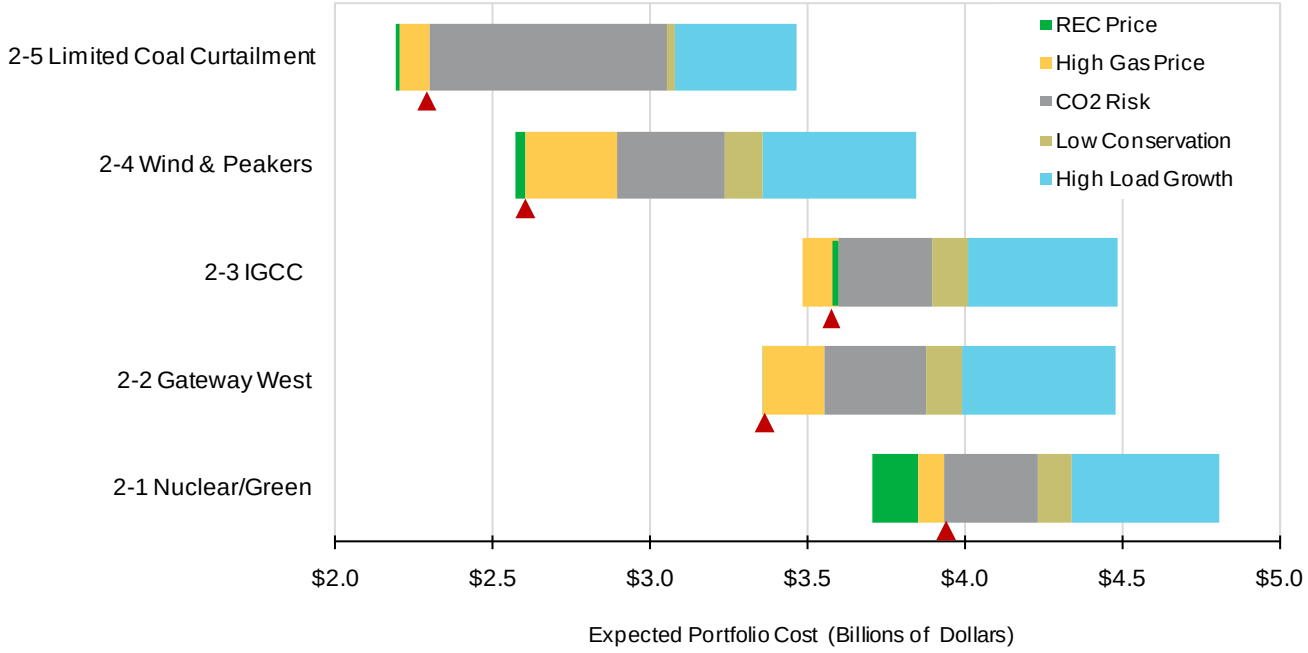

## Quantitative Risk Analysis Summary (2020-2029)

The 2009 IRP considered several assumptions when analyzing the quantitative risk analysis for years 2020 through 2029. Portfolio 1-4 was used to define the 2010-2019 resources for the second 10–year modeling period. Another assumption that had a substantial effect on total portfolio costs is the addition of the Gateway West transmission project. Additional quantitative risk factors with significant portfolio differentiation include natural gas price effects ranging from $0–$1,140 million and the expected carbon allowance price with a $43 increase ranging between $296 to $749 million.

Portfolio 2-5 Limited Coal Curtailment has the lowest expected portfolio cost, but has the highest carbon risk of all the portfolios. The carbon risk in Portfolio 2-5 could be even greater than the estimate should the carbon allowance price caps be adjusted upward. Portfolio 2-1 Nuclear/Green has the highest expected portfolio cost, but has the least risk because of the limited exposure to the carbon price risk.

Figure 10.6 shows the expected total portfolio cost and the cumulative risk for each portfolio analyzed for the 2020–2029 time period.

**Figure 10.6 Cumulative Portfolio Risk (2020–2029)**




## *Qualitative Risk Analysis*

The qualitative risks associated with the four 2010-2019 resource portfolios and the five 2020-2029 resource portfolios are more difficult to assess. Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Many of the qualitative factors are considered in public forums like the IRPAC meetings as well as in regulatory workshops and proceedings. For the 2009 IRP, Idaho Power qualitatively analyzed the risk associated with carbon regulation, technology, and resource siting.

### Carbon Regulation

Congress is embarking on the most comprehensive energy legislation in many years. While the Waxman–Markey bill (H.R. 2454) has emerged from the House with an extensive section on carbon regulation, at the time of this IRP, the form of carbon regulation from a Senate bill is still uncertain. Carbon regulation has become a contentious point in the Senate. Idaho Power has analyzed the Waxman–Markey bill and developed portfolios to comply with proposed carbon regulations. If the Senate were to pass an energy bill, the bill would then go to conference with the House of Representatives. Major components could be changed, particularly carbon regulation. In addition, political analysts and Washington D.C. insiders have speculated that due to the record federal deficit and continued high unemployment in the economy, President Obama could ask Congress to drop the carbon emission cap-and-trade provisions from the energy bill. If cap-and-trade was removed, carbon regulation could become an independent piece of legislation separate from any energy bill. Given the energy legislation uncertainty, Idaho Power believes that it is important to select a resource portfolio that has the flexibility to adapt to carbon regulation changes.

### Technology

Technology risk primarily occurs during the second 10-year period of the forecast. The principal area in which technology risk is considered in this resource plan is the uncertainty associated with developing

new advanced nuclear and coal technologies, such as integrated gasification combined cycle (IGCC). IGCC resources provide increased efficiency, reduced emissions, and the ability to capture and potentially sequester $CO_2$ emissions at reduced costs. However, IGCC plants have higher capital costs and there is uncertainty regarding the performance of the proposed technology.

While there are certain risks associated with each type of generation resource, Idaho Power is specifically concerned about the technology risk associated with IGCC projects. IGCC projects have received a considerable amount of attention in the press recently. Idaho Power is supportive of IGCC technology and believes that the technology may play a significant role in meeting the nation's future energy needs. However, Idaho Power also believes that there is considerable technology risk associated with developing an IGCC project for use with western coals. With only two operating IGCC projects in the entire United States, much of the electric industry, including Idaho Power, does not consider IGCC to be a proven technology.

Considering Idaho Power's modest size and the significant cost of an IGCC project, Idaho Power believes it would be imprudent for the company to assume the IGCC development risk alone. Idaho Power is more comfortable taking a lesser share in a jointly-owned regional IGCC project and the company believes that an ownership share is the appropriate way for Idaho Power to allocate the IGCC technology risk if a future joint development opportunity becomes available.

### Market Risk

All market participants, including Idaho Power, face price risks when buying or selling in the market. The magnitude of the risk depends on the characteristics of the portfolio of power supply resources. Portfolios with a large quantity of either market sales or market purchases have greater exposure to changes in market prices. Additional factors to consider in the market price risk faced by each portfolio are the quantity and timing, e.g., spring, summer, daytime or nighttime of renewable resource generation, the quantity of natural gas-fired resources, and the seasonal cost of natural gas.

Idaho Power's current resource base consists primarily of low, marginal-cost coal and hydroelectric resources. Idaho Power's customers have historically benefited because the company can sell excess capacity to the market on a short-term basis during periods of high prices. To a lesser degree, Idaho Power can buy from the market during low-price periods and curtail existing resources, thereby shifting fuel (water and coal) use to more valuable hours. However, both opportunities are limited by existing transmission constraints.

In the 2009 IRP, Idaho Power's excess capacity is eventually consumed by load growth and the base case assumption of coal resource curtailment. These assumptions reduce seasonal excess capacity and limit the opportunities to capitalize on market price volatility. Tables 10.3 and 10.4 show the amount of market purchases and sales for each portfolio. "Resource Total" represents the total generation from existing resources and the new resources in each portfolio. "Native Load" represents the amount of generation required to serve customers.

As shown in Table 10.3, Portfolio 1-1 has the least exposure to market purchases and the greatest exposure to market sales, thus leaving it more exposed to a future of low prices when selling power in the wholesale electric market. On the other hand, Portfolio 1-2 has the least amount of market sales and the greatest amount of market purchases, leaving it more exposed to the risk of high market prices. Although there are differences between each of the portfolios in the amount of market purchases and sales, the differences are minor. The relatively small difference between the portfolios highlights the fact that Idaho Power is able to use market purchases and sales to increase the total value of any portfolio.

Compared to the first ten-year period, the second ten-year period shows a more significant variation between portfolios. The portfolios with large base-load units that are not impaired by carbon legislation (Portfolios 2-1, 2-2 and 2-5) show greater exposure to low market prices. The remaining portfolios (2-2

and 2-4) are significantly more exposed to high market prices due to a reliance on market purchases. Figure 10.4 shows the results of the analysis for the second ten-year period.

**Table 10.3 Market Purchases and Sales Summary (2010–2019)**

| MWh (000) | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H* | 1-4 B2H |
|---|---|---|---|---|
| Market Purchases | 8,312 | 8,861 | 8,771 | 8,828 |
| Market Sales | (26,395) | (25,175) | (25,722) | (25,178) |
| Resource Total | 187,614 | 185,845 | 186,482 | 185,881 |
| Native Load | 169,531 | 169,531 | 169,531 | 169,531 |
| Diff Market Purchases to Lowest | | 549 | 459 | 516 |
| Diff Market Sales to Lowest | (1,220) | | (547) | (3) |

*B2H–Boardman to Hemingway

**Table 10.4 Market Purchases and Sales Summary (2020–2029)**

| MWh (000) | 2-1 Nuclear/Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| Market Purchases | 7,186 | 19,629 | 8,475 | 15,566 | 11,135 |
| Market Sales | (34,372) | (18,645) | (34,170) | (19,246) | (28,063) |
| Resource Total | 204,869 | 176,698 | 203,378 | 181,363 | 194,610 |
| Native Load | 177,683 | 177,683 | 177,683 | 177,683 | 177,683 |
| Diff Market Purchases to Lowest | | 12,440 | 1,289 | 8,380 | 3,949 |
| Diff Market Sales to Lowest | (15,727) | | (15,525) | (601) | (9,418) |

## Resource Siting

Time delays and cost increases associated with resource siting and public acceptance are risks that Idaho Power considers when developing generation and transmission resources. Resource siting becomes even more critical when attempting to locate a generation resource close to an existing load center. In addition to the permitting requirements associated with developing generation resources, Idaho Power must also ensure that the public supports the project and that the project will remain productive throughout its useful life.

The problems that Alternate Energy Holdings, Inc has encountered during the past several years with a proposed nuclear generation plant near Bruneau, Idaho, and the difficulties MidAmerican Nuclear Energy Company, LLC faced with a proposed nuclear generation plant in Payette County are indicative of the risks associated with resource siting and public acceptance. Presently, Idaho Power recognizes there are siting concerns with portions of the Boardman to Hemingway transmission line and the company is working with the local communities and regulatory agencies to develop the project in appropriate areas. Resource siting is a potential issue with any of the generation and transmission resources identified in the IRP.

## Qualitative Risk Analysis Summary

Generation resources represent significant capital expenditures and resource development entails considerable risk. The public recognizes the risk and electric utilities are regulated to insure that the risks are prudent. One part of the risk assessment is the public involvement when developing long-term resource plans. A second part of the risk assessment is regular periodic review of the company's long-term resource strategy. Idaho Power develops its IRP on a biennial schedule to address the

changing economic, regulatory, and technology risks. Idaho Power recognizes the capital risk in developing generation resources and understands that a diverse resource portfolio of a variety of supply-side, demand-side, and regional transmission resources will allow the company to maintain operational flexibility, minimize risk, and adapt to future economic, demographic, and regulatory conditions.

# Preferred Portfolio Selection

## *2010–2019 (Portfolio 1-4 Boardman to Hemingway)*

The selection Portfolio 1-4 Boardman to Hemingway is based primarily on the portfolio having the lowest expected portfolio cost. The low cost is a result of the portfolio having a relatively low new resource capital cost and low AURORA portfolio cost. Portfolio 1-4 has the highest transmission cost with a 37 percent stake in the Boardman to Hemingway project.

An important consideration in selecting a preferred portfolio is the ability to maintain flexibility in the face of uncertainty and not to foreclose various resource options. The flexibility to adjust to changes during the present period of unusually high regulatory uncertainty is very important. To maintain operational flexibility in some cases means Idaho Power must commit to long lead time resources, such as the Boardman to Hemingway project.

## *2020–2029 (Portfolio 2-4 Wind and Peakers)*

The theme of maintaining resource flexibility continues in the second 10-year period. Portfolio 2-4 focuses on relatively short lead time resources, such as wind projects and natural gas-fired resources. The coal curtailment assumption in Portfolio 2-4 will require significant replacement resources during the last years of the study horizon. In order to accommodate the needed quantity of replacement resources, a significant share (600 MW) of Gateway West is included in the preferred portfolio. The Gateway West transmission project enables access to the high-capacity wind regions of Wyoming (500 MW) as well as access to some energy-rich coal and natural gas deposits in southern Wyoming. The feasibility and risks of natural gas transport for 1,400 MW of new natural gas generation located near the load center in the Treasure Valley has not been included in this analysis.

Figures 10.7 and 10.8 show projections for Idaho Power's energy sources by resource type, for 2019 and 2029 respectively, assuming the preferred portfolio for each 10-year period and the carbon regulations proposed in the Waxman–Markey bill are implemented. The percentages presented in Figures 10.7 and 10.8 are estimates of Idaho Power's future energy sources and are not a representation of the energy expected to be delivered to customers. An accounting of the energy delivered to customers, by resource type, is posted on Idaho Power's Web site at www.idahopower.com.

It is important to note the Waxman–Markey bill presents only one scenario out of many possible futures for the regulation of carbon emissions. In addition, alternative compliance options implemented as part of any future carbon regulation may allow the continued operation of Idaho Power's coal resources.

The level of hydroelectric generation presented in Figures 10.7 and 10.8 is based on 50$^{th}$ percentile or median water conditions. As shown in the figures, the addition of the Langley Gulch combined-cycle combustion turbine (CCCT) in 2012 increases the amount of natural gas generation in 2019 to 12 percent which increases to 29 percent in 2029 with the addition of the natural gas peaking units identified in the second 10 years of the planning period. The addition of gas peaking resources is necessary to integrate the wind resources (500 MW) in the preferred portfolio.

The annual percentage of energy supplied through power purchases is projected to increase from 7 percent in 2019 to 12 percent in 2029. The market purchases component of the power supply portfolio

includes purchases from non-wind Public Utility Regulatory Policy Act (PURPA) resources and market-purchased power. Existing PURPA wind generation is accounted for in the wind generation category.

**Figure 10.7 2019 Supply-Side Resources**

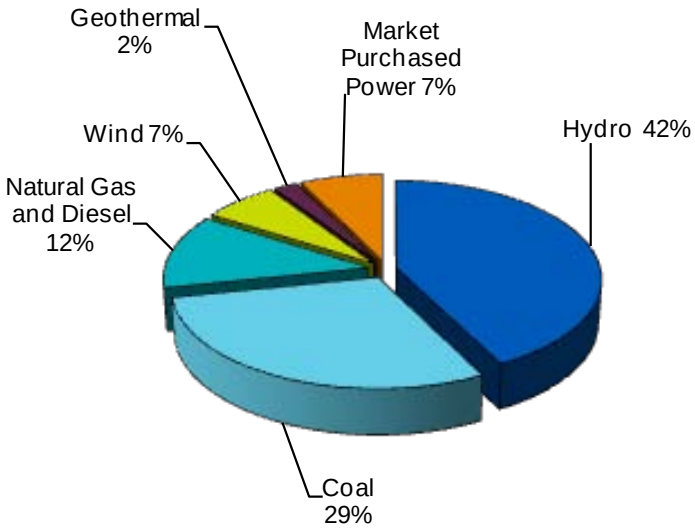
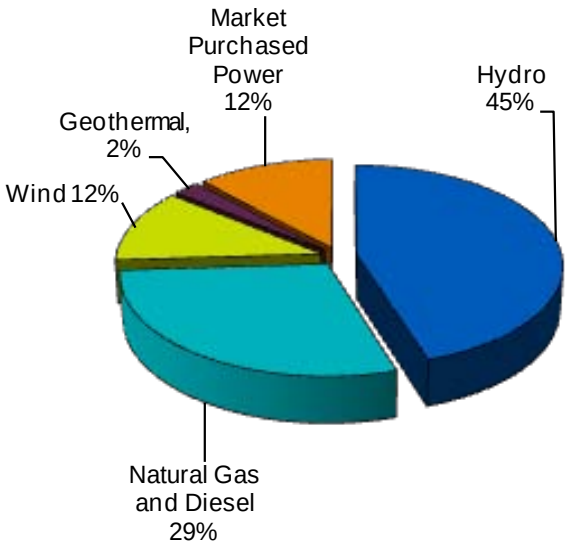



**Figure 10.8 2029 Supply-Side Resources**




Figures 10.7 and 10.8 represent Idaho Power's energy resource mix in 2019 and 2029 respectively, under the assumptions that Idaho Power's coal resources are curtailed as proposed in the Waxman–Markey bill, and portfolios 1-4 Boardman to Hemingway and 2-4 Wind and Peakers are implemented. If the cost of emitting carbon is less than $30 per ton, it may be more economical for Idaho Power to continue to operate existing coal resources.

## Developing Alternate Portfolios

Idaho Power developed two alternate resource portfolios that identify the resource choices should the assumptions used to determine the preferred portfolio not materialize. The most likely scenario leading to selecting an alternative portfolio in the near term is limited third-party interest in the Boardman to Hemingway transmission line. Idaho Power anticipates identifying other partners for the Boardman to Hemingway transmission line by the end of 2012. Should there be insufficient interest in the project, Idaho Power will assess the construction start date in 2013 and possibly delay construction until there is sufficient committed interest in the project. Idaho Power would likely replace the Boardman to Hemingway project with a natural gas-fired generation resource and begin the acquisition process for the natural gas resource with a competitive RFP in 2013. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. The preferred and alternate portfolios for the first 10-year period are shown in Table 10.5.

The alternate portfolio for the second 10-year period assumes Idaho Power curtails existing coal resources based on the Waxman–Markey bill through 2020 with no additional curtailment through the second 10 years of the planning period. Idaho Power believes this is a likely scenario and the alternate portfolio contains additional resources to offset the level of coal curtailment. The preferred and alternate portfolios for the second 10-year period are shown in Table 10.6.

**Table 10.5 Preferred and Alternate Portfolios (2010–2019)**

| Preferred Portfolio 1–4 Boardman to Hemingway | | | Alternate Portfolio 1–2 Gas Peakers | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2010 | | | 2010 | | |
| 2012 | Wind* | 150 | 2012 | Wind* | 150 |
| | CCCT (Langley Gulch)* | 300 | | CCCT (Langley Gulch)* | 300 |
| | Geothermal* | 20 | | Geothermal* | 20 |
| 2015 | Shoshone Falls | 49 | 2015 | Shoshone Falls | 49 |
| | Boardman to Hemingway | 250 | | SCCT (Frame Peaker) | 170 |
| 2016 | Geothermal* | 20 | 2016 | Geothermal* | 20 |
| 2017 | Boardman to Hemingway | 175 | 2017 | SCCT (Frame Peaker) | 170 |
| 2019 | | | 2019 | | |

* Committed Resource

**Table 10.6 Preferred and Alternate Portfolios (2020–2029)**

| Preferred Portfolio 2–4 Wind & Peakers | | | Alternate Portfolio 2–5 Limited Curtailment | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2020 | SCCT (Large Aero) | 100 | 2020 | | |
| 2021 | | | 2021 | Wind | 100 |
| 2022 | Wind | 100 | 2022 | SCCT (Large Aero) | 100 |
| 2023 | | | 2023 | | |
| 2024 | SCCT (Large Aero) | 200 | 2024 | | |
| 2025 | Gateway West | 100 | 2025 | | |
| 2026 | Large Aero | 200 | 2026 | SCCT (Large Aero) | 100 |
| 2027 | Wind | 400 | 2027 | Wind | 200 |
| | | | | SCCT (Large Aero) | 100 |
| 2028 | SCCT (Large Aero) | 400 | 2028 | | |
| 2029 | SCCT (Large Aero) | 500 | 2029 | | |

## Estimated Cost of Proposed Carbon Legislation

Meeting the proposed carbon legislation is not without cost. As mentioned in Chapter 9, Idaho Power prepared Portfolio 2-5 where carbon emissions are reduced up to 2020 and then held flat at the 2020 level throughout the remainder of the planning period. Idaho Power also prepared an additional resource portfolio, with no carbon emission reductions. The additional portfolio was used to isolate the estimated costs to comply with the proposed carbon legislation. Tables 10.7 and 10.8 compare the estimated costs of the no curtailment portfolio with the cost estimates for the preferred resource portfolios 1-4 and 2-4 for both time periods.

There are only minor costs of the proposed carbon legislation in the first 10 years of the planning period because the carbon legislation does not change Idaho Power's resource choices during the first 10 years. However, the proposed carbon legislation does affect how Idaho Power operates its resources in the first 10 years, but the effects are minor and result from reduced off-system sales.

The second 10-year period is considerably different. By the 2020–2029 time period, Idaho Power must replace the generation capacity lost due to coal curtailment with alternate generation resources. The analysis estimates the total cost of the carbon legislation to be almost one billion dollars. The total is composed of almost $700 million of generation capital and over $300 million in lost market sales.

Idaho Power will continue to evaluate the federal carbon emission legislation and the topic will be discussed in the 2011 IRP.

**Table 10.7 Carbon Legislation Costs (2010–2019)**

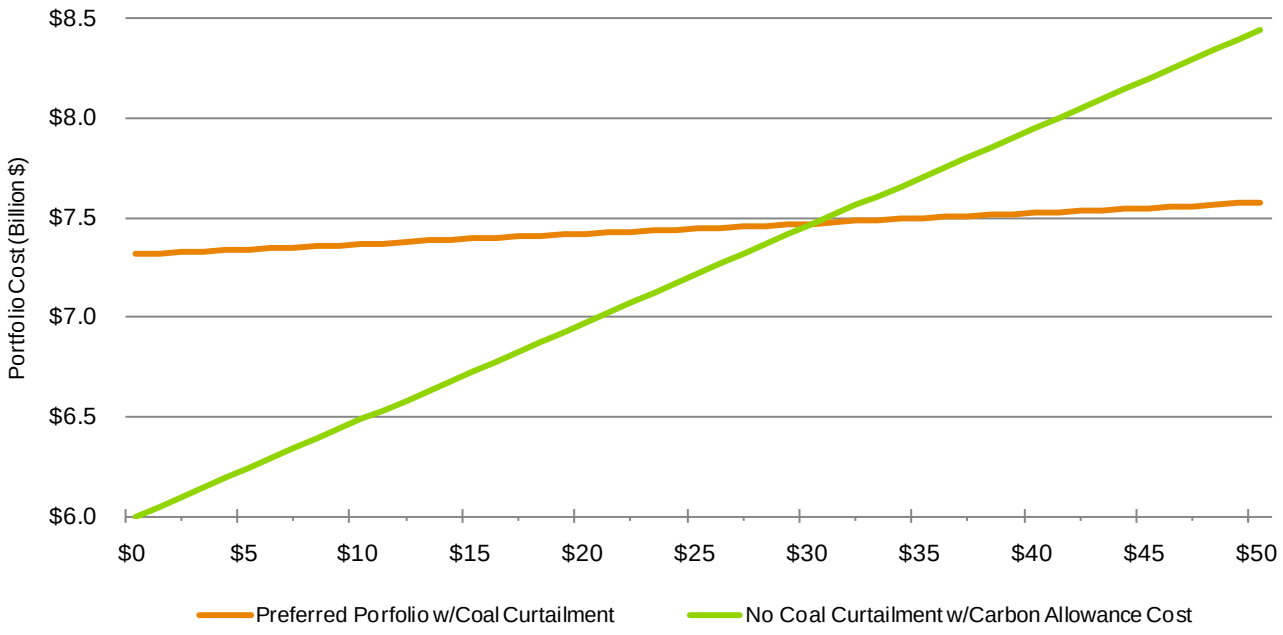
| | 1-4 Boardman to Hemingway | No Coal Curtailment | Difference |
|---|---|---|---|
| **Aurora Nominal ($000)** | | | |
| Market Purchases | $510,000 | $495,000 | $15,000 |
| Market Sales | (1,209,000) | (1,458,000) | 249,000 |
| Resources Total | 3,483,000 | 3,600,000 | (117,000) |
| Total | 2,784,000 | 2,637,000 | 147,000 |
| **Aurora NPV ($000)** | | | |
| Market Purchases | 381,000 | 372,000 | 9,000 |
| Market Sales | (889,000) | (1,055,000) | 166,000 |
| Resources Total | 2,561,000 | 2,631,000 | (71,000) |
| Total | 2,053,000 | 1,948,000 | 104,000 |
| **2009 Dollars** | | | |
| Transmission New | 110,870,000 | 110,870,000 | 0 |
| Generation Capital Costs | 96,951,000 | 96,951,000 | 0 |

**Table 10.8 Carbon Legislation Costs (2020–2029)**

| Aurora Nominal ($000) | 2-4 Wind & Peakers | No Coal Curtailment | Difference |
|---|---|---|---|
| **Aurora Nominal ($000)** | | | |
| Market Purchases | $1,162,000 | $509,000 | $653,000 |
| Market Sales | (1,221,000) | (2,600,000) | 1,379,000 |
| Resources Total | 4,003,000 | 5,088,000 | (1,085,000) |
| Total | 3,944,000 | 2,997,000 | 947,000 |
| **Aurora NPV ($000)** | | | |
| Market Purchases | 423,000 | 199,000 | 224,000 |
| Market Sales | (484,000) | (953,000) | 469,000 |
| Resources Total | 1,540,000 | 1,916,000 | (376,000) |
| Total | 1,479,000 | 1,162,000 | 317,000 |
| **2009 Dollars** | | | |
| Transmission New | 799,000,000 | 799,000,000 | 0 |
| Generation Capital Costs | 1,957,200,000 | 1,270,500,000 | 686,700,000 |

An analysis was performed to determine the sensitivity of total portfolio cost to the price of carbon allowances. The purpose of the analysis was to determine a "tipping point" where the cost of buying allowances and emitting carbon becomes high enough that coal curtailment becomes a lower cost option. The sensitivity of the total 20-year portfolio costs (AURORA nominal and Capital NPV) of both the preferred portfolios (1-4 and 2-4) and the no-coal curtailment scenario are shown in Figure 10.9. The results of the analysis indicate at an allowance price of less than $30, the no-coal curtailment scenario is a lower cost option. If the cost of carbon allowances exceeds $30, the coal curtailment scenario becomes the lowest cost option.

**Figure 10.9 Carbon Allowance Cost and Portfolio Costs**




## Capacity Planning Margin

Idaho Power discussed planning criteria assumptions with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is instead driven by the objective to develop resources sufficient to meet higher-than-expected load conditions, under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2009 IRP, Idaho Power has calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected case ($50^{th}$ percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with expected-case ($50^{th}$ percentile) peak-hour load, with the excess resource capacity designated as planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecasted peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the Pacific Northwest Power Pool. A 330 MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of one day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Tables 10.9 and 10.10 at the end of this chapter.

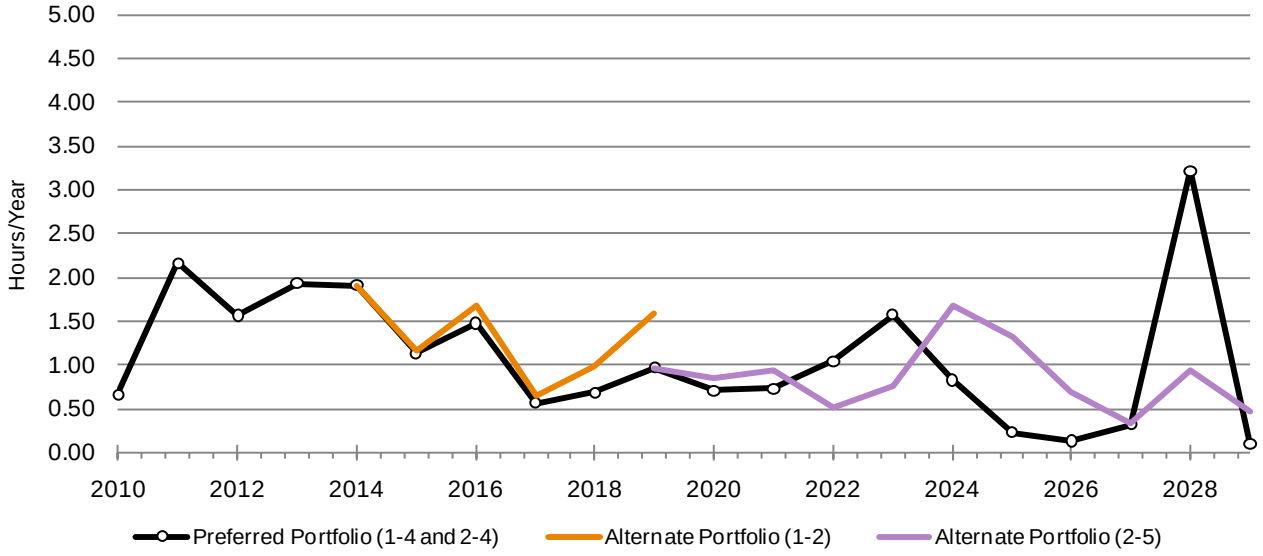
## Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2009 IRP. The assessment assumes critical water conditions at the existing hydro facilities and the planned additions for the preferred and alternate scenarios. As mentioned in the previous section, Idaho Power uses a Capacity Benefit Margin (CBM) of 330 MW in transmission planning to provide for the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2009 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator/purchase outage rates (EFORd) and generation and transmission capacities, to compute a LOLE for each hour of the 20-year planning horizon. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has chosen to calculate LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1 day in 10 years metric is roughly equivalent to 2.4 hours/year. The results of the loss of load probability analysis are shown in Figure 10.10 and additional data can be found in *Appendix C–Technical Appendix*.

**Figure 10.10 Loss of Load Expectation**




In performing the analyses, there were several instances where extending purchases of east-side energy similar to the purchases contemplated in 2010–2012 were necessary to achieve the results shown in Figure 10.10. The high value in 2028 indicates that a minor adjustment in the preferred portfolio would

[3] Based on Roy Billinton "Power System Reliability Evaluation" Charter 2&3, Copyright 1970.

be desirable from a reliability perspective. Moving two of the five 100-MW units scheduled in 2029 to an on-line date in 2028 would reduce the spike without changing the results for 2029.

The LOLE analysis indicates there are periods where a consistent capacity-based load and resource balance was not achieved, in part due to the uneven nature of capacity additions. In future IRPs, Idaho Power may use the LOLE model during the development of the initial resource portfolios to smooth out capacity additions.

**Table 10.9 Capacity Planning Margin (2010–2019)**

| Load and Resource Balance | July-10 | July-11 | July-12 | July-13 | July-14 | July-15 | July-16 | July-17 | July-18 | July-19 |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast (95th%)—Aug 2009 w/No DSM | (3,296) | (3,408) | (3,495) | (3,596) | (3,670) | (3,734) | (3,796) | (3,860) | (3,924) | (3,990) |
| Existing DSM (Energy Efficiency) | 17 | 33 | 48 | 64 | 79 | 93 | 107 | 121 | 135 | 149 |
| Load Forecast (95th%)—w/EE DSM | (3,279) | (3,375) | (3,447) | (3,533) | (3,592) | (3,641) | (3,689) | (3,739) | (3,790) | (3,842) |
| Existing DSM (Irrigation Timer) | 8 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Existing DSM (AC Cool Credit) | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| Total Existing Demand Response | 59 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Peak-Hour Load Forecast w/Existing DSM | (3,220) | (3,318) | (3,390) | (3,476) | (3,535) | (3,585) | (3,633) | (3,683) | (3,733) | (3,785) |
| **Existing Resources** | | | | | | | | | | |
| Coal (w/Curtailment) | 967 | 972 | 978 | 983 | 983 | 982 | 980 | 980 | 977 | 977 |
| Hydro (50th%) —HCC | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 |
| Hydro (50th%)—Other | 254 | 254 | 253 | 252 | 249 | 246 | 245 | 244 | 243 | 243 |
| Sho-Ban Water Lease | 42 | 47 | 48 | 48 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,431 | 1,435 | 1,435 | 1,434 | 1,383 | 1,380 | 1,379 | 1,378 | 1,377 | 1,377 |
| CSPP (PURPA) | 133 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| Power Purchase Agreements | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Clatskanie Energy Exchange | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| EnergyPlus—Jefferson (83 MW) | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| East Side Purchase (50 MW) | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Mead Purchase | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| **Total Power Purchase Agreements** | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Firm Pacific NW Import Capability | 122 | 105 | 97 | 87 | 79 | 71 | 65 | 58 | 54 | 48 |
| Salmon Diesel | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| Subtotal | 3,309 | 3,309 | 3,307 | 3,302 | 3,243 | 3,231 | 3,221 | 3,214 | 3,206 | 3,199 |
| Net Position - Monthly Surplus/Deficit | 88 | (9) | (83) | (174) | (292) | (354) | (412) | (469) | (528) | (586) |
| Planning Margin | 2.7% | -0.3% | -2.4% | -5.0% | -8.3% | -9.9% | -11.3% | -12.7% | -14.1% | -15.5% |
| **2006 IRP Resources** | | | | | | | | | | |
| Wind RFP | 0 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 |
| Net Position—Remaining Monthly Surplus/Deficit | 88 | (9) | 225 | 153 | 35 | (26) | (84) | (122) | (180) | (238) |
| Planning Margin | 2.7% | -0.3% | 6.6% | 4.4% | 1.0% | -0.7% | -2.3% | -3.3% | -4.8% | -6.3% |
| **2009 IRP DSM** | Jul-10 | Jul-11 | Jul-12 | Jul-13 | Jul-14 | Jul-15 | Jul-16 | Jul-17 | Jul-18 | Jul-19 |
| Commercial (FlexPeak) | 40 | 45 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Irrigation Peak Rewards | 212 | 244 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 |
| Energy Efficiency Peak Reduction | 3 | 7 | 12 | 18 | 24 | 31 | 37 | 44 | 51 | 58 |
| **Total New DSM Peak Reduction** | 254 | 296 | 323 | 329 | 335 | 341 | 348 | 355 | 362 | 369 |
| Net Position - Remaining Monthly Surplus/Deficit | 343 | 287 | 547 | 482 | 370 | 315 | 264 | 233 | 182 | 130 |
| Planning Margin | 10.6% | 8.7% | 16.1% | 13.9% | 10.5% | 8.8% | 7.3% | 6.3% | 4.9% | 3.4% |
| **2009 IRP Resources** | Jul-10 | Jul-11 | Jul-12 | Jul-13 | Jul-14 | Jul-15 | Jul-16 | Jul-17 | Jul-18 | Jul-19 |
| Boardman-Hemingway Transmission | | | | | | 250 | 250 | 250 | 250 | 250 |
| Shoshone Falls Upgrade | | | | | | | 0 | 0 | 0 | 0 |
| Boardman-Hemingway Transmission | | | | | | | | 175 | 175 | 175 |
| Large Aero | | | | | | | | | | |
| Wind | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Gateway West Transmission | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Wind | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Net Position - Monthly Surplus/Deficit | 343 | 287 | 547 | 482 | 370 | 565 | 514 | 658 | 607 | 555 |
| Planning Margin | 10.6% | 8.7% | 16.1% | 13.9% | 10.5% | 15.8% | 14.1% | 17.9% | 16.2% | 14.7% |

## Table 10.10 Capacity Planning Margin (2020–2029)

| Load and Resource Balance | July-20 | July-21 | July-22 | July-23 | July-24 | July-25 | July-26 | July-27 | July-28 | July-29 |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast (95th%)—Aug 2009 w/No DSM | (4,058) | (4,110) | (4,171) | (4,231) | (4,271) | (4,331) | (4,393) | (4,434) | (4,480) | (4,505) |
| Existing DSM (Energy Efficiency) | 163 | 177 | 191 | 205 | 219 | 233 | 247 | 261 | 275 | 289 |
| Load Forecast (95th%)—w/EE DSM | (3,895) | (3,933) | (3,980) | (4,027) | (4,052) | (4,098) | (4,146) | (4,173) | (4,204) | (4,216) |
| Existing DSM (Irrigation Timer) | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Existing DSM (AC Cool Credit) | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| Total Existing Demand Response | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Peak-Hour Load Forecast w/Existing DSM | (3,839) | (3,877) | (3,923) | (3,970) | (3,995) | (4,041) | (4,089) | (4,116) | (4,148) | (4,159) |
| **Existing Resources** | | | | | | | | | | |
| Coal (w/Curtailment) | 977 | 977 | 977 | 977 | 977 | 977 | 977 | 977 | 0 | 0 |
| Hydro (50th%) —HCC | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 |
| Hydro (50th%)—Other | 242 | 241 | 240 | 240 | 239 | 238 | 237 | 236 | 235 | 234 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,376 | 1,375 | 1,374 | 1,374 | 1,373 | 1,372 | 1,371 | 1,370 | 1,369 | 1,368 |
| CSPP (PURPA) | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| Power Purchase Agreements | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Clatskanie Energy Exchange | 12 | 12 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| EnergyPlus—Jefferson (83 MW) | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| East Side Purchase (50 MW) | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Mead Purchase | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| **Total Power Purchase Agreements** | 235 | 235 | 235 | 235 | 235 | 235 | 223 | 223 | 223 | 223 |
| Firm Pacific NW Import Capability | 41 | 34 | 28 | 23 | 19 | 13 | 6 | 2 | 0 | 0 |
| Salmon Diesel | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| Subtotal | 3,191 | 3,184 | 3,177 | 3,171 | 3,167 | 3,160 | 3,140 | 3,135 | 2,155 | 2,154 |
| Net Position - Monthly Surplus/Deficit | (647) | (693) | (747) | (799) | (828) | (882) | (949) | (981) | (1,993) | (2,005) |
| Planning Margin | -16.9% | -17.9% | -19.0% | -20.1% | -20.7% | -21.8% | -23.2% | -23.8% | -48.1% | -48.2% |
| **2006 IRP Resources** | | | | | | | | | | |
| Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Net Position—Remaining Monthly Surplus/Deficit | (300) | (346) | (399) | (452) | (481) | (534) | (602) | (634) | (1,646) | (1,658) |
| Planning Margin | -7.8% | -8.9% | -10.2% | -11.4% | -12.0% | -13.2% | -14.7% | -15.4% | -39.7% | -39.9% |
| **2009 IRP DSM** | | | | | | | | | | |
| Commercial (FlexPeak) | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Irrigation Peak Rewards | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 |
| Energy Efficiency Peak Reduction | 66 | 73 | 80 | 87 | 95 | 103 | 111 | 119 | 127 | 127 |
| **Total New DSM Peak Reduction** | 376 | 383 | 390 | 398 | 406 | 413 | 421 | 429 | 438 | 438 |
| Net Position - Remaining Monthly Surplus/Deficit | 76 | 37 | (9) | (54) | (75) | (121) | (181) | (204) | (1,208) | (1,220) |
| Planning Margin | 2.0% | 1.0% | -0.2% | -1.4% | -1.9% | -3.0% | -4.4% | -5.0% | -29.1% | -29.3% |
| **2009 IRP Resources** | | | | | | | | | | |
| Boardman-Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Boardman-Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| Large Aero | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Wind | | | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Large Aero | | | | | 200 | 200 | 200 | 200 | 200 | 200 |
| Gateway West Transmission | | | | | | 100 | 100 | 100 | 100 | 100 |
| Large Aero | | | | | | | 200 | 200 | 200 | 200 |
| Wind | | | | | | | | 20 | 20 | 20 |
| Large Aero | | | | | | | | | 400 | 400 |
| Large Aero | | | | | | | | | | 500 |
| Net Position - Monthly Surplus/Deficit | 601 | 562 | 521 | 476 | 655 | 709 | 849 | 846 | 242 | 730 |
| Planning Margin | 15.7% | 14.5% | 13.3% | 12.0% | 16.4% | 17.6% | 20.8% | 20.5% | 5.8% | 17.5% |

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# 11. Action Plan

## Near-Term Action Plan

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years (2010–2019) as part of implementing the preferred portfolio. Because the near-term time period is so short, no long lead time generation resources, such as advanced nuclear or integrated gasification combined cycle (IGCC) are considered in the near-term plan. However, Idaho Power intends to continue its efforts to explore regional alliances and participate in regional utility planning forums as these technologies develop. Table 11.1 presents a list of the actions Idaho Power expects to take in the next 10 years as part of implementing the preferred portfolio.

**Table 11.1 Near-Term Action Plan**

| Year | Action |
|---|---|
| 2010 | Present and gain acceptance of 2009 IRP with regulatory commissions<br>File wind contract resulting from the 2012 Wind RFP with the IPUC<br>File geothermal contract with the IPUC<br>Irrigation Peak Rewards program increases from 160 MW to 220 MW<br>FlexPeak Management program increases from 20 MW to 40 MW<br>Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins<br>Langley Gulch CCCT construction continues<br>Irrigation Peak Rewards program increases from 220 MW to 250 MW<br>FlexPeak Management program increases from 40 MW to 45 MW<br>File 2011 IRP with regulatory commissions |
| 2012 | Wind project on-line (approximately 150 MW)<br>Langley Gulch CCCT on-line (300 MW)<br>Geothermal project on-line (approximately 20 MW) |
| 2013 | Boardman to Hemingway construction begins<br>Shoshone Falls Upgrade Project construction begins<br>File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls Upgrade Project construction continues<br>Boardman to Hemingway construction continues |
| 2015 | Shoshone Falls Upgrade Project on-line (49 MW)<br>Boardman to Hemingway completed (250 MW)<br>File 2015 IRP with regulatory commissions |
| 2016 | Geothermal project on-line (approximately 20 MW) |
| 2017 | Boardman to Hemingway additional capacity for market purchases (175 MW)<br>File 2017 IRP with regulatory commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with regulatory commissions |

## Long-Term Action Plan

The long-term action plan describes Idaho Power resource acquisitions during the 2020–2029 time period. The long-term action plan assumes that the near-term action plan is completed with only minor variations. The long-term action plan includes a combination of renewable resources and natural gas-fired resources to firm the output from wind resources. The main event in the long-term action plan is that Idaho Power continues to curtail the output from the coal-fired generation resources in order to meet the proposed federal carbon legislation. In this potential future, Idaho Power's coal-fired resource operations will be limited to seasonal needs in early years until they are fully curtailed by the end of the

planning period. Table 11.2 presents a list of the actions Idaho Power expects to take from 2020 through 2029 as part of implementing the preferred portfolio.

**Table 11.2 Long-Term Action Plan**

| Year | Action |
|---|---|
| 2020 | Natural gas generation project on-line (approximately 100 MW) |
| 2021 | No action |
| 2022 | Wind project on-line (approximately 100 MW) |
| 2023 | No action |
| 2024 | Natural gas generation project on-line (approximately 200 MW) |
| 2025 | No action |
| 2026 | Natural gas generation project on-line (approximately 200 MW) |
| 2027 | Wind project on-line (approximately 400 MW) |
| 2028 | Natural gas generation project on-line (approximately 400 MW) |
| 2029 | Natural gas generation project on-line (approximately 500 MW) |

Delayed interest in the Boardman to Hemingway project may result in Idaho Power constructing both a replacement generation resource as well as constructing the transmission line at a later date. The alternate resource portfolio may lead to constructing the Boardman to Heming project in the second 10-year period. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. Table 11.3 shows the changes to the near-term action plan if sufficient interest by third parties in the Boardman to Hemingway project does not materialize.

**Table 11.3 Alternate Portfolio Near-Term Action Plan**

| Year | Action |
|---|---|
| 2010 | File 2009 IRP with regulatory commissions |
| | File wind contract (2012 Wind RFP) with the IPUC |
| | File geothermal contract with IPUC |
| | Irrigation Peak Rewards Program increases to 220 MW |
| | FlexPeak Management program increases to 40 MW |
| | Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins |
| | Langley Gulch CCCT construction |
| | Irrigation Peak Rewards Program increases to 250 MW |
| | FlexPeak Management program increases to 45 MW |
| | File 2011 IRP with regulatory commissions |
| 2012 | Wind project on line (approximately 150 MW) |
| | Langley Gulch CCCT on-line (300 MW) |
| | Geothermal generation on-line (approximately 20 MW) |
| | ***Natural gas generation resource one RFP*** |
| 2013 | File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls upgrade construction |
| | ***Natural gas generation resource two RFP*** |
| 2015 | Shoshone Falls upgrade on-line (50 MW) |
| | ***Natural gas generation resource one on-line*** |
| | File 2015 IRP with regulatory commissions |
| 2016 | Geothermal Generation on-line (approximately 20 MW) |
| 2017 | ***Natural Gas generation resource two on-line*** |
| | File 2017 IRP with commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with commissions |

## Conclusion

Each Idaho Power Integrated Resource Plan (IRP) builds on the foundation of earlier resource plans and each plan includes incremental changes due to forecasts of future events. The 2009 plan is no exception. However, the 2009 IRP is different in two key aspects.

First, Idaho Power, and other utilities in the west, face major regional transmission decisions. No significant interstate transmission has been built in the region for many years. Idaho Power's 2009 IRP is the first company resource plan where the company and others in the region, must make a significant commitment to new interstate transmission projects.

Secondly, Idaho Power, and the nation, face the likelihood of significant carbon legislation. There has been considerable discussion on aspects of the legislation; however, all recognize the objective of the proposed legislation is to reduce the quantity of carbon released into the earth's atmosphere. Reducing carbon emissions will require curtailment of certain resources as either demand declines or additional energy is produced from alternate resources. Idaho Power has chosen to directly face the issue of curtailment and the 2009 IRP attempts to quantify the impact of proposed carbon legislation.

Idaho Power would like to thank the IRP Advisory Council (IRPAC) members and the public for their contributions to the 2009 IRP. The IRPAC debated these two major issues along with a significant number of other social topics. Idaho Power's 2009 IRP is better because of the contributions from the IRPAC members and the public.

In recognition of the amount of time and effort expended by the IRPAC, at the final meeting members discussed the possibility of including a statement in the IRP indicating the advisory council's support of the IRP. Because the IRPAC represents such a diverse set of stakeholders, the members determined it would not be possible for the group to unanimously support all aspects of the IRP. However, the IRPAC was supportive of the public process and asked Idaho Power to include the following statement in the 2009 IRP: "The members of the IRP Advisory Council support the public process Idaho Power Company conducted as part of preparing the 2009 IRP."

Idaho Power prepares an integrated resource plan biennially. At the time of the next plan in 2011, Idaho Power will have additional information regarding supply-side resources, demand-side management (DSM) programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the development of a federal renewable electricity standard (RES), and the feasibility of advanced nuclear, IGCC, and other technology issues.

One of the key strengths of Idaho Power's planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the IRPAC, the IPUC and the OPUC, and concerned customers to revisit the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near term action plan allows for discussion and adjustment of the IRP as warranted.

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# *Appendix A — Sales and Load Forecast*

For the 2009 Integrated Resource Plan – December 2009




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# TABLE OF CONTENTS

List of Tables ..... ii
List of Figures ..... ii
List of Appendices ..... iii
Introduction ..... 1
2009 IRP Sales and Load Forecast ..... 3
Average Load ..... 3
Peak-Hour Demands ..... 4
Overview of the Forecast ..... 5
Fuel Prices ..... 5
Forecast Probabilities ..... 7
Load Forecasts Based on Weather Variability ..... 7
Load Forecasts Based on Economic Uncertainty ..... 9
Residential ..... 13
Commercial ..... 15
Irrigation ..... 17
Industrial ..... 21
Additional Firm Load ..... 23
Micron Technology ..... 23
Simplot Fertilizer ..... 24
Idaho National Laboratory ..... 24
Hoku Materials ..... 24
Raft River Rural Electric Cooperative ..... 24
Company Firm Load ..... 25
Company Firm Peak ..... 27
Company System Load ..... 29
Contract Off-System Load ..... 31
Total Company Load ..... 33
Demand-Side Management ..... 35
Energy Efficiency Programs ..... 35
Demand Response Programs ..... 36

# LIST OF TABLES

Table 1. Residential Fuel-Price Escalation (2009–2029).....6
Table 2. Average Load and Peak-Demand Forecast Scenarios .....8
Table 3. Forecast Probabilities.....10
Table 4. System/Firm Load Growth .....10
Table 5. Residential Load Growth .....13
Table 6. Commercial Load Growth .....15
Table 7. Irrigation Load Growth.....17
Table 8. Industrial Load Growth.....21
Table 9. Additional Firm Load Growth .....23
Table 10. Firm Load Growth .....25
Table 11. Firm Summer Peak-Load Growth.....27
Table 12. Firm Winter Peak Load Growth .....28
Table 13. System Load Growth .....29
Table 14. Total Company Load Growth .....33
Table 15. DSM Programs.....35

# LIST OF FIGURES

Figure 1. Forecasted Electricity Prices.....6
Figure 2. Forecasted Residential Natural Gas Prices .....7
Figure 3. Forecasted Firm Load .....11
Figure 4. Forecasted Residential Load.....13
Figure 5. Forecasted Residential-Use-Per-Customer .....14
Figure 6. Forecasted Commercial Load .....15
Figure 7. Forecasted Commercial-Use-Per-Customer .....16
Figure 8. Forecasted Irrigation Load.....17
Figure 9. Forecasted Industrial Load.....21
Figure 10. Industrial Electricity Consumption by Industry Group .....22
Figure 11. Forecasted Additional Firm Load .....23
Figure 12. Forecasted Firm Load .....25
Figure 13. Forecasted Firm Summer Peak .....27
Figure 14. Forecasted Firm Winter Peak.....28
Figure 15. Forecasted System Load .....29

Figure 16. Forecasted Contract Off-System Load by Customer ..... 31
Figure 17. Forecasted Total Load ..... 33
Figure 18. Composition of Electricity Sales ..... 34

## LIST OF APPENDICES

Appendix A1. Historical and Projected Sales and Load ..... 37
Residential Load ..... 37
Historical Residential Sales and Load, 1970–2008 ..... 37
Projected Residential Sales and Load, 2009–2029 ..... 38
Commercial Load ..... 39
Historical Commercial Sales and Load, 1970–2008 ..... 39
Projected Commercial Sales and Load, 2009–2029 ..... 40
Irrigation Load ..... 41
Historical Irrigation Sales and Load, 1970–2008 ..... 41
Projected Irrigation Sales and Load, 2009–2029 ..... 42
Industrial Load ..... 43
Historical Industrial Sales and Load, 1970–2008 ..... 43
Projected Industrial Sales and Load, 2009–2029 ..... 44
Additional Firm Sales and Load ..... 45
Historical Additional Firm Sales and Load, 1970–2008 ..... 45
Projected Additional Firm Sales and Load, 2009–2029 ..... 46
Company Firm Load ..... 47
Historical Company Firm Load, 1970–2008 ..... 47
Projected Company Firm Load, 2009–2029 ..... 48
Astaris Load ..... 49
Historical Astaris Sales and Load, 1970–2008 ..... 49
Projected Astaris Sales and Load, 2009–2029 ..... 50
Company System Load ..... 51
Historical Company System Sales and Load, 1970–2008 ..... 51
Projected Company System Sales and Load, 2009–2029 ..... 52
Contract Off-System Load ..... 53
Historical Contract Off-System Sales and Load, 1970–2008 ..... 53
Projected Contract Off-System Sales and Load, 2009–2029 ..... 54

Total Company Load ..... 55
Historical Total Company Sales and Load, 1970–2008 ..... 55
Projected Total Company Sales and Load, 2009–2029 ..... 56
Appendix A2. Demand-Side Management Program Impacts ..... 57
Energy Efficiency Programs ..... 57
Energy Reductions ..... 57
Residential Programs ..... 57
Commercial Building Efficiency ..... 57
Industrial Program ..... 58
Irrigation Efficiency Program ..... 58
Energy Efficiency Programs—Total ..... 59
Peak Demand Reductions ..... 59
Residential Programs ..... 59
Commercial Programs ..... 60
Industrial Program ..... 60
Irrigation Efficiency Program ..... 61
Energy Efficiency Programs—Total ..... 61

# INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2009 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2010 through 2029. For planning purposes, the future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts: 1) a 50$^{th}$ percentile or expected-case load forecast, 2) a 70$^{th}$ percentile load forecast, and 3) a 90$^{th}$ percentile load forecast. These forecasts define three possible load conditions based on variable weather evaluated in the 2009 IRP. The expected-case total load growth rate is 0.7 percent per year over the 20-year planning period. This is Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area.

Two additional load forecasts for Idaho Power's service area were prepared. These forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast.

The expected-case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly, dependent on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70$^{th}$ percentile average load forecast and 90$^{th}$ percentile average load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70$^{th}$ percentile load forecast assumes monthly loads that can be exceeded in three-out-of-ten years (30 percent of the time). The 90$^{th}$ percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's total load is forecast to increase to 2,015 average megawatts (aMW) in the year 2029 from the 2010 forecast load of 1,797 aMW. The expected-case forecast total load growth rate averages 0.7 percent per year over the 20 years of the planning period (2010–2029). The number of Idaho Power retail customers increased from the December 2008 level of 485,655 customers to over 682,000 customers at year-end 2029. Idaho Power system peak load is forecast to grow to 4,445 megawatts (MW) in the year 2029 from the 2008 actual system peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.5 percent per year over the 20 years of the planning period (2010–2029).

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.3 percent during the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections,

economic output, real retail electricity prices, and customer consumption patterns are used to form load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated in the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2008 Annual Report*. This report is Appendix B to the 2009 IRP.

The expected-case load forecast represents Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not follow exactly the path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide boundaries on each side of the expected-case scenario and historical load variability potential on future load due to demographic, economic, and other non-weather-related influences. The 70$^{th}$ percentile and 90$^{th}$ percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon legislation and fossil fuel market disequilibrium. The high degree of uncertainty associated with such changes is assumed to be reflected in the economic high and low load growth scenarios described above. However, due to the increasing probability of impending carbon legislation becoming law, the impact of carbon legislation on the load forecast was reflected in the forecast of retail electricity prices, which is a driver in the major sector sales forecasting models. The alternative sales and load scenarios of *Appendix A–Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for the sales and load forecast is presented in Appendix A1 of this report.

# 2009 IRP SALES AND LOAD FORECAST

## Average Load

The 2009 IRP average system load forecast is lower than the 2006 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow dramatically. In addition, the significant increase in energy efficiency and demand response measures, combined with retail electricity prices that incorporate estimates of proposed carbon legislation, result in a decrease of forecast average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include the following.

- For the first time, the sales and load forecasts are influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C–Technical Appendix*.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and will reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2012.
- A collapse in the housing sector dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. The number of commercial customers being added has also slowed dramatically as a result of the economic downturn. Both the residential and commercial customer forecasts were adjusted downward in the near-term to reflect the current housing slowdown and credit crisis. However, by 2012, residential and commercial customer growth is expected to recover, and customer additions are expected to be similar to the growth that occurred prior to the housing bubble in the 1993–2003 timeframe.
- The irrigation sales forecast is somewhat higher due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). Higher farm commodity prices seem to be the primary reason behind the irrigation sales increase. Irrigators appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.
- There is uncertainty associated with the growth of new industrial and special contract customers. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area in conjunction with the uncertain magnitude of associated energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the number of large customers that have contacted

Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

## Peak-Hour Demands

Peak day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The 2009 IRP peak forecast reflects the increased expected peak demand of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho.
- The 2009 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs that were selected for implementation since 2006. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2009 IRP peak-demand forecast model no longer considers or adjusts for the impact of demand response programs. The demand response programs are included in the load and resource balance as a reduction in peak demand.
- The peak model allows peaks to be calculated at 0, $10^{th}$, $20^{th}$, $30^{th}$, $40^{th}$, $50^{th}$, $60^{th}$, $70^{th}$, $80^{th}$, $90^{th}$, $95^{th}$, and $100^{th}$ percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the $100^{th}$ percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. The median peak day temperature has a 50 percent probability of being exceeded. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore the median temperature better reflects expected temperatures. The weighted average peak day temperature drivers are calculated over the 1978–2007 time period (the most recent 30 years).

# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for Micron Technology, Inc, (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These five special-contract customers are combined into a single forecast category labeled Additional Firm Load. Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as they are billed, it is necessary to adjust these billed sales to the proper timeframe to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual-average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2009 sales forecast. Idaho Power has two distinct peak periods: a winter peak, resulting from space heating demand that normally occurs in December, January, or February, and a larger summer peak that normally occurs in June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of temperature, space heating saturation (winter only), air conditioning saturation (summer only), historical average load, and precipitation (summer only). The peak forecast uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, Hoku Materials, and Raft River are forecast based on historical analysis and contractual considerations.

The primary exogenous factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

## Fuel Prices

Fuel prices, in combination with service area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real

historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. Moody's Analytics provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

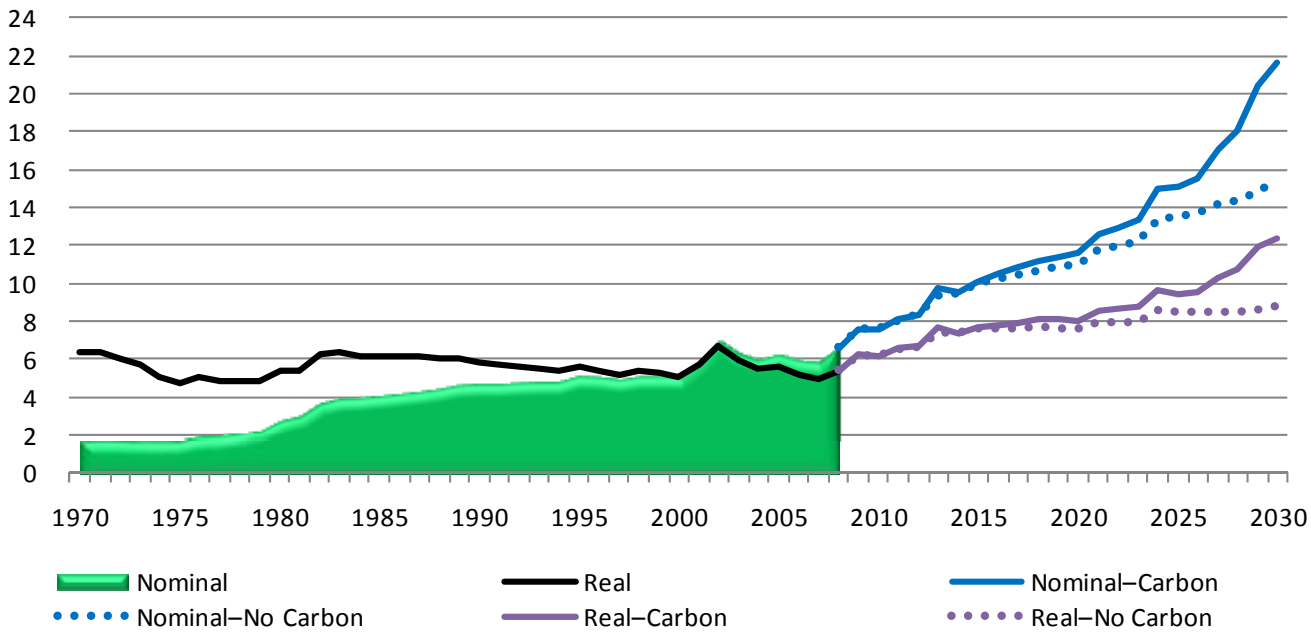
**Table 1. Residential Fuel-Price Escalation (2009–2029)**
*(average annual percent change)*

| | Nominal | Real* |
|---|---|---|
| Electricity–Carbon | 5.1% | 3.3% |
| Electricity–No Carbon | 3.4% | 1.6% |
| Natural Gas | 2.3% | 0.5% |

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2008 and over the forecast period 2009–2029. Both nominal and real prices are shown. In the carbon scenario, nominal electricity prices are expected to slowly climb to 20 cents per kWh by the end of the forecast period in 2029. Real electricity prices (inflation-adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 3.3 percent each year.

**Figure 1. Forecasted Electricity Prices**
*(cents per kWh)*

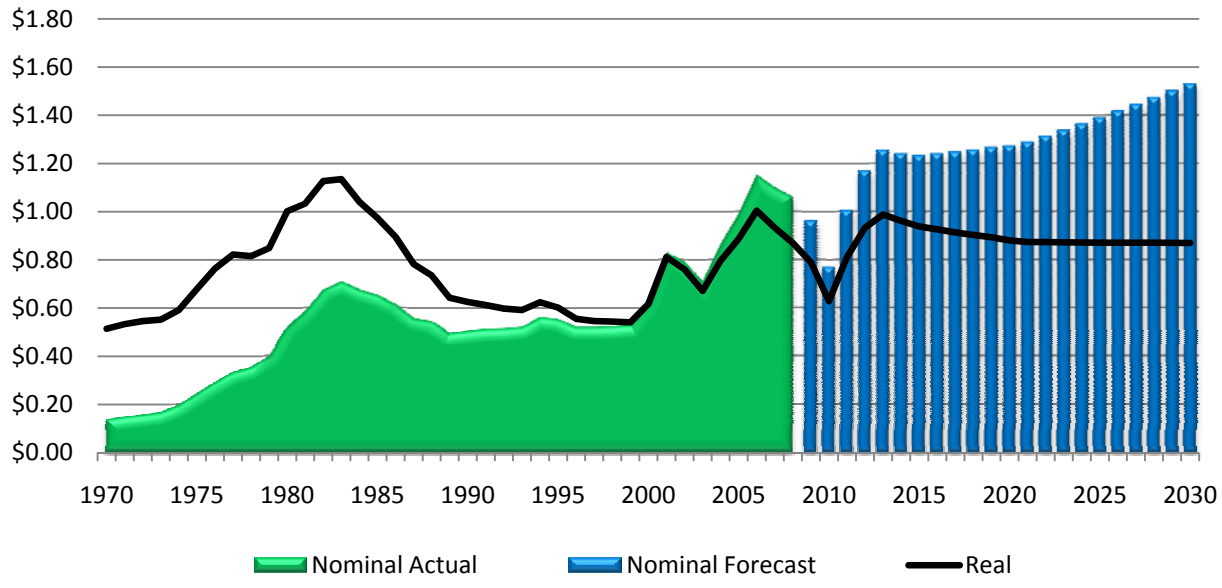



Electricity prices for Idaho Power customers moved significantly higher beginning in 2001 because of the Power Cost Adjustment (PCA) impact on rates. Prior to 2001, Idaho Power's electricity prices were

historically quite stable. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2008. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since 2001, natural gas prices moved downward for a couple of years before again moving sharply upward in 2004, 2005, and 2006. Natural gas prices are expected to move downward in 2009 and 2010, reflecting the collapse in natural gas prices in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise rapidly through 2013 and then slowly rise through the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2008, growing at an average rate of 2.3 percent per year over the forecast period (2009–2029). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.5 percent each year.

**Figure 2. Forecasted Residential Natural Gas Prices**
*(dollars per therm)*




If future electricity price increases continue to outpace natural gas price increases, as expected in this forecast, the operating costs of space heating and water heating with natural gas will become even more advantageous when compared to that of electricity. This could result in lowering the winter demand for electricity.

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation, i.e., there is a 50 percent chance that loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures, or wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December over the 1978–2007 time period (the most recent 30 years) was 1,035. The 70$^{th}$ percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90$^{th}$ percentile HDD is 1,291 and would be exceeded in one-out-of-ten years. The 100$^{th}$ percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$ percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$ percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$ percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume that temperatures and precipitation would maintain a 70$^{th}$ percentile or 90$^{th}$ percentile level continuously, month after month throughout an entire year, would be much less probable. It is the monthly forecast numbers that are being evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70$^{th}$ percentile or 90$^{th}$ percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2009 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual average-load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak day temperatures. The probability associated with each individual peak-demand scenario is also indicated in Table 2.

**Table 2. Average Load and Peak-Demand Forecast Scenarios**

| Scenario | Weather Probability | Probability of Exceeding | Weather Driver |
|---|---|---|---|
| ***Forecasts of Average Load*** | | | |
| 90$^{th}$ Percentile | 90% | 1-in-10 years | HDD, CDD, GDD, Precipitation |
| 70$^{th}$ Percentile | 70% | 3-in-10 years | HDD, CDD, GDD, Precipitation |
| Expected Case | 50% | 1-in-2 years | HDD, CDD, GDD, Precipitation |
| ***Forecasts of Peak Demand*** | | | |
| 95$^{th}$ Percentile | 95% | 1-in-20 years | Peak Day Temperatures |
| 90$^{th}$ Percentile | 90% | 1-in-10 years | Peak Day Temperatures |
| 50$^{th}$ Percentile | 50% | 1-in-2 years | Peak Day Temperatures |

The analysis of resource requirements is based on the 70th percentile average-load forecast coupled with the 95th percentile peak-demand forecast to provide a more adverse representation of average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th percentile peak-demand forecast are typically used.

## Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the full integration of existing energy efficiency DSM program effects as a reduction to the average-load forecast. In addition, higher retail electricity prices resulting from carbon legislation also serve to slow the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1984–2008).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted firm sales observed between 1984 and 2008. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50 percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50 percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1984–2008). The high- and low-case load forecasts also reflect the full integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts. However, impacts from carbon legislation do not influence the high- and low-case load forecasts at this time.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10 percent probability that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, there is a 10 percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 20-year time period, there is an 80 percent probability that the actual growth rate of firm load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26 percent probability that the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter one-year, five-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast Probabilities**

| Probability of Exceeding | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 90% | 90% | 90% | 90% |
| Expected Case | 50% | 50% | 50% | 50% |
| High Growth | 10% | 10% | 10% | 10% |

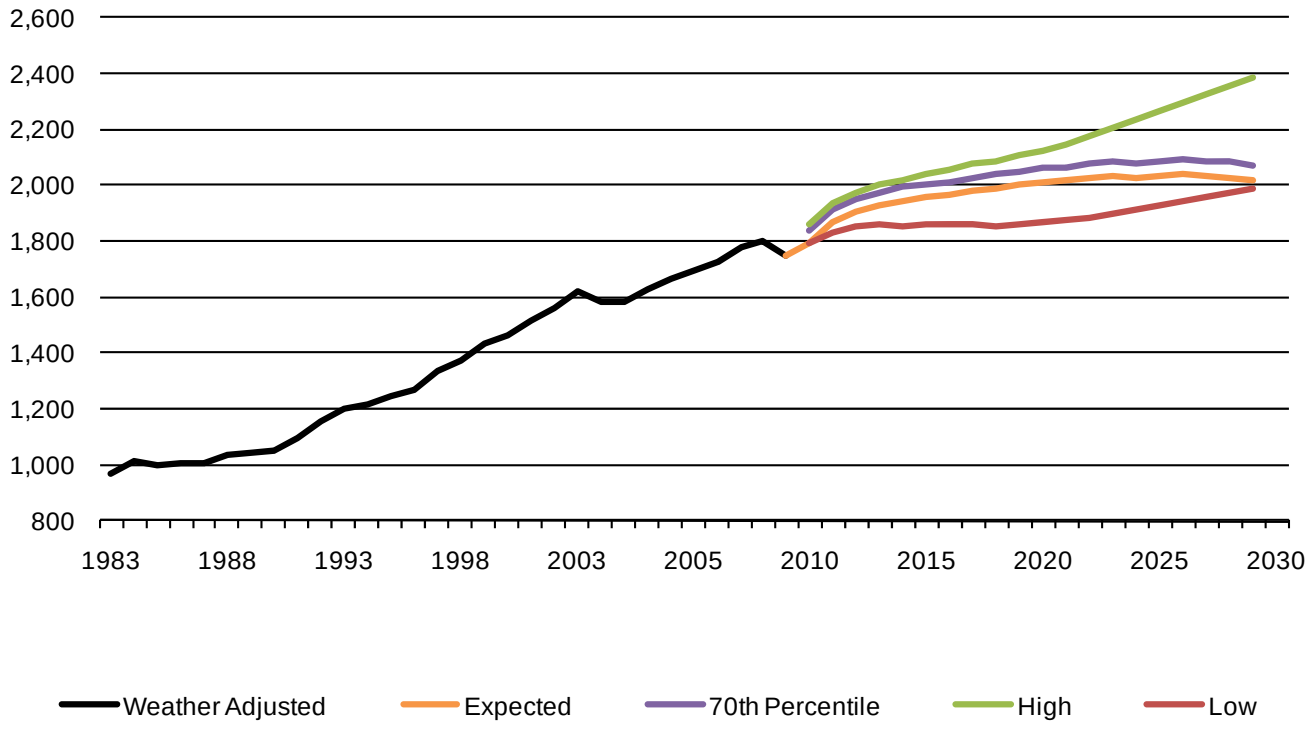
| Probability of Occurrence | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 26% | 26% | 26% | 26% |
| Expected Case | 48% | 48% | 48% | 48% |
| High Growth | 26% | 26% | 26% | 26% |

Firm load includes the sum of residential, commercial, industrial, irrigation, as well as special contracts (excluding Astaris), and Raft River. Idaho Power firm load projections are reported in Table 4 and pictured in Figure 3. The expected-case firm load forecast growth rate averages 0.7 percent per year over the 20 years of the planning period. The low scenario projects that firm load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.6 percent per year. Idaho Power has experienced both the high and low growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System/Firm Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| High | 1,752 | 2,020 | 2,105 | 2,389 | 1.6% |
| Expected | 1,752 | 1,857 | 2,002 | 2,015 | 0.7% |
| Low | 1,752 | 1,876 | 1,862 | 1,991 | 0.6% |

**Figure 3. Forecasted Firm Load**
*(aMW)*



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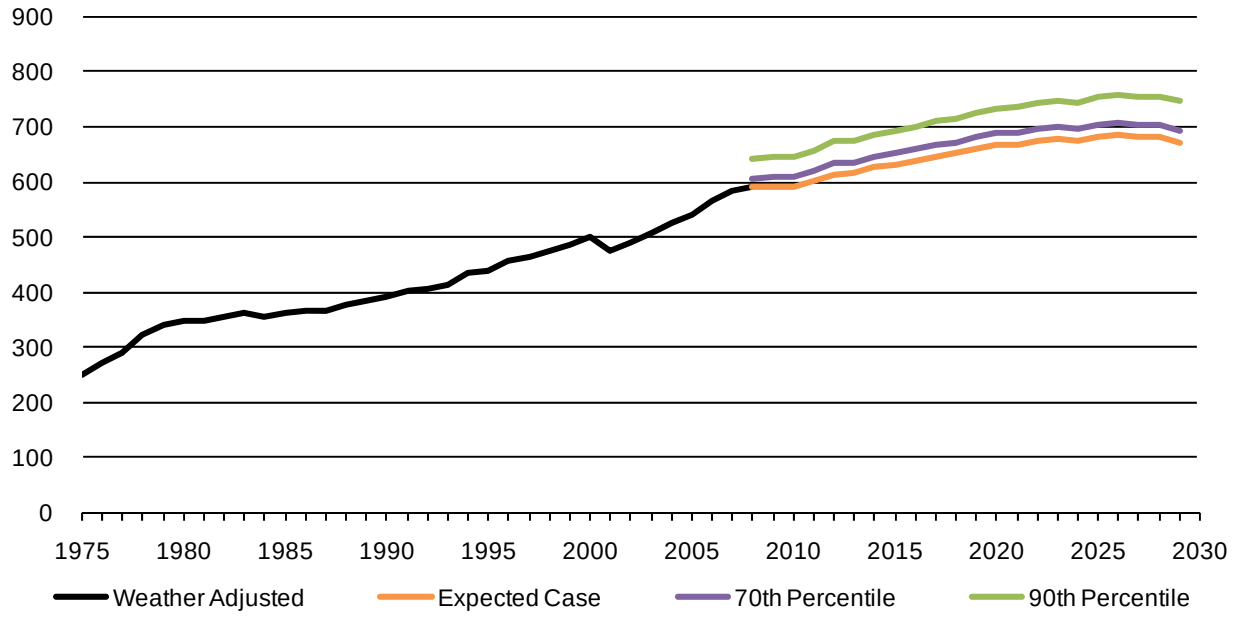
# RESIDENTIAL

The expected-case residential load is forecast to increase from 590 aMW in 2009 to 670 aMW in 2029, an average annual compound growth rate of 0.6 percent. In the 70th percentile scenario residential load is forecast to increase from 608 aMW in 2009 to 694 aMW in 2029, nearly matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

**Table 5. Residential Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90th Percentile | 645 | 687 | 725 | 747 | 0.7% |
| 70th Percentile | 608 | 647 | 681 | 694 | 0.7% |
| Expected Case | 590 | 627 | 659 | 670 | 0.6% |

**Figure 4. Forecasted Residential Load**
*(aMW)*

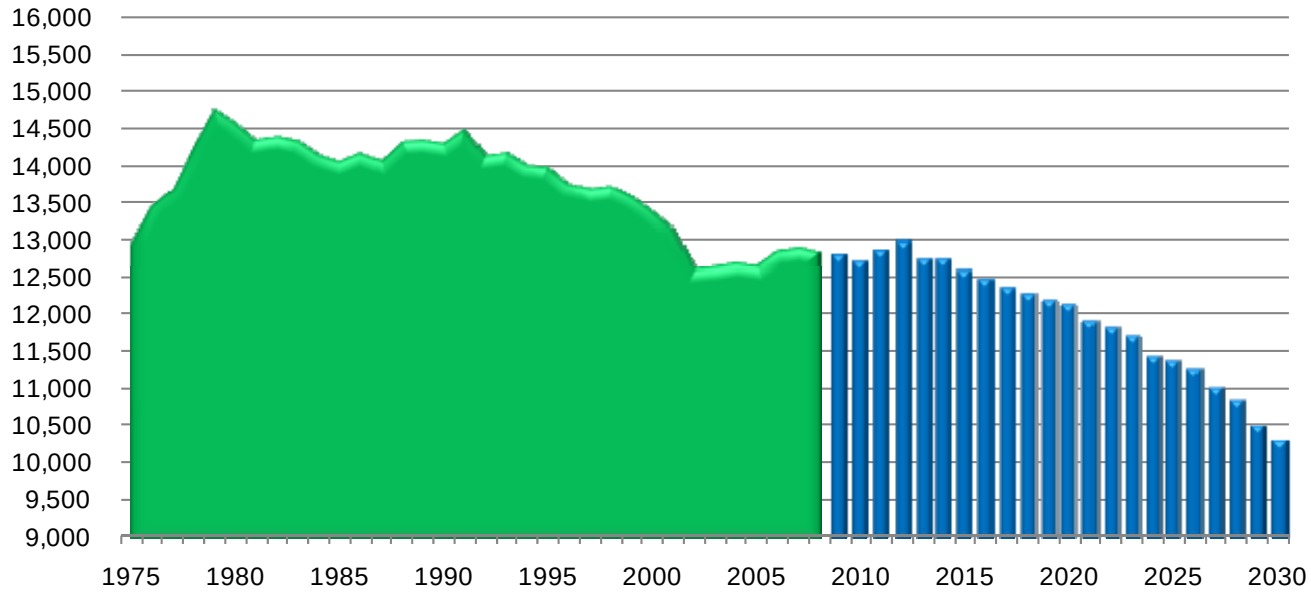



Sales to residential customers made up 24 percent of Idaho Power's system sales in 1970 and 36 percent of system sales in 2008. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2029. There were 404,373 residential customers as of December 2008. The number of residential customers is projected to increase to approximately 563,000 by December 2029. The relative customer proportions of the total Idaho Power electricity sales are shown in Figure 18.

The average sales per residential customer were about 10,000 kWh in 1970. Average sales increased to nearly 14,800 kWh per residential customer in 1979 before declining to 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential-use-per-customer to stabilize and rise through 2007. However,

the recession in 2008 and 2009 slowed the growth in residential-use-per-customer. The average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2029. Average annual sales per residential customer are shown in Figure 5.

**Figure 5. Forecasted Residential-Use-Per-Customer**
*(weather-adjusted kWh)*




The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service area households as derived from Moody's Analytics May 2009 forecast of county housing stock and demographic data. The customer forecast for 2010–2029 shows an average annual growth rate of 1.7 percent.

The residential-sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential-use-per-customer is arrived at by dividing the residential sales forecast, which includes the impact of forecasted DSM, by the residential-customer forecast.

# COMMERCIAL

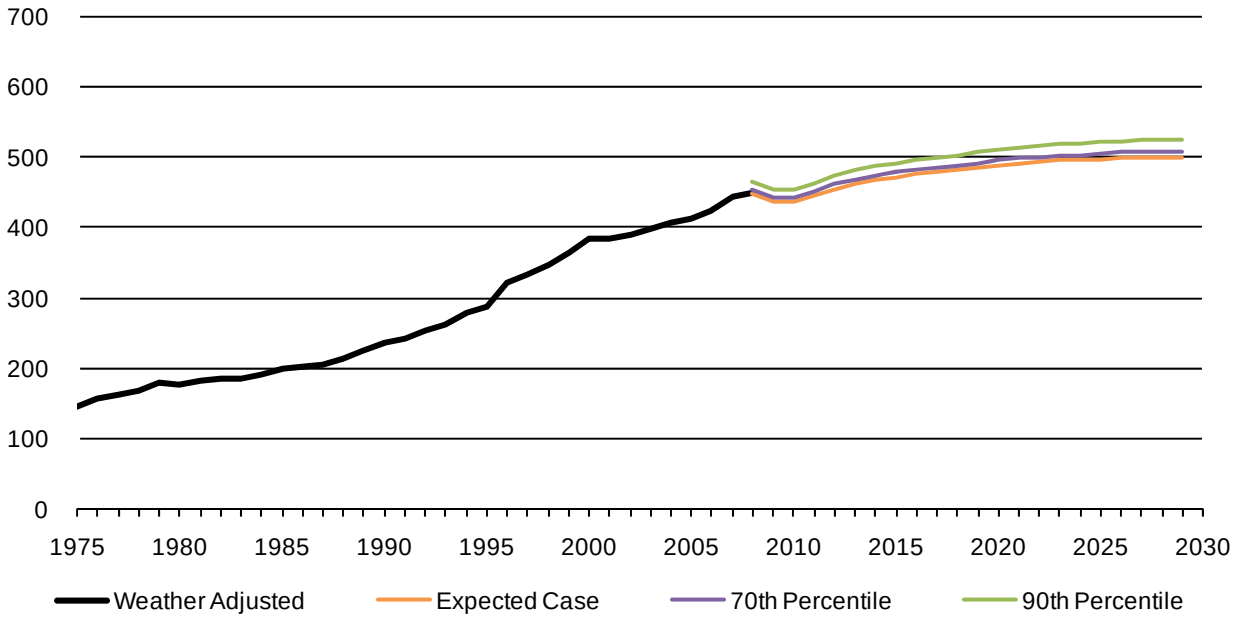
The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules that are considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 437 aMW in 2009 to 500 aMW in 2029. The average annual compound growth rate of commercial load is 0.7 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 442 aMW in 2009 to 509 aMW in 2029. The commercial load forecasts are illustrated in Figure 6.

**Table 6. Commercial Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90th Percentile | 453 | 488 | 507 | 526 | 0.7% |
| 70th Percentile | 442 | 475 | 492 | 509 | 0.7% |
| Expected Case | 437 | 469 | 486 | 500 | 0.7% |

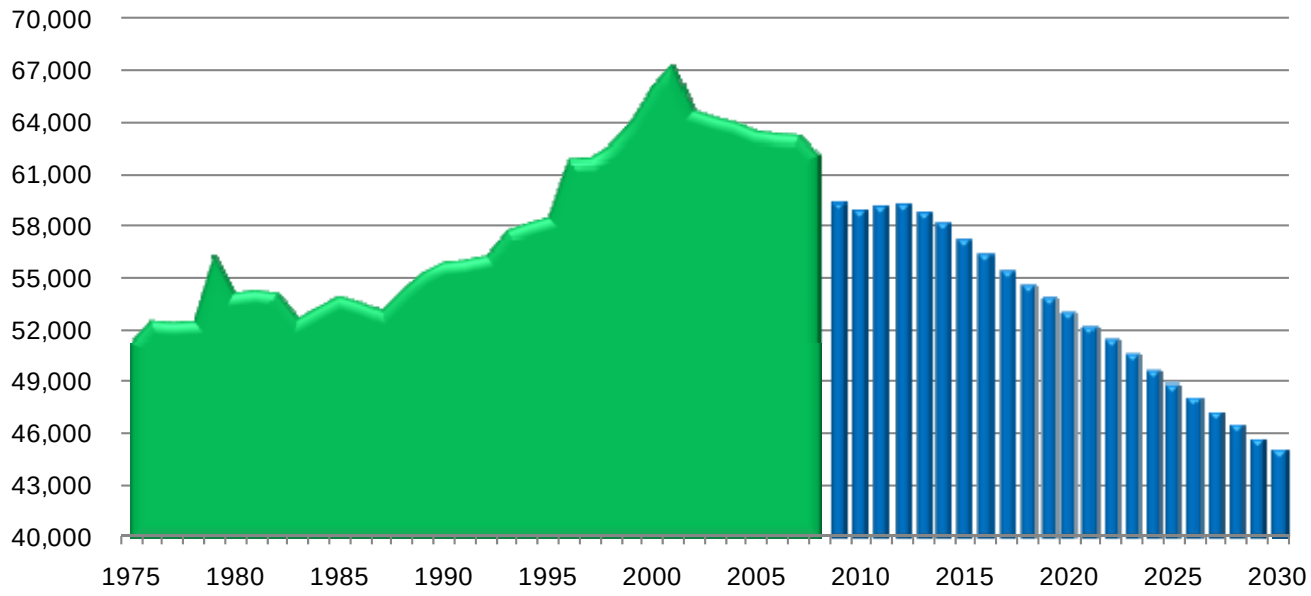
**Figure 6. Forecasted Commercial Load**
*(aMW)*




As of December 2008, Idaho Power had 64,125 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2.1 percent, reaching 96,500 customers by 2029. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1970 and 27 percent of system sales in 2008. The commercial customer proportion of system sales is projected to increase to 27 percent of system sales by 2029. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 18.

The average consumption per commercial customer increased to a record 67,400 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening over the time period from 2009–2012, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions, carbon regulation, and significant DSM impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 46,000 kWh per customer in 2029. Average annual use per commercial customer is shown in Figure 7.

**Figure 7. Forecasted Commercial-Use-Per-Customer**
*(weather-adjusted kWh)*




The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service area households as derived from Moody's Analytics May 2009 economic forecast of county housing stock and demographic information. The commercial-customer forecast for 2010–2029 shows an average annual growth rate of 2.1 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, including the impacts of DSM, by the commercial customer forecast.

# IRRIGATION

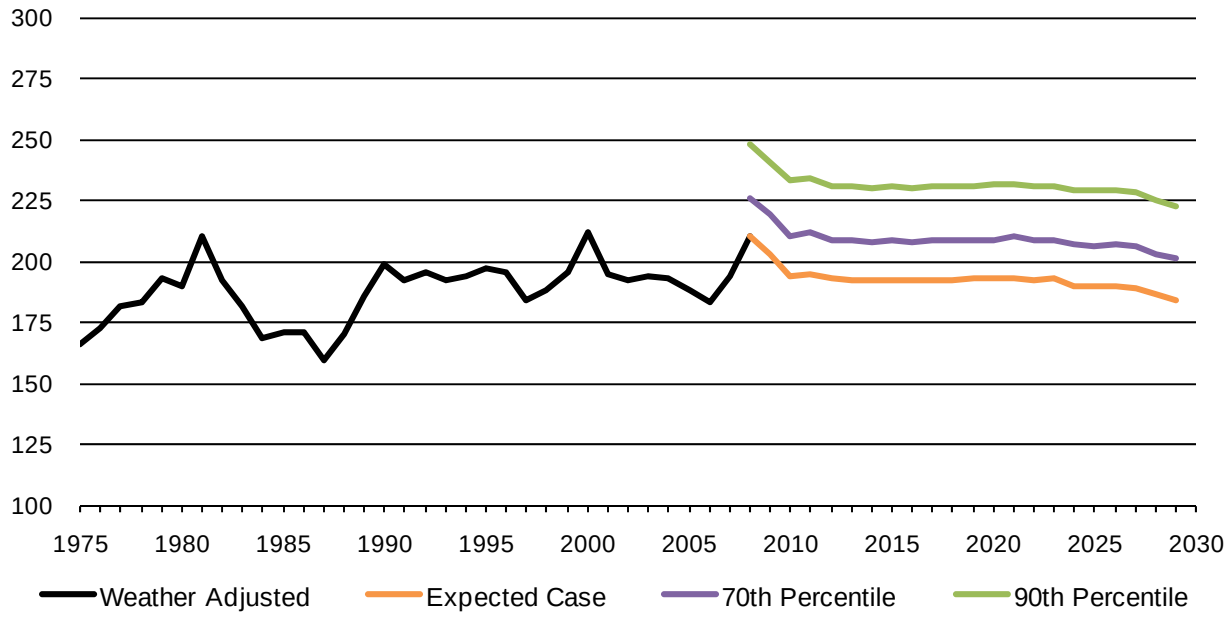
The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly decline from 203 aMW in 2009 to 184 aMW in 2029, an average annual compound growth rate of –0.5 percent. The expected-case, 70$^{th}$ percentile, and 90$^{th}$ percentile scenarios forecast declining growth in irrigation load over the 2009–2029 time period. In the 70$^{th}$ percentile scenario, irrigation load is projected to be 219 aMW in 2009 and 201 aMW in 2029. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 8. The figure illustrates the poorer economic conditions and the drop-off in land being put into production that was experienced by the agricultural economy in the mid-1980s.

**Table 7. Irrigation Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 241 | 230 | 231 | 223 | –0.4% |
| 70$^{th}$ Percentile | 219 | 208 | 209 | 201 | –0.4% |
| Expected Case | 203 | 192 | 193 | 184 | –0.5% |

**Figure 8. Forecasted Irrigation Load**
*(aMW)*




It is important to understand that annual average-load figures being reported in Table 7 and graphed in Figure 8 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 900 MW. In a normal July, irrigation pumping accounts for roughly

25 percent of the energy generated during the hour of the annual system peak and 30 percent of the energy generated during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

In early 2001, wholesale electricity prices reached unprecedented levels, and Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to not use electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hours (MWh) reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season. In the future, Idaho Power does not anticipate that it will be necessary to implement similar load-reduction programs to irrigators. Any future reductions to irrigation load are assumed to occur through DSM programs or other natural economic pressures.

The 2009 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. During the period 1970–1996, Idaho Power experienced an increase in electricity-using irrigated acres of 1,179,000 acres. This growth in total electricity-using irrigated acres represented approximately a 2.8 percent average annual compound rate of growth. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented over 15 percent of weather-normalized Idaho Power system sales in 1970. Irrigation sales reached a maximum proportion of nearly 20 percent of Idaho Power system sales in 1975–1977. In 2008, the irrigation proportion of system sales was 13 percent due to the very rapid growth in other customer classes. By 2029, irrigation customers are projected to consume 10 percent of Idaho Power system sales. The customer load proportions are shown in Figure 18.

In 1970, Idaho Power had about 7,300 active irrigation accounts. By 2008, the number of active irrigation accounts had increased to 17,428 and is projected to be over 23,000 irrigation accounts at the end of the planning period in 2029.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep groundwater wells. In 2007 and 2008, electricity sales (weather-adjusted) increased by 6 percent and over 8 percent, respectively, over each prior year. However, this is not completely unexpected because both 2007 and 2008 irrigation sales were below the annual sales numbers for years 1992 and 2000. Part of the increase can be explained by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of

Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids has consumed, on average, 55,000 MWh each year.

In the future, factors related to the conjunctive management of ground and surface water, and the possible litigation associated with the resolution, will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

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# INDUSTRIAL

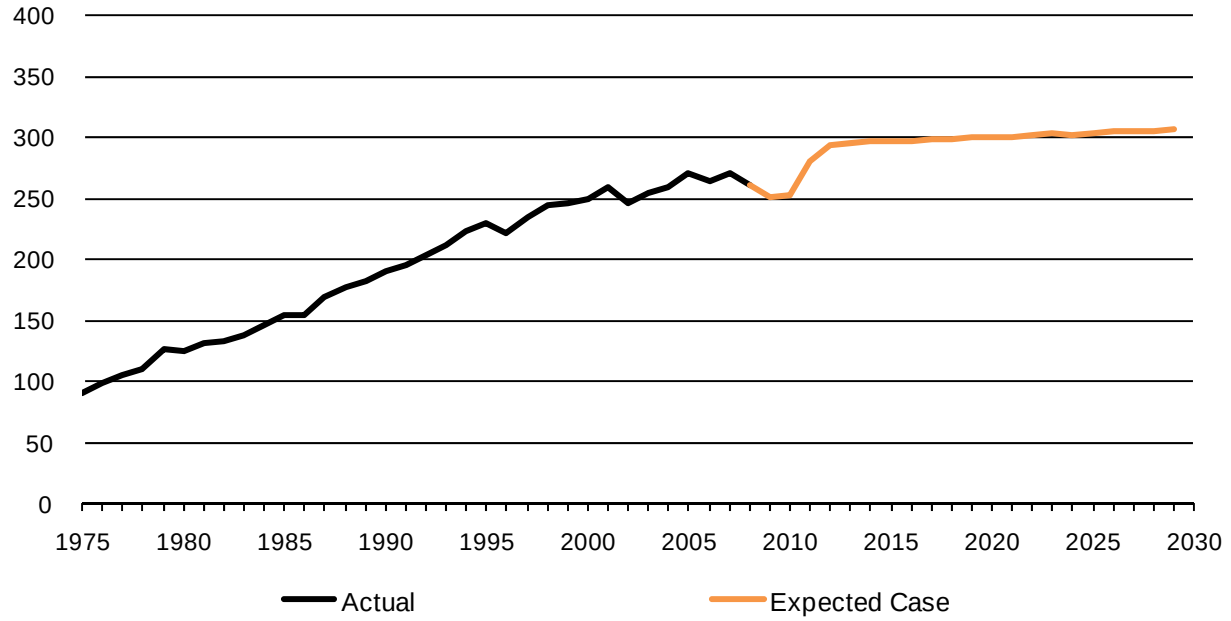
The industrial category is made up of Idaho Power's Large Power Service (Schedule 19) customers with metered demands exceeding 1,000 kilowatts (kw). In 1970, Idaho Power had about 50 industrial customers which represented 8 percent of Idaho Power system sales. By December 2008, the number of industrial customers had risen to 122, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 251 aMW in 2009 to 306 aMW in 2029, an average annual growth rate of 1.0 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 9.

**Table 8. Industrial Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2028 |
|---|---|---|---|---|---|
| Expected Case | 251 | 297 | 300 | 306 | 1.0% |

**Figure 9. Forecasted Industrial Load**
*(aMW)*



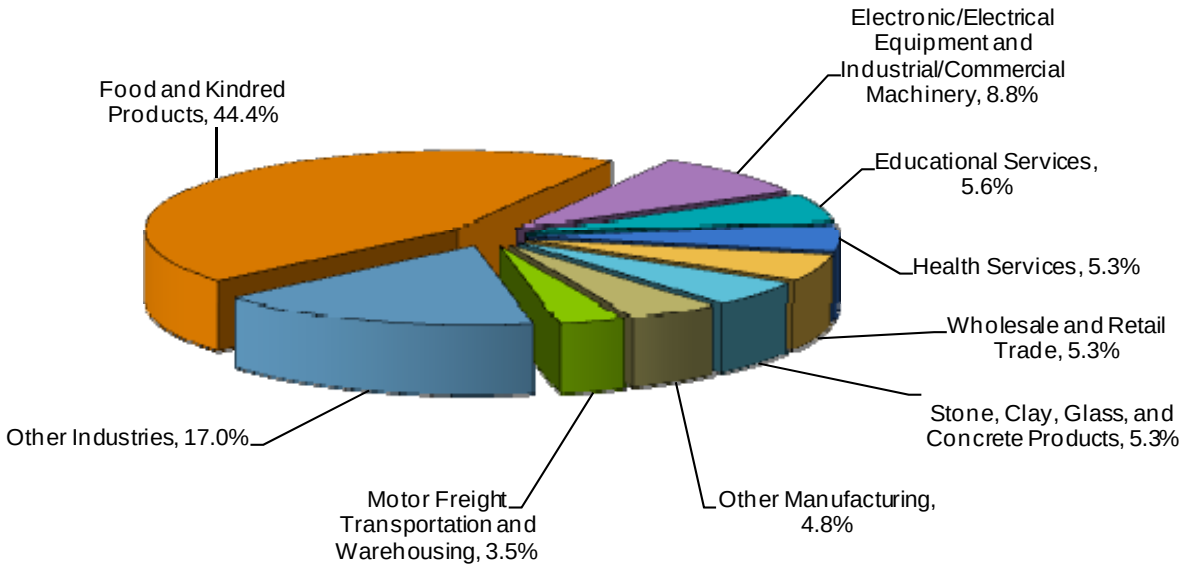

The industrial energy forecast is based on the most recent (June 2009) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to

each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment or population and other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment or population drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2008 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (44 percent), followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (9 percent); Educational Services (6 percent); and Health Services, Wholesale and Retail Trade, and Stone, Clay, Glass, and Concrete Products (each representing 5 percent). As Figure 10 shows, several other industry groups make up the remaining share of the 2008 industrial electricity consumption.

**Figure 10. Industrial Electricity Consumption by Industry Group**
*(based on 2008 figures)*



# ADDITIONAL FIRM LOAD

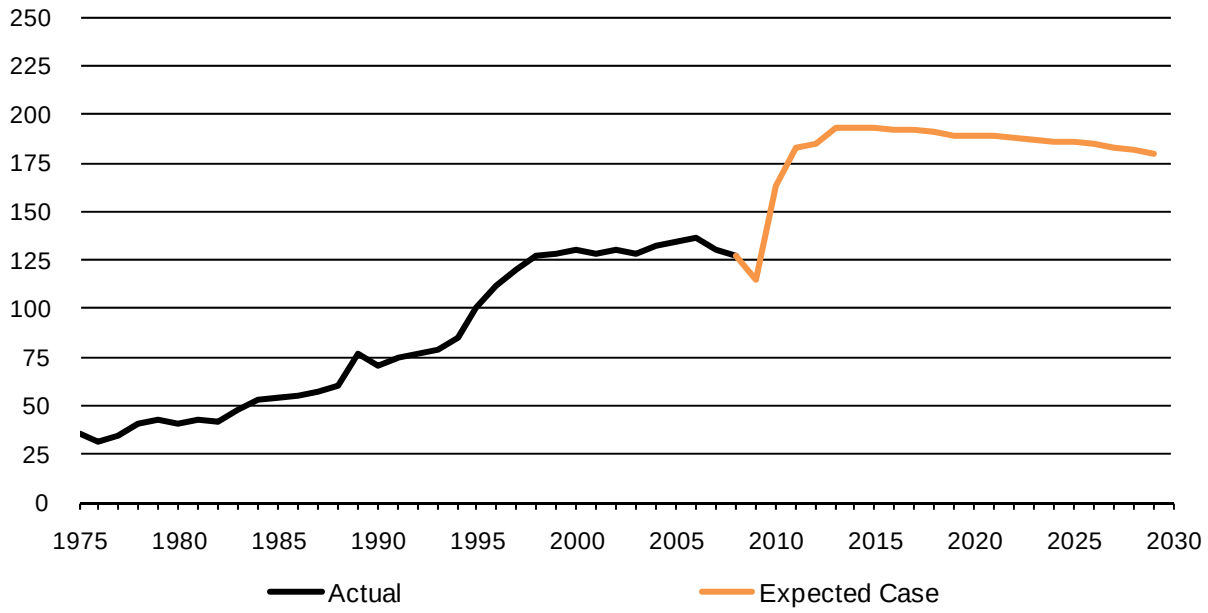
Special contracts currently exist for five large customers that are recognized as firm load customers. These customers are Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River. Together, these customers make up the additional firm load category. Historically, a long-term firm sales contract existed with the City of Weiser. However, the contract with the City of Weiser expired as of December 31, 2006 and was not renewed.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2009 to 180 aMW in 2029, an average growth rate of 2.3 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$ percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

**Table 9. Additional Firm Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| Expected Case | 115 | 193 | 189 | 180 | 2.3% |

**Figure 11. Forecasted Additional Firm Load**
*(aMW)*




## Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 9,000 workers in the Boise area. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company will continue to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product

design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on new product development and market demand reflected in Moody's Analytics forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing for the Pocatello MSA.

## Idaho National Laboratory

The United States Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2029 for the INL. The forecast calls for loads to increase through 2012, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. Looking back well over a decade ago, the annual loads at the INL were quite volatile due to operational constraints affecting the availability of an on-site nuclear reactor to generate electricity. However, as of October 1994, the INL nuclear reactor no longer generates electricity and, consequently, the amount of electricity provided by Idaho Power increased considerably.

## Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2012.

## Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. The closing date on the transaction was April 2, 2001. Raft River is also located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2009. However, Raft River may renew the agreement on a year-to-year basis for two additional one-year terms, which would extend service until September 30, 2011. The load forecasts in the 2009 IRP assume that Idaho Power will continue to provide service to the Raft River area by extending contracts each year through September 30, 2011.

# COMPANY FIRM LOAD

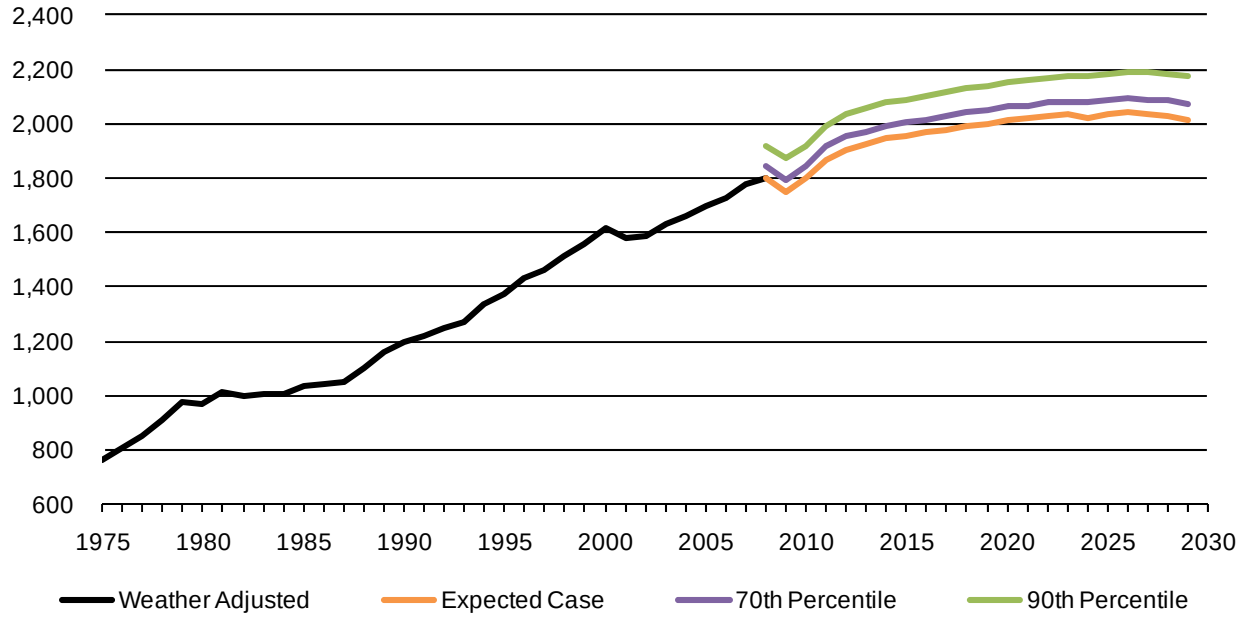
Firm load is the sum of the individual loads of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), past sales to the City of Weiser, and Raft River. Firm load excludes not only Astaris, but also all contracts to provide firm energy to off-system customers. Without the dampening effects of Astaris and expiring off-system contracts on load growth, firm load more accurately portrays the underlying growth trend within the service area than total load, which includes both Astaris and off-system commitments.

In the expected-case forecast, total firm load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). In the 70$^{th}$ percentile forecast, total firm load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). The three scenarios of projected firm load are illustrated in Figure 12.

**Table 10. Firm Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,875 | 2,078 | 2,141 | 2,172 | 0.7% |
| 70$^{th}$ Percentile | 1,796 | 1,994 | 2,051 | 2,070 | 0.7% |
| Expected Case | 1,752 | 1,947 | 2,002 | 2,015 | 0.7% |

**Figure 12. Forecasted Firm Load**
*(aMW)*



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# COMPANY FIRM PEAK

As defined here, firm peak load includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), and Raft River.

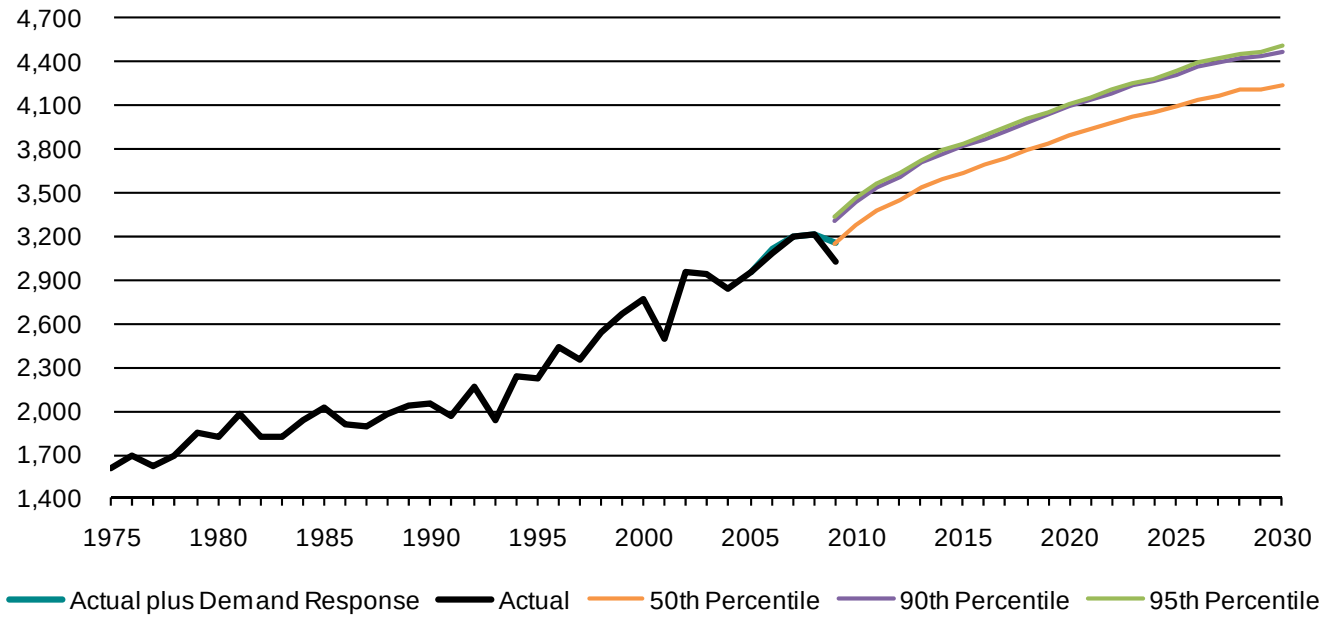
The all-time firm summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer firm peak load growth has accelerated over the past ten years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2001 summer peak was dampened by the nearly 30 percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

In the 90th percentile forecast, total firm summer peak load is expected to increase from 3,310 MW in 2009 to 4,445 MW in the year 2029, an average growth rate of 1.5 percent per year over the planning period (Table 11). In the 95th percentile forecast, total firm summer peak load is expected to increase from 3,330 MW in 2009 to 4,475 MW in the year 2029. The three scenarios of projected firm summer peak load are illustrated in Figure 13.

**Table 11. Firm Summer Peak-Load Growth**
*(MW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 95th Percentile | 3,330 | 3,789 | 4,060 | 4,475 | 1.5% |
| 90th Percentile | 3,310 | 3,766 | 4,034 | 4,445 | 1.5% |
| 50th Percentile | 3,154 | 3,592 | 3,842 | 4,216 | 1.5% |

**Figure 13. Forecasted Firm Summer Peak**
*(MW)*



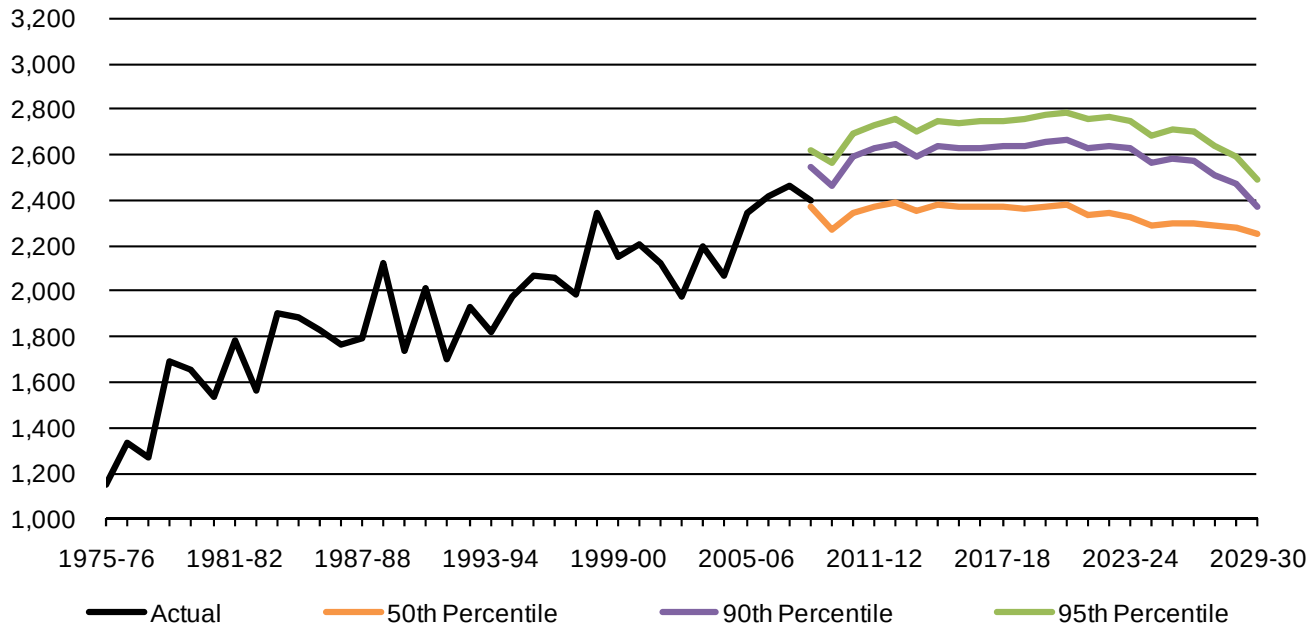
The maximum firm winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical firm winter peak load is much more variable than summer firm peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak day temperatures.

In the 90th percentile forecast, total firm winter peak load is expected to decrease from 2,466 MW in 2009 to 2,376 MW in 2029, an average growth rate of –0.2 percent per year over the planning period (Table 12). In the 95th percentile forecast, total firm winter peak load is expected to decrease from 2,565 MW in 2009 to 2,493 MW in 2029, an average growth rate of –0.1 percent per year over the planning period (Table 12). The three scenarios of projected firm winter peak load are illustrated in Figure 14.

**Table 12. Firm Winter Peak Load Growth**
*(MW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 95th Percentile | 2,565 | 2,748 | 2,773 | 2,493 | -0.1% |
| 90th Percentile | 2,466 | 2,637 | 2,654 | 2,376 | -0.2% |
| 50th Percentile | 2,270 | 2,385 | 2,370 | 2,250 | 0.0% |

**Figure 14. Forecasted Firm Winter Peak**
*(MW)*



# COMPANY SYSTEM LOAD

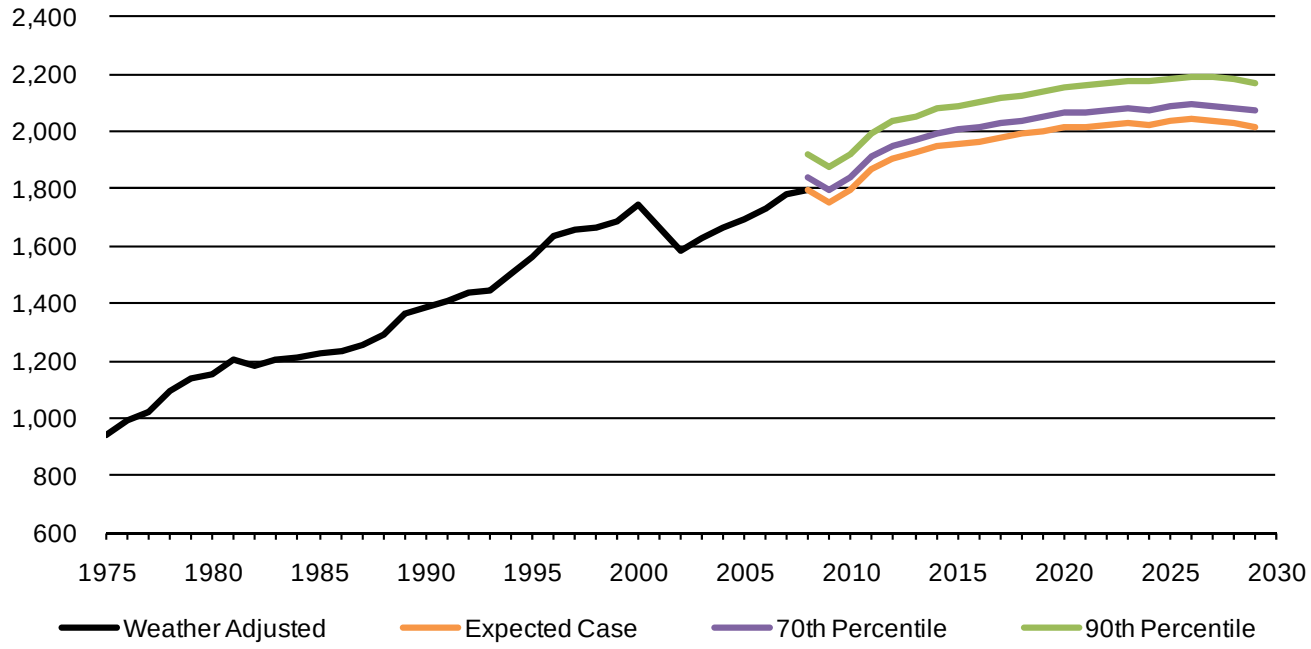
System load historically is made up of firm load plus Astaris load, but excludes long-term, off-system contracts. The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris was Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Since Astaris ceased production in April 2002, system load and firm load are identical.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 0.7 percent per year over the 2009–2029 time period. Company system load projections are reported in Table 13 and shown in Figure 15.

**Table 13. System Load Growth**
*(aMW)*

| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90th Percentile | 1,875 | 2,078 | 2,141 | 2,172 | 0.7% |
| 70th Percentile | 1,796 | 1,994 | 2,051 | 2,070 | 0.7% |
| Expected Case | 1,752 | 1,947 | 2,002 | 2,015 | 0.7% |

**Figure 15. Forecasted System Load**
*(aMW)*




In the expected-case forecast, company system load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW in 2029. In the 70th percentile forecast, company system load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 13).

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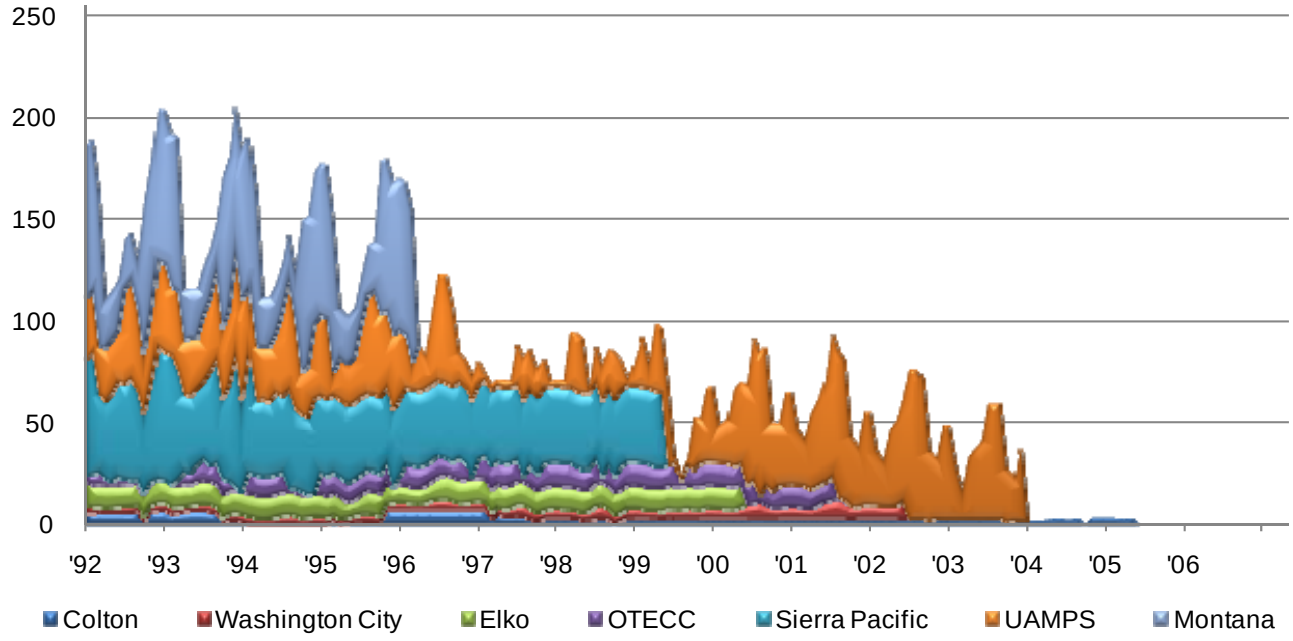
# CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

As illustrated in Figure 16, the historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

**Figure 16. Forecasted Contract Off-System Load by Customer**
*(aMW)*



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# TOTAL COMPANY LOAD

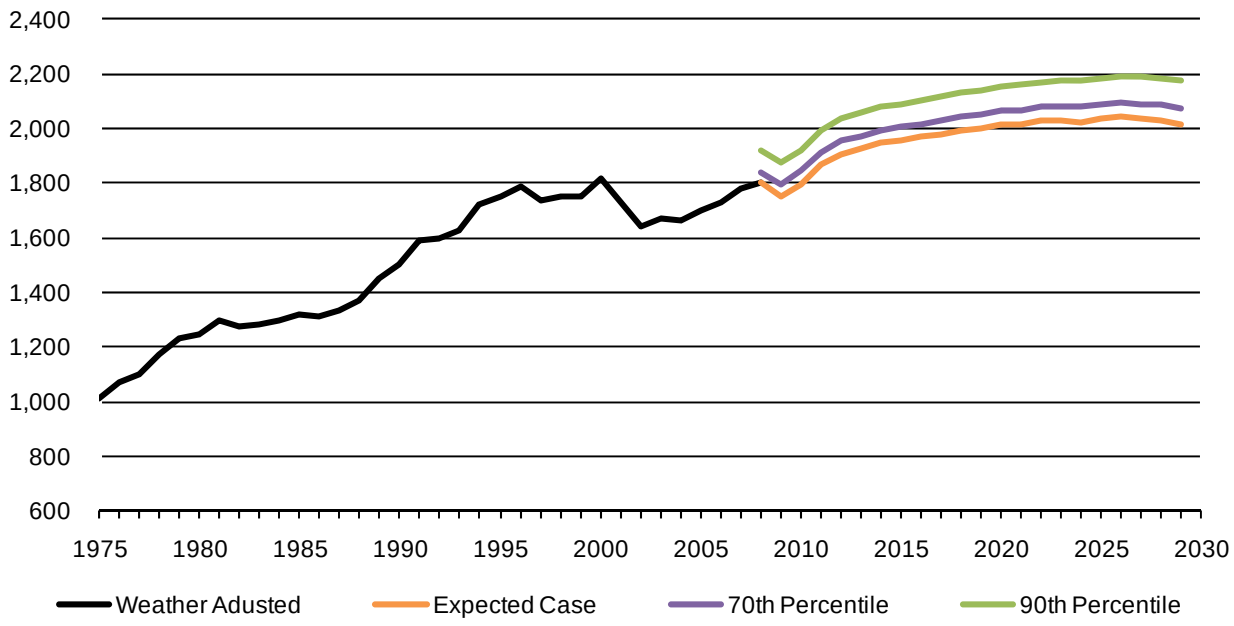
Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. Total load is made up of system load plus long-term firm off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

Total company load projections are listed in Table 14 and illustrated in Figure 17. The expected-case scenario average growth rate of 0.7 percent per year represents the most probable outlook expected by Idaho Power. In the 70th percentile forecast, company total load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029.

**Table 14. Total Company Load Growth**
*(aMW)*

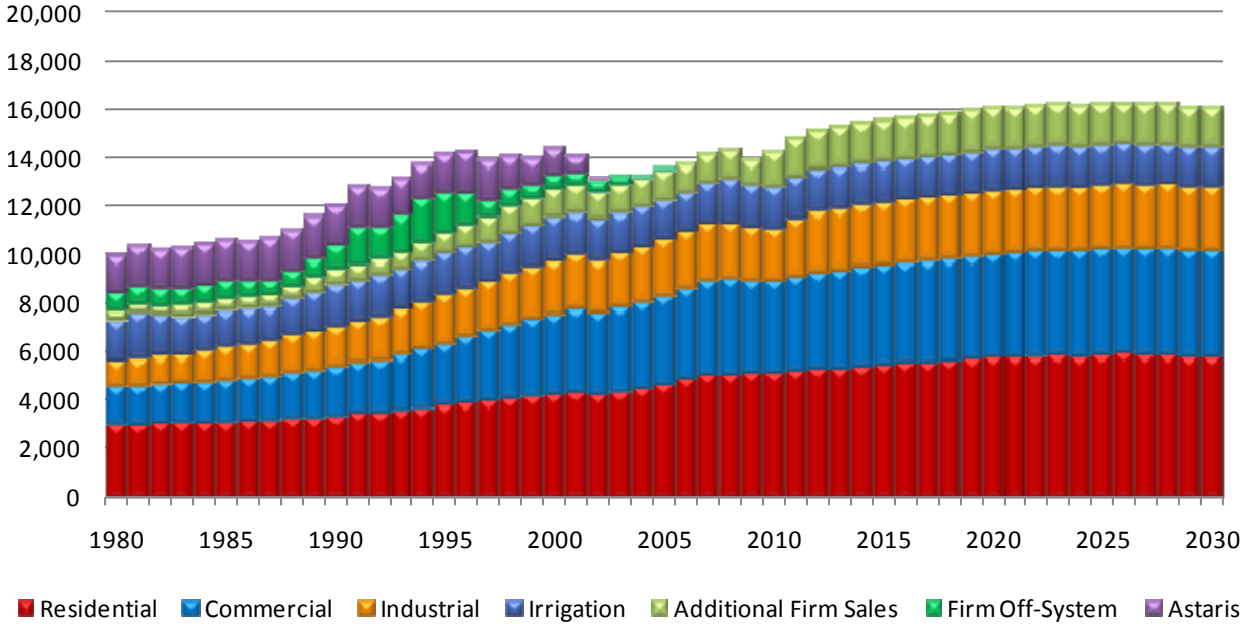
| Growth | 2009 | 2014 | 2019 | 2029 | Growth Rate (per year) 2009–2029 |
|---|---|---|---|---|---|
| 90th Percentile | 1,875 | 2,078 | 2,141 | 2,172 | 0.7% |
| 70th Percentile | 1,796 | 1,994 | 2,051 | 2,070 | 0.7% |
| Expected Case | 1,752 | 1,947 | 2,002 | 2,015 | 0.7% |

**Figure 17. Forecasted Total Load**
*(aMW)*




The composition of total company electricity sales by year is shown in Figure 18. Residential sales are forecast to be over 13 percent higher in 2029, gaining nearly 0.7 million MWh over 2009. Commercial sales are expected to be nearly 15 percent higher or nearly 0.6 million MWh above 2009 followed by industrial (22 percent higher or nearly 0.5 million additional MWh) and irrigation (nearly 10 percent lower than 2029). Electricity sales to Astaris ended in April 2002.

**Figure 18. Composition of Electricity Sales**
*(thousands of MWh)*




The additional firm sales category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River) is forecast to grow by nearly 57 percent over the 2009–2029 time period, largely due to the addition of Hoku Materials as a special contract customer.

# DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs which reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are integrated into *Appendix A –Sales and Load Forecast;* however, demand response programs are accounted for in the 2009 IRP load and resource balance. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which are used to develop portfolios for the IRP. Table 15 shows the existing and committed energy efficiency programs included in the current sales and load forecast.

**Table 15. DSM Programs**

| DSM Program | Customer Sector |
|---|---|
| Building Efficiency | Commercial/Industrial |
| Custom Efficiency | Commercial/Industrial |
| Easy Upgrades | Commercial/Industrial |
| Energy House Calls | Residential |
| Home Products Program | Residential |
| ENERGY STAR® Homes Northwest | Residential |
| Energy Efficient Lighting | Residential |
| Heating & Cooling Efficiency Program | Residential |
| Irrigation Efficiency Rewards | Irrigation |
| Oregon Residential Weatherization | Residential |
| Rebate Advantage | Residential |
| Weatherization Assistance for Qualified Customers (WAQC) | Residential |

## Energy Efficiency Programs

In developing data for the forecasting regression models, historical energy sales are adjusted for program performance in past years (which is added to the sales history) in order to isolate sales relationships to the causative independent drivers (economic, demographic, weather, price, et al.) from the impact of energy efficiency programs. The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

The reduced energy use for each customer class associated with each of the existing energy efficiency programs is shown in Appendix A2. Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customers' meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customers' meter.

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the sales and load forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs are shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be accounted for in the updated sales and load forecast.

## Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response programs are described in greater detail in Chapter 4 of the 2009 IRP and in *Appendix C-Technical Appendix*.

Demand response programs are treated as supply-side resources in the IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast performance of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs tend to result in reduced load year-round, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as all energy efficiency programs are integrated into the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B–Demand-Side Management 2008 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

### Residential Load

**Historical Residential Sales and Load, 1970–2008**
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 132,135 | | 9,983 | 1,319 | | 152 |
| 1971 | 138,071 | 4.5% | 10,539 | 1,455 | 10.3% | 167 |
| 1972 | 145,208 | 5.2% | 10,955 | 1,591 | 9.3% | 184 |
| 1973 | 152,957 | 5.3% | 11,525 | 1,763 | 10.8% | 202 |
| 1974 | 160,151 | 4.7% | 12,057 | 1,931 | 9.5% | 223 |
| 1975 | 167,622 | 4.7% | 12,939 | 2,169 | 12.3% | 250 |
| 1976 | 175,720 | 4.8% | 13,445 | 2,363 | 8.9% | 271 |
| 1977 | 184,561 | 5.0% | 13,673 | 2,524 | 6.8% | 290 |
| 1978 | 194,650 | 5.5% | 14,256 | 2,775 | 10.0% | 321 |
| 1979 | 202,982 | 4.3% | 14,766 | 2,997 | 8.0% | 342 |
| 1980 | 209,629 | 3.3% | 14,580 | 3,056 | 2.0% | 348 |
| 1981 | 213,579 | 1.9% | 14,346 | 3,064 | 0.2% | 349 |
| 1982 | 216,696 | 1.5% | 14,393 | 3,119 | 1.8% | 356 |
| 1983 | 219,849 | 1.5% | 14,334 | 3,151 | 1.0% | 362 |
| 1984 | 222,695 | 1.3% | 14,145 | 3,150 | 0.0% | 357 |
| 1985 | 225,185 | 1.1% | 14,055 | 3,165 | 0.5% | 362 |
| 1986 | 227,081 | 0.8% | 14,168 | 3,217 | 1.7% | 367 |
| 1987 | 228,868 | 0.8% | 14,068 | 3,220 | 0.1% | 366 |
| 1988 | 230,771 | 0.8% | 14,326 | 3,306 | 2.7% | 377 |
| 1989 | 233,370 | 1.1% | 14,342 | 3,347 | 1.2% | 384 |
| 1990 | 238,117 | 2.0% | 14,300 | 3,405 | 1.7% | 393 |
| 1991 | 243,207 | 2.1% | 14,488 | 3,524 | 3.5% | 401 |
| 1992 | 249,767 | 2.7% | 14,135 | 3,531 | 0.2% | 407 |
| 1993 | 258,271 | 3.4% | 14,173 | 3,660 | 3.7% | 413 |
| 1994 | 267,854 | 3.7% | 14,001 | 3,750 | 2.4% | 434 |
| 1995 | 277,131 | 3.5% | 13,973 | 3,872 | 3.3% | 437 |
| 1996 | 286,227 | 3.3% | 13,743 | 3,934 | 1.6% | 456 |
| 1997 | 294,674 | 3.0% | 13,681 | 4,031 | 2.5% | 463 |
| 1998 | 303,300 | 2.9% | 13,713 | 4,159 | 3.2% | 475 |
| 1999 | 312,901 | 3.2% | 13,583 | 4,250 | 2.2% | 487 |
| 2000 | 322,402 | 3.0% | 13,383 | 4,315 | 1.5% | 499 |
| 2001 | 331,009 | 2.7% | 13,163 | 4,357 | 1.0% | 476 |
| 2002 | 339,764 | 2.6% | 12,620 | 4,288 | –1.6% | 488 |
| 2003 | 349,219 | 2.8% | 12,645 | 4,416 | 3.0% | 507 |
| 2004 | 360,462 | 3.2% | 12,689 | 4,574 | 3.6% | 525 |
| 2005 | 373,602 | 3.6% | 12,650 | 4,726 | 3.3% | 541 |
| 2006 | 387,707 | 3.8% | 12,842 | 4,979 | 5.3% | 566 |
| 2007 | 397,286 | 2.5% | 12,885 | 5,119 | 2.8% | 583 |
| 2008 | 402,520 | 1.3% | 12,823 | 5,161 | 0.8% | 590 |

## Residential Load

### Projected Residential Sales and Load, 2009–2029

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2009 | 404,916 | 0.6% | 12,779 | 5,174 | 0.3% | 590 |
| 2010 | 406,743 | 0.5% | 12,707 | 5,168 | –0.1% | 591 |
| 2011 | 409,192 | 0.6% | 12,846 | 5,256 | 1.7% | 601 |
| 2012 | 414,346 | 1.3% | 12,984 | 5,380 | 2.3% | 614 |
| 2013 | 422,101 | 1.9% | 12,737 | 5,376 | –0.1% | 615 |
| 2014 | 430,667 | 2.0% | 12,746 | 5,489 | 2.1% | 627 |
| 2015 | 439,230 | 2.0% | 12,592 | 5,531 | 0.8% | 632 |
| 2016 | 447,681 | 1.9% | 12,480 | 5,587 | 1.0% | 638 |
| 2017 | 456,082 | 1.9% | 12,379 | 5,646 | 1.0% | 645 |
| 2018 | 464,527 | 1.9% | 12,274 | 5,701 | 1.0% | 651 |
| 2019 | 473,045 | 1.8% | 12,197 | 5,770 | 1.2% | 659 |
| 2020 | 481,587 | 1.8% | 12,129 | 5,841 | 1.2% | 667 |
| 2021 | 490,126 | 1.8% | 11,918 | 5,841 | 0.0% | 667 |
| 2022 | 498,618 | 1.7% | 11,824 | 5,895 | 0.9% | 673 |
| 2023 | 507,071 | 1.7% | 11,714 | 5,940 | 0.8% | 678 |
| 2024 | 515,508 | 1.7% | 11,427 | 5,891 | –0.8% | 673 |
| 2025 | 523,994 | 1.6% | 11,365 | 5,955 | 1.1% | 680 |
| 2026 | 532,612 | 1.6% | 11,260 | 5,997 | 0.7% | 684 |
| 2027 | 541,310 | 1.6% | 11,006 | 5,957 | –0.7% | 680 |
| 2028 | 550,147 | 1.6% | 10,830 | 5,958 | 0.0% | 680 |
| 2029 | 559,091 | 1.6% | 10,494 | 5,867 | –1.5% | 670 |

## Commercial Load

### Historical Commercial Sales and Load, 1970–2008

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 21,375 | | 42,768 | 914 | | 105 |
| 1971 | 22,077 | 3.3% | 45,386 | 1,002 | 9.6% | 115 |
| 1972 | 22,585 | 2.3% | 46,141 | 1,042 | 4.0% | 120 |
| 1973 | 23,286 | 3.1% | 48,142 | 1,121 | 7.6% | 128 |
| 1974 | 24,096 | 3.5% | 49,025 | 1,181 | 5.4% | 136 |
| 1975 | 25,045 | 3.9% | 51,217 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,509 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,415 | 1,421 | 4.0% | 162 |
| 1978 | 27,831 | 2.7% | 52,467 | 1,460 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,394 | 1,584 | 8.5% | 180 |
| 1980 | 28,797 | 2.5% | 54,135 | 1,559 | -1.6% | 178 |
| 1981 | 29,567 | 2.7% | 54,278 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,126 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,649 | 1,620 | -0.8% | 186 |
| 1984 | 31,554 | 2.5% | 53,312 | 1,682 | 3.8% | 191 |
| 1985 | 32,417 | 2.7% | 53,944 | 1,749 | 4.0% | 200 |
| 1986 | 33,208 | 2.4% | 53,590 | 1,780 | 1.8% | 203 |
| 1987 | 33,975 | 2.3% | 53,126 | 1,805 | 1.4% | 205 |
| 1988 | 34,723 | 2.2% | 54,319 | 1,886 | 4.5% | 215 |
| 1989 | 35,638 | 2.6% | 55,327 | 1,972 | 4.5% | 226 |
| 1990 | 36,785 | 3.2% | 55,922 | 2,057 | 4.3% | 236 |
| 1991 | 37,922 | 3.1% | 56,027 | 2,125 | 3.3% | 243 |
| 1992 | 39,022 | 2.9% | 56,292 | 2,197 | 3.4% | 253 |
| 1993 | 40,047 | 2.6% | 57,764 | 2,313 | 5.3% | 262 |
| 1994 | 41,629 | 4.0% | 58,187 | 2,422 | 4.7% | 280 |
| 1995 | 43,165 | 3.7% | 58,523 | 2,526 | 4.3% | 287 |
| 1996 | 44,995 | 4.2% | 61,940 | 2,787 | 10.3% | 322 |
| 1997 | 46,819 | 4.1% | 62,007 | 2,903 | 4.2% | 333 |
| 1998 | 48,404 | 3.4% | 62,771 | 3,038 | 4.7% | 348 |
| 1999 | 49,430 | 2.1% | 64,085 | 3,168 | 4.3% | 363 |
| 2000 | 50,117 | 1.4% | 66,079 | 3,312 | 4.5% | 383 |
| 2001 | 51,501 | 2.8% | 67,424 | 3,472 | 4.9% | 383 |
| 2002 | 52,915 | 2.7% | 64,650 | 3,421 | -1.5% | 389 |
| 2003 | 54,194 | 2.4% | 64,268 | 3,483 | 1.8% | 399 |
| 2004 | 55,577 | 2.6% | 63,972 | 3,555 | 2.1% | 407 |
| 2005 | 57,145 | 2.8% | 63,472 | 3,627 | 2.0% | 414 |
| 2006 | 59,050 | 3.3% | 63,320 | 3,739 | 3.1% | 425 |
| 2007 | 61,640 | 4.4% | 63,233 | 3,898 | 4.2% | 444 |
| 2008 | 63,492 | 3.0% | 62,122 | 3,944 | 1.2% | 449 |

## Commercial Load

### Projected Commercial Sales and Load, 2009–2029

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2009 | 64,261 | 1.2% | 59,445 | 3,820 | –3.2% | 437 |
| 2010 | 64,925 | 1.0% | 58,988 | 3,830 | 0.3% | 438 |
| 2011 | 65,712 | 1.2% | 59,205 | 3,890 | 1.6% | 445 |
| 2012 | 67,085 | 2.1% | 59,330 | 3,980 | 2.3% | 455 |
| 2013 | 68,768 | 2.5% | 58,863 | 4,048 | 1.7% | 463 |
| 2014 | 70,486 | 2.5% | 58,172 | 4,100 | 1.3% | 469 |
| 2015 | 72,191 | 2.4% | 57,262 | 4,134 | 0.8% | 472 |
| 2016 | 73,883 | 2.3% | 56,354 | 4,164 | 0.7% | 476 |
| 2017 | 75,568 | 2.3% | 55,480 | 4,193 | 0.7% | 479 |
| 2018 | 77,249 | 2.2% | 54,646 | 4,221 | 0.7% | 482 |
| 2019 | 78,930 | 2.2% | 53,842 | 4,250 | 0.7% | 486 |
| 2020 | 80,608 | 2.1% | 53,054 | 4,277 | 0.6% | 489 |
| 2021 | 82,282 | 2.1% | 52,180 | 4,293 | 0.4% | 490 |
| 2022 | 83,952 | 2.0% | 51,378 | 4,313 | 0.5% | 493 |
| 2023 | 85,621 | 2.0% | 50,569 | 4,330 | 0.4% | 495 |
| 2024 | 87,288 | 1.9% | 49,653 | 4,334 | 0.1% | 495 |
| 2025 | 88,956 | 1.9% | 48,907 | 4,351 | 0.4% | 497 |
| 2026 | 90,628 | 1.9% | 48,165 | 4,365 | 0.3% | 499 |
| 2027 | 92,301 | 1.8% | 47,350 | 4,370 | 0.1% | 499 |
| 2028 | 93,980 | 1.8% | 46,599 | 4,379 | 0.2% | 500 |
| 2029 | 95,661 | 1.8% | 45,780 | 4,379 | 0.0% | 500 |

## Irrigation Load

### Historical Irrigation Sales and Load,1970–2008

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 7,319 | | 117,492 | 860 | | 98 |
| 1971 | 7,518 | 2.7% | 132,445 | 996 | 15.8% | 114 |
| 1972 | 7,815 | 4.0% | 126,555 | 989 | -0.7% | 113 |
| 1973 | 8,341 | 6.7% | 134,540 | 1,122 | 13.5% | 128 |
| 1974 | 8,971 | 7.6% | 143,892 | 1,291 | 15.0% | 147 |
| 1975 | 9,480 | 5.7% | 153,349 | 1,454 | 12.6% | 166 |
| 1976 | 9,936 | 4.8% | 153,080 | 1,521 | 4.6% | 173 |
| 1977 | 10,238 | 3.0% | 156,073 | 1,598 | 5.1% | 182 |
| 1978 | 10,476 | 2.3% | 152,167 | 1,594 | -0.2% | 183 |
| 1979 | 10,711 | 2.2% | 158,121 | 1,694 | 6.2% | 193 |
| 1980 | 10,854 | 1.3% | 154,113 | 1,673 | -1.2% | 190 |
| 1981 | 11,248 | 3.6% | 163,787 | 1,842 | 10.1% | 210 |
| 1982 | 11,312 | 0.6% | 148,385 | 1,679 | -8.9% | 192 |
| 1983 | 11,133 | -1.6% | 143,103 | 1,593 | -5.1% | 182 |
| 1984 | 11,375 | 2.2% | 130,822 | 1,488 | -6.6% | 169 |
| 1985 | 11,576 | 1.8% | 129,069 | 1,494 | 0.4% | 171 |
| 1986 | 11,308 | -2.3% | 132,200 | 1,495 | 0.1% | 171 |
| 1987 | 11,254 | -0.5% | 124,128 | 1,397 | -6.6% | 160 |
| 1988 | 11,378 | 1.1% | 131,448 | 1,496 | 7.1% | 170 |
| 1989 | 11,957 | 5.1% | 136,351 | 1,630 | 9.0% | 186 |
| 1990 | 12,340 | 3.2% | 141,532 | 1,747 | 7.1% | 199 |
| 1991 | 12,484 | 1.2% | 134,476 | 1,679 | -3.9% | 192 |
| 1992 | 12,809 | 2.6% | 134,469 | 1,722 | 2.6% | 196 |
| 1993 | 13,078 | 2.1% | 128,681 | 1,683 | -2.3% | 192 |
| 1994 | 13,559 | 3.7% | 125,547 | 1,702 | 1.2% | 194 |
| 1995 | 13,679 | 0.9% | 126,417 | 1,729 | 1.6% | 197 |
| 1996 | 14,074 | 2.9% | 122,219 | 1,720 | -0.5% | 196 |
| 1997 | 14,383 | 2.2% | 111,783 | 1,608 | -6.5% | 184 |
| 1998 | 14,695 | 2.2% | 112,347 | 1,651 | 2.7% | 188 |
| 1999 | 14,912 | 1.5% | 115,126 | 1,717 | 4.0% | 196 |
| 2000 | 15,253 | 2.3% | 121,883 | 1,859 | 8.3% | 212 |
| 2001 | 15,522 | 1.8% | 110,306 | 1,712 | -7.9% | 195 |
| 2002 | 15,840 | 2.0% | 105,996 | 1,679 | -1.9% | 192 |
| 2003 | 16,020 | 1.1% | 106,160 | 1,701 | 1.3% | 194 |
| 2004 | 16,297 | 1.7% | 103,886 | 1,693 | -0.4% | 193 |
| 2005 | 16,936 | 3.9% | 97,135 | 1,645 | -2.8% | 188 |
| 2006 | 17,062 | 0.7% | 94,015 | 1,604 | -2.5% | 183 |
| 2007 | 17,001 | -0.4% | 100,043 | 1,701 | 6.0% | 194 |
| 2008 | 17,428 | 2.5% | 105,738 | 1,843 | 8.3% | 210 |

## Irrigation Load

### Projected Irrigation Sales and Load, 2009–2029

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2009 | 17,705 | 1.6% | 100,269 | 1,775 | –3.7% | 203 |
| 2010 | 17,982 | 1.6% | 94,477 | 1,699 | –4.3% | 194 |
| 2011 | 18,261 | 1.6% | 93,557 | 1,708 | 0.6% | 195 |
| 2012 | 18,537 | 1.5% | 91,454 | 1,695 | –0.8% | 193 |
| 2013 | 18,812 | 1.5% | 89,510 | 1,684 | –0.7% | 192 |
| 2014 | 19,090 | 1.5% | 87,891 | 1,678 | –0.4% | 192 |
| 2015 | 19,367 | 1.5% | 86,947 | 1,684 | 0.4% | 192 |
| 2016 | 19,644 | 1.4% | 85,637 | 1,682 | –0.1% | 192 |
| 2017 | 19,921 | 1.4% | 84,516 | 1,684 | 0.1% | 192 |
| 2018 | 20,199 | 1.4% | 83,465 | 1,686 | 0.1% | 192 |
| 2019 | 20,474 | 1.4% | 82,524 | 1,690 | 0.2% | 193 |
| 2020 | 20,755 | 1.4% | 81,683 | 1,695 | 0.3% | 193 |
| 2021 | 21,031 | 1.3% | 80,425 | 1,691 | –0.2% | 193 |
| 2022 | 21,308 | 1.3% | 79,093 | 1,685 | –0.4% | 192 |
| 2023 | 21,583 | 1.3% | 78,135 | 1,686 | 0.1% | 193 |
| 2024 | 21,861 | 1.3% | 76,541 | 1,673 | –0.8% | 190 |
| 2025 | 22,140 | 1.3% | 75,146 | 1,664 | –0.6% | 190 |
| 2026 | 22,415 | 1.2% | 74,420 | 1,668 | 0.3% | 190 |
| 2027 | 22,691 | 1.2% | 73,007 | 1,657 | –0.7% | 189 |
| 2028 | 22,967 | 1.2% | 71,354 | 1,639 | –1.1% | 187 |
| 2029 | 23,244 | 1.2% | 69,359 | 1,612 | –1.6% | 184 |

## Industrial Load

### Historical Industrial Sales and Load, 1970–2008

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 49 | | 9,173,784 | 445 | | 52 |
| 1971 | 50 | 3.3% | 10,474,941 | 525 | 17.9% | 60 |
| 1972 | 56 | 12.1% | 10,944,714 | 615 | 17.2% | 71 |
| 1973 | 63 | 12.3% | 10,889,056 | 687 | 11.7% | 79 |
| 1974 | 65 | 2.2% | 11,464,249 | 739 | 7.6% | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,415,391 | 2,308 | -2.4% | 261 |

## Industrial Load

### Projected Industrial Sales and Load, 2009–2029

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2009 | 123 | 3.2% | 17,962,012 | 2,203 | –4.6% | 251 |
| 2010 | 123 | 0.3% | 17,854,906 | 2,196 | –0.3% | 252 |
| 2011 | 125 | 1.6% | 19,535,073 | 2,442 | 11.2% | 281 |
| 2012 | 128 | 2.4% | 20,058,798 | 2,568 | 5.1% | 293 |
| 2013 | 128 | 0.0% | 20,226,984 | 2,589 | 0.8% | 296 |
| 2014 | 130 | 1.6% | 19,997,345 | 2,600 | 0.4% | 297 |
| 2015 | 131 | 0.8% | 19,881,653 | 2,604 | 0.2% | 297 |
| 2016 | 134 | 2.3% | 19,485,326 | 2,611 | 0.3% | 297 |
| 2017 | 134 | 0.0% | 19,527,376 | 2,617 | 0.2% | 299 |
| 2018 | 136 | 1.5% | 19,281,769 | 2,622 | 0.2% | 299 |
| 2019 | 136 | 0.0% | 19,327,437 | 2,629 | 0.2% | 300 |
| 2020 | 138 | 1.5% | 19,089,792 | 2,634 | 0.2% | 300 |
| 2021 | 140 | 1.4% | 18,842,449 | 2,638 | 0.1% | 301 |
| 2022 | 141 | 0.7% | 18,758,363 | 2,645 | 0.3% | 302 |
| 2023 | 141 | 0.0% | 18,812,300 | 2,653 | 0.3% | 303 |
| 2024 | 145 | 2.8% | 18,316,503 | 2,656 | 0.1% | 302 |
| 2025 | 146 | 0.7% | 18,230,053 | 2,662 | 0.2% | 304 |
| 2026 | 147 | 0.7% | 18,153,540 | 2,669 | 0.3% | 305 |
| 2027 | 148 | 0.7% | 18,053,489 | 2,672 | 0.1% | 305 |
| 2028 | 150 | 1.4% | 17,857,001 | 2,679 | 0.2% | 305 |
| 2029 | 151 | 0.7% | 17,741,963 | 2,679 | 0.0% | 306 |

## Additional Firm Sales and Load*

### Historical Additional Firm Sales and Load, 1970–2008

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 319 | | 36 |
| 1971 | 295 | -7.5% | 34 |
| 1972 | 284 | -3.7% | 32 |
| 1973 | 290 | 2.2% | 33 |
| 1974 | 282 | -2.7% | 32 |
| 1975 | 314 | 11.1% | 36 |
| 1976 | 277 | -11.9% | 31 |
| 1977 | 311 | 12.4% | 35 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.6% | 43 |
| 1980 | 360 | -3.6% | 41 |
| 1981 | 376 | 4.5% | 43 |
| 1982 | 368 | -2.2% | 42 |
| 1983 | 425 | 15.5% | 48 |
| 1984 | 466 | 9.8% | 53 |
| 1985 | 473 | 1.3% | 54 |
| 1986 | 482 | 2.0% | 55 |
| 1987 | 503 | 4.3% | 57 |
| 1988 | 531 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 626 | -6.8% | 71 |
| 1991 | 661 | 5.7% | 75 |
| 1992 | 681 | 3.0% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 877 | 18.4% | 100 |
| 1996 | 988 | 12.6% | 112 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,112 | 6.2% | 127 |
| 1999 | 1,121 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | -2.1% | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | -1.7% | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,142 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |

*Includes Micron Technology, Simplot Fertilizer, INL, and Raft River Rural Electric Cooperative, Inc.

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009 | 1,004 | –9.9% | 115 |
| 2010 | 1,429 | 42.3% | 163 |
| 2011 | 1,605 | 12.3% | 183 |
| 2012 | 1,621 | 1.0% | 185 |
| 2013 | 1,687 | 4.1% | 193 |
| 2014 | 1,690 | 0.2% | 193 |
| 2015 | 1,689 | 0.0% | 193 |
| 2016 | 1,684 | –0.3% | 192 |
| 2017 | 1,678 | –0.3% | 192 |
| 2018 | 1,676 | –0.1% | 191 |
| 2019 | 1,657 | –1.1% | 189 |
| 2020 | 1,657 | 0.0% | 189 |
| 2021 | 1,652 | –0.3% | 189 |
| 2022 | 1,650 | –0.1% | 188 |
| 2023 | 1,637 | –0.8% | 187 |
| 2024 | 1,638 | 0.1% | 186 |
| 2025 | 1,633 | –0.3% | 186 |
| 2026 | 1,619 | –0.8% | 185 |
| 2027 | 1,606 | –0.9% | 183 |
| 2028 | 1,595 | –0.6% | 182 |
| 2029 | 1,579 | –1.0% | 180 |

*Includes Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

## Company Firm Load

### Historical Company Firm Load, 1970–2008

*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 3,857 | | 487 |
| 1971 | 4,272 | 10.8% | 539 |
| 1972 | 4,521 | 5.8% | 571 |
| 1973 | 4,983 | 10.2% | 628 |
| 1974 | 5,425 | 8.9% | 685 |
| 1975 | 6,004 | 10.7% | 759 |
| 1976 | 6,385 | 6.3% | 805 |
| 1977 | 6,782 | 6.2% | 854 |
| 1978 | 7,158 | 5.5% | 907 |
| 1979 | 7,735 | 8.1% | 972 |
| 1980 | 7,753 | 0.2% | 971 |
| 1981 | 8,035 | 3.6% | 1,011 |
| 1982 | 7,960 | -0.9% | 1,000 |
| 1983 | 7,983 | 0.3% | 1,008 |
| 1984 | 8,069 | 1.1% | 1,008 |
| 1985 | 8,238 | 2.1% | 1,036 |
| 1986 | 8,330 | 1.1% | 1,045 |
| 1987 | 8,398 | 0.8% | 1,051 |
| 1988 | 8,764 | 4.4% | 1,098 |
| 1989 | 9,215 | 5.1% | 1,159 |
| 1990 | 9,496 | 3.1% | 1,198 |
| 1991 | 9,707 | 2.2% | 1,215 |
| 1992 | 9,900 | 2.0% | 1,247 |
| 1993 | 10,200 | 3.0% | 1,271 |
| 1994 | 10,564 | 3.6% | 1,335 |
| 1995 | 11,026 | 4.4% | 1,373 |
| 1996 | 11,363 | 3.1% | 1,434 |
| 1997 | 11,632 | 2.4% | 1,464 |
| 1998 | 12,106 | 4.1% | 1,516 |
| 1999 | 12,416 | 2.6% | 1,558 |
| 2000 | 12,820 | 3.3% | 1,618 |
| 2001 | 12,948 | 1.0% | 1,582 |
| 2002 | 12,683 | -2.0% | 1,586 |
| 2003 | 12,954 | 2.1% | 1,627 |
| 2004 | 13,247 | 2.3% | 1,663 |
| 2005 | 13,525 | 2.1% | 1,697 |
| 2006 | 13,835 | 2.3% | 1,729 |
| 2007 | 14,225 | 2.8% | 1,780 |
| 2008 | 14,370 | 1.0% | 1,798 |

**Company Firm Load**

**Projected Company Firm Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009 | 13,977 | –2.7% | 1,752 |
| 2010 | 14,322 | 2.5% | 1,797 |
| 2011 | 14,902 | 4.0% | 1,869 |
| 2012 | 15,244 | 2.3% | 1,906 |
| 2013 | 15,384 | 0.9% | 1,926 |
| 2014 | 15,557 | 1.1% | 1,947 |
| 2015 | 15,642 | 0.5% | 1,957 |
| 2016 | 15,728 | 0.5% | 1,967 |
| 2017 | 15,817 | 0.6% | 1,979 |
| 2018 | 15,907 | 0.6% | 1,991 |
| 2019 | 15,995 | 0.6% | 2,002 |
| 2020 | 16,105 | 0.7% | 2,013 |
| 2021 | 16,116 | 0.1% | 2,017 |
| 2022 | 16,189 | 0.5% | 2,026 |
| 2023 | 16,245 | 0.3% | 2,032 |
| 2024 | 16,192 | –0.3% | 2,024 |
| 2025 | 16,264 | 0.4% | 2,035 |
| 2026 | 16,318 | 0.3% | 2,041 |
| 2027 | 16,262 | –0.3% | 2,034 |
| 2028 | 16,250 | –0.1% | 2,030 |
| 2029 | 16,116 | –0.8% | 2,015 |

## Astaris Load

### Historical Astaris Sales and Load, 1970–2008

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 1,657 | | 189 |
| 1971 | 1,508 | -9.0% | 172 |
| 1972 | 1,819 | 20.6% | 207 |
| 1973 | 1,645 | -9.6% | 188 |
| 1974 | 1,643 | -0.1% | 188 |
| 1975 | 1,557 | -5.3% | 178 |
| 1976 | 1,575 | 1.2% | 179 |
| 1977 | 1,418 | -10.0% | 162 |
| 1978 | 1,542 | 8.8% | 176 |
| 1979 | 1,395 | -9.6% | 159 |
| 1980 | 1,513 | 8.5% | 172 |
| 1981 | 1,634 | 8.0% | 186 |
| 1982 | 1,554 | -4.9% | 177 |
| 1983 | 1,610 | 3.6% | 184 |
| 1984 | 1,701 | 5.7% | 194 |
| 1985 | 1,614 | -5.1% | 184 |
| 1986 | 1,554 | -3.7% | 177 |
| 1987 | 1,692 | 8.9% | 193 |
| 1988 | 1,635 | -3.4% | 186 |
| 1989 | 1,703 | 4.2% | 194 |
| 1990 | 1,604 | -5.8% | 183 |
| 1991 | 1,609 | 0.3% | 184 |
| 1992 | 1,570 | -2.4% | 179 |
| 1993 | 1,437 | -8.4% | 164 |
| 1994 | 1,420 | -1.2% | 162 |
| 1995 | 1,567 | 10.4% | 179 |
| 1996 | 1,689 | 7.8% | 192 |
| 1997 | 1,628 | -3.6% | 186 |
| 1998 | 1,273 | -21.8% | 145 |
| 1999 | 1,051 | -17.4% | 120 |
| 2000 | 1,054 | 0.3% | 120 |
| 2001 | 658 | -37.5% | 75 |
| 2002 | 11 | -98.3% | 1 |
| 2003 | 0 | -100.0% | 0 |
| 2004 | 0 | 0.0% | 0 |
| 2005 | 0 | 0.0% | 0 |
| 2006 | 0 | 0.0% | 0 |
| 2007 | 0 | 0.0% | 0 |
| 2008 | 0 | 0.0% | 0 |

**Astaris Load**

**Projected Astaris Sales and Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009–2029 | 0 | 0.0% | 0 |

## Company System Load

### Historical Company System Sales and Load, 1970–2008

*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 5,515 | | 686 |
| 1971 | 5,781 | 4.8% | 719 |
| 1972 | 6,340 | 9.7% | 789 |
| 1973 | 6,628 | 4.5% | 825 |
| 1974 | 7,068 | 6.6% | 882 |
| 1975 | 7,561 | 7.0% | 945 |
| 1976 | 7,960 | 5.3% | 994 |
| 1977 | 8,200 | 3.0% | 1,024 |
| 1978 | 8,701 | 6.1% | 1,092 |
| 1979 | 9,130 | 4.9% | 1,139 |
| 1980 | 9,266 | 1.5% | 1,152 |
| 1981 | 9,669 | 4.3% | 1,207 |
| 1982 | 9,514 | -1.6% | 1,186 |
| 1983 | 9,593 | 0.8% | 1,201 |
| 1984 | 9,770 | 1.9% | 1,212 |
| 1985 | 9,851 | 0.8% | 1,229 |
| 1986 | 9,884 | 0.3% | 1,231 |
| 1987 | 10,090 | 2.1% | 1,254 |
| 1988 | 10,400 | 3.1% | 1,293 |
| 1989 | 10,918 | 5.0% | 1,363 |
| 1990 | 11,101 | 1.7% | 1,390 |
| 1991 | 11,316 | 1.9% | 1,408 |
| 1992 | 11,470 | 1.4% | 1,435 |
| 1993 | 11,637 | 1.5% | 1,444 |
| 1994 | 11,984 | 3.0% | 1,505 |
| 1995 | 12,593 | 5.1% | 1,561 |
| 1996 | 13,051 | 3.6% | 1,636 |
| 1997 | 13,260 | 1.6% | 1,659 |
| 1998 | 13,378 | 0.9% | 1,668 |
| 1999 | 13,467 | 0.7% | 1,684 |
| 2000 | 13,874 | 3.0% | 1,744 |
| 2001 | 13,607 | -1.9% | 1,661 |
| 2002 | 12,695 | -6.7% | 1,587 |
| 2003 | 12,954 | 2.0% | 1,627 |
| 2004 | 13,247 | 2.3% | 1,663 |
| 2005 | 13,525 | 2.1% | 1,697 |
| 2006 | 13,835 | 2.3% | 1,729 |
| 2007 | 14,225 | 2.8% | 1,780 |
| 2008 | 14,370 | 1.0% | 1,798 |

**Company System Load**

**Projected Company System Sales and Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009 | 13,977 | –2.7% | 1,752 |
| 2010 | 14,322 | 2.5% | 1,797 |
| 2011 | 14,902 | 4.0% | 1,869 |
| 2012 | 15,244 | 2.3% | 1,906 |
| 2013 | 15,384 | 0.9% | 1,926 |
| 2014 | 15,557 | 1.1% | 1,947 |
| 2015 | 15,642 | 0.5% | 1,957 |
| 2016 | 15,728 | 0.5% | 1,967 |
| 2017 | 15,817 | 0.6% | 1,979 |
| 2018 | 15,907 | 0.6% | 1,991 |
| 2019 | 15,995 | 0.6% | 2,002 |
| 2020 | 16,105 | 0.7% | 2,013 |
| 2021 | 16,116 | 0.1% | 2,017 |
| 2022 | 16,189 | 0.5% | 2,026 |
| 2023 | 16,245 | 0.3% | 2,032 |
| 2024 | 16,192 | –0.3% | 2,024 |
| 2025 | 16,264 | 0.4% | 2,035 |
| 2026 | 16,318 | 0.3% | 2,041 |
| 2027 | 16,262 | –0.3% | 2,034 |
| 2028 | 16,250 | –0.1% | 2,030 |
| 2029 | 16,116 | –0.8% | 2,015 |

## Contract Off-System Load

### Historical Contract Off-System Sales and Load, 1970–2008

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 386 | | 44 |
| 1971 | 439 | 13.6% | 50 |
| 1972 | 448 | 2.0% | 51 |
| 1973 | 489 | 9.3% | 56 |
| 1974 | 501 | 2.3% | 57 |
| 1975 | 568 | 13.5% | 65 |
| 1976 | 613 | 7.9% | 70 |
| 1977 | 659 | 7.5% | 75 |
| 1978 | 684 | 3.7% | 78 |
| 1979 | 759 | 11.1% | 87 |
| 1980 | 762 | 0.3% | 87 |
| 1981 | 752 | -1.2% | 86 |
| 1982 | 736 | -2.2% | 84 |
| 1983 | 710 | -3.5% | 81 |
| 1984 | 747 | 5.2% | 85 |
| 1985 | 779 | 4.3% | 89 |
| 1986 | 670 | -13.9% | 77 |
| 1987 | 644 | -4.0% | 73 |
| 1988 | 675 | 4.9% | 77 |
| 1989 | 740 | 9.7% | 84 |
| 1990 | 968 | 30.8% | 111 |
| 1991 | 1,537 | 58.8% | 175 |
| 1992 | 1,348 | -12.3% | 154 |
| 1993 | 1,557 | 15.5% | 178 |
| 1994 | 1,811 | 16.3% | 207 |
| 1995 | 1,583 | -12.6% | 181 |
| 1996 | 1,285 | -18.8% | 146 |
| 1997 | 674 | -47.5% | 77 |
| 1998 | 716 | 6.2% | 82 |
| 1999 | 568 | -20.6% | 65 |
| 2000 | 587 | 3.3% | 67 |
| 2001 | 538 | -8.4% | 61 |
| 2002 | 454 | -15.7% | 52 |
| 2003 | 346 | -23.6% | 40 |
| 2004 | 19 | -94.4% | 2 |
| 2005 | 10 | -47.0% | 1 |
| 2006 | 0 | -100.0% | 0 |
| 2007 | 0 | 0.0% | 0 |
| 2008 | 0 | 0.0% | 0 |

**Contract Off-System Load**

**Projected Contract Off-System Sales and Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009–2029 | 0 | 0.0% | 0 |

## Total Company Load

### Historical Total Company Sales and Load, 1970–2008

*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 5,901 | | 732 |
| 1971 | 6,220 | 5.4% | 771 |
| 1972 | 6,788 | 9.1% | 841 |
| 1973 | 7,118 | 4.9% | 883 |
| 1974 | 7,569 | 6.3% | 941 |
| 1975 | 8,129 | 7.4% | 1,012 |
| 1976 | 8,573 | 5.5% | 1,066 |
| 1977 | 8,859 | 3.3% | 1,101 |
| 1978 | 9,384 | 5.9% | 1,173 |
| 1979 | 9,889 | 5.4% | 1,229 |
| 1980 | 10,028 | 1.4% | 1,242 |
| 1981 | 10,422 | 3.9% | 1,296 |
| 1982 | 10,250 | -1.6% | 1,273 |
| 1983 | 10,303 | 0.5% | 1,285 |
| 1984 | 10,517 | 2.1% | 1,300 |
| 1985 | 10,630 | 1.1% | 1,321 |
| 1986 | 10,554 | -0.7% | 1,310 |
| 1987 | 10,734 | 1.7% | 1,330 |
| 1988 | 11,075 | 3.2% | 1,373 |
| 1989 | 11,658 | 5.3% | 1,451 |
| 1990 | 12,069 | 3.5% | 1,504 |
| 1991 | 12,853 | 6.5% | 1,590 |
| 1992 | 12,818 | -0.3% | 1,594 |
| 1993 | 13,194 | 2.9% | 1,628 |
| 1994 | 13,795 | 4.6% | 1,719 |
| 1995 | 14,176 | 2.8% | 1,748 |
| 1996 | 14,336 | 1.1% | 1,787 |
| 1997 | 13,934 | -2.8% | 1,738 |
| 1998 | 14,094 | 1.1% | 1,753 |
| 1999 | 14,035 | -0.4% | 1,752 |
| 2000 | 14,461 | 3.0% | 1,813 |
| 2001 | 14,145 | -2.2% | 1,725 |
| 2002 | 13,148 | -7.0% | 1,641 |
| 2003 | 13,300 | 1.2% | 1,668 |
| 2004 | 13,267 | -0.3% | 1,665 |
| 2005 | 13,535 | 2.0% | 1,698 |
| 2006 | 13,835 | 2.2% | 1,729 |
| 2007 | 14,225 | 2.8% | 1,780 |
| 2008 | 14,370 | 1.0% | 1,798 |

**Total Company Load**

**Projected Total Company Sales and Load, 2009–2029**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2009 | 13,977 | –2.7% | 1,752 |
| 2010 | 14,322 | 2.5% | 1,797 |
| 2011 | 14,902 | 4.0% | 1,869 |
| 2012 | 15,244 | 2.3% | 1,906 |
| 2013 | 15,384 | 0.9% | 1,926 |
| 2014 | 15,557 | 1.1% | 1,947 |
| 2015 | 15,642 | 0.5% | 1,957 |
| 2016 | 15,728 | 0.5% | 1,967 |
| 2017 | 15,817 | 0.6% | 1,979 |
| 2018 | 15,907 | 0.6% | 1,991 |
| 2019 | 15,995 | 0.6% | 2,002 |
| 2020 | 16,105 | 0.7% | 2,013 |
| 2021 | 16,116 | 0.1% | 2,017 |
| 2022 | 16,189 | 0.5% | 2,026 |
| 2023 | 16,245 | 0.3% | 2,032 |
| 2024 | 16,192 | –0.3% | 2,024 |
| 2025 | 16,264 | 0.4% | 2,035 |
| 2026 | 16,318 | 0.3% | 2,041 |
| 2027 | 16,262 | –0.3% | 2,034 |
| 2028 | 16,250 | –0.1% | 2,030 |
| 2029 | 16,116 | –0.8% | 2,015 |

**Appendix A2. Demand-Side Management Program Impacts**

# Energy Efficiency Programs

## Residential Programs

*(MWh including losses)*

| Energy Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| 2010 | 2,058 | 1,871 | 2,075 | 2,007 | 2,049 | 1,852 | 1,913 | 1,913 | 1,999 | 2,067 | 1,999 | 2,067 | 23,871 |
| 2011 | 3,410 | 3,100 | 3,437 | 3,325 | 3,397 | 3,104 | 3,199 | 3,208 | 3,311 | 3,424 | 3,311 | 3,437 | 39,663 |
| 2012 | 4,544 | 4,114 | 4,563 | 4,394 | 4,525 | 4,146 | 4,281 | 4,289 | 4,375 | 4,563 | 4,394 | 4,525 | 52,712 |
| 2013 | 5,662 | 5,125 | 5,662 | 5,498 | 5,662 | 5,188 | 5,370 | 5,370 | 5,453 | 5,684 | 5,475 | 5,639 | 65,786 |
| 2014 | 6,781 | 6,138 | 6,781 | 6,584 | 6,781 | 6,244 | 6,454 | 6,446 | 6,558 | 6,807 | 6,532 | 6,781 | 78,886 |
| 2015 | 7,711 | 6,980 | 7,711 | 7,487 | 7,682 | 7,131 | 7,370 | 7,360 | 7,487 | 7,740 | 7,428 | 7,711 | 89,798 |
| 2016 | 8,613 | 7,828 | 8,682 | 8,397 | 8,578 | 8,023 | 8,268 | 8,293 | 8,363 | 8,647 | 8,363 | 8,682 | 100,736 |
| 2017 | 9,587 | 8,680 | 9,627 | 9,271 | 9,547 | 8,914 | 9,186 | 9,214 | 9,271 | 9,587 | 9,271 | 9,547 | 111,703 |
| 2018 | 10,525 | 9,530 | 10,570 | 10,179 | 10,481 | 9,797 | 10,116 | 10,137 | 10,135 | 10,570 | 10,179 | 10,481 | 122,699 |
| 2019 | 11,461 | 10,375 | 11,461 | 11,129 | 11,461 | 10,681 | 11,056 | 11,056 | 11,038 | 11,506 | 11,084 | 11,415 | 133,723 |
| 2020 | 12,396 | 11,220 | 12,396 | 12,035 | 12,349 | 11,592 | 11,980 | 11,963 | 12,035 | 12,443 | 11,942 | 12,396 | 144,748 |
| 2021 | 13,292 | 12,085 | 13,404 | 12,964 | 13,236 | 12,486 | 12,896 | 12,896 | 12,908 | 13,348 | 12,908 | 13,348 | 155,772 |
| 2022 | 14,225 | 12,929 | 14,339 | 13,869 | 14,168 | 13,388 | 13,795 | 13,838 | 13,812 | 14,282 | 13,812 | 14,339 | 166,796 |
| 2023 | 15,230 | 13,789 | 15,293 | 14,728 | 15,166 | 14,283 | 14,717 | 14,763 | 14,728 | 15,230 | 14,728 | 15,166 | 177,819 |
| 2024 | 16,163 | 14,632 | 16,163 | 15,695 | 16,163 | 15,147 | 15,680 | 15,680 | 15,566 | 16,227 | 15,631 | 16,098 | 188,843 |
| 2025 | 17,095 | 15,474 | 17,095 | 16,598 | 17,095 | 16,062 | 16,604 | 16,582 | 16,534 | 17,160 | 16,469 | 17,095 | 199,865 |
| 2026 | 18,035 | 16,325 | 18,035 | 17,511 | 17,967 | 16,959 | 17,528 | 17,502 | 17,511 | 18,104 | 17,374 | 18,035 | 210,887 |
| 2027 | 18,913 | 17,195 | 19,072 | 18,446 | 18,833 | 17,854 | 18,439 | 18,439 | 18,367 | 18,992 | 18,367 | 18,992 | 221,910 |
| 2028 | 19,856 | 18,059 | 20,031 | 19,286 | 19,856 | 18,758 | 19,328 | 19,389 | 19,286 | 19,943 | 19,286 | 19,856 | 232,931 |
| 2029 | 20,873 | 18,899 | 20,961 | 20,186 | 20,786 | 19,632 | 20,271 | 20,314 | 20,098 | 20,961 | 20,186 | 20,786 | 243,952 |

## Commercial Building Efficiency

*(MWh including losses)*

| Energy Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| 2010 | 3,898 | 3,481 | 3,843 | 3,722 | 3,926 | 3,884 | 4,014 | 4,014 | 3,750 | 3,870 | 3,750 | 3,870 | 46,024 |
| 2011 | 8,157 | 7,283 | 8,037 | 7,786 | 8,217 | 8,121 | 8,388 | 8,392 | 7,846 | 8,097 | 7,846 | 8,037 | 96,206 |
| 2012 | 12,679 | 11,405 | 12,588 | 12,285 | 12,770 | 12,725 | 13,147 | 13,152 | 12,376 | 12,588 | 12,285 | 12,770 | 150,769 |
| 2013 | 17,282 | 15,543 | 17,282 | 16,617 | 17,282 | 17,323 | 17,911 | 17,911 | 16,872 | 17,154 | 16,745 | 17,409 | 205,331 |
| 2014 | 21,893 | 19,688 | 21,893 | 21,047 | 21,893 | 21,937 | 22,671 | 22,661 | 21,213 | 21,726 | 21,380 | 21,893 | 259,894 |
| 2015 | 26,489 | 23,821 | 26,489 | 25,465 | 26,691 | 26,540 | 27,424 | 27,428 | 25,465 | 26,287 | 25,869 | 26,489 | 314,457 |
| 2016 | 31,288 | 27,934 | 30,829 | 29,864 | 31,518 | 31,151 | 32,173 | 32,191 | 30,093 | 31,058 | 30,093 | 30,829 | 369,020 |
| 2017 | 35,621 | 32,042 | 35,366 | 34,514 | 35,877 | 35,757 | 36,930 | 36,950 | 34,514 | 35,621 | 34,514 | 35,877 | 423,583 |
| 2018 | 40,210 | 36,170 | 39,921 | 38,959 | 40,499 | 40,355 | 41,695 | 41,710 | 39,248 | 39,921 | 38,959 | 40,499 | 478,145 |
| 2019 | 44,835 | 40,325 | 44,835 | 43,111 | 44,835 | 44,944 | 46,469 | 46,469 | 43,774 | 44,503 | 43,442 | 45,167 | 532,708 |
| 2020 | 49,470 | 44,488 | 49,470 | 47,558 | 49,846 | 49,565 | 51,216 | 51,224 | 47,558 | 49,093 | 48,311 | 49,470 | 587,271 |
| 2021 | 54,363 | 48,552 | 53,588 | 51,909 | 54,750 | 54,170 | 55,979 | 55,979 | 52,297 | 53,975 | 52,297 | 53,975 | 641,834 |
| 2022 | 59,045 | 52,716 | 58,178 | 56,357 | 59,479 | 58,786 | 60,715 | 60,749 | 56,791 | 58,612 | 56,791 | 58,178 | 696,397 |
| 2023 | 63,152 | 56,807 | 62,699 | 61,188 | 63,606 | 63,392 | 65,472 | 65,508 | 61,188 | 63,152 | 61,188 | 63,606 | 750,959 |
| 2024 | 67,796 | 60,976 | 67,796 | 65,189 | 67,796 | 67,961 | 70,267 | 70,267 | 66,191 | 67,295 | 65,690 | 68,297 | 805,522 |
| 2025 | 72,451 | 65,155 | 72,451 | 69,651 | 72,451 | 72,597 | 75,027 | 74,994 | 70,203 | 71,900 | 70,754 | 72,451 | 860,085 |
| 2026 | 77,047 | 69,288 | 77,047 | 74,070 | 77,634 | 77,195 | 79,767 | 79,779 | 74,070 | 76,461 | 75,243 | 77,047 | 914,648 |
| 2027 | 82,091 | 73,316 | 80,921 | 78,386 | 82,677 | 81,800 | 84,532 | 84,532 | 78,971 | 81,506 | 78,971 | 81,506 | 969,211 |
| 2028 | 86,628 | 77,394 | 85,430 | 83,350 | 86,628 | 86,422 | 89,258 | 89,307 | 83,350 | 86,029 | 83,350 | 86,628 | 1,023,773 |
| 2029 | 90,683 | 81,571 | 90,032 | 87,863 | 91,334 | 91,010 | 94,032 | 94,066 | 88,514 | 90,032 | 87,863 | 91,334 | 1,078,336 |

**Industrial Program**
*(MWh including losses)*

| Energy Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| 2010 | 3,663 | 3,272 | 3,611 | 3,498 | 3,689 | 3,650 | 3,772 | 3,772 | 3,524 | 3,637 | 3,524 | 3,637 | 43,251 |
| 2011 | 7,240 | 6,464 | 7,134 | 6,911 | 7,293 | 7,208 | 7,445 | 7,449 | 6,964 | 7,187 | 6,964 | 7,134 | 85,393 |
| 2012 | 10,445 | 9,396 | 10,370 | 10,120 | 10,520 | 10,483 | 10,831 | 10,835 | 10,195 | 10,370 | 10,120 | 10,520 | 124,208 |
| 2013 | 13,721 | 12,341 | 13,721 | 13,193 | 13,721 | 13,754 | 14,221 | 14,221 | 13,396 | 13,619 | 13,294 | 13,822 | 163,023 |
| 2014 | 17,002 | 15,290 | 17,002 | 16,345 | 17,002 | 17,037 | 17,607 | 17,599 | 16,475 | 16,873 | 16,604 | 17,002 | 201,838 |
| 2015 | 20,272 | 18,230 | 20,272 | 19,489 | 20,426 | 20,311 | 20,987 | 20,991 | 19,489 | 20,118 | 19,797 | 20,272 | 240,653 |
| 2016 | 23,695 | 21,155 | 23,347 | 22,617 | 23,869 | 23,591 | 24,365 | 24,379 | 22,790 | 23,521 | 22,790 | 23,347 | 279,468 |
| 2017 | 26,766 | 24,077 | 26,574 | 25,934 | 26,958 | 26,868 | 27,750 | 27,765 | 25,934 | 26,766 | 25,934 | 26,958 | 318,283 |
| 2018 | 30,030 | 27,013 | 29,815 | 29,096 | 30,246 | 30,139 | 31,139 | 31,151 | 29,312 | 29,815 | 29,096 | 30,246 | 357,098 |
| 2019 | 33,322 | 29,970 | 33,322 | 32,040 | 33,322 | 33,403 | 34,536 | 34,536 | 32,533 | 33,075 | 32,287 | 33,568 | 395,913 |
| 2020 | 36,620 | 32,932 | 36,620 | 35,205 | 36,899 | 36,691 | 37,913 | 37,918 | 35,205 | 36,341 | 35,763 | 36,620 | 434,728 |
| 2021 | 40,109 | 35,821 | 39,537 | 38,298 | 40,395 | 39,967 | 41,301 | 41,301 | 38,584 | 39,823 | 38,584 | 39,823 | 473,543 |
| 2022 | 43,441 | 38,784 | 42,803 | 41,464 | 43,760 | 43,251 | 44,670 | 44,694 | 41,783 | 43,122 | 41,783 | 42,803 | 512,358 |
| 2023 | 46,351 | 41,694 | 46,018 | 44,910 | 46,684 | 46,527 | 48,054 | 48,080 | 44,910 | 46,351 | 44,910 | 46,684 | 551,173 |
| 2024 | 49,656 | 44,661 | 49,656 | 47,746 | 49,656 | 49,776 | 51,466 | 51,466 | 48,481 | 49,289 | 48,113 | 50,023 | 589,988 |
| 2025 | 52,968 | 47,634 | 52,968 | 50,922 | 52,968 | 53,075 | 54,852 | 54,828 | 51,325 | 52,565 | 51,728 | 52,968 | 628,803 |
| 2026 | 56,238 | 50,575 | 56,238 | 54,065 | 56,666 | 56,346 | 58,223 | 58,232 | 54,065 | 55,810 | 54,921 | 56,238 | 667,618 |
| 2027 | 59,834 | 53,439 | 58,981 | 57,134 | 60,261 | 59,622 | 61,613 | 61,613 | 57,560 | 59,408 | 57,560 | 59,408 | 706,433 |
| 2028 | 63,060 | 56,338 | 62,188 | 60,674 | 63,060 | 62,910 | 64,974 | 65,010 | 60,674 | 62,624 | 60,674 | 63,060 | 745,248 |
| 2029 | 65,936 | 59,311 | 65,463 | 63,886 | 66,410 | 66,174 | 68,371 | 68,396 | 64,359 | 65,463 | 63,886 | 66,410 | 784,063 |

**Irrigation Efficiency Program**
*(MWh including losses)*

| Energy Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| 2010 | 0 | 0 | 0 | 499 | 1,831 | 2,486 | 2,659 | 2,244 | 1,146 | 225 | 0 | 0 | 11,090 |
| 2011 | 0 | 0 | 0 | 998 | 3,662 | 4,973 | 5,319 | 4,487 | 2,291 | 450 | 0 | 0 | 22,180 |
| 2012 | 0 | 0 | 0 | 1,447 | 5,310 | 7,210 | 7,712 | 6,506 | 3,322 | 653 | 0 | 0 | 32,161 |
| 2013 | 0 | 0 | 0 | 1,846 | 6,775 | 9,200 | 9,840 | 8,301 | 4,239 | 833 | 0 | 0 | 41,033 |
| 2014 | 0 | 0 | 0 | 2,196 | 8,056 | 10,940 | 11,701 | 9,871 | 5,041 | 991 | 0 | 0 | 48,796 |
| 2015 | 0 | 0 | 0 | 2,455 | 9,008 | 12,233 | 13,084 | 11,038 | 5,636 | 1,108 | 0 | 0 | 54,563 |
| 2016 | 0 | 0 | 0 | 2,715 | 9,960 | 13,526 | 14,467 | 12,205 | 6,232 | 1,225 | 0 | 0 | 60,330 |
| 2017 | 0 | 0 | 0 | 2,974 | 10,913 | 14,819 | 15,850 | 13,371 | 6,828 | 1,342 | 0 | 0 | 66,096 |
| 2018 | 0 | 0 | 0 | 3,234 | 11,865 | 16,112 | 17,233 | 14,538 | 7,423 | 1,459 | 0 | 0 | 71,863 |
| 2019 | 0 | 0 | 0 | 3,493 | 12,817 | 17,405 | 18,616 | 15,705 | 8,019 | 1,576 | 0 | 0 | 77,630 |
| 2020 | 0 | 0 | 0 | 3,753 | 13,769 | 18,698 | 19,999 | 16,871 | 8,615 | 1,693 | 0 | 0 | 83,397 |
| 2021 | 0 | 0 | 0 | 4,012 | 14,721 | 19,990 | 21,381 | 18,038 | 9,211 | 1,810 | 0 | 0 | 89,164 |
| 2022 | 0 | 0 | 0 | 4,272 | 15,673 | 21,283 | 22,764 | 19,204 | 9,806 | 1,927 | 0 | 0 | 94,930 |
| 2023 | 0 | 0 | 0 | 4,531 | 16,625 | 22,576 | 24,147 | 20,371 | 10,402 | 2,044 | 0 | 0 | 100,697 |
| 2024 | 0 | 0 | 0 | 4,791 | 17,577 | 23,869 | 25,530 | 21,538 | 10,998 | 2,161 | 0 | 0 | 106,464 |
| 2025 | 0 | 0 | 0 | 5,050 | 18,529 | 25,162 | 26,913 | 22,704 | 11,593 | 2,278 | 0 | 0 | 112,231 |
| 2026 | 0 | 0 | 0 | 5,310 | 19,481 | 26,455 | 28,296 | 23,871 | 12,189 | 2,395 | 0 | 0 | 117,998 |
| 2027 | 0 | 0 | 0 | 5,569 | 20,434 | 27,748 | 29,679 | 25,038 | 12,785 | 2,512 | 0 | 0 | 123,764 |
| 2028 | 0 | 0 | 0 | 5,829 | 21,386 | 29,041 | 31,062 | 26,204 | 13,381 | 2,629 | 0 | 0 | 129,531 |
| 2029 | 0 | 0 | 0 | 6,088 | 22,338 | 30,334 | 32,444 | 27,371 | 13,976 | 2,747 | 0 | 0 | 135,298 |

**Energy Efficiency Programs—Total**
*(MWh including losses)*

| Energy Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| 2010 | 9,620 | 8,624 | 9,529 | 9,727 | 11,496 | 11,873 | 12,359 | 11,943 | 10,418 | 9,799 | 9,273 | 9,574 | 124,236 |
| 2011 | 18,807 | 16,846 | 18,609 | 19,019 | 22,569 | 23,406 | 24,351 | 23,536 | 20,412 | 19,158 | 18,121 | 18,609 | 243,442 |
| 2012 | 27,668 | 24,915 | 27,521 | 28,246 | 33,125 | 34,564 | 35,972 | 34,782 | 30,268 | 28,174 | 26,799 | 27,815 | 359,849 |
| 2013 | 36,664 | 33,009 | 36,664 | 37,154 | 43,438 | 45,465 | 47,342 | 45,803 | 39,960 | 37,290 | 35,514 | 36,870 | 475,173 |
| 2014 | 45,676 | 41,116 | 45,676 | 46,171 | 53,732 | 56,157 | 58,434 | 56,578 | 49,287 | 46,396 | 44,516 | 45,676 | 589,415 |
| 2015 | 54,472 | 49,032 | 54,472 | 54,896 | 63,807 | 66,215 | 68,866 | 66,817 | 58,077 | 55,253 | 53,094 | 54,472 | 699,471 |
| 2016 | 63,596 | 56,917 | 62,857 | 63,592 | 73,925 | 76,291 | 79,274 | 77,067 | 67,479 | 64,451 | 61,247 | 62,857 | 809,553 |
| 2017 | 71,975 | 64,799 | 71,567 | 72,693 | 83,295 | 86,357 | 89,715 | 87,300 | 76,546 | 73,316 | 69,719 | 72,382 | 919,665 |
| 2018 | 80,766 | 72,712 | 80,305 | 81,468 | 93,090 | 96,402 | 100,183 | 97,535 | 86,118 | 81,764 | 78,234 | 81,226 | 1,029,805 |
| 2019 | 89,617 | 80,670 | 89,617 | 89,773 | 102,434 | 106,432 | 110,677 | 107,766 | 95,364 | 90,661 | 86,812 | 90,150 | 1,139,974 |
| 2020 | 98,486 | 88,641 | 98,486 | 98,552 | 112,863 | 116,545 | 121,108 | 117,976 | 103,414 | 99,571 | 96,016 | 98,486 | 1,250,144 |
| 2021 | 107,764 | 96,458 | 106,529 | 107,184 | 123,102 | 126,614 | 131,557 | 128,213 | 113,000 | 108,956 | 103,789 | 107,146 | 1,360,313 |
| 2022 | 116,711 | 104,429 | 115,320 | 115,962 | 133,080 | 136,708 | 141,945 | 138,485 | 122,192 | 117,943 | 112,385 | 115,320 | 1,470,481 |
| 2023 | 124,733 | 112,289 | 124,011 | 125,357 | 142,081 | 146,778 | 152,391 | 148,723 | 131,228 | 126,777 | 120,826 | 125,455 | 1,580,649 |
| 2024 | 133,615 | 120,269 | 133,615 | 133,421 | 151,192 | 156,753 | 162,943 | 158,950 | 141,236 | 134,972 | 129,434 | 134,419 | 1,690,817 |
| 2025 | 142,515 | 128,264 | 142,515 | 142,222 | 161,044 | 166,897 | 173,396 | 169,108 | 149,655 | 143,903 | 138,951 | 142,515 | 1,800,984 |
| 2026 | 151,321 | 136,188 | 151,321 | 150,956 | 171,748 | 176,956 | 183,814 | 179,383 | 157,835 | 152,770 | 147,538 | 151,321 | 1,911,151 |
| 2027 | 160,839 | 143,950 | 158,974 | 159,536 | 182,204 | 187,025 | 194,262 | 189,621 | 167,683 | 162,419 | 154,898 | 159,906 | 2,021,318 |
| 2028 | 169,544 | 151,791 | 167,648 | 169,139 | 190,929 | 197,130 | 204,622 | 199,909 | 176,691 | 171,226 | 163,310 | 169,544 | 2,131,484 |
| 2029 | 177,493 | 159,781 | 176,456 | 178,023 | 200,868 | 207,150 | 215,119 | 210,147 | 186,948 | 179,202 | 171,935 | 178,530 | 2,241,649 |

**Residential Programs**
*(MW including losses)*

| Peak Demand Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Max** |
| 2010 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 2011 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 |
| 2012 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 2013 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 |
| 2014 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| 2015 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| 2016 | 12 | 11 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 12 | 12 | 12 |
| 2017 | 13 | 13 | 13 | 13 | 13 | 12 | 12 | 12 | 13 | 13 | 13 | 13 | 13 |
| 2018 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| 2019 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| 2020 | 17 | 16 | 17 | 17 | 17 | 16 | 16 | 16 | 17 | 17 | 17 | 17 | 17 |
| 2021 | 18 | 18 | 18 | 18 | 18 | 17 | 17 | 17 | 18 | 18 | 18 | 18 | 18 |
| 2022 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| 2023 | 20 | 21 | 21 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 21 |
| 2024 | 22 | 21 | 22 | 22 | 22 | 21 | 21 | 21 | 22 | 22 | 22 | 22 | 22 |
| 2025 | 23 | 23 | 23 | 23 | 23 | 22 | 22 | 22 | 23 | 23 | 23 | 23 | 23 |
| 2026 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| 2027 | 25 | 26 | 26 | 26 | 25 | 25 | 25 | 25 | 26 | 26 | 25 | 26 | 26 |
| 2028 | 27 | 26 | 27 | 27 | 27 | 26 | 26 | 26 | 27 | 27 | 27 | 27 | 27 |
| 2029 | 28 | 28 | 28 | 28 | 28 | 27 | 27 | 27 | 28 | 28 | 28 | 28 | 28 |

**Commercial Programs**
*(MW including losses)*

| Peak Demand Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Max** |
| 2010 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2011 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| 2012 | 17 | 16 | 17 | 17 | 17 | 18 | 18 | 18 | 17 | 17 | 17 | 17 | 18 |
| 2013 | 23 | 23 | 23 | 23 | 23 | 24 | 24 | 24 | 23 | 23 | 23 | 23 | 24 |
| 2014 | 29 | 29 | 29 | 29 | 29 | 30 | 30 | 30 | 29 | 29 | 30 | 29 | 30 |
| 2015 | 36 | 35 | 36 | 35 | 36 | 37 | 37 | 37 | 35 | 35 | 36 | 36 | 37 |
| 2016 | 42 | 40 | 41 | 41 | 42 | 43 | 43 | 43 | 42 | 42 | 42 | 41 | 43 |
| 2017 | 48 | 48 | 48 | 48 | 48 | 50 | 50 | 50 | 48 | 48 | 48 | 48 | 50 |
| 2018 | 54 | 54 | 54 | 54 | 54 | 56 | 56 | 56 | 55 | 54 | 54 | 54 | 56 |
| 2019 | 60 | 60 | 60 | 60 | 60 | 62 | 62 | 62 | 61 | 60 | 60 | 61 | 62 |
| 2020 | 66 | 64 | 67 | 66 | 67 | 69 | 69 | 69 | 66 | 66 | 67 | 66 | 69 |
| 2021 | 73 | 72 | 72 | 72 | 74 | 75 | 75 | 75 | 73 | 73 | 73 | 73 | 75 |
| 2022 | 79 | 78 | 78 | 78 | 80 | 82 | 82 | 82 | 79 | 79 | 79 | 78 | 82 |
| 2023 | 85 | 85 | 84 | 85 | 85 | 88 | 88 | 88 | 85 | 85 | 85 | 85 | 88 |
| 2024 | 91 | 88 | 91 | 91 | 91 | 94 | 94 | 94 | 92 | 90 | 91 | 92 | 94 |
| 2025 | 97 | 97 | 98 | 97 | 97 | 101 | 101 | 101 | 98 | 97 | 98 | 97 | 101 |
| 2026 | 104 | 103 | 104 | 103 | 104 | 107 | 107 | 107 | 103 | 103 | 104 | 104 | 107 |
| 2027 | 110 | 109 | 109 | 109 | 111 | 114 | 114 | 114 | 110 | 110 | 110 | 110 | 114 |
| 2028 | 116 | 111 | 115 | 116 | 116 | 120 | 120 | 120 | 116 | 116 | 116 | 116 | 120 |
| 2029 | 122 | 121 | 121 | 122 | 123 | 126 | 126 | 126 | 123 | 121 | 122 | 123 | 126 |

**Industrial Program**
*(MW including losses)*

| Peak Demand Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Max** |
| 2010 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2011 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| 2012 | 14 | 14 | 14 | 14 | 14 | 15 | 15 | 15 | 14 | 14 | 14 | 14 | 15 |
| 2013 | 18 | 18 | 18 | 18 | 18 | 19 | 19 | 19 | 19 | 18 | 18 | 19 | 19 |
| 2014 | 23 | 23 | 23 | 23 | 23 | 24 | 24 | 24 | 23 | 23 | 23 | 23 | 24 |
| 2015 | 27 | 27 | 27 | 27 | 27 | 28 | 28 | 28 | 27 | 27 | 27 | 27 | 28 |
| 2016 | 32 | 30 | 31 | 31 | 32 | 33 | 33 | 33 | 32 | 32 | 32 | 31 | 33 |
| 2017 | 36 | 36 | 36 | 36 | 36 | 37 | 37 | 37 | 36 | 36 | 36 | 36 | 37 |
| 2018 | 40 | 40 | 40 | 40 | 41 | 42 | 42 | 42 | 41 | 40 | 40 | 41 | 42 |
| 2019 | 45 | 45 | 45 | 45 | 45 | 46 | 46 | 46 | 45 | 44 | 45 | 45 | 46 |
| 2020 | 49 | 47 | 49 | 49 | 50 | 51 | 51 | 51 | 49 | 49 | 50 | 49 | 51 |
| 2021 | 54 | 53 | 53 | 53 | 54 | 56 | 56 | 56 | 54 | 54 | 54 | 54 | 56 |
| 2022 | 58 | 58 | 58 | 58 | 59 | 60 | 60 | 60 | 58 | 58 | 58 | 58 | 60 |
| 2023 | 62 | 62 | 62 | 62 | 63 | 65 | 65 | 65 | 62 | 62 | 62 | 63 | 65 |
| 2024 | 67 | 64 | 67 | 66 | 67 | 69 | 69 | 69 | 67 | 66 | 67 | 67 | 69 |
| 2025 | 71 | 71 | 71 | 71 | 71 | 74 | 74 | 74 | 71 | 71 | 72 | 71 | 74 |
| 2026 | 76 | 75 | 76 | 75 | 76 | 78 | 78 | 78 | 75 | 75 | 76 | 76 | 78 |
| 2027 | 80 | 80 | 79 | 79 | 81 | 83 | 83 | 83 | 80 | 80 | 80 | 80 | 83 |
| 2028 | 85 | 81 | 84 | 84 | 85 | 87 | 87 | 87 | 84 | 84 | 84 | 85 | 87 |
| 2029 | 89 | 88 | 88 | 89 | 89 | 92 | 92 | 92 | 89 | 88 | 89 | 89 | 92 |

**Irrigation Efficiency Program**
*(MW including losses)*

| Peak Demand Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Max |
| 2010 | 0 | 0 | 0 | 1 | 2 | 3 | 4 | 3 | 2 | 0 | 0 | 0 | 4 |
| 2011 | 0 | 0 | 0 | 1 | 5 | 7 | 7 | 6 | 3 | 1 | 0 | 0 | 7 |
| 2012 | 0 | 0 | 0 | 2 | 7 | 10 | 10 | 9 | 5 | 1 | 0 | 0 | 10 |
| 2013 | 0 | 0 | 0 | 3 | 9 | 13 | 13 | 11 | 6 | 1 | 0 | 0 | 13 |
| 2014 | 0 | 0 | 0 | 3 | 11 | 15 | 16 | 13 | 7 | 1 | 0 | 0 | 16 |
| 2015 | 0 | 0 | 0 | 3 | 12 | 17 | 18 | 15 | 8 | 1 | 0 | 0 | 18 |
| 2016 | 0 | 0 | 0 | 4 | 13 | 19 | 19 | 16 | 9 | 2 | 0 | 0 | 19 |
| 2017 | 0 | 0 | 0 | 4 | 15 | 21 | 21 | 18 | 9 | 2 | 0 | 0 | 21 |
| 2018 | 0 | 0 | 0 | 4 | 16 | 22 | 23 | 20 | 10 | 2 | 0 | 0 | 23 |
| 2019 | 0 | 0 | 0 | 5 | 17 | 24 | 25 | 21 | 11 | 2 | 0 | 0 | 25 |
| 2020 | 0 | 0 | 0 | 5 | 19 | 26 | 27 | 23 | 12 | 2 | 0 | 0 | 27 |
| 2021 | 0 | 0 | 0 | 6 | 20 | 28 | 29 | 24 | 13 | 2 | 0 | 0 | 29 |
| 2022 | 0 | 0 | 0 | 6 | 21 | 30 | 31 | 26 | 14 | 3 | 0 | 0 | 31 |
| 2023 | 0 | 0 | 0 | 6 | 22 | 31 | 32 | 27 | 14 | 3 | 0 | 0 | 32 |
| 2024 | 0 | 0 | 0 | 7 | 24 | 33 | 34 | 29 | 15 | 3 | 0 | 0 | 34 |
| 2025 | 0 | 0 | 0 | 7 | 25 | 35 | 36 | 31 | 16 | 3 | 0 | 0 | 36 |
| 2026 | 0 | 0 | 0 | 7 | 26 | 37 | 38 | 32 | 17 | 3 | 0 | 0 | 38 |
| 2027 | 0 | 0 | 0 | 8 | 27 | 39 | 40 | 34 | 18 | 3 | 0 | 0 | 40 |
| 2028 | 0 | 0 | 0 | 8 | 29 | 40 | 42 | 35 | 19 | 4 | 0 | 0 | 42 |
| 2029 | 0 | 0 | 0 | 8 | 30 | 42 | 44 | 37 | 19 | 4 | 0 | 0 | 44 |

**Energy Efficiency Programs—Total**
*(MW including losses)*

| Peak Demand Reductions | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Max |
| 2010 | 13 | 13 | 13 | 14 | 15 | 16 | 17 | 16 | 14 | 13 | 13 | 13 | 17 |
| 2011 | 25 | 25 | 25 | 26 | 30 | 33 | 33 | 32 | 28 | 26 | 25 | 25 | 33 |
| 2012 | 37 | 36 | 37 | 39 | 45 | 48 | 48 | 47 | 42 | 38 | 37 | 37 | 48 |
| 2013 | 49 | 49 | 49 | 52 | 58 | 63 | 64 | 62 | 56 | 50 | 49 | 50 | 64 |
| 2014 | 61 | 61 | 61 | 64 | 72 | 78 | 79 | 76 | 68 | 62 | 62 | 61 | 79 |
| 2015 | 73 | 73 | 73 | 76 | 86 | 92 | 93 | 90 | 81 | 74 | 74 | 73 | 93 |
| 2016 | 85 | 82 | 85 | 88 | 99 | 106 | 107 | 104 | 94 | 87 | 85 | 84 | 107 |
| 2017 | 97 | 96 | 96 | 101 | 112 | 120 | 121 | 117 | 106 | 99 | 97 | 97 | 121 |
| 2018 | 109 | 108 | 108 | 113 | 125 | 134 | 135 | 131 | 120 | 110 | 109 | 109 | 135 |
| 2019 | 120 | 120 | 121 | 125 | 138 | 148 | 149 | 145 | 132 | 122 | 120 | 121 | 149 |
| 2020 | 132 | 127 | 133 | 137 | 152 | 162 | 163 | 159 | 144 | 134 | 133 | 132 | 163 |
| 2021 | 145 | 144 | 143 | 149 | 165 | 176 | 177 | 172 | 157 | 146 | 144 | 144 | 177 |
| 2022 | 157 | 155 | 155 | 161 | 179 | 190 | 191 | 186 | 170 | 159 | 156 | 155 | 191 |
| 2023 | 168 | 167 | 167 | 174 | 191 | 204 | 205 | 200 | 182 | 170 | 168 | 169 | 205 |
| 2024 | 180 | 173 | 180 | 185 | 203 | 218 | 219 | 214 | 196 | 181 | 180 | 181 | 219 |
| 2025 | 192 | 191 | 192 | 198 | 216 | 232 | 233 | 227 | 208 | 193 | 193 | 192 | 233 |
| 2026 | 203 | 203 | 204 | 210 | 231 | 246 | 247 | 241 | 219 | 205 | 205 | 203 | 247 |
| 2027 | 216 | 214 | 214 | 222 | 245 | 260 | 261 | 255 | 233 | 218 | 215 | 215 | 261 |
| 2028 | 228 | 218 | 226 | 235 | 257 | 274 | 275 | 269 | 245 | 230 | 227 | 228 | 275 |
| 2029 | 239 | 238 | 237 | 247 | 270 | 288 | 289 | 282 | 260 | 241 | 238 | 240 | 289 |

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# Demand-Side Management 2008 Annual Report

March 13, 2009

IDAHO POWER®
An IDACORP Company

# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... iii
List of Figures ..... iii
Glossary of Acronyms ..... iv
Executive Summary ..... 1
Introduction ..... 3
DSM Program Portfolio Structure ..... 5
Program Performance ..... 6
Regulatory Initiatives ..... 8
DSM Expenditures and Funding ..... 8
Future Plans ..... 9
Customer Satisfaction ..... 9
Cost-Effectiveness ..... 11
DSM Annual Report Structure ..... 12
Residential Sector Overview ..... 13
Description ..... 13
Programs ..... 13
A/C Cool Credit ..... 15
Attic Insulation Pilot ..... 18
Energy Efficient Lighting ..... 19
Energy House Calls ..... 21
ENERGY STAR® Homes Northwest ..... 23
Heating & Cooling Efficiency Program ..... 26
Home Products Program ..... 29
Home Weatherization Pilot ..... 31
Oregon Residential Weatherization ..... 33
Rebate Advantage ..... 35
Weatherization Assistance for Qualified Customers ..... 37
Commercial/Industrial Sector Overview ..... 39
Description ..... 39
Programs ..... 39
Building Efficiency ..... 41

Custom Efficiency ....43
Easy Upgrades ....46
Holiday Lighting Program ....49
Oregon Commercial Audits ....51
Irrigation Sector Overview ....53
Description ....53
Programs ....53
Irrigation Peak Rewards ....54
Irrigation Efficiency Rewards ....56
Market Transformation ....59
Northwest Energy Efficiency Alliance (NEEA) ....59
NEEA Activities ....59
NEEA Funding ....61
Energy Efficiency Advisory Group (EEAG) ....63
EEAG Program Recommendations ....63
Residential Programs ....63
Commercial and Industrial Programs ....65
Irrigation Programs ....67
Additional Topics Covered ....67
Other Programs and Activities ....69
Residential Energy Efficiency Education Initiative ....69
Commercial Education Initiative ....70
Local Energy Efficiency Funds (LEEF) ....70
Regulatory Initiatives ....71
Fixed-Cost Adjustment Pilot ....71
Performance-Based DSM Incentive Pilot ....71
Enhanced Commitment ....73
Building Code Improvement Activity ....74
Pursuit of Appliance Code Standards ....74
Continued Expansion of DSM Programs Beyond Peak-Shaving/Load-Shifting Programs ....74
Third-Party Verification ....75
Promotion of Energy Efficiency through Electricity Rate Design ....76
Idaho Power's Internal Energy Efficiency Commitment ....76
Appendices ....79

Appendix 1. Idaho Rider, Oregon Rider, BPA, and NEEA Funding Balances ..... 80
Appendix 2. 2008 DSM Expenses by Funding Source (Dollars) ..... 81
Appendix 3. 2008 DSM Program Activity ..... 82
Appendix 4. DSM Expense and Performance ..... 85

## LIST OF TABLES

**Table 1.** 2008 DSM Programs, Sectors, and Operational Type ..... 6
**Table 2.** 2008 Program Sector Summary and Energy Usage ..... 8
**Table 3.** 2008 Funding Source and Energy Impact ..... 9
**Table 4.** 2008 Residential Program Summary ..... 13
**Table 5.** Energy Efficient Lighting Energy Savings ..... 20
**Table 6.** 2008 Commercial/Industrial Program Summary ..... 39
**Table 7.** Custom Efficiency Annual Energy Savings by Measure ..... 44
**Table 8.** 2008 Irrigation Program Summary ..... 53

## LIST OF FIGURES

**Figure 1.** DSM Incremental Expense History 2002–2008 (Millions of dollars) ..... 4
**Figure 2.** DSM Incremental Energy Savings 2002–2008 (Gigawatt-hour [GWh]) ..... 4
**Figure 3.** Percent of Customers Whose Needs are Met or Exceeded by Idaho Power's Conservation Efforts ..... 10

# GLOSSARY OF ACRONYMS

aMW—Average Megawatt

akW—Average Kilowatt

A/C—Air Conditioning

ACEEE—American Council for an Energy-Efficient Economy

ASHRAE—American Society of Heating, Refrigerating, and Air-Conditioning Engineers

AMI—Advanced Metering Infrastructure

B/C—Benefit Cost

BCA—Building Contractors Association

BEEP—Building Owners and Managers Association's Energy Efficiency Program

BETC—Business Energy Tax Credit

BLC—Basic Load Capacity

BOC—Boise Operations Center

BOMA—Building Owners and Managers Association

BPA—Bonneville Power Administration

BSU—Boise State University

CAC—Central Air Conditioning/Conditioners

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCOA—Canyon County Organization on Aging and Community Services

CCNO—Community Connection of Northeast Oregon, Inc.

CEE—Consortium for Energy Efficiency Inc.

CFL—Compact Fluorescent Lighting

CHQ—Corporate Headquarters (Idaho Power)

CR—Customer Representative

CSR—Customer Service Representatives

DEI—Distribution Efficiency Initiative

DOE—U.S. Department of Energy

DSM—Demand Side Management

EEAG—Energy Efficiency Advisory Group

El-Ada—El-Ada Community Action Partnership

EEBA—Energy and Environmental Building Association

EICAP—Eastern Idaho Community Action Partnership

ETO—Energy Trust of Oregon

FCA—Fixed-Cost Adjustment

GWh—Gigawatt-hour

H&CE—Heating and Cooling Efficiency Program

HCSCS—Harney County Senior and Community Services Center

HMCAA—Harney–Malheur Community Action Agency

HVAC—Heating, Ventilation, and Air Conditioning

HVR—Home Voltage Regulator

IDL—Integrated Design Lab

IEA—Industrial Efficiency Alliance

IECC—International Energy Conservation Code

IESBP—Idaho ENERGY STAR® Builders Partnership

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

kvar—Kilovolt ampere reactive

kW—Kilowatt

kWh—Kilowatt-hour

LDL—Lighting Design Lab

LED—Light-Emitting Diode

LEED—Leadership in Energy and Environmental Design

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Programs

MCOA—Malheur Council on Aging

MHAFB—Mountain Home Air Force Base

MW—Megawatt

MWh—Megawatt-hour

NEEM—Northwest Energy Efficient Manufactured Housing Program

NEEA—Northwest Energy Efficiency Alliance

NWPCC—Northwest Power and Conservation Council

OER—Office of Energy Resources (formerly the Idaho Energy Division)

ODOE—Oregon Department of Energy

OPUC—Public Utility Commission of Oregon

PECI—Portland Energy Conservation, Inc.

PLC—Power Line Carrier

PTCS—Performance Tested Comfort System

RFP—Request for Proposal

RTF—Regional Technical Forum

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

SCCAP—South Central Community Action Partnership

SEER—Seasonal Energy Efficiency Ratio

SEICAA—Southeastern Idaho Community Action Agency

SIR—Savings Investment Ratio

TAG—Technical Assessment Guide

TRC—Total Resource Cost

UC—Utility Cost

USB—Utility Sounding Board

WAQC—Weatherization Assistance for Qualified Customers

# EXECUTIVE SUMMARY

Idaho Power's *Demand-Side Management (DSM) 2008 Annual Report* provides a review of its DSM activities and finances throughout 2008, expresses its future plans for DSM activities, and satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order No. 29419 and the Public Utility Commission of Oregon's (OPUC) Order No. 89–507.

Idaho Power considers energy efficiency and demand response to be an important and necessary part of a balanced approach to meeting the electricity needs of its customers. Energy efficiency is recognized by Idaho Power and its customers as providing economic, operational, and environmental benefits. Therefore, the pursuit of all cost-effective demand-side resources is a primary objective for Idaho Power. Idaho Power accomplishes this objective with input and consultation with its Energy Efficiency Advisory Group (EEAG).

Idaho Power achieves energy and demand savings through four types of programs, 1) Energy Efficiency, 2) Demand Response, 3) Market Transformation, and 4) Other Programs and Activities. Idaho Power's annual energy savings from 2002 through 2008 increased more than eight-fold. This increase was the result of customers' participation in Idaho Power's energy efficiency and demand response programs. In 2008, these efficiency efforts saved 140,156 megawatt-hours (MWh) of electricity, or 16 average megawatts (aMW), enough energy to serve about 11,000 average homes for one year. The 2008 energy savings was a 54% increase over the 91,145 MWh energy savings in 2007.

The demand reduction for Idaho Power's demand response programs increased by 20% from 48 MW in 2007 to 58 MW in 2008. By year-end 2008, participation in the A/C Cool Credit program increased by 72%. Total DSM expenses were slightly over $21 million in 2008, which is a 35% increase over 2007 expenditures of $15.7 million.

In 2008, Idaho Power's energy efficiency and demand response programs continue to increase in number and customer participation. Idaho Power offered 16 energy efficiency programs, two demand response programs, and added three new programs, the Home Products program, the Home Weatherization pilot, and the Attic Insulation pilot. Additional significant energy savings continue to be realized through market transformation partnership activities with the Northwest Energy Efficiency Alliance (NEEA).

Idaho Power was successful in providing customers with accurate and timely information to assist them in making wise energy choices and participating in energy efficiency programs. In 2008, the results of Idaho Power's quarterly customer satisfaction survey showed steady improvement over recent years, as the percent of customers who have a positive perception of Idaho Power's energy efficiency efforts has continued to rise.

The American Council for an Energy-Efficient Economy (ACEEE) annually publishes a scorecard that ranks individual states in terms of commitment to energy efficiency. In 2008, the ACEEE identified Idaho as the "most improved" state in the nation, having moved up 12 spots, compared to the 2007 scorecard. The following annual report provides detailed information on activities and programs resulting from Idaho Power's support of DSM initiatives.

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# INTRODUCTION

Idaho Power's *Demand-Side Management (DSM) 2008 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for the 2008 calendar year. These programs provide a wide range of opportunities for all customer classes to balance their energy needs and reduce their energy consumption.

Idaho Power considers energy efficiency to be an important and necessary part of a balanced approach to meeting the growing demand for electricity. Consistent with this view, energy efficiency is one of the cornerstones supporting Idaho Power's resource acquisition strategy. Energy efficiency is recognized by Idaho Power and its customers as providing economic, operational, and environmental benefits. Therefore, the pursuit of all cost-effective demand-side resources is a primary objective for Idaho Power.

This *DSM Annual Report* is produced to convey Idaho Power's DSM activities and finances throughout 2008, to express Idaho Power's future plans for DSM activities, and to conform to the IPUC Order No. 29419 and the OPUC Order No. 89–507.

During 2008, Idaho Power continued to expand the programs that began with the *2004 Integrated Resource Plan* (IRP). Idaho Power's 2006 IRP included the addition of three new DSM programs and the expansion of one program. In addition to the DSM programs identified in the IRP, Idaho Power continued to offer other energy efficiency programs that began prior to the 2004 IRP. Also in 2008, Idaho Power continued to use its field staff in building customer awareness of, and participation in, energy efficiency, demand response, and educational programs.

In 2008, the energy savings from Idaho Power's DSM activities increased by 54%, and the expenditures for DSM-related activities increased by 35%, compared to 2007. This increase in spending included increased participation in programs and the development of new programs that will result in future savings. DSM activities throughout 2008 were focused predominantly on increasing program participation, customer education, and the planning and implementation of new programs.

Idaho Power's two main objectives for DSM programs are to acquire all cost-effective demand-side resources in order to meet the electrical system's energy and demand needs and to provide all Idaho Power customers with programs and information to help them manage their energy usage. Idaho Power achieves these objectives through the development and implementation of programs with specific energy, economic, and customer satisfaction objectives. When possible, Idaho Power implements identical programs in its Idaho and Oregon service areas.

Figures 1 and 2 show the historical growth in expenditures and resource acquisition from 2002 to the present.

**Figure 1.** DSM Incremental Expense History 2002–2008 (Millions of dollars)

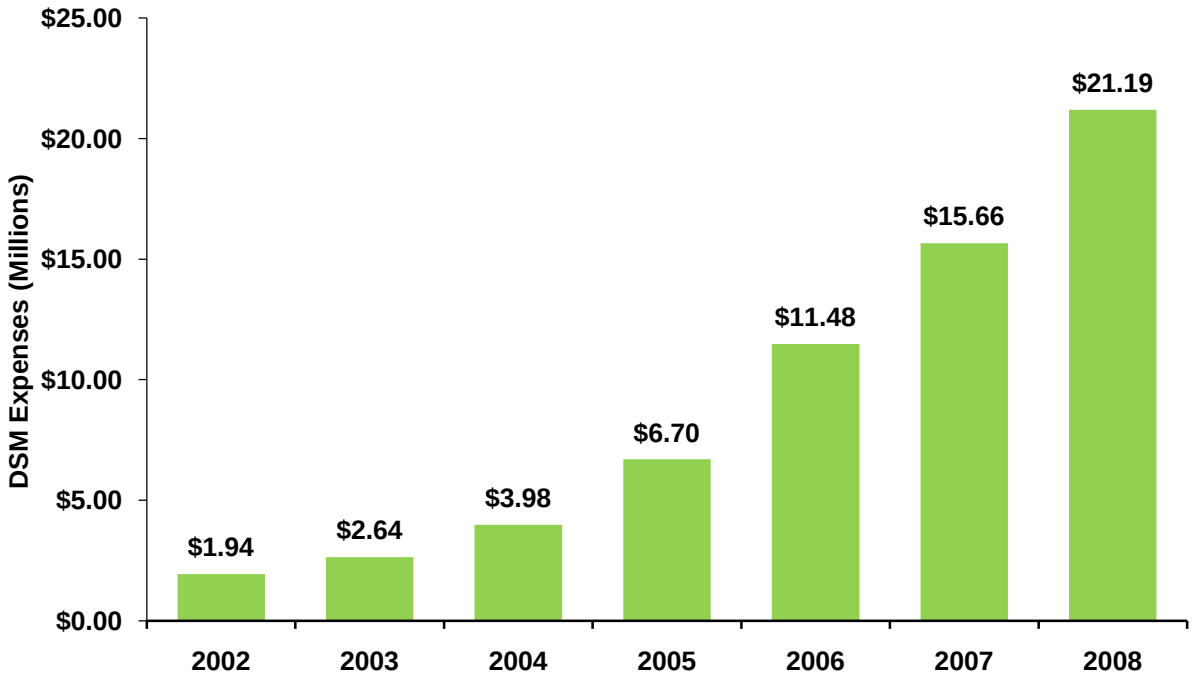
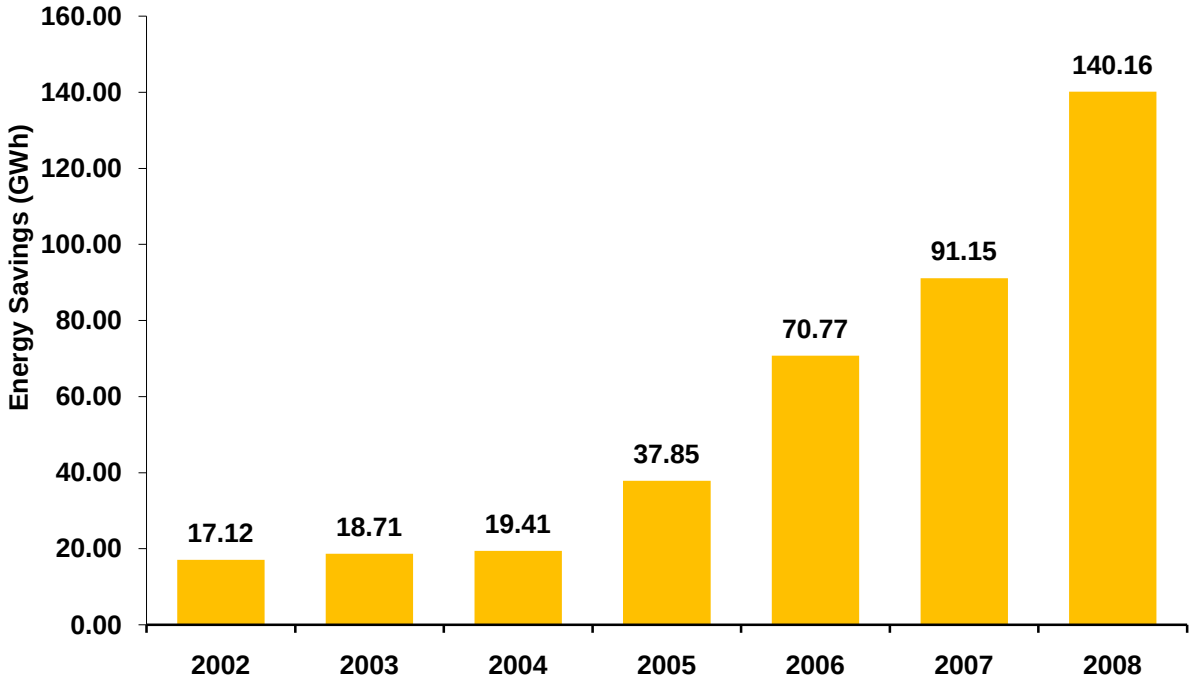



**Figure 2.** DSM Incremental Energy Savings 2002–2008 (Gigawatt-hour [GWh])




Idaho Power relies on input from the Energy Efficiency Advisory Group (EEAG) to provide customer and public interest review of DSM programs and expenses. In addition to the EEAG, Idaho Power solicits further customer input through stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power also has enhanced relationships with trade allies,

trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

During 2008, Idaho Power continued its contractual participation in, and funding of, the Northwest Energy Efficiency Alliance (NEEA). NEEA's efforts in the northwest impact Idaho Power's customers by providing regional market transformation.

## DSM Program Portfolio Structure

The programs within the DSM portfolio are offered to four major customer sectors: residential, commercial, industrial, and irrigation. Beginning in 2007, the commercial and industrial energy efficiency programs were made available to customers in either sector, expanding the availability of these programs. Because of this change, the sector is now often referred to as the commercial/industrial sector. Idaho Power achieved energy and demand savings through four types of programs. These programs include Demand Response, Energy Efficiency, Market Transformation, and Other Programs and Activities. A brief description of each of these operational categories follows.

### *Demand Response Programs*

Demand response programs are designed to reduce participant electricity loads at specific times of the day and year when electricity is normally in short supply. The need for these programs continues to increase. Idaho Power set a new system peak of 3,214 megawatts (MW) on Monday, June 30, 2008, at 3:00 p.m. The goal of demand response programs within Idaho Power's DSM portfolio is to reduce the system summer peak demand, thus minimizing the need for acquiring higher-cost, supply-side alternatives, such as gas turbine generation. Demand reduction through demand response programs is usually achieved through the use of load control devices installed on customer equipment. The measure of program performance is the number of megawatts (MW) of reduced demand for electricity during peak periods. In 2008, Idaho Power offered two demand response programs, one for residential customers and one for irrigation customers.

### *Energy Efficiency Programs*

Energy efficiency programs focus on reducing energy usage through identifying buildings, equipment, or components where energy-efficient design, replacement, or repair can yield significant energy savings. These programs are applicable to all customer sectors. Typical project measures range from entire building construction to simple light bulb replacement. Savings from these programs are measured in terms of reduced kilowatt-hour (kWh) usage, or megawatt-hour (MWh) usage for larger projects. These programs usually supply energy benefits throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction, residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

### *Market Transformation*

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional organizations. These organizations are in a position to impact the design of energy usage in products, services, and methods that affect electrical power consumption. Idaho Power primarily achieves market transformation savings through its participation in NEEA. Idaho Power also

supports market transformation accomplished by appliance or building code modifications or enforcement.

### *Other Programs and Activities*

Other Programs and Activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Local Energy Efficiency Funds (LEEF), the Residential Energy Efficiency Education initiative, and the Commercial Educational Initiative. These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a summary of the DSM programs and their respective sectors, as well as operational category and the state in which each was available in 2008.

**Table 1.** 2008 DSM Programs, Sectors, and Operational Type

| Program | Sector | Operational Type | State |
|---|---|---|---|
| A/C Cool Credit | Residential | Demand Response | ID |
| Attic Insulation Pilot | Residential | Energy Efficiency | ID |
| Building Efficiency | Commercial/Industrial | Energy Efficiency | ID/OR |
| Commercial Education Initiative | Commercial/Industrial | Other Programs and Activities | ID/OR |
| Custom Efficiency | Commercial/Industrial | Energy Efficiency | ID/OR |
| Easy Upgrades | Commercial/Industrial | Energy Efficiency | ID/OR |
| Energy Efficient Lighting | Residential | Energy Efficiency | ID/OR |
| Energy House Calls | Residential | Energy Efficiency | ID/OR |
| ENERGY STAR® Homes Northwest | Residential | Energy Efficiency | ID/OR |
| Heating & Cooling Efficiency Program | Residential | Energy Efficiency | ID/OR |
| Holiday Lighting Program | Commercial/Industrial | Energy Efficiency | ID/OR |
| Home Products Program | Residential | Energy Efficiency | ID/OR |
| Home Weatherization Pilot | Residential | Energy Efficiency | ID |
| Irrigation Efficiency Rewards | Irrigation | Energy Efficiency | ID/OR |
| Irrigation Peak Rewards | Irrigation | Demand Response | ID/OR |
| Local Energy Efficiency Funds | All | Other Programs and Activities | ID/OR |
| Northwest Energy Efficiency Alliance | All | Market Transformation | ID/OR |
| Oregon Commercial Audits | Commercial/Industrial | Energy Efficiency | OR |
| Oregon Residential Weatherization | Residential | Energy Efficiency | OR |
| Rebate Advantage | Residential | Energy Efficiency | ID/OR |
| Residential Education Initiative | Residential | Other Programs and Activities | ID/OR |
| Weatherization Assistance for Qualified Customers | Residential | Energy Efficiency | ID/OR |

## Program Performance

Participation in DSM programs at Idaho Power continues to increase, as does the energy impact in the form of energy savings and demand reduction. The energy savings for Idaho Power's energy efficiency programs in 2008 was 107,484 MWh, a 72% increase over the 62,544 MWh energy savings in 2007. Demand reduction for the demand response programs also increased in 2008. Combined,

the Irrigation Peak Rewards and A/C Cool Credit programs resulted in estimated summer peak reduction of 58 MW, which represented a 20% increase over 48 MW in 2007.

In 2008, energy savings increased, as compared to 2007, for the residential, commercial, and industrial sectors by 75%, 310%, and 38% respectively. The residential sector savings increased to 21,778 MWh, the commercial sector savings increased to 32,786 MWh, and the industrial sector increased to 41,059 MWh. The 2008 irrigation sector energy savings decreased slightly to 11,746 MWh, from 12,304 MWh in 2007. Additional energy savings continue to be realized through market transformation partnership activities with NEEA.

Customer participation increased in nearly every existing program from 2007 to 2008. The number of projects completed under the Easy Upgrades program increased from 104 projects in 2007 to 685 projects in 2008. Projects completed under the Building Efficiency program increased from 22 to 60. While the energy savings decreased slightly from the Irrigation Efficiency Rewards program, participation increased from 816 to 961 projects. As a result of the downturn in the housing market in 2008, the number of homes incented under the ENERGY STAR® Homes Northwest and the Rebate Advantage programs both decreased. Participation in the A/C Cool Credit program increased by 72% to approximately 24,000 customers by year's end.

A few individual programs were big contributors to the overall energy savings. The Custom Efficiency program, the only energy efficiency program in the industrial sector, accounted for 38% of Idaho Power's energy savings from programs, resulting in 41,059 MWh of savings. The Easy Upgrades program in the commercial sector provided 24%, or 25,928 MWh, energy savings. In the residential sector, the Energy Efficient Lighting program saved 14,309 MWh, accounting for 13% of the overall energy savings.

ACEEE publishes an annual scorecard ranking individual states in terms of commitment to energy efficiency. In 2008, Idaho was identified as the "most improved" state in the nation, having moved up 12 spots, as compared to the 2007 scorecard. As the largest utility company in the state, Idaho Power is proud to contribute to this recognition.

Table 2 shows the 2008 annual energy savings, summer peak demand reduction, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2008 contribution of each sector in terms of weather-adjusted energy usage and its respective size in number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

**Table 2.** 2008 Program Sector Summary and Energy Usage

| | Energy Efficiency Program Impacts[a] | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Direct Expenses | MWh Energy Savings | aMW Load Reduction | Peak Load Reduction[b] | MWh Sector Total | % of Energy Usage | Number of Customers |
| **Energy Efficiency** | | | | | | | |
| Residential | $7,192,562 | 21,778 | 2 | 23 | 5,282,337 | 36% | 404,373 |
| Commercial | $4,076,109 | 32,786 | 4 | 5 | 3,979,113 | 27% | 64,125 |
| Industrial | $4,045,671 | 41,059 | 5 | 5 | 3,365,761 | 23% | 122 |
| Irrigation | $3,535,542 | 11,746 | 1 | 39 | 1,921,608 | 13% | 18,542 |
| Market Transformation | $942,014 | 32,671 | 4 | n/a | n/a | n/a | n/a |
| Other Programs and Activities | $421,317 | 116 | 0 | n/a | n/a | n/a | n/a |
| **Total** | **$20,213,215** | **140,156** | **16** | **72** | **14,548,819** | **100%** | **487,162** |

[a] Energy, demand, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.

[b] Includes peak load reduction from both demand response and energy efficiency programs.

## Regulatory Initiatives

Idaho Power has aligned itself with the IPUC and the members of the environmental community to work toward creating a financial and regulatory environment supportive of utility DSM resource acquisition. Resulting from this collaborative effort are two financial mechanisms designed to 1) remove the financial disincentives to utility DSM resource acquisition and 2) provide a financial incentive to shareowners when DSM programs perform above baseline goals. Idaho Power is optimistic that this effort will lead to a sustained environment supportive of its plans to pursue all cost-effective DSM opportunities while balancing its shareowner's financial objectives.

In response to these regulatory mechanisms, Idaho Power has committed to enhancing its efforts toward promoting DSM and energy efficiency in several key areas, including a broad availability of efficiency and load-management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs beyond peak shaving/load shifting programs, and third-party verification.

## DSM Expenditures and Funding

Funding for DSM programs in 2008 came from several sources. The Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider funds are collected directly from customers on their monthly bills. In June 2008, the Idaho Rider was increased from a rate of 1.5% of base rate revenues to 2.5%. The monthly caps on residential and irrigation customer contributions formerly in place were removed. The Oregon Rider remains at 1.5% of base rate revenues. DSM-related expenses not funded through the Rider funds, including costs for administration and overhead, are included as part of Idaho Power's ongoing operation and maintenance costs. Total DSM expenses funded from these sources were slightly over $21 million in 2008.

Table 3 provides a summary of the 2008 expenses and energy savings by each funding category.

**Table 3.** 2008 Funding Source and Energy Impact

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider..... | $18,880,276 | 131,662 |
| Oregon Rider..... | $625,000 | 4,277 |
| BPA ..... | $6,950 | 0 |
| Idaho Power ..... | $1,681,294 | 4,217 |
| **Total** | **$21,193,520** | **140,156** |

## Future Plans

Many of Idaho Power's DSM programs are selected for implementation through its biennial IRP. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances risk, environmental, economic, and other considerations in developing a preferred portfolio of future resources that meet the specific energy needs of Idaho Power and its customers. The IRP is normally updated every two years to reflect changes in supply costs, demand for electricity, and other factors. However, with its acceptance of the 2006 IRP, the IPUC requested that Idaho Power align the submittal of its next IRP with those submitted by other utilities. To comply with this request, Idaho Power provided an update on the status of the 2006 IRP to both the IPUC and OPUC in June 2008, and will file a new IRP in June 2009. Idaho Power DSM staff has participated on the collaborative team compiling both the 2006 IRP Update and the 2009 IRP.

In 2009, Idaho Power plans to continue to increase participation and energy savings from existing programs and continue to implement new energy efficiency and demand response programs. In 2009, Idaho Power plans to expand its efforts in energy efficiency by continuing the Attic Insulation Pilot under the new name Home Improvement Program, continuing the Home Weatherization Pilot under the new name Weatherization Solutions for Eligible Customers program, and implementing a refrigerator recycling program. Idaho Power will expand the Irrigation Peak Rewards program to add an option of a dispatchable demand response program, which will greatly increase the demand reduction potential from this program. Also in 2009, Idaho Power plans to offer a demand response program to its commercial and industrial customers through a third-party demand response aggregator.

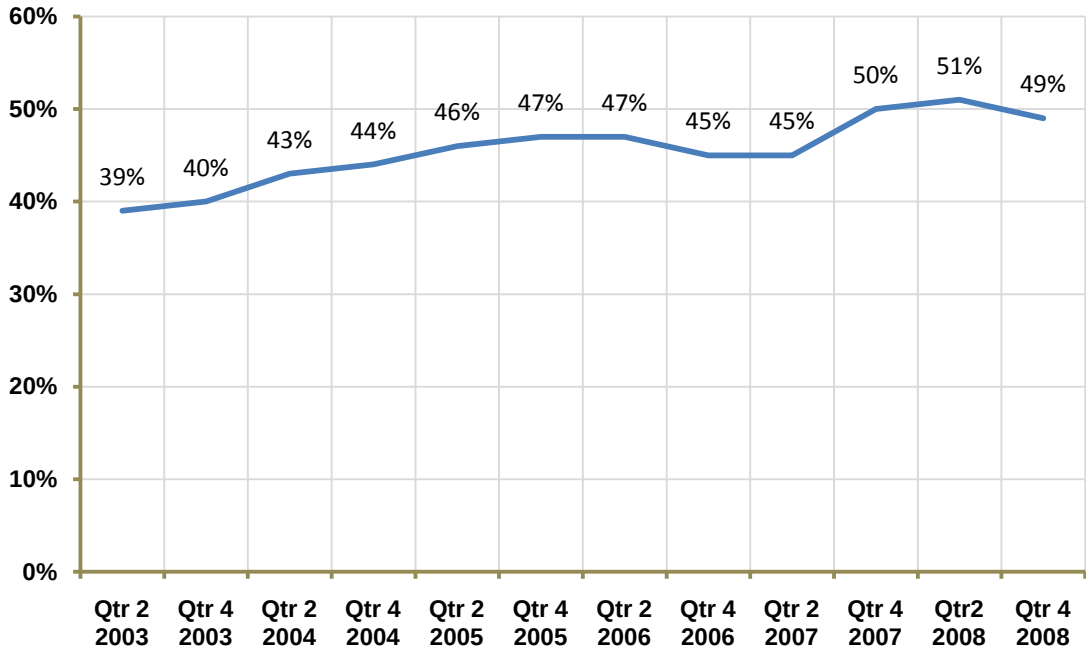
Idaho Power will participate in the development of the Northwest Power and Conservation Council's (NWPCC) Sixth Power Plan, continue and enhance consumer education on energy efficiency, and complete various research and development projects.

## Customer Satisfaction

Customer satisfaction is a key consideration in Idaho Power's program design, operations, and management. Idaho Power uses surveys, focus groups, stakeholder input, and input from the EEAG and Idaho Power field personnel to assess and monitor customer satisfaction. This information and input aids in the design and modification of programs and assists in program marketing and management throughout the life of each program.

In 2008, the results of Idaho Power's quarterly customer satisfaction survey showed steady improvement over recent years as the percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts has continued to increase. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39% in early 2003 to 49% in late 2008. This represents a 26% increase in positive customer perception. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for improvement. Figure 3 depicts biannual growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy conservation efforts encouraged by Idaho Power.

**Figure 3.** Percent of Customers Whose Needs are Met or Exceeded by Idaho Power's Conservation Efforts




Several surveys measured customer satisfaction with programs in 2008. The surveys also provide guidance for program modification, marketing, and evaluation. Survey results are presented in the following program sections of this report: A/C Cool Credit, Energy House Calls, Rebate Advantage, Residential Energy Efficiency Education, Heating & Cooling Efficiency Program, Weatherization Assistance for Qualified Customers (WAQC), and Easy Upgrades.

An important measure of customer satisfaction is the retention rate of participants in ongoing programs. A review of utility service agreement end dates indicates less than 1% of A/C Cool Credit participants cancel enrollment due to dissatisfaction with the program. Both irrigation sector programs, the Irrigation Peak Rewards and the Irrigation Efficiency Rewards programs, have continued with a high level of participation. Idaho Power programs have on-going customer satisfaction measurements as a follow-up to the application process. For example, Easy Upgrades provides an ongoing Web-based customer survey for its participants. Results of these surveys indicate general satisfaction and help guide program improvement and marketing efforts. Idaho Power energy efficiency program staff is preparing surveys for future use in determining customer satisfaction. Building Efficiency developed a customer satisfaction survey in 2008 and plans to implement it in 2009. Custom Efficiency plans to develop a customer satisfaction survey in 2009. The WAQC program collected customer satisfaction surveys from participating customers. The results of these surveys showed that customers thought the program helped

them learn about saving electricity in their homes and helped them try some of the ways to save energy in their homes.

## Cost-Effectiveness

Idaho Power considers cost-effectiveness the primary screening tool prior to DSM program implementation. Most of Idaho Power's energy efficiency programs are preliminarily identified through the IRP planning process. In this process, specific programs or potential energy savings are screened by sector to determine if the levelized cost of these programs is less than supply-side resource alternatives. If they are shown to be less costly than supply-side resources from a levelized cost perspective, the hourly shaped energy savings is subsequently included in the IRP.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power analytical staff creates cost-effectiveness models to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models are inputs from various sources in order to use the most current and reliable information available. When possible, Idaho Power staff leverages the experiences of other companies in the region, or throughout the country, to help identify specific program parameters. This is typically accomplished through discussions with other utilities' program managers and research staff. Idaho Power also uses electric industry research organizations, such as E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA), Association of Energy Service Professionals (AESP), Energy Insights, and others, to identify similar programs and their results.

For other assumptions, including estimated costs, savings, and net-to-gross ratio estimates, Idaho Power relies on sources such as the Northwest Power and Conservation Council, the Regional Technical Forum (RTF), NEEA, E Source, the Database for Energy Efficiency Resources (DEER), the Energy Trust of Oregon (ETO), Bonneville Power Administration (BPA), third-party consultants, and other regional utilities. Idaho Power uses a cost-effectiveness model to perform sensitivity analyses in order to determine optimal program designs. The remaining inputs used in the cost-effectiveness models are obtained from the IRP process. The Technical Appendix of Idaho Power's most recent IRP is the source for the financial assumptions, including the discount rate and inflation rate. The IRP is also the source of the DSM alternative costs, which is the value of energy savings and demand reduction resulting from the DSM programs. These DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a peaking unit or forward market prices as determined by Idaho Power's power supply model, AURORAxmp® Electric Market Model. The avoided capital cost is based on a gas-fired simple-cycle turbine.

For its cost-effectiveness methodology, Idaho Power relies on the Electric Power Research Institute End Use Technical Assessment Guide (TAG) and the California Standard Practice Manual. Idaho Power primarily uses the Total Resource Cost (TRC) test and the Utility Cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs. As defined in the TAG and California Standard Practice Manual, the TRC and UC tests are most similar to supply-side tests and provide a useful basis to compare demand-side and supply-side resources. Idaho Power determines cost-effectiveness on a measure-by-measure basis and a program basis. To be consistent with the IRP, program life B/C ratios for A/C Cool Credit and Irrigation Peak Rewards are calculated over a 20-year period. In order for a measure or a program to be considered cost-effective, it must have B/C ratios greater than one for both the TRC and UC tests.

Idaho Power may choose to launch a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness model. Following implementation of a program, cost-effectiveness models are reviewed as new inputs from actual program activity become available, such as actual program expenses, savings, or participation. If measures or programs are determined to not be cost-effective after implementation, the program or measures are reexamined.

A new addition to the 2008 DSM report is the presentation in Appendix 4 of the UC and TRC B/C ratios using actual cost information over the life of the program through 2008. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction is realized.

### *Program Evaluation*

Program evaluation is an important facet of Idaho Power's DSM operational activities. Idaho Power relies on evaluation by third-party contractors, internal analyses, and regional studies to ensure the ongoing cost-effectiveness of programs through validation of energy savings and demand reduction. The results of Idaho Power's evaluation efforts are used to enhance or initiate program changes when warranted. In 2008, Idaho Power developed a comprehensive evaluation plan for its energy efficiency programs and commenced evaluations for several programs and measures, including Building Efficiency, ENERGY STAR® Homes Northwest, Rebate Advantage, Energy House Calls, and the Attic Insulation pilot.

As part of its evaluation efforts, Idaho Power is actively participating in several regional studies to identify and promote emerging technologies that may further enhance opportunities for new program deployment. Some examples include 1) the Distribution Efficiency Initiative, which is a study managed by NEEA to determine efficient ways to design and operate distribution feeders through voltage regulators, 2) a regional study to evaluate the energy-savings potential of ductless heat pumps, and 3) efforts to measure the impacts of light-emitting diode (LED) lighting. Other regional analyses in which Idaho Power actively participated include the Commercial Building Stock Assessment and market progress evaluations.

## DSM Annual Report Structure

The structure of the remaining portion of this report is based on customer sectors (categorized by residential, commercial/industrial, and irrigation). The description of each sector is followed by information about each program in that sector. Each program section includes a general program description, annual activities, and future plans. A chart at the beginning of each program section contains 2008 and 2007 program metrics in tabular format. Following the sector and program sections of the report are descriptions of Idaho Power's activities in Market Transformation, Other Programs and Activities, and Idaho Power's Regulatory Initiatives. The appendices follow the written sections and contain tabular information on the 2008 expenses and savings, as well as historic information for all energy efficiency and demand response activities at Idaho Power.

# RESIDENTIAL SECTOR OVERVIEW

## Description

With over 404,000 service points serving a population of approximately one million people, residential customers represent Idaho Power's largest customer segment. Growth within this segment slowed considerably in 2008, largely in response to regional and national economic conditions. During 2008, Idaho Power added about 4,000 customers, equaling a growth rate of 1%. Idaho Power experienced the smallest residential customer growth rate since 1989. The residential segment represents 36% of Idaho Power's total electricity usage.

## Programs

**Table 4.** 2008 Residential Program Summary

| | | | Total Costs | | Savings | |
|---|---|---|---|---|---|---|
| | Participants | | Utility | Resource | Annual Energy | Summer Peak Demand |
| **Program** | *(Number)* | *(Units)* | *(Dollars)* | *(Dollars)* | *(kWh)* | *(MW)* |
| **Demand Response** | | | | | | |
| A/C Cool Credit | 20,195 | homes | $2,969,377 | $2,616,072 | n/a | 23 |
| **Total** | | | **$2,969,377** | **$2,616,072** | **n/a** | 23 |
| **Energy Efficiency** | | | | | | |
| Attic Insulation Pilot | 282 | homes | $123,454 | $157,866 | 317,814 | |
| Energy Efficient Lighting | 436,264 | CFL bulbs | $1,018,292 | $793,265 | 14,309,444 | |
| Energy House Calls | 1,099 | homes | $484,379 | $484,379 | 883,038 | |
| ENERGY STAR® Homes Northwest | 254 | homes | $302,061 | $375,007 | 468,958 | 1 |
| Heating & Cooling Efficiency Program | 359 | homes | $473,551 | $599,771 | 561,441 | |
| Home Products Program | 3,034 | appliances/fixtures | $250,860 | $468,056 | 541,615 | |
| Home Weatherization Pilot | 16 | homes | $52,807 | $48,162 | 71,680 | |
| Oregon Residential Weatherization | 3 | homes | $7,417 | $28,752 | 22,196 | |
| Rebate Advantage | 107 | homes | $90,888 | $179,868 | 463,401 | |
| Weatherization Assistance for Qualified Customers—Idaho | 439 | homes/non-profits | $1,375,632 | $1,755,749 | 4,064,301 | |
| Weatherization Assistance for Qualified Customers—Oregon | 13 | homes/non-profits | $43,843 | $74,048 | 73,841 | |
| **Total** | | | **$4,223,185** | **$4,964,924** | **21,777,729** | **24** |

Note: See Appendix 3 for notes on methodology and column definitions.

Programs available to residential customers include one demand response program, nine energy efficiency programs, and the energy educational program. The demand response program offering is the A/C Cool Credit program, with approximately 24,000 customers enrolled. During 2008, this program expanded into Idaho Power's Payette and Twin Falls service areas. The residential efficiency programs include Energy House Calls, Rebate Advantage, ENERGY STAR® Homes

Northwest, Oregon Residential Weatherization, Energy Efficient Lighting, WAQC, and Heating & Cooling Efficiency Program. The new ENERGY STAR Home Products Program was operational in 2008, with strong residential customer participation.

Additionally, two new pilots were implemented in 2008. One was the Attic Insulation Pilot and the other was the Home Weatherization Pilot. Analysis was conducted about the viability of the attic retrofit pilot program. Plans are underway for implementation in June 2009 under the name Home Improvement Program. The Home Weatherization Pilot will launch as a program in the Twin Falls area in 2009 under the name Weatherization Solutions for Eligible Customers.

Idaho Power continued significantly increasing its outreach activities by participating in numerous retail and community events during 2008. These partnerships and outreach activities created specific opportunities for the company to share the importance of energy efficiency and give customers information and options about participating.

Many of these events were partnerships with community retailers, including Home Depot, Lowe's, Albertson's, Wal-Mart, and small, locally owned retailers. Idaho Power also participated in home and garden shows, Parade of Homes, library education series, and other community events across Idaho Power's service area. A sample of the new community events Idaho Power participated in during the course of 2008 include the Susan G. Komen Race for a Cure, the St. Luke's Women's Challenge, and the Idaho Green Expo, where Idaho Power released the new booklet *30 Simple Things You Can Do To Save Energy*. These events drew large crowds, providing Idaho Power an opportunity to share energy efficiency information.

Presentations to community groups and businesses were another emphasis during the year. Idaho Power customer representatives made approximately 100 presentations to civic and community groups, including chambers of commerce, school boards, service organizations, and businesses. Idaho Power also developed a new energy efficiency presentation, targeting fourth-grade through sixth-grade students.

# A/C Cool Credit

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes)[a] | 20,195 | 13,692 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW)[a] | 23 | 11 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,922,985 | $2,421,461 |
| Oregon Energy Efficiency Rider | $45,404 | $0 |
| Idaho Power Funds | $988 | $4,692 |
| Total Program Costs—All Sources | $2,969,377 | $2,426,154 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.38 | |
| Total Resource Benefit/Cost Ratio | 1.38 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Program participation and demand reduction reflect enrollment as of July 15th. Year end enrollment in the program was 23,505 homes.

## *Description*

A/C Cool Credit is a voluntary dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners on and off via a direct load-control device installed on the air conditioning unit. Participants receive a monthly, monetary incentive for participating in the program during the summer season. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high.

Individual radio-controlled or power line carrier (PLC) switches are installed on customers' air conditioning units. These switches allow Idaho Power to cycle customers' air conditioners during a cycling event. Under this program, Idaho Power may cycle participants' air conditioners for up to 40 hours each month in the months of June, July, and August.

## *2008 Activities*

In 2008, the program expanded beyond Ada County, Canyon County, and the Emmett valley to the Payette and Twin Falls area. Mountain Home Air Force Base (MHAFB) housing residents also joined the program in 2008. Cycling event hours changed from four-hour cycles to three-hour cycles, pinpointing the peak time with less potential impact on participants. There were 15 cycling events in 2008, one in June, seven in July, and seven in August. The 2008 target was 16,000 new participants. There were approximately 13,222 new participants in 2008.

Marketing approaches during 2008 covered a range of methods. A/C Cool Credit pooled resources with the City of Boise Recycling department and with United Water on a joint bill-stuffer campaign. Idaho Power specialists visited large businesses, providing program information to the businesses' employees. Idaho Power in-house A/C Cool Credit promotions attracted further program signups.

A cause-related marketing approach involved partnering with both The Idaho Foodbank and Southeast Oregon Regional Food Bank. During a "limited time offer," a $20 donation went to the food bank in the participant's location for enrolling in the A/C Cool Credit program. As of December 2008, this approach yielded 489 new signups and a total of $9,780 to the two food banks.

During 2008, a call center customer service representative (CSR) pilot was conducted. The CSRs received training in signing up new A/C Cool Credit participants at the point of contact when an Idaho Power customer initiates or transfers his/her account by phone. The project was successful. During the first five months after the training was completed, five trained CSRs signed up 140 new participants.

An outreach project included an Idaho Power specialist and a heating, ventilating, and air conditioning (HVAC) journeyman providing A/C Cool Credit switch training for field technicians of HVAC companies. Technicians learned about the direct load-control device installed on participating Idaho Power customers' air conditioning units. Increasing the HVAC technician's knowledge of switch boxes contributes to positive customer relations between the customer and the technician servicing the A/C Cool Credit program participant's air conditioning unit.

## Customer Satisfaction

The A/C Cool Credit program conducted a customer satisfaction survey between September and October 2008. Of the 3,958 surveys sent out, 1,671 completed responses were returned, resulting in a 42% response rate. A portion of the participants received the survey by e-mail, while the others received the survey through postal mail. Results showed a high level of satisfaction with the program, with high ratings in program application process, comfort, frequency of cycling, overall satisfaction with the program, and amount of information received. Most respondents indicated they chose to participate in the program "to help reduce electrical usage on hot summer days," to "receive the bill credit," or both. An overwhelming majority of respondents indicated they would recommend the program to friends or family.

## 2009 Strategies

The A/C Cool Credit program is expanding into the Pocatello area this spring, with marketing starting in February. The program will expand to areas where the paging signal does not reach, as meters are installed in those areas as part of the Advanced Metering Infrastructure (AMI) project. The 2009 A/C Cool Credit target is to add 12,000 new participants. An evaluation of the results of this demand response program will be implemented in Pocatello, Twin Falls, and MHAFB. Data loggers will be installed on a random sample of participating customer's air conditioning units to collect data on run time. Once the information is collected, analysis will commence in autumn 2009 to estimate demand reduction.

Idaho Power plans to distribute A/C Cool Credit program information by using the technicians installing the new AMI meters in the upcoming year. The technicians will leave a door hanger with A/C Cool Credit program information on the customers' doorknob after completing their installation work.

# Attic Insulation Pilot

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 282 | n/a |
| Energy Savings (kWh) | 317,814 | n/a |
| Demand Reduction (MW) | .03 | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $123,454 | n/a |
| Oregon Energy Efficiency Rider | $0 | n/a |
| Idaho Power Funds | $0 | n/a |
| Total Program Costs—All Sources | $123,454 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.029 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.037 | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Cost Benefit/Cost Ratio | 2.48 | |
| Total Resource Benefit/Cost Ratio | 1.94 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Attic Insulation Pilot, conducted in Idaho during 2008, consisted of paying an incentive to residential customers in the Idaho Power service area for installing additional attic insulation. This program specifically targets the reduction of summer peak demand.

## *2008 Activities*

The pilot was conducted in Boise, Twin Falls, and Pocatello. Installations began May 2008 and were completed by the first week of July. The attic insulation program paid a $0.15 per square foot incentive for professionally installed attic insulation. Analysis of the information obtained from the attic insulation pilot indicates that this is an opportunity for Idaho Power to provide a cost-effective program beginning in 2009.

## *2009 Strategies*

The Attic Insulation Pilot will become a program in Idaho and Oregon in June 2009 under the name Home Improvement Program. Plans include creating program information brochures to market the program and incentive application forms for customers. In July, a bill stuffer explaining the new program will be included in all residential customers' bills. Marketing will include a direct mail campaign after the program launch, followed by a print campaign later in 2009.

# Energy Efficient Lighting

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (CFL bulbs) | 436,234 | 219,739 |
| Energy Savings (kWh) | 14,309,444 | 7,207,439 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,011,850 | $519,818 |
| Oregon Energy Efficiency Rider | $6,242 | $11,787 |
| Idaho Power Funds | $200 | $10,445 |
| Total Program Costs—All Sources | $1,018,292 | $557,646 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.011 | $0.012 |
| Total Resource Levelized Cost ($/kWh) | $0.009 | $0.015 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.56 | |
| Total Resource Benefit/Cost Ratio | 4.31 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy Efficient Lighting program, called the ENERGY STAR® Lighting program in 2007, strives for residential energy savings through the replacement of less efficient lighting with more efficient technology. The average existing home has 38 light bulbs. New homes have an average of 77 light bulbs. Changing these bulbs to more efficient bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR qualified compact fluorescent lights (CFLs) are an efficient alternative to standard incandescent light bulbs and save money and energy. Bulbs come in a variety of wattages, colors, and applications, including bulbs for three-way and dimmable fixtures. ENERGY STAR qualified bulbs use 75% less energy and last up to 10 times longer than incandescent bulbs.

## *2008 Activities*

In 2008, the majority of energy savings were achieved through Idaho Power's participation in two regional Change a Light promotions sponsored by the BPA and one sponsored by Idaho Power. The 2007 BPA Change a Light promotion (spiral bulbs) carried over until February 2008. The BPA promotion focusing on specialty bulbs extended through December 2008. Additionally, Idaho Power initiated its own spiral-bulb promotion during autumn 2008. This spiral promotion ran independent of the BPA promotion, focusing on smaller retailers and covering a greater Idaho Power service area than the BPA program.

Table 5 describes the energy savings and the number of CFL bulbs contributed by each segment of the program.

**Table 5.** Energy Efficient Lighting Energy Savings

| Promotion | Description | Contractor | Timeframe | Bulbs Sold | Estimated kWh Savings |
|---|---|---|---|---|---|
| 2007 Change a Light Spiral..... | 99¢ spiral single pack spiral bulbs | BPA/Fluid | 2007 carryover | 60,987 | 2,000,357 |
| 2007 Change a Light Specialty .. | Specialty bulbs in "big-box" stores | BPA/PECI | 2007 carryover | 31,880 | 1,045,664 |
| 2008 Change a Light Spiral..... | 99¢ single pack spiral bulbs | BPA/Fluid | Spring 2008 | 41,660 | 1,366,448 |
| 2008 Change a Light Specialty .. | Specialty bulbs in "big-box" stores | BPA/PECI | 2008 | 228,169 | 7,483,943 |
| Change a Light Spiral..... | 99¢ single pack spiral bulbs | Fluid | Fall 2008 | 71,935 | 2,359,470 |
| Direct Install ..... | Bulbs given directly to customers | n/a | 2008 | 1,633 | 53,562 |
| | | | **Total** | **436,234** | **14,309,444** |

Marketing during 2008 focused on education and outreach by educating customers about the benefits of CFLs and selecting the appropriate bulb for a specific application. Idaho Power also marketed the program through point-of-purchase materials and signs, in-store events and energy efficiency events, the Idaho Power *Customer Connection* monthly newsletter, and the Idaho Power Web site.

In 2008, Idaho Power conducted 13 special events at national retail stores in Ontario, Nampa, Boise, Twin Falls, Pocatello, and Chubbuck. Special events served as opportunities for Idaho Power staff to talk directly with customers at the point-of-purchase, answer questions, and promote all Idaho Power energy efficiency programs as well as energy efficient lighting. Idaho Power held staff training events on energy efficient lighting and proper disposal of mercury-containing light bulbs.

## *2009 Strategies*

Idaho Power will continue advocating the Energy Efficient Lighting program in 2009 through participation in regional lighting promotions. To ensure geographic coverage and bulb types that are not included in BPA promotions, Idaho Power will also continue its independent promotion. Additionally, Idaho Power will research purchasing habits and market segments of program participants using coupon-based marketing promotions. The information will be used to enhance program marketing and increase program participation.

# Energy House Calls

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 1,099 | 700 |
| Energy Savings (kWh) | 883,038 | 699,899 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $448,992 | $251,743 |
| Oregon Energy Efficiency Rider | $35,388 | $3,349 |
| Idaho Power Funds | $0 | $450 |
| Total Program Costs—All Sources | $484,379 | $336,372 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.045 | $0.039 |
| Total Resource Levelized Cost ($/kWh) | $0.045 | $0.039 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.20 | |
| Total Resource Benefit/Cost Ratio | 2.20 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program helps manufactured and mobile home owners with electric heat save on their energy bills by improving the home's efficiency. This energy efficiency program provides free duct sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump.

Leaking duct systems can lose as much as 70% of the air intended for heating or cooling in a home. Ducts operate under pressure, making a one-square-inch hole in a system similar to a 20-square-inch hole in a wall. Previous studies show typical losses from ducts are about 30%.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) specifications, installation of five CFL bulbs, provision of two furnace filters along with replacement instructions, water heater temperature test for proper setting, and distribution of energy efficiency educational materials for manufactured home occupants. The value of the service to the customer is dependent on the complexity of the repair. The typical range of the average Idaho Power cost of a service call is from $300 to $350. Idaho Power provides the customer with the contractor contact information. Customers access the service by directly calling one of the recognized, certified contractors specially trained to provide these services in their region.

Program management is under contract with Ecos Consulting, a company with experience managing and supplying duct-sealing service programs. Ecos Consulting coordinates the contractors performing local

weatherization and energy efficiency services. To monitor quality assurance, third-party audits are conducted in 5% of the homes served.

## 2008 Activities

Idaho Power renegotiated the contract with Ecos Consulting for continuation of administrative management of the Energy House Calls program. Idaho Power continued its direct mail campaign. Recipients were targeted using a database of electrically heated manufactured homes in the Idaho Power service area in Idaho and Oregon.

After reviewing the locations of program activity and market saturation, it was determined that marketing efforts should focus primarily in the Treasure Valley area. In 2008, an updated cost-effectiveness analysis was conducted representing the focused regional marketing efforts, and was determined to be cost-effective through 2009.

During 2008, Energy House Calls serviced 1,099 manufactured homes, resulting in approximately 883,038 kWh savings. The program conducted quality assurance on 5% of the homes serviced in the Energy House Calls program. Idaho Power's third-party contractors inspected 57 homes, with 43 homes passing and 13 homes failing the inspection. Contractors are required to revisit failed homes and correct identified problems. The majority of failed homes occurred during a specific period and was the result of one contractor's activity. Once Ecos Consulting, who manages the three contractors, was aware of the issue, the contractor sent a quality-assurance person out with the technician for a few weeks of observation and released one employee from their duties. The inspection failures were from jobs completed in early 2008, while subsequent quality inspections were positive. All contractors sufficiently addressed and corrected issues that were identified.

## Customer Satisfaction

Idaho Power conducted a customer satisfaction survey evaluating past experience with the service. A total of 243 Energy House Calls program participants completed the survey. The majority of these customers indicated both an improved comfort level in their home as a result of participating in the program and a high level of satisfaction with the program. Over 90% of the respondents indicated they would recommend the program to friends or family. Additionally, all 57 Energy House Calls customers who participated in the quality assurance check on 5% of the homes serviced reported having a positive experience with the Energy House Calls program.

## 2009 Strategies

Plans for the upcoming year include continuing the direct mail campaign to all areas to improve limited participation in some areas. Because of turnover in manufactured homes, some of the customers are not being reached. Idaho Power plans to update its database to enable targeting new customers who were not contacted previously. To determine other possible avenues of recruitment and adjustments to direct mail campaign, Idaho Power is conducting a survey of non-participants, defined as those who have received direct mail letters but have elected to not participate.

# ENERGY STAR® Homes Northwest

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 254 | 303 |
| Energy Savings (kWh) | 468,958 | 629,634 |
| Demand Reduction (MW) | 1 | 1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $294,579 | $451,775 |
| Oregon Energy Efficiency Rider | $6,388 | $12,249 |
| Idaho Power Funds | $1,094 | $11,020 |
| Total Program Costs—All Sources | $302,061 | $475,044 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.048 | $0.056 |
| Total Resource Levelized Cost ($/kWh) | $0.059 | $0.067 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/cost Ratio | 1.76 | |
| Total Resource Benefit/Cost Ratio | 1.43 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

ENERGY STAR Homes Northwest is a regionally coordinated initiative supported by a partnership of Idaho Power, NEEA, and the State of Idaho Office of Energy Resources (OER) to improve energy efficient construction practices for new, single-family homes. Although this program results in summer peak reduction, the program specifically targets the reduction in energy usage accomplished by increasing the efficiency of residential building envelope and air delivery system.

The ENERGY STAR Homes Northwest residential construction program builds homes that are at least 20% more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes are verified by independent third-party home performance specialists and are certified by the Idaho OER and the United States Environmental Protection Agency. The homes are more efficient, comfortable, and durable than standard homes constructed according to local building codes.

Homes that earn the ENERGY STAR label include six “must-have” specifications. The specifications found in all ENERGY STAR qualified homes are 1) effective insulation, 2) high-performance windows, 3) tight construction and sealed ductwork, 4) energy efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

Builders involved in ENERGY STAR Homes Northwest receive up to a $400 incentive per home built to the Northwest Builder Option Package standards in Idaho Power’s service area. Builders who enter their homes in a Parade of Homes receive a $1,000 incentive.

The Idaho Power program collaborates with many local entities for program management, such as ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2008 was conducting education and training activities for residential, new construction industry partners.

The 2006 International Energy Conservation Code (IECC), which the State of Idaho adopted as its standard building code, took effect January 1, 2008. This new code meets ENERGY STAR Homes Northwest program standards in several key areas, which decreases the energy savings of each ENERGY STAR Home. As a direct result of the change in Idaho code and the resulting reduction of energy savings, Idaho Power reduced the participating builder incentive to $400 per qualifying home in 2008, down from the $750 incentive previously offered. Incentives for Parade of Homes entries remain unchanged.

## *2008 Activities*

Although new housing starts were down throughout the Idaho Power service area, the ENERGY STAR Homes Northwest program achieved a market share of 6.2% of new housing starts through 2008. This is up from 2007 market share of 5%.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2008. Idaho Power sponsored the energy efficiency awards for the Building Contractor's Association of Southwest Idaho (BCASWI) and the Snake River Valley Building Contractor's Association (SRVBCA) Parade of Homes. Idaho Power presented energy efficiency awards at both the BCASWI Parade of Homes awards banquet and the SRVBCA Parade of Home awards banquet. Idaho Power maintained a presence in the building industry by participating in and supporting the SRVBCA Builder's Expo, the Magic Valley Builder's Association Builders Expo, the Idaho Building Efficiency Conference, the Home Depot Contractor's show, and the Idaho Building Contractors Association Convention.

Media campaigns heightened awareness of the ENERGY STAR Homes program. Using radio and billboard advertising, Idaho Power conducted a cooperative media campaign in conjunction with ENERGY STAR Homes Northwest and the Environmental Protection Agency. Idaho Power also co-sponsored, and participated in, activities such as the Cedar Crossing 100% ENERGY STAR community kick-off event in Caldwell. Cedar Crossing is Caldwell's first 100% ENERGY STAR community.

Training is a major function of Idaho Power's ENERGY STAR Homes program. To that end, numerous realtor trainings were conducted in Caldwell, Nampa, and Boise. A builder training was held in Pocatello.

Other marketing projects involved adding a message about this program to residential customers' electric bill. These bill messages encouraged Idaho Power customers to visit ENERGY STAR qualified homes in their local Parade of Homes events. An ENERGY STAR Homes program bill stuffer sent information to all residential customers in the Idaho Power service area. Additionally, Idaho Power continued to support the activities of the Idaho ENERGY STAR Builder's Partnership (IESBP) 100% Builders group. Idaho Power was instrumental in the formation of this group in 2007. Currently Idaho Power assists the group with marketing activities by funding and offering marketing services.

## 2009 Strategies

A key promotional strategy is participation in industry conferences and home shows. During 2009, Idaho Power will continue providing realtor trainings; supporting Parade of Homes events, the Building Contractors Association (BCA), and realtor associations; improving marketing material distributions; and supporting the IESBP group and its activities.

Marketing plans include using print advertising to assist existing builders with moving unsold ENERGY STAR qualified homes inventory. The Idaho Power program staff will explore new and innovative ways to educate consumers, realtors, and appraisers about the benefits and features of ENERGY STAR Homes.

# Heating & Cooling Efficiency Program

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 359 | 4 |
| Energy Savings (kWh) | 561,440 | 1,595 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $466,094 | $482,051 |
| Oregon Energy Efficiency Rider | $6,959 | $3,289 |
| Idaho Power Funds | $498 | $2,871 |
| Total Program Costs—All Sources | $473,551 | $488,211 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.073 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.092 | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.53 | |
| Total Resource Benefit/Cost Ratio | 0.28 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The residential Heating & Cooling Efficiency (H&CE) Program provides incentives for the purchase and proper installation of qualified high-efficiency heating and cooling equipment and services to Idaho Power residential customers. This program has been available to Idaho customers since September 2007 and to Oregon customers since August 2008.

Objectives of the H&CE program are acquiring kWh savings through the implementation of energy-saving HVAC measures in the existing and new residential sector. Cash incentives are provided to residential customers and HVAC contractors who install eligible central air conditioners (CAC), heat pumps, and evaporative coolers. Incentives are also awarded for qualifying heat pump tune-ups and CAC tune-ups meeting Idaho Power's program specifications. A participating HVAC company must perform all services, except for installation on evaporative coolers. Evaporative coolers are self-installed pieces of equipment. There is no need for a contractor to be involved and no specific installation requirements as there are for CACs and heat pumps.

In keeping with quality installation principles, the H&CE Program requires contractors to become "participating" companies. To do this, contractors in the program must sign an agreement with Idaho Power. The participating companies must ensure their service technicians and installers attend required training on the proper installation of air conditioners and heat pumps. These companies must purchase and use TrueFlow® Meters to measure air flow and adhere to program specifications.

## 2008 Activities

New in 2008 was the addition of the open-loop water source heat pump measure. Idaho Power expanded the program into Oregon upon approval, in August 2008, of Schedule 72 by the OPUC. In 2008, the H&CE Program processed 359 incentive applications and paid $72,900 in incentives, resulting in a total energy savings of 561,440 kWh. During 2008, Idaho Power conducted 22 contractor training sessions on the proper sizing and installation of heat pumps and air conditioners, simplified duct design, and program refresher classes, reaching 201 attendees.

Marketing tactics began in March, using bill inserts, radio ads, newspaper articles, home and garden shows, and exhibitor booths at various community events.

## Customer Satisfaction

Idaho Power conducted a customer satisfaction survey during 2008. The majority of respondents heard about the H&CE Program from their heating and cooling contractor. Almost 75% of respondents indicated their heating and cooling contractor was “very knowledgeable” about the program. Eight out of ten respondents said they “definitely would recommend” the contractor they used to a friend or relative. Almost 80% of the respondents said participation in the program was “very easy.” The majority of respondents pursued additional program information from the H&CE Program equipment page on Idaho Power’s Web site. Of those who did go to the Web site, most said it was “easy to use” and the information they gained from the Web site was “useful.” Most of the respondents said they were “very satisfied” with the program and would recommend it to a friend or family member. When asked what it was they liked best about the program, most responded that it was the incentive or the energy savings that they liked best.

During 2008, an H&CE Program contractor survey was conducted. Eighteen contractors responded to the survey. Responses reflected contractors from all regions of Idaho Power’s operations. The majority of the respondents said they heard about the program through a “notification letter from Idaho Power” At the time of the survey, in September, most contractors had submitted somewhere between one and five incentive applications, but there were three contractors who had submitted more than 20 applications. Two contractors indicated they had not submitted any incentive applications, and one of those said it was because he/she was too busy. Most of the contractors indicated they have a good understanding of the technical requirements of the programs and had opportunities for training in the program. The majority of the respondents indicated they had promoted the H&CE Program by encouraging customers to participate. Satisfaction with the program was varied with one-third of the contractor respondents being satisfied, one-third being neutral, and one-third being dissatisfied. Results for willingness to recommend the program were similar to satisfaction ratings. Most of the contractors’ dissatisfaction with the program was centered around the paperwork and program design. In response, Idaho Power modified the paperwork to reduce the duplication of information, and also consolidated forms. Several of the contractors requested removing airflow and sizing requirements. Idaho Power considers the quality installation requirements of this program essential to maintaining the program’s integrity. In 2009, Idaho Power will continue to require quality installation of qualifying heats pumps and increase the contractor incentives.

## 2009 Strategies

The first-year cost-effectiveness review identified measures that were not cost-effective. Plans for the upcoming year include removing air conditioner and tune-up incentives, effective second quarter 2009. The program enhanced its criteria for contractors to remain on the participating Idaho Power list.

Contractor training and marketing the program through bill stuffers and community events will continue throughout 2009. Idaho Power is investigating cross-promoting the evaporative coolers with the Home Products Program and determining the feasibility of adding duct sealing as a measure.

Idaho Power joined the Northwest Ductless Heat Pump Project and will implement the Idaho Power pilot in its service area beginning March 2009. The goals of this pilot are to promote the ductless heat pump technology as an energy-saving alternative for customers with electrically heated homes, to determine how much electricity this technology saves in order to validate a deemed-savings number, and to obtain customer satisfaction and behavior patterns regarding the technology. Idaho Power will offer customers incentives for participating in the pilot. Pilot results will be available in 2011.

# Home Products Program

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances) | 3,034 | n/a |
| Energy Savings (kWh) | 541,615 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $245,219 | $8,746 |
| Oregon Energy Efficiency Rider | $5,541 | $460 |
| Idaho Power Funds | $100 | $69 |
| Total Program Costs—All Sources | $250,860 | $9,275 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.044 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.082 | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.42 | |
| Total Resource Benefit/Cost Ratio | 0.77 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program, formerly the ENERGY STAR® Appliance Program, provides an incentive payment to Idaho Power residential customers for purchasing ENERGY STAR qualified appliances, lighting, or other products. ENERGY STAR is a government-backed program designating products as energy efficient. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards. Washers must have a Modified Energy Factor of 1.72 or greater and a Water Factor of 8.0 or lower, the minimum qualifications for an ENERGY STAR qualified clothes washer. To qualify, the washer must have been purchased after April 1, 2008 for customers in Idaho and after May 21, 2008 for customers in Oregon.

The ENERGY STAR Appliance Program rolled out on April 1, 2008 for Idaho Power Idaho customers and on May 21, 2008 for Idaho Power Oregon customers. With the addition of ENERGY STAR qualified refrigerators, ceiling fans with light kits, light kits, and light fixtures, the ENERGY STAR Appliance Program was renamed and launched on August 1, 2008.

Initially, the clothes washer incentive was the only product offered under the original program. Current offerings and related incentives include clothes washers ($50), refrigerators ($30), light fixtures (up to $15 per fixture), ceiling fans with light kits, or ceiling fan light kit attachments (up to $20 per fixture). Only products purchased after August 1, 2008 are eligible. Program participation is a simple process for customers. The customer completes the brief incentive application, submits it with a copy of the sales receipt, and then receives an incentive check in the mail if the purchase qualifies.

## 2008 Activities

Marketing of the Home Product Program to customers occurs primarily through retail outlets. Idaho Power provides information to store managers and employees through training sessions at store staff meetings and through periodic visits by Idaho Power representatives. Collateral materials, such as program brochures with application tear-off forms, were developed and distributed to nearly 100 retail stores. In addition, program modifications are delivered via letters sent directly to store managers.

Retail salespeople also assisted in promoting the program to their customers. Information gathered from a series of marketing questions on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. One question pertains to how the customer learned about the program. The most common answer was the salesperson.

Idaho Power promotes the program directly to residential customers via bill stuffers, community promotions, Idaho Power field staff, and other outreach activities. During summer 2008, bill stuffers detailing the program were mailed to all Idaho Power residential customers.

The Home Products Program exceeded the goals for 2008. Idaho Power paid the first Home Products Program incentive in May 2008, and paid 3,034 incentives during 2008, resulting in 541,615 kWh of savings. Incentives were issued for 2,451 clothes washers, 480 refrigerators, 98 light fixtures, three ceiling fans, and two light kits.

## 2009 Strategies

Based on the current success, the marketing strategy for 2009 will remain similar with only minimal adjustments and updates as needed. The current strategy enhances Idaho Power's ability to meet the 2009 program goals. The Home Products Program will cross-promote with other Idaho Power programs, evaluate success, and develop promotional materials. Idaho Power will continue to evaluate potential products for addition to the program during 2009 and beyond.

# Home Weatherization Pilot

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 16 | n/a |
| Energy Savings (kWh) | 71,680 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $51,670 | n/a |
| Oregon Energy Efficiency Rider | $0 | n/a |
| Idaho Power Funds | $1,138 | n/a |
| Total Program Costs—All Sources | $52,807 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.055 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.050 | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.31 | |
| Total Resource Benefit/Cost Ratio | 1.43 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

Idaho Power introduced a new weatherization pilot in the Twin Falls area. This program is modeled after the Weatherization Assistance for Qualified Customers (WAQC) program. The pilot targeted customers who applied, but were deemed financially ineligible, for participation in Low Income Home Energy Assistance Programs (LIHEAP), and who are not likely to participate in other programs. The difference between the existing WAQC program and the pilot are the pilot's higher income eligibility criteria of 151% to 250% of the state poverty level, and federal government dollars are not used in the pilot. In all other aspects, the pilot resembled WAQC.

Idaho Power contracted with Home Energy Management, LLC, with a goal of weatherizing 20 homes in 2008 at no cost for the customer. After the weatherization measures were installed, Idaho Power completed the verification and analysis process, comparing the current Savings Investment Ratio (SIR) with Idaho Power cost-effectiveness model.

## *2008 Activities*

The pilot was launched during the last quarter of 2008 in the Twin Falls area. Home Energy Management, LLC, weatherized 16 electrically heated homes of eligible Idaho Power customers. Energy savings achieved was 71,680 kWh/year with an average home saving 4,480 kWh/year. Total costs were $52,807 with an average job cost of $3,300.

## 2009 Strategies

Based on the pilot results, Idaho Power plans to expand the pilot into a program offered in the Twin Falls area in 2009. Home Energy Management, LLC, will weatherize 45 homes in Idaho Power's southern region service area under the newly named program, Weatherization Solutions for Eligible Customers Program. Eligible customers will include Idaho Power customers that heat their homes electrically and earn an income between 161% and 250% of the federal poverty level. Customers who are either purchasing or renting their homes may be eligible.

Identification of potential participants is done through the Community Action Partnership Association of Idaho (CAPAI), who serves as administrator for LIHEAP for the Idaho Department of Health and Welfare. Customers deemed financially ineligible for federal LIHEAP assistance are sent denial letters by CAPAI. For the 2009 program, eligible candidates with electrically heated homes are selected from the list of denial letter recipients within the Twin Falls service area.

Idaho Power plans to save an average of 6,000 kWh per weatherized home per year, for a total energy savings of 270,000 kWh annually. The Idaho Power program and field staff plans to complete an evaluation of measures installed in weatherized homes in 2009 and the participants' knowledge gained regarding energy efficiency.

# Oregon Residential Weatherization

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 3 | 1 |
| Energy Savings (kWh) | 22,196 | 9,971 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $1,908 | $0 |
| Idaho Power Funds | $5,509 | $3,781 |
| Total Program Costs—All Sources | $7,417 | $3,781 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.025 | $0.028 |
| Total Resource Levelized Cost ($/kWh) | $0.096 | $0.042 |
| **Program Life Benefit/Costs Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1980 | |

## *Description*

Idaho Power offers free energy audits for electrically heated homes of customers within the Oregon service area. This is a statutory program offered under Oregon Rate Schedule No. 78. Upon a customer's request, an Idaho Power representative visits the home to analyze it for energy efficiency. An estimate of costs and savings for specific measures is given to the customer. Idaho Power offers financial assistance for a portion of the costs for weatherization measures, either as a cash incentive or with a 6.5% interest loan.

## *2008 Activities*

During the month of July, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. A total of 37 Oregon customers responded. Each of the 37 customers returned a card from the brochure indicating they were interested in a home energy audit, weatherization loan, or incentive payment. Twenty-three audits and responses to customer inquiries to the program were completed.

Idaho Power issued three rebates totaling $1,908.22 for 22,196 kWh savings. The rebates and related savings were for ceiling insulation, window replacement, and a wall insulation project. There were no loans made through this program during 2008. Five customer responses were directed to Cascade Natural Gas.

## 2009 Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective rebate and loan applications.

# Rebate Advantage

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 107 | 123 |
| Energy Savings (kWh) | 463,401 | 554,018 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $79,547 | $58,854 |
| Oregon Energy Efficiency Rider | $11,341 | $4,609 |
| Idaho Power Funds | $0 | $733 |
| Total Program Costs—All Sources | $90,888 | $89,269 |
| **Program Levelized Costs Ratios** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.010 |
| Total Resource Levelized Cost ($/kWh) | $0.025 | $0.021 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.19 | |
| Total Resource Benefit/Cost Ratio | 2.80 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

Idaho Power customers who purchase a new all-electric, ENERGY STAR® qualified manufactured home and site it in Idaho Power's service area are eligible for a $500 rebate through the Rebate Advantage program. Salespersons receive a $100 incentive for each qualified home that they sell.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy efficient models. Quality control and energy efficiency specifications for qualified homes are established by the Northwest Energy Efficient Manufactured Housing (NEEM) program. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

The Rebate Advantage program helps Idaho Power customers with the initial costs associated with purchasing a new energy efficient ENERGY STAR qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. In addition, Idaho Power encourages sales consultants to discuss energy efficiency with their customers during the sales process.

## 2008 Activities

During 2008, Idaho Power paid 107 incentives on new manufactured homes. The customer target for 2008 on the number of homes purchased was 150 homes. The slow economy had a dramatic effect on all types of housing and contributed to the lower number of incentives. New Rebate Advantage marketing materials were developed during the year, including a program brochure and new display posters for placement at dealership sales offices and in ENERGY STAR qualified model homes. Idaho Power customer representatives (CR) visited each of the approximately 19 dealerships at least three times during 2008, answering questions and distributing materials.

## Customer Satisfaction

Idaho Power conducted two different surveys in 2008 for the Rebate Advantage program. The first survey covered manufactured home dealers who participated in the Rebate Advantage program. Seventeen dealer program participants completed the survey. Results indicated strong awareness and understanding of the Rebate Advantage program. One hundred percent of the respondents indicated they "always use" or "occasionally use" the program materials provided by Idaho Power. Almost 94% of the respondents "strongly agreed" and "somewhat agreed" the materials were useful in promoting ENERGY STAR qualified manufactured homes.

The second Rebate Advantage program survey conducted was with customers who purchased an ENERGY STAR qualified manufactured home and received an incentive from Idaho Power. Ninety-four program participants responded to this survey, with almost 87% using their new home as a primary residence. Close to 68% of the respondents reported they were "very knowledgeable" or "somewhat knowledgeable" about ENERGY STAR qualified homes before entering the dealership, and almost 95% of the respondents were "very knowledgeable" or "somewhat knowledgeable" about ENERGY STAR qualified homes after leaving the dealership.

## 2009 Strategies

Idaho Power plans to continue the Rebate Advantage program in 2009, explore new marketing methods, and promote the program. CRs will enhance relationships with dealerships by visiting each dealership quarterly, offering program support, answering questions, and distributing materials. The involvement of local Idaho Power personnel interacting with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

# Weatherization Assistance for Qualified Customers

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 452 | 408 |
| Energy Savings (KWh) | 4,138,142 | 3,338,126 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,419,475 | $1,323,624 |
| Total Program Costs—All Sources | $1,419,475 | $1,323,624 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.026 | $0.030 |
| Total Resource Levelized Cost ($/kWh) | $0.033 | $0.040 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.17 | |
| Total Resource Benefit/Cost Ratio | 1.50 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

## *Description*

The WAQC program provides funding for the installation of cost-effective weatherization measures in qualified owner-occupied and rental homes that are electrically heated. Enhancements enable qualified families to maintain a comfortable home environment, while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their home.

WAQC is modeled after the United States Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. Idaho Power, in conjunction with Community Action Partnership (CAP) agencies in the Idaho Power service area, serves as the administrator of WAQC. Federal funds are allocated to the Idaho Department of Health and Welfare and Oregon Housing and Community Services, then to CAP agencies based upon United States Census data of qualifying household income within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors providing implementations that improve energy efficiency of the homes. WAQC allows these state agencies to leverage their federal weatherization dollars and serve more residents by attaining nonfederal supplemental funding and other resources to supplement federal LIHEAP and weatherization funds.

## *2008 Activities*

During 2008, Idaho CAP agencies weatherized 434 electrically heated homes in Idaho and 13 in Oregon, totaling 452 weatherized homes. Annual energy savings were 4,064 MWh for Idaho and

74 MWh for Oregon. WAQC funded the weatherization of five buildings housing nonprofit organizations that serve special needs populations in their Idaho communities. The annual energy savings from the nonprofit weatherization was 130 MWh.

## Customer Satisfaction

Surveys are sent to program participants after completion of the weatherization process in order to measure satisfaction, education efforts, and behavior changes. Idaho Power mailed a WAQC participant survey during June and December 2008 to customers who received WAQC services in the previous six months. Twenty-nine percent, or 104 of 360, of all customers surveyed responded to the survey about WAQC. Of those customers who responded, nearly 87% said they learned "some" or "a lot" about saving electricity in their home. Additionally, 101 of those same customers, or over 97%, said that they had tried "some" or "a lot" of ways to save energy in their homes.

Additionally, Idaho Power program specialists participated in the Idaho state peer review process, which involved peer agency weatherization crews within the state reviewing homes weatherized by each of the agencies. Results show all CAP agency weatherization departments are weatherizing in accordance to federal guidelines.

## 2009 Strategies

Idaho Power is involved with the Policy Advisory Council, which serves as an oversight committee for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho.

The customer satisfaction weatherization survey used during 2008 will be used again in 2009. Additionally, in response to a request from regional CAP agencies, Idaho Power employees plan to participate in National Weatherization Day on October 30.

# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

The commercial and industrial sector consists of over 64,000 customers. During 2008, new commercial customers increased by 1,360, for an increase of about 2% over 2007. Individual customer energy usage within this segment varies from a few kWh each month to several hundred thousand kWh each month. The commercial segment of this sector represents approximately 27% of total electricity usage, while the industrial segment of this sector represents about 30% of Idaho Power's total electricity usage. Industrial customers and special contract customers in this sector are Idaho Power's largest individual energy consumers. This group consists of approximately 122 customers.

## Programs

**Table 6.** 2008 Commercial/Industrial Program Summary

| | | | Total Costs | | Savings | |
|---|---|---|---|---|---|---|
| | Participants | | Utility | Resource | Annual Energy | Summer Peak Demand |
| **Program** | *(Number)* | *(Units)* | *(Dollars)* | *(Dollars)* | *(kWh)* | *MW* |
| **Energy Efficiency** | | | | | | |
| Building Efficiency | 60 | projects | $1,055,009 | $1,671,375 | 6,598,123 | 1 |
| Easy Upgrades | 685 | projects | $2,992,261 | $10,096,627 | 25,928,391 | 4 |
| Holiday Lighting Program | 14 | businesses | $28,782 | $73,108 | 259,092 | |
| Oregon Commercial Audit | 0 | audits | $58 | $58 | | |
| Custom Efficiency | 100 | projects | $4,045,671 | $16,312,379 | 41,058,639 | 5 |
| **Total** | | | **$8,121,779** | **$28,153,548** | **73,844,245** | **10** |

Note: See Appendix 3 for notes on methodology and column definitions.

Three major programs targeting different energy efficiency market segments are offered to commercial/industrial customers in Idaho Power's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical commercial retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. The Building Efficiency program for new construction projects achieves energy savings that are cost-effective at the time of construction, enabling Idaho Power customers to apply energy efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. This program encourages incorporation of qualified energy-saving improvements for lighting, cooling, building shell, and energy control options. Participants in the Building Efficiency and Easy Upgrades programs can receive incentives for any projects completed up to $100,000 per site per year. The Custom Efficiency program offers financial incentives for large commercial and industrial energy users undertaking custom projects to improve the efficiency of their electrical systems or processes. Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

In 2009, Idaho Power plans to launch a commercial demand response program. Idaho Power has contracted with a third-party aggregator to reduce peak demand at critical times. The aggregator contracts directly with Idaho Power commercial and industrial customers to achieve the demand reduction.

In 2008, Idaho Power contracted with the Integrated Design Lab (IDL) in Boise to accomplish specific tasks to be completed in 2009. IDL will create an Energy Use Index database from Idaho Power customers and analyze the quality of commissioning services in the Treasure Valley. IDL will provide educational sessions for the local design community and organize a building simulation users group to help promote and enhance the local simulation skills. Other IDL tasks are to conduct a post-occupancy survey to study customer satisfaction with technology incentives through the commercial energy efficiency programs and to evaluate and report on the current market conditions for system sizing of package rooftop HVAC units. Lastly, IDL will identify and summarize key energy efficiency resources, events, news items, and technologies useful to Idaho Power for evaluating current incentives and future incentive opportunities for the commercial and industrial sector customers.

# Building Efficiency

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 60 | 22 |
| Energy Savings (kWh) | 6,598,123 | 2,817,248 |
| Demand Reduction (MW) | 1 | <1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,006,025 | $661,485 |
| Oregon Energy Efficiency Rider | $47,550 | $5,766 |
| Idaho Power Funds | $1,434 | $1,781 |
| Total Program Costs—All Sources | $1,055,009 | $669,032 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.017 | $0.026 |
| Total Resource Levelized Cost ($/kWh) | $0.028 | $0.032 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.14 | |
| Total Resource Benefit/Cost Ratio | 1.55 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area in Idaho and Oregon to apply energy efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The Building Efficiency program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Program incentives also include funding for custom projects, as well as additional incentives for commissioning that ensures the systems perform as designed.

The Building Efficiency program is offered to commercial and industrial customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions. The program offers incentives up to $100,000. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special contract customers are eligible to participate.

Program marketing is targeted at architects, engineers, and other local design professionals. Monthly e-mail program updates are sent to building developers, design professionals, contractors, building owners, Idaho Power field personnel, and other interested parties.

Through the Building Efficiency program, Idaho Power is a primary sponsor of the Boise Integrated Design Lab (IDL), which provides technical assistance and training seminars to local architects and

designers. Much of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the annual BetterBricks awards held in October in Boise.

## 2008 Activities

In 2008, Idaho Power made minor modifications to accommodate Idaho's adoption of the 2006 IECC, effective January 1, 2008. Eligibility requirements for three of the 14 measures changed in 2008. The Building Efficiency program completed 60 new construction, major renovations, and major additions projects in 2008, resulting in 6,598,123 kWh in energy savings. Idaho Power paid $846,931 in incentives for completed projects in 2008.

The IDL began a measurement and verification study on four of the 14 measures offered under the Building Efficiency program. Through the contract with IDL, additional measurement and verification activities for the program are expected to continue through 2009. The results of the first four measures evaluated will be available in 2009.

## 2009 Strategies

Two incentive measures used through 2008 have been altered for 2009. Idaho Power made minor modifications to the menu of 14 measures, effective January 1, 2009. One under-used measure, premium windows, was replaced with a more popular option, exterior window shading. On another measure, demand-control ventilation, the incentive level was adjusted down. The incentive payment is now based on the outside airflow, not the unit-rated airflow, resulting in a lesser incentive amount.

Measurement and verification of selected measures offered through the Building Efficiency program will continue through the IDL. IDL will install monitoring equipment on selected Building Efficiency participant facilities and report the results in 2009. Idaho Power has designed a survey to measure participant satisfaction in the Building Efficiency program. The program plans to implement this survey in 2009.

# Custom Efficiency

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 101 | 49 |
| Energy Savings (kWh) | 41,058,639 | 29,789,304 |
| Demand Reduction (MW) | 5 | 4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $3,948,617 | $3,032,047 |
| Oregon Energy Efficiency Rider | $86,858 | $110,634 |
| Idaho Power Funds | $10,196 | $19,185 |
| Total Program Costs—All Sources | $4,045,671 | $3,161,866 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.011 | $0.012 |
| Total Resource Levelized Cost ($/kWh) | $0.043 | $0.026 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.83 | |
| Total Resource Benefit/Cost Ratio | 1.55 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

The Custom Efficiency program targets energy savings through the implementation of customized energy efficiency projects at customers' sites. The program is an opportunity for large- and mid-sized commercial and industrial customers in Idaho and Oregon to lower their electrical bills and receive a financial incentive by completing energy efficient projects. Incentives enable companies to do projects that might not be completed otherwise. Program offerings include training and education on energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power staff, or by the customer as applicable to their facility. The applications must provide sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application, followed by the finalization of the terms and conditions of the applicant's and Idaho Power's obligations. When possible, Idaho Power conducts on-site power monitoring and data collection, before and after project implementation. The measurement and verification process ensures achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and within program guidelines.

If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs, based on the actual installed equipment. Large, complex projects may take as long as two years to complete.

## 2008 Activities

In 2008, the minimum project size requirement increased from an annual 20,000 kWh to 100,000 kWh. This change is expected to result in customers with smaller projects participating in other Idaho Power energy efficiency programs, allowing greater Idaho Power resources to be focused on larger projects. For smaller projects, or those with less complex retrofits, the Easy Upgrades or Building Efficiency programs may be applicable. If a smaller project cannot be accommodated through other Idaho Power energy efficiency programs, the project may be completed under the Custom Efficiency program, subject to cost-effectiveness analysis. Incentive levels for the Custom Efficiency program remain at 70% of the project cost, or $0.12/kWh, whichever is less.

Key components in facilitating customer implementation of energy efficiency projects are energy auditing, customer training, and education services. The link between energy audits and the completion of projects is historically significant; thus, Idaho Power continued expanding the number of contractors available for customer scoping audits from four companies in 2007 to five companies in 2008. Selection of engineering firms was based on the firm's expertise in all major equipment areas and their ability to provide resources for customers throughout Idaho Power's service area.

The Custom Efficiency program achieved a high service area penetration rate. Through 2008, approximately 50% of the large power service customers had submitted an application for a project. Idaho Power reviewed and approved 135 applications for incentive projects in 2008. A total of 101 projects were completed in 2008 for 59 companies, including four Oregon projects.

Program energy savings increased in 2008 by 37% over the prior year, from 29,789 MWh to 41,059 MWh. Additionally, completed projects increased by 106% and approved incentive applications increased by 55%.

**Table 7.** Custom Efficiency Annual Energy Savings by Measure

| Project Breakdowns | # of projects | kWh saved |
|---|---|---|
| Lighting | 57 | 15,300,158 |
| Fan | 12 | 11,399,810 |
| Compressed Air | 11 | 6,612,292 |
| Pump | 4 | 717,068 |
| Refrigeration | 6 | 3,554,444 |
| Other | 11 | 3,474,867 |
| **Total** | **101** | **41,058,639** |

## 2009 Strategies

Eleven more Oregon projects are scheduled for completion in 2009. In 2009, Idaho Power is expanding the Custom Efficiency program through a number of activities. These activities will include direct marketing of the Custom Efficiency program by Idaho Power field staff to inform the customers of

the Idaho Power energy efficiency programs available and ways the customer can reduce energy costs. Also, Idaho Power will continue to provide site visits and energy audits for project identification, technical training for customers, detailed energy audits for larger, complex projects, and delivery of Industrial Efficiency Alliance (IEA)-sponsored continuous energy improvement practices to customers.

# Easy Upgrades

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 685 | 104 |
| Energy Savings (kWh) | 25,928,391 | 5,183,640 |
| Demand Reduction (MW) | 5 | 1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,922,340 | $680,376 |
| Oregon Energy Efficiency Rider | $52,566 | $28,014 |
| Idaho Power Funds | $17,364 | $3,105 |
| Total Program Costs—All Sources | $2,992,261 | $711,494 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.013 | $0.015 |
| Total Resource Levelized Cost ($/kWh) | $0.043 | $0.040 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.88 | |
| Total Resource Benefit/Cost Ratio | 1.21 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2006 | |

## *Description*

Available in the Idaho and Oregon Idaho Power service areas, the objective of the Easy Upgrades program is to encourage commercial and industrial customers to implement energy efficiency retrofits by offering incentives up to $100,000 per site. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration.

Idaho Power commercial or industrial customers on Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), and special contracts are eligible. Potential participants first assess their energy-saving opportunities by talking with their equipment supplier, contractor, or Idaho Power service representative. For projects with expected incentive payments of more than $1,000, applicants must submit a pre-app prior to initiating the project. In that case, the customer completes the preliminary application (pre-app) form and submits it with relevant worksheet(s), describing the location and planned scope of their project. Upon Idaho Power's review and acceptance, the pre-app allows a customer to collect an incentive for up to 90 days for project completion. For smaller projects with expected incentive payments of less than $1,000, customers may elect to skip the pre-app and just submit their final application for payment. These projects must have been completed no more than six months prior to submitting their application for payment.

## *2008 Activities*

In July, a special lighting incentive promotion was offered under Easy Upgrades. This promotion, limited to Idaho customers, offered higher incentives for many lighting measures. A review of prior

lighting projects' actual operating hours justified the higher promotional incentive levels for the lighting measures. An increased number of lighting project applications occurred after the promotion. In Oregon, an expanded state tax credit pass-through was offered in July for lighting projects. No apparent additional activity was generated from the offer.

The special offer for VendingMiser™ installations, initiated in November 2007, concluded in October 2008, with more than 3,600 units installed. An assessment of the VendingMiser installations was conducted to determine if the units remained in place. After revisiting a sampling of the installations, and correcting problems in some cases, the results showed that over 90% of the VendingMisers were still in place and functioning within the year after installation.

Additionally, the Lighting Savings/Incentive Calculator became available on the Idaho Power Web site in April 2008. The calculator helps customers determine the costs and benefits of their potential lighting projects. Due to the lighting promotion and the online savings/incentive calculator, there was an increase in applications received and projects completed.

Marketing activities included publishing "Success Stories" on the Idaho Power Web site, providing workshops, and sponsoring events. Trade ally workshops continued through the spring and autumn. Idaho Power sponsored events, including the Commercial Real Estate Symposium, an American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) technical conference, the second annual Building Owners and Managers Association (BOMA) Energy Efficiency Workshop, and the annual Idaho Energy and Green Building Conference. Additionally, Idaho Power presented payments at incentive check ceremonies when requested by customers.

Idaho Power continued to sponsor the Lighting Design Lab (LDL) in Seattle through the Easy Upgrades program. The LDL provides technical assistance and periodic local training seminars encouraging energy saving lighting. Additionally, Idaho Power is a sponsor of NEEA's BetterBricks® program, disseminating general energy efficiency information to commercial customers.

## Customer Satisfaction

Easy Upgrades conducts a regular follow-up regarding customer satisfaction. As of December 2008, 81% of the program participants surveyed "strongly agree" they received excellent value through Easy Upgrades, while 11% of the respondents "somewhat agree." Additionally, 86% of the survey respondents "strongly agree" that they received excellent service while 87% "strongly agree" their experience when dealing with Idaho Power employees was positive.

## 2009 Strategies

The fall series workshops focused on stakeholder input regarding program change implementation for 2009. Based on input from stakeholders, plans for the upcoming year include significant program changes. New measures eligible for incentives are being added, while others are being dropped. Idaho Power customers will have 143 eligible measures in 2009, in contrast to the 129 offered in 2008.

Certain incentive levels and a few application requirements are scheduled to change in 2009. Additionally, an electronic application form will go online during the upcoming year. To encourage customers to use the electronic application, an additional incentive is being considered for each

electronic application submitted within a limited period. Details on program changes for 2009 and additional “Success Stories” will be available on the Idaho Power Web site in the spring of 2009.

Generally, major program changes occur approximately every two years. A program evaluation is planned for 2009. Results will be available in early 2010, allowing incorporation of the results of this evaluation into the program planning for 2011.

# Holiday Lighting Program

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 14 | n/a |
| Energy Savings (kWh) | 259,092 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $28,782 | n/a |
| Oregon Energy Efficiency Rider | $0 | n/a |
| Idaho Power Funds | $0 | n/a |
| Total Program Costs—All Sources | $28,782 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.014 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.035 | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.85 | |
| Total Resource Benefit/Cost Ratio | 1.12 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The overall goal of the Holiday Lighting Program is to encourage customers to purchase more efficient light emitting diode (LED) holiday lights. Although the incentive is available only to commercial customers, the program is useful as a means of introducing all Idaho Power customers to the advantages of LED lighting. In doing this, Idaho Power is rapidly helping make LED lighting the preferred choice when it comes to replacing existing holiday lights. In time, the exposure to commercial LED lighting should filter into the residential market. Along with spreading the message of LED lighting's energy efficiency, Idaho Power also informs customers about the safety benefits of using LED lights.

## *2008 Activities*

For the second year, Idaho Power offered an incentive for commercial customers to replace holiday lighting with higher-efficiency LED lighting. There was over a 700% increase in participation compared to 2007, resulting in greatly increased savings. With its revitalization of the downtown and train depot areas, the largest participant in 2008's program was the City of Caldwell. The city's holiday lighting served as an excellent exposure to LED holiday lighting for a large number of viewers. In Boise, the Idaho Botanical Gardens enlarged their Winter Garden Aglow holiday display, replacing nearly 53,000 incandescent lights with LED lights. Posted at the entrance to the Botanical Garden were signs promoting energy and safety benefits of LED lights. It is estimated that over 29,000 visitors attended the event.

## 2009 Strategies

Many of the same marketing approaches will be used in 2009 to increase customer participation. These promotional methods include providing materials in advance to chambers of commerce, business and professional organizations, and participating trade allies. Idaho Power plans to coordinate with municipalities and the Idaho Botanical Garden to support their LED-display efforts. A Holiday Lighting bill stuffer will be sent in autumn 2009 to promote the program.

# Oregon Commercial Audits

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 0 | 8 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $1,800 |
| Idaho Power Funds | $58 | $181 |
| Total Program Costs—All Sources | $58 | $1,981 |
| **Program Levelized Costs Ratios** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program offered under Oregon Schedule No. 82. Through this program, free energy audits offer evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2008 Activities*

The third-party energy auditing contract was renewed in 2008, with EnerTech Services providing services through 2011. Idaho Power sent out its annual mailing to all Oregon commercial customers in December 2008. Customers were notified of the availability of no-cost energy audits and the Idaho Power publication *Saving Energy Dollars*. Three customers requested this publication in 2008. There were no energy audits conducted in 2008. However, ten customers requested an energy audit, which will be completed in 2009.

## *2009 Strategies*

In 2009, as a method for introducing participants to additional energy efficiency resources and practices, the audit process will be maximized by providing Idaho Power incentive information targeting specific areas for improvement found in the audits. Idaho Power will help customers turn their maintenance requirements into energy saving opportunities by providing energy efficiency information to the customers.

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# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is comprised of agricultural customers operating a water-pumping or water-delivery system to irrigate agricultural crops or pasturage. The end-use equipment primarily includes irrigation pumps, pivots, fertilizer pumps, and drainage pumps. This customer group does not include water pumping for non-agricultural purposes, such as irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

The maximum number of active customers in 2008 was 17,428. In 2008, irrigation customers accounted for 1,921,608 MWh of energy usage and 772 MW of peak demand. This sector represented about 13% of Idaho Power's total electricity usage and about 23% of peak demand.

## Programs

**Table 8.** 2008 Irrigation Program Summary

| | | | Total Costs | | Savings | |
|---|---|---|---|---|---|---|
| | Participants | | Utility | Resource | Annual Energy | Summer Peak Demand |
| **Program** | *(Number)* | *(Units)* | *(Dollars)* | *(Dollars)* | *(kWh)* | *MW* |
| **Demand Response** | | | | | | |
| Irrigation Peak Rewards ..... | 897 | service points | $1,431,840 | $189,492 | n/a | 35 |
| **Total** | | | **$1,431,840** | **$189,492** | **n/a** | **35** |
| **Energy Efficiency** | | | | | | |
| Irrigation Efficiency Rewards ..... | 961 | projects | $2,103,702 | $5,850,778 | 11,746,395 | 3 |
| **Total** | | | **$2,103,702** | **$5,850,778** | **11,746,395** | **38** |

Note: See Appendix 3 for notes on methodology and column definitions.

Idaho Power currently offers two programs to the irrigation sector, 1) Irrigation Peak Rewards, a demand response program designed to decrease peak demand, and 2) the Irrigation Efficiency Rewards, an energy efficiency program designed to encourage replacement or improvement of inefficient systems and components. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in demand due primarily to the impact of weather on irrigation needs. There are about 200 new service locations added each year. The new locations are typically smaller systems that are only pressurizing water. New for the Irrigation Peak Rewards program in 2009 is a dispatchable demand response option approved by the IPUC on January 14, 2009.

# Irrigation Peak Rewards

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 897 | 947 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 35 | 37 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,373,855 | $1,520,106 |
| Oregon Energy Efficiency Rider | $17,570 | $54,747 |
| Idaho Power Funds | $40,415 | $41,028 |
| Total Program Costs—All Sources | $1,431,840 | $1,615,881 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.15 | |
| Total Resource Benefit/Cost Ratio | 1.15 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

Available to Idaho Power's Idaho and Oregon customers, the 2008 Irrigation Peak Rewards program was a voluntary program targeted toward agricultural irrigation customers with pumps of 75 horsepower (Hp) or greater. The program objective is reduction of peak electrical load during summer, weekday afternoons. In exchange for a financial incentive, preprogrammed electronic time activated switches turn off the pumps of participating irrigation customers during intervals predetermined by Idaho Power.

Participants select one of three different options for the months of June, July, and August. A monthly demand credit is associated with each of the one-, two-, or three-day options and is paid based on the participating customer's monthly billing demand. Electronic timers are programmed to turn irrigation pumps off during preprogrammed times associated with the selected option. The following three options and associated demand credit incentives were available to customers from 4:00 to 8:00 p.m. on weekdays: 1) one day per week, $2.01 per kW demand, 2) two days per week, $3.36 per kW demand, or 3) three days per week, $4.36 per kW demand. Incentive amounts are credited to the monthly billing demand at each customer's metered service point. Customers with pumps of 75–99 Hp pay a one-time $250 installation fee to help offset the cost of the switches and maintain the program's cost effectiveness.

## *2008 Activities*

Idaho Power provided five workshops promoting the Irrigation Peak Rewards program across the service area. Additionally, a list of each customer's pumps, information for estimating potential incentives on each pump, and a program application was mailed to every eligible irrigation customer.

Other marketing efforts included providing an Idaho Power exhibitor booth at regional agricultural trade shows, such as the Eastern and Western Idaho Agriculture Expos, the United Dairymen of Idaho Expo, the Agri-Action Ag show, the Idaho Farm Bureau convention, and the Idaho Irrigation Equipment Association show and convention. In 2008, several meetings occurred with the Idaho Irrigation Pumpers Association, IPUC staff, and customers regarding proposed changes to the program for 2009, which include a dispatchable demand response option. In December 2008, the Irrigation Peak Rewards Program Report was submitted to the IPUC. The report describes program results, costs, and savings for 2008.

## *2009 Strategies*

A dispatchable demand response option was approved by the IPUC on January 14, 2009, and the OPUC on February 25, 2009. The proposal included modifications to the Irrigation Peak Rewards program for 2009. A shorter program operating time throughout the summer, from June 15 to August 15, was proposed. Idaho Power plans to make the program available to all agricultural customers receiving service under Irrigation Rate Schedule 24 in 2009, potentially leading to greater energy demand and increased customer participation.

The program marketing strategy includes sponsoring 7 to 10 program update workshops across Idaho Power's service area, covering new program offerings and demonstrating the new technology operating the dispatchable demand response option. Simultaneously, customer mailings to all eligible customers will provide a detailed explanation of the program offerings and increase awareness of the significant changes to the program. Additionally, one-on-one training with Idaho Power agriculture representatives will familiarize customers with the new technology and program details. Results of the program will be reported in the 2009 Irrigation Peak Rewards Report.

# Irrigation Efficiency Rewards

| | 2008 | 2007 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 961 | 819 |
| Energy Savings (kWh) | 11,746,395 | 12,304,073 |
| Demand Reduction (MW) | 3 | 3 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,878,960 | $1,881,116 |
| Oregon Energy Efficiency Rider | $193,276 | $93,924 |
| Idaho Power Funds | $31,466 | $26,922 |
| Total Program Costs—All Sources | $2,103,702 | $2,001,961 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.026 | $0.024 |
| Total Resource Levelized Cost ($/kWh) | $0.073 | $0.103 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.49 | |
| Total Resource Benefit/Cost Ratio | 1.64 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

The Irrigation Efficiency Rewards program encourages energy efficient equipment and design in irrigation systems. Irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electric bills. Idaho Power helps qualified irrigators pay for energy efficiency features in their irrigation system and helps them use electricity efficiently. Incentives for the Irrigation Efficiency Rewards program helps the customer recover the costs of installation of a new, more efficient irrigation system and energy efficient improvements to an existing irrigation system.

Two separate reward options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is $0.25 per kWh saved above standard installation methods, not to exceed 10% of total project cost. For existing system upgrades, the incentive is $0.25 per kWh saved or $450 per kW, whichever is greater, not to exceed 75% of the total project cost. Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is re-evaluated. Prior usage history, actual invoices, and, in many situations, post-usage demand data, are used to calculate savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which small maintenance upgrades provide energy savings. Incentives vary based on specific component replacement.

Payments are calculated on predetermined average kWh savings per component. Idaho Power reviews and analyzes each proposal for a system or component modification, determining and verifying the energy savings.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power agricultural representatives sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits, conducted by Idaho Power agricultural representatives, evaluate prospective customers' potential savings. Agricultural representatives from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing awareness of the program and promoting it through the irrigation equipment distribution channels. Marketing efforts include direct mailings, advertisements in agricultural publications, and agricultural trade show participation.

## 2008 Activities

Idaho Power provided five workshops promoting the Irrigation Efficiency Reward program across the service area. The program had an Idaho Power exhibitor booth at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the United Dairymen of Idaho Expo, Agri-Action Ag show, the Idaho Farm Bureau convention, and the Idaho Irrigation Equipment Association show and convention.

## 2009 Strategies

Marketing plans for 2009 include conducting seven to 10 irrigation workshops. These workshops enable discussions between Idaho Power representatives and customers, while continually educating customers about the program and ways to participate.

All agricultural customers in Idaho Power's service area are eligible for the Irrigation Efficiency Reward program. The Irrigation Efficiency Reward program has little room for expansion within the customer class, though additional energy-saving measures may expand as technology becomes available. The market is becoming saturated to some extent, though there is still potential in this large market.

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# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance (NEEA)

NEEA encourages and supports cost-effective market transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA.

### *NEEA Activities*

#### Industrial Efficiency Alliance (IEA) Activities in Idaho

The IEA is a multi-year strategic effort designed to improve energy efficiency in two regional industries considered heavy energy users, 1) the food processing and 2) the pulp and paper industries. Although Idaho Power does not have any pulp and paper customers, because of the large number of food processing customers, Idaho Power considers participation in IEA valuable. The IEA also works with companies that produce equipment and provide services for these industries and with the utilities that serve them.

Participants achieve cost savings through the adoption of energy-efficient business practices. The IEA provides expert support, resources, and services, providing companies with the training and tools for making energy efficiency a core business value. Participants are asked for a commitment to a Continuous Energy Improvement Program, which potentially increases production capacity, improves equipment reliability, and reduces operating costs and energy use by 5% to 20%. This effort is supported by providing technical knowledge for individuals, organizations, and manufacturing companies collaborating on energy efficiency implementation. IEA members include the BPA, regional utilities, the Energy Trust of Oregon (ETO), the Oregon Department of Energy (ODOE), and the Idaho Office of Energy Resources (OER).

Training activity in 2008 increased over 2007 and included eight industrial workshops co-sponsored by the IEA, Idaho Power, and others. Topics focused on pumps, compressed air, motors, and industrial refrigeration. A market progress evaluation of the IEA was completed in May 2008.

#### Commercial Alliance Activities in Idaho

NEEA continued to provide support for commercial energy efficient activities in Idaho in 2008. NEEA continued funding the Boise Integrated Design Lab (IDL) and local BetterBricks® trainings and workshops. NEEA sponsored Idaho's Fourth Annual BetterBricks Awards, issued in October in conjunction with the Idaho Energy & Green Building Conference. Idaho Power's commercial programs, Building Efficiency and Easy Upgrades, are designed to leverage NEEA, BetterBricks, and Boise IDL activities.

#### Distribution Efficiency Initiative

In 2008, Idaho Power continued to participate with other northwest utilities in NEEA's Distribution Efficiency Initiative (DEI) project study.

#### *Phase I Projects Completed*

NEEA conducted a DEI project study, which included a Load Research project and Pilot Demonstration projects. The Load Research project was designed to establish the relationship between applied voltage and energy, in addition to how applied voltage affects demand for different end-use load types, such as electric heating, electric water heating, and air conditioning. The Pilot Demonstration projects controlled the voltage at the substation in order to determine the performance of different efficiency methods.

#### *Phase I Concluded in 2007*

The NEEA study's final report shows that operating a utility distribution system in the lower half of the acceptable voltage range of 120 through 114 volts saves energy (kWh), reduces demand (kW), and reduces reactive power (i.e., kilovolt ampere reactive [kvar]) requirements without negatively impacting the customer. The energy-savings results are within the expected values of 1% to 3% total energy reduction, 2% to 4% reduction in kW demand, and a 4% to 10% reduction in kvar demand. As part of the completion of this project, the 66 Home Voltage Regulators (HVRs) operating in southern Idaho since March 2006 were removed during the summer of 2007. The purpose of the HVR was to adjust service entrance voltage at the residence.

#### *Project for 2007*

A new pilot was implemented during the second quarter of 2007 to demonstrate remote end-of-feeder control of the station transformer load-tap changer. The project used wireless communication between the end-of-feeder and the substation to adjust the substation voltage based on the measured end-of-feeder voltage. Application of technology allows better control of the end-of-feeder voltage.

In December 2007, R. W. Beck, Inc., a contractor for NEEA, published the Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report. This report and additional information about DEI is available at http://rwbeck.com/neea. The estimated, annual project savings were reported to be 8,563 MWh.

#### *Project for 2008*

In 2008, the remote end-of-feeder control of the station transformer load-tap changer project was changed from a pilot project to a permanent installation. In addition, studies began to identify additional locations to implement the techniques identified in the pilot study. The initial phase will include locations that can be converted with minimal or no capital expenditures. Future phases will be those locations that require more extensive resources to implement.

In 2008, DEI Calculators, which are Excel-based tools, were completed and presented to the RTF. These calculators include a manager's tool that provides high-level results and an engineer's tool that allows users to develop multiple scenarios and compare results. These tools were developed to be used primarily by smaller utilities that may or may not have the resources to do the analysis necessary to implement a DEI-based project.

### Residential NEEA Activities in Idaho

NEEA continues to provide support for the ENERGY STAR® Homes Northwest program offered by Idaho Power. NEEA offers technical assistance, funding for certifications, and builder and marketing support.

### Other NEEA Activities in Idaho

In 2008, Idaho Power participated in two major studies in Idaho Power's service area. The ENERGY STAR Homes Northwest impact evaluation continued throughout 2008 with final results available in 2009. Idaho Power assisted NEEA in developing the sample plan for this study and provided data necessary to assess the program. The impact evaluation required that ENERGY STAR certified homes were audited and had measurement and verification equipment installed.

Idaho Power participated with NEEA to conduct a Commercial Building Stock Assessment (CBSA). The purpose of this study was to update the original CBSA completed in 2003. Idaho Power contracted with the Cadmus Group to over-sample buildings in Idaho Power's service area to gather more detailed information to enhance program planning in the commercial sector. Idaho Power provided data and assisted the contractor in reviewing the commercial-building characteristics in Idaho Power's service area.

Each year, NEEA underwrites the Idaho Energy Conference through a contract with the Association of Idaho Cities. NEEA continues to provide general information support to the region by funding the EnergyIdeas Clearinghouse® and ConWeb®.

NEEA funded a variety of research projects that were reported on in 2008. These reports are valuable to Idaho Power in that they provide information for creating and evaluating Idaho Power's programs. These research projects included Baseline Characteristics of the 2002–2004 Nonresidential Sector of Idaho, Montana, Oregon, and Washington. They also included Market Research Reports for ENERGY STAR Homes Northwest Focus Groups, Residential Ductless Heat Pump Market Research and Analysis, Residential New Construction Billing Analysis, Analysis of Window Energy Savings in Commercial Buildings in the Northwest, ENERGY STAR Consumer Products Lighting Project, 80 PLUS Personal Computer Power Supplies, and seven reports on the BetterBricks initiative in the commercial sector.

## *NEEA Funding*

In 2005, Idaho Power began the first year of the 2005–2009 contract and funding agreement with NEEA. Per this agreement, Idaho Power committed to fund $1.3 million annually in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2008, 72% was funded through the Idaho and Oregon Riders, and 28% was funded by a credit accumulated during the previous contract period.

In 2008, Idaho Power paid $942,014 to NEEA. The Idaho jurisdictional share of the payments was $894,913.31, while $47,100.69 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

Preliminary estimates reported by NEEA indicate that Idaho Power's share of regional market transformation MWh savings for 2008 is 32,672 MWh, or 3.7 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their Web site at www.nwalliance.org.

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# ENERGY EFFICIENCY ADVISORY GROUP (EEAG)

Formed in May 2002, the EEAG provides input on formulating and implementing energy efficiency and demand-reduction programs funded by the Rider. Currently, the EEAG consists of 12 members from across Idaho Power's service area and the Pacific Northwest. Members represent a cross-section of customers, including individuals from the residential, industrial, commercial, and irrigation sectors, as well as representatives for the elderly, low-income, environmental organizations, state agencies, public utility commissions, and Idaho Power.

In 2008, the EEAG met three times: February 7, May 13, and October 2. During the meetings, Idaho Power requested recommendations on new program proposals, provided a status of the Rider funding and expenses, updated ongoing programs and projects, and supplied information on DSM issues.

## EEAG Program Recommendations

The following section provides an overview of topics addressed during the meetings and a review of the input provided to Idaho Power by the EEAG regarding major program implementation and operational issues in 2008. Various operational DSM programs were reviewed by EEAG during the 2008 meetings. Only substantial changes or modifications associated with EEAG input and new programs and pilots are presented in the following.

## Residential Programs

Residential programs reviewed in 2008 included the Home Products Program, Heating & Cooling Efficiency Program, ENERGY STAR® Homes Northwest, and A/C Cool Credit. Progress updates were provided on the Holiday Lighting Program, Idaho Green Expo, and Energy Efficient Lighting program. Pilots started in 2008, and new programs for 2009, including the Attic Insulation Pilot and the Home Weatherization Pilot, and the 2009 Refrigerator Recycling Program, were also discussed.

### *Home Products Program*

The Home Products Program targets changing consumer purchases from regular appliances to ENERGY STAR qualified appliances. Initially Idaho Power considered three types of appliances to include in this program. Ultimately, clothes washers were the only appliance that met the cost-effectiveness tests. The Consortium for Energy Efficiency, Inc. (CEE) rates the energy efficiency of home appliances, including residential clothes washers. CEE rates clothes washers as tier 1, tier 2, or tier 3, with tier 3 being the most efficient. However, the CEE tier ratings are not readily apparent to customers. Due to this difficulty of letting the public know about the difference in the tier levels of washers, Idaho Power was considering one incentive amount regardless of the ENERGY STAR qualified washer purchased.

#### Recommendations

Members discussed reasonable incentive amounts and recommended an incentive of $50 for either Tier I or Tier II clothes washers be offered. Idaho Power was advised to consider joining with water suppliers or wastewater companies to add an educational piece to the incentive.

### Action

Effective April 2008, the $50 clothes washer incentive was offered for either tier clothes washers. Washer purchases made after April 2008 qualified for Idaho customers, and washer purchases made after May 21, 2008 qualified for Oregon customers. The ENERGY STAR Appliance program was renamed the Home Products Program in August 2008 and expanded to include ENERGY STAR qualified refrigerators, ceiling fans with light kits, or ceiling fan light kit attachments.

Idaho Power staff met with the Idaho Department of Environmental Quality (DEQ) to discuss how to educate water-system operators regarding Idaho Power energy efficiency programs. Many of the water systems use pump configurations similar to irrigation. There might be opportunities for the users to participate in Idaho Power Commercial energy efficiency programs and receive incentives for upgrading pumps or, for larger systems, performing facility upgrades. Discussions included the possibility of putting information in the state drinking and wastewater newsletters.

## *Refrigerator Recycling Program*

Idaho Power proposed to the EEAG two program management options for conducting the Refrigerator Recycling program. The first option was through an internal program managed and operated completely by Idaho Power, while the second option was through a contract with a third-party for management and operation of the program. Pros and cons of the two options were discussed. Under the Idaho Power-operated program, participating customers would be responsible for removal and disposal of the old refrigerator. Some members felt that might be challenging and prohibitive for customers, especially the elderly. The EEAG group favored the third-party management option, where the third-party contractor handles the removal and disposal of the old unit. The third-party contractor could also conduct the verification of the condition of the old unit. Though an internally managed program was the more cost-effective option, EEAG thought that the third-party management option might attract higher participation levels.

### Recommendations

The EEAG recommended that Idaho Power pursue a third-party contractor for program implementation and offer the program in Oregon.

### Action

Idaho Power plans to issue a request for proposal (RFP) for a third-party contractor to operate the program. After the RFP is received and reviewed, a potential successful contractor will be selected and a contract negotiated. Program implementation is planned for May 2009. Idaho Power plans to offer a $30 refrigerator incentive to customers recycling working refrigerators.

## *Attic Insulation Pilot*

Idaho Power presented to the EEAG a potential program structure for the Attic Insulation Pilot. Potential energy savings, incentives, data collection, and timelines were discussed.

### Recommendations

Data collection suggestions included taking spot measures from the air handler and measuring attic temperatures and compressor run-time for air conditioners. Other suggestions included checking the ductwork prior to insulation.

### Action

The Attic Insulation Pilot program was launched. It offered customers a $0.15 per square foot incentive for the professional installation of additional attic insulation. The pilot was conducted in Boise, Twin Falls, and Pocatello. Installations began in May 2008 and were completed by mid-July. Idaho Power collected indoor and outdoor temperatures and compressor runtimes. Also collected was information on the physical characteristics of the participants' homes, including the pre- and post-installed insulation R-values.

Information from the pilot was used to evaluate the cost-effectiveness of the potential program. It was determined that this was a cost-effective program opportunity. As a result of the Attic Insulation Pilot, Idaho Power will proceed in 2009 with the pilot, renamed the Home Improvement Program.

## *Home Weatherization Pilot*

Introduced in 2008 was a new Home Weatherization Pilot concept, which targeted customers who applied for, but were deemed ineligible for participation in, WAQC and who are probably not likely to participate in other programs. Idaho Power collaborated with Home Energy Management, LLC, to complete 20 homes in 2008 in the Twin Falls area. Like the WAQC program, there is no cost to the customer. After the weatherization projects are completed, Idaho Power will complete the verification and analysis process, comparing the current SIR with Idaho Power cost-effectiveness models. The differences between the existing WAQC program and the pilot are the pilot's higher income eligibility criteria and that federal dollars cannot be leveraged in the pilot. The guidelines for the pilot resemble WAQC guidelines in all other aspects. Using the pilot structure allows Idaho Power to proceed and evaluate the results to determine utility costs.

### Recommendations

Members expressed support of the pilot.

### Action

The pilot was launched during the last quarter of 2008. Energy Management, LLC, weatherized 16 homes for the pilot. Energy savings achieved were 71,680 kWh/year. The average home saved 4,480 kWh/year. Total costs were $52,807. Average individual project cost was $3,300. Based on the pilot, Idaho Power plans to expand in 2009 and weatherize 60 homes in Idaho Power's southern region service area under the newly named Weatherization Solutions for Eligible Customers program.

# Commercial and Industrial Programs

At the October EEAG meeting, Idaho Power presented the Commercial Demand Response program and the Small Commercial A/C Cycling Pilot program. Updates were also provided on the Easy Upgrades program changes.

## Commercial Demand Response Program

Idaho Power proposed the Commercial Demand Response program where Idaho Power would contract with a third-party demand response aggregator for provision of peak load reduction. The third-party would recruit customers and guarantee Idaho Power a determined amount of peak load reduction at a contracted price.

### Recommendations

The third-party contractor selected for the program should tailor their program to Idaho Power's service area commercial customers.

### Action

Idaho Power issued an RFP in August for a demand response aggregator. Four proposals were received and reviewed. Idaho Power selected EnerNOC as the contractor. EnerNOC provides demand response services for numerous other utility companies throughout the United States, has established relationships with the many businesses in Idaho Power's service area, and understands the unique characteristics of Idaho Power's customers. Idaho Power and EnerNOC have negotiated a contract to reduce peak demand at critical times. The aggregator will negotiate contracts directly with Idaho Power commercial and industrial customers to achieve the contracted demand reduction. Analysis has shown that this program will be cost-effective. Pending IPUC approval, Idaho Power expects to launch the commercial demand response program in 2009.

## Small Commercial A/C Cycling Pilot

Idaho Power introduced a proposed demand response program for small commercial users. Demand reduction would be achieved by controlling customers' use of air conditioners using programmable thermostats. It is similar to the residential A/C Cool Credit program, except it is designed for small commercial customers using less than 2,000 kWh per month. Under this proposed program, there would not be a customer bill credit, as there is in the residential program, and the customer's benefit would be the provided programmable thermostat and installation.

### Recommendations

Given the high cost of serving the summer peak hours, it was requested that Idaho Power consider aggressively launching the program and, if possible, incorporate a lighting retrofit along with the programmable thermostat.

### Action

The cost-effectiveness analysis of a small commercial A/C Cycling program is under review.
The proposed implementation and administrative costs are higher than initially expected. The potential for cost-effective peak load reduction in the market is uncertain. Idaho Power believes a pilot program to study the energy impacts is needed. Idaho Power is renegotiating with vendors, exploring additional program offerings, and considering including the small commercial program in the current residential A/C Cool Credit program. Through these efforts, Idaho Power is attempting to design a cost-effective program.

## Irrigation Programs

The redesigned Irrigation Peak Rewards program was introduced at the October 2, 2008, EEAG meeting. Idaho Power proposed the Irrigation Peak Rewards program include a dispatchable demand response option.

This program would be offered to Idaho Power customers in Idaho and Oregon. Three options would be available for customers to choose between: 1) the currently offered timer option, 2) a dispatchable option that allows Idaho Power to remotely turn participants' pumps on or off, or 2) a large service location option that allows participating customers, after being notified by Idaho Power, to turn large horsepower pumps off during summer peak hours. High savings and benefits are expected from this new program.

### Recommendations

Based on the success of the current Irrigation Peak Rewards program and the potential for substantially increased cost-effective peak-demand reduction, the EEAG recommended that Idaho Power expand the program. A dispatchable irrigation demand response option could be implemented for irrigation customers in 2009.

### Actions

Expanding on the current Irrigation Peak Rewards program, Idaho Power developed a new program that offers three options for eligible service locations in Idaho and Oregon. The first option will continue with a timer option. The second, new dispatchable option allows Idaho Power to remotely turn on and off participating customers' pumps. Under the third option, for large service locations of 1,000 or greater, participants would manually turn their pumps on and off. The combination of these three options enables Idaho Power to substantially decrease demand during peak load hours.

On January 14, 2009, the IPUC approved the program proposal. In February 2009, Idaho Power began sending mailings to irrigation customers and holding workshops to educate irrigation customers and market the new program offering.

## Additional Topics Covered

In the EEAG meetings, Idaho Power presented additional topics, including an overview of the *Demand-Side Management 2007 Annual Report*, the report's structure, and 2007 programs documented in the report. EEAG was updated throughout the year regarding the Rider balance and energy efficiency program performance.

In 2008, as the result of an RFP process, Idaho Power hired a consultant company, Nexant, for a DSM potential study regarding creating or expanding programs. Preliminary findings from this report indicated that, within the residential sector, there was a limited amount of additional energy savings potential beyond what Idaho Power is currently offering.

### Recommendations

A peer review of the results of the Nexant report 2008 market potential study was recommended.

### Action

A peer review was initiated and results are due in the spring of 2009.

# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavior change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education initiative's goal is promoting energy efficiency to the residential community sector. This goal is achieved by creating and delivering educational programs that result in energy-efficient and conservation-oriented behaviors and choices.

### *Activities*

The Residential Energy Efficiency Education initiative distributed energy efficiency messages through a variety of communication methods during 2008. Increased customer awareness of energy-saving ideas was accomplished via distribution of over 8,000 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. In June, an Energy Efficiency Guide outlining the residential programs and monthly tips was published in area newspapers. Energy Awareness month, held in October, included a jointly sponsored energy efficiency exhibit at the Discovery Center, a newspaper campaign, and the Fall Energy Efficiency & Green Livings Series. Held at the Boise Public Library, this five-class series promoting energy efficiency was initiated in 2007. This year's topics included an open dialogue with energy leaders; simple no- and low-cost ways to save energy; easy ways to re-think, reduce, reuse, and recycle; how to landscape for energy savings; and how to remodel existing homes and build new homes consistent with the Leadership in Energy and Environmental Design (LEED) and Northwest ENERGY STAR® Homes Northwest standards. The five sessions combined attracted 147 participants.

The Residential Energy Efficiency Education initiative collected participant evaluations at the end of each of the five classes focusing on energy efficiency held at the Boise Public Library during 2008. Combined, the five sessions had 147 participants and a survey return rate of 51%. The majority of respondents indicated they "strongly agreed" that the information was useful and met their expectations. The majority of respondents indicated they "definitely would" recommend the class to family and friends.

During the fourth quarter of 2008, Idaho Power provided weekly energy efficiency messages on The HomeFix Show with Joe Prin on 580 KIDO AM. Another media campaign around energy-efficient gift purchases rounded out the year.

In addition to these activities, Idaho Power sponsored the Energy Conservation and Recycling track at the first annual Idaho Green Expo. Specialists from Idaho Power presented three workshops and addressed attendees' questions at the Idaho Power's exhibitor booth. During 2008, Idaho Power developed a new educational program for fourth- to sixth-grade students. "Simple Ways to Save Energy" is a 45–60 minute presentation focusing on energy-efficient actions within each child's ability. Idaho Power further increased its energy efficiency presence in the community by providing program information at events such as Teachers' Night Out, Idaho Smart Growth, and the St. Luke's Women's Show.

Plans for 2009 include expanding the Energy Efficiency & Green Livings Series to other customers outside the Treasure Valley. Adult energy efficiency presentations for corporate and community settings are being developed for use by Idaho Power staff. Energy efficiency displays such as three-dimensional demonstration devices, brochures, and other educational materials will be developed in 2009. Placing stand-alone energy efficiency displays in high-traffic public venues, such as libraries and corporate lobbies, is another method Idaho Power intends to use to reach large numbers of customers with energy efficiency messages.

## Commercial Education Initiative

Idaho Power launched its Commercial Education initiative in the spring of 2008. The main objectives of this initiative are to educate commercial customers about energy efficiency, increase participation in existing commercial energy efficiency and demand-reduction programs, enhance customer satisfaction, and reduce energy use. In 2008, Idaho Power identified methods for educating customers about energy efficiency and addressed ways of changing customer practices and behaviors.

The initiative made progress in helping commercial customers, trade allies, field staff, professional organizations, and community organizations indentify common problems or energy efficiency opportunities. Potential solutions and ideas were addressed through networking with energy information sources, such as E Source, Idaho Power staff, trade allies, and customers. For example, many customers have been very successful in reducing their energy usage by utilizing Idaho Power incentive programs. Subsequently, customers have invited Idaho Power field staff and other customers with similar facilities to visit their projects and see, firsthand, successful energy efficiency projects.

In 2009, the initiative will continue its efforts in commercial customer education. Plans are to increase the focus on providing commercial customers with information pertinent to their facilities and operational constraints and to identify resources for achievement of their energy efficiency objectives.

## Local Energy Efficiency Funds (LEEF)

The purpose of LEEF, formerly called the Small Projects and Education Fund, is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs, but that still provide a defined benefit to furthering DSM targets.

Two projects were paid for from this fund in 2008. In spring 2007, MHAFB applied for funds to remove incandescent lighting from an outdoor running track and replace them with solar lighting. A cost-effective analysis was completed for the project in 2007 and permission was provided by Idaho Power for the AFB to move forward. The actual lighting was installed in the summer of 2008, and LEEF funds paid $13,764 for 114,700 kWh savings per year.

Another completed project in 2008 was in a Marsing home. The owner created a “Living Wall” consisting of hundreds of plants blanketing a wall and floor. The plants serve as an air conditioner, decreasing the air temperature around the “Living Wall” and reducing energy use by up to 20% per month. LEEF funds paid $450 for 1,231 kWh savings per year.

# REGULATORY INITIATIVES

Idaho Power is testing the effects of a Fixed Cost Adjustment (FCA) and a Performance-Based DSM Incentive as part of a three-year, two-pilot initiative. The two pilots are being operated on a limited basis to allow for a thorough evaluation to be conducted prior to a broader application of the financial mechanisms. 2007 was the first year of the pilots. Actual performance and usage data from 2007 was evaluated during the spring of 2008, and Idaho Power made the following filings in response to the first-year results.

## Fixed-Cost Adjustment Pilot

Under the FCA, rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent rate case and the fixed costs that Idaho Power actually received the previous year through energy sales. This decoupling mechanism removes the financial disincentive that exists when Idaho Power invests in DSM resources. The FCA pilot is limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through energy charges. Confining the pilot to the residential and small commercial classes also allows the true-up mechanism to be tested on a limited basis to minimize any unintended consequences. On March 12, 2007, the IPUC authorized a three-year pilot of the FCA under Order No. 30267.

On March 14, 2008, Idaho Power filed an application to implement FCA rates reflecting 2007 actual data. According to the application, during 2007, the average energy use per residential customer increased. Idaho Power collected approximately $3.5 million more for its fixed costs than was established in the agreed-upon residential FCA formula. The application also indicated that the small commercial class saw a decrease in per-customer energy use during 2007. This means Idaho Power under-collected approximately $1.1 million of its fixed costs for this customer class. On May 30, 2008, the IPUC issued Order No. 30556 directing Idaho Power to collect the net fixed cost adjustment of $2.4 million and to distribute the rate adjustment across both residential and small commercial customers. This action resulted in a rate reduction of 0.045676 cents/kWh, effective June 1, 2008, through May 31, 2009, for all residential and small commercial customers. On March 13, 2009, Idaho Power will file an application to implement FCA rates reflecting 2008 actual data.

## Performance-Based DSM Incentive Pilot

To complement the FCA pilot, Idaho Power is testing the effects of a Performance-Based DSM Incentive mechanism. On March 12, 2007, the IPUC issued Order No. 30268 authorizing the implementation of a Performance-Based DSM Incentive pilot that allows Idaho Power to retain a portion of the financial benefits resulting from DSM activities when energy savings targets are exceeded. Should it fail to meet energy savings levels previously achieved, Idaho Power is subject to a penalty under the incentive pilot. During the pilot period, the incentive mechanism is being applied only to the ENERGY STAR Homes Northwest Program. By applying this mechanism on a limited basis, Idaho Power is able to gain a better understanding of the effects of a performance incentive while minimizing the potential impact to customers. Idaho Power ultimately intends to use the information gained during the pilot period to develop a performance-based incentive mechanism that can be applied to the entire portfolio of DSM programs.

On March 14, 2008, Idaho Power filed the actual 2007 data in the *Performance-Based Demand-Side Management Incentive Pilot Performance Update*. According to the final ENERGY STAR Homes Northwest program results for 2007, Idaho Power has estimated the program achieved a market share of 5%. This value is within the market share dead-band established for 2007 at 5.0% to 7.0%, and, therefore, Idaho Power is not eligible for a performance incentive nor is Idaho Power subject to a penalty.

# ENHANCED COMMITMENT

As part of the FCA implementation process, Idaho Power is committed to enhancing its efforts toward promoting energy efficiency. Idaho Power's overall DSM performance last year is an indication of this commitment. In 2008, the energy savings from Idaho Power's DSM in-house programs increased 54% over 2007 levels while expenditures increased only 35%. In several other key areas, Idaho Power actively pursued numerous, additional opportunities to promote energy efficiency, including, but not limited to:

- Broad availability of efficiency and load management programs
- Building code improvement activity
- Pursuit of appliance code standards
- Continued expansion of DSM programs beyond peak-shaving/load-shifting programs
- Third-party verification
- Promotion of energy efficiency through electricity rate design
- Idaho Power's internal energy efficiency commitment

Through its DSM portfolio, Idaho Power now offers programs in virtually every major market segment in its service area. For residential customers, there are programs for new homes, existing homes, and lower-income buildings. In the commercial and industrial sectors, there are programs in both the new and existing building market segments. In the irrigation sector, Idaho Power offers incentives for existing systems and new irrigation systems. Furthermore, Idaho Power has implemented demand response programs in the residential and irrigation sectors and plans to implement a new demand response program in the commercial and industrial sector in 2009. The specific programs added, modified, or expanded in 2008 include:

- A new Home Weatherization Pilot launched in the Twin Falls area in the fourth quarter of 2008. Based on the pilot results, Idaho Power plans to expand the pilot into a full-scale program, titled Weatherization Solutions for Eligible Customers, offered in the Twin Falls area in 2009.
- A new Attic Insulation Pilot was launched in 2008. This successful pilot will expand to a full-scale program in 2009 under the name Home Improvement.
- A new ENERGY STAR® Appliance Program began in 2008 and will continue into 2009 under the name Home Products Program.
- The A/C Cool Credit program expanded into the new service areas of Payette and Twin Falls. Additionally in 2008, Idaho Power applied this program to the housing at Mountain Home Air Force Base.

- The Easy Upgrades program sponsored a special summer lighting product promotion.

- Easy Upgrades concluded a special offer of VendingMiser™ units that ran from November 2007 through October 2008, with more than 3,600 units installed.

- In 2008, Idaho Power filed with the IPUC to expand the Irrigation Peak Rewards program to provide a dispatchable demand response option.

- The Custom Efficiency program was modified to increase the minimum project size from 20,000 kWh to 100,000 kWh in order to allow resources to be focused on larger projects.

- For Oregon customers, Idaho Power filed three new programs and modified three more. The new programs are A/C Cool Credit, Home Products Program, and Heating & Cooling Efficiency Program. The programs modified are Change a Light Program, Easy Upgrades, and Manufactured Housing Energy Efficiency Program.

## Building Code Improvement Activity

Through Idaho Power's funding of the NEEA and codes-related efforts, Idaho Power has assisted in increasing energy efficiency requirements in Idaho's building codes, including the adoption of a new commercial and residential code (2006 IECC) effective January 1, 2008. Idaho Power has two key roles once the codes are adopted: 1) informing the design community of code changes and 2) modifying Idaho Power energy efficiency programs to reflect the new codes. In 2008, Idaho Power modified the Building Efficiency program to reflect the adoption of the new 2006 IECC. Furthermore, the new residential code in 2008 resulted in code coming closer to the requirements in the ENERGY STAR Homes Northwest Builder Option Package, which directly led to a decrease in the Idaho Power ENERGY STAR Homes Northwest program incentive amount.

## Pursuit of Appliance Code Standards

Idaho Power contracted with Quantec, LLC, to conduct a study of potential savings and costs associated with enacting appliance efficiency standards in Idaho similar to those recently enacted in Oregon. The final report, *Idaho Power Appliance Standards Assessment*, was completed January 9, 2008. The 2009 IRP will include an evaluation of the findings from this study.

## Continued Expansion of DSM Programs Beyond Peak-Shaving/Load-Shifting Programs

Idaho Power has focused additional resources toward energy efficiency education, marketing, and promotion. Increased customer awareness of energy-saving ideas was accomplished via distribution of over 8,000 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*. The five-class Fall Energy Efficiency & Green Living Series were held for a second year at the Boise Public Library, with 147 participants attending in 2008. Incremental educational programs for 2008 included weekly energy efficiency messages on The HomeFix Show with Joe Prin on 580 KIDO AM radio, provision of energy efficient gift purchase tips during the holidays, sponsorship of the Energy Conservation and Recycling track at the first annual Idaho Green Expo, and development of a new presentation for fourth- and sixth-grade students titled "Simple Ways to Save Energy."

For industrial and commercial customers, Idaho Power continues to promote the offerings of the IEA through NEEA to food processing customers. In 2008, there were six facilities in the Idaho Power service area committed to implementing Continuous Energy Improvement practices at their facilities. In 2008, there were nine offered classes covering motors, pump systems, compressed air, and ammonia refrigeration. This technical training is a key element of customer education, which helps drive energy efficiency projects at customer facilities. Idaho Power strengthened the working relationship with the Boise chapter of the Building Owners and Managers Association (BOMA). Also, Idaho Power worked closely with Bonneville Power and other utilities on research into the effectiveness of replacing damaged door gaskets in refrigerated walk-ins and reach-in display cases. In 2008, Idaho Power became a member of the Utility IT Energy Efficiency Coalition, which is charged with supporting development of energy efficient instructional technology and data center operations. Idaho Power also became an associate member of the Climate Savers Computing Initiative.

In 2008, Idaho Power continued to increase energy efficiency awareness among its customers through a variety of media outlets. Idaho Power distributed energy efficiency information via 28 *Update* articles, 22 *News Scans* articles, 5 *E-News* videos, 15 articles in *Consumer Connection*, 10 bill inserts, 13 radio interviews, 1 television article, and 2 press releases. In March, Idaho Power celebrated its first company-wide Energy Efficiency Month for employees, encouraging their participation in programs.

## Third-Party Verification

Idaho Power uses third-party consultants to verify that program specifications are met, to verify the amount of energy savings achieved, and to obtain data on energy efficiency, demand response measures, and programs.

Idaho Power provides funding and participation in the RTF. The RTF is an advisory committee that was established in 1999 to develop standards for verifying and evaluating savings from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information on programs and measures, and uses the RTF databases to provide deemed savings for some energy efficiency measures.

In 2008, Idaho Power contracted with Nexant, Inc., to assess the market potential for DSM activities in Idaho Power's service area. For this study, Nexant developed spreadsheet models estimating DSM potential as economic conditions and end-use measure assumptions change. Nexant will provide a final document in 2009. The information provided by the potential study will be included in the 2009 IRP.

In spring 2008, Idaho Power contracted with Ecotope, Inc., to provide energy savings estimates for the Attic Insulation Pilot. At the conclusion of the pilot, Idaho Power sought Ecotope's expertise to update the estimated energy savings impacts of the program based on revised assumptions from the pilot. With these updated energy-savings estimates, the cost-effective program will continue under the name Home Improvement Program.

Idaho Power contracted with the Boise Integrated Design Laboratory (IDL) to provide evaluation functions, including measurement and verification. Under this contract, an evaluation has been initiated on certain measures in the Building Efficiency program. Idaho Power expects to work closely with IDL to study other commercial sector programs in the future.

In the commercial sector, Idaho Power participated in the NEEA Commercial Building Stock Assessment (CBSA), updating the original study from 2003, which is used for identifying and verifying commercial building stock characteristics in the Pacific Northwest. Idaho Power contracted with the Cadmus Group for this study, requesting an over-sample of Idaho Power's service area to obtain a statistically valid building sample for program planning purposes.

Since 2005, the A/C Cool Credit program contracted with a third-party installation contractor, Honeywell, Inc., for installation of radio-pager controlled switches on participants' A/C units. To ensure customer satisfaction, this contractor performs quality-assurance inspections on installations and makes follow-up phone calls to recent switch recipients. Honeywell submits weekly reports to Idaho Power program staff on inspections, follow-ups, and results.

Idaho Power participated with NEEA throughout 2008 to evaluate the impacts of the ENERGY STAR Homes Northwest program. Results of this study will be finalized in 2009. The ENERGY STAR Homes program regularly uses certified Home Performance Specialists for third-party verification, ensuring that each ENERGY STAR qualified home is built to ENERGY STAR standards. The Idaho Office of Energy Resources then certifies each of these homes as an ENERGY STAR home.

The Energy House Calls program contracts with third-party experts to perform quality assurance on 5% of homes serviced by the program. These contractors visit the site within approximately one month of the energy house call and verify that the energy efficiency measures were performed to program specifications.

The Heating & Cooling Efficiency Program has a third-party quality assurance contractor. Honeywell, Inc., performs on-site verifications on approximately 5–7% of completed jobs.

## Promotion of Energy Efficiency through Electricity Rate Design

In June, Idaho Power filed the 2008 General Rate Case with proposals for significant changes in rate design for most customer classes. These rate-change proposals were driven by the explicit Idaho Power objective of providing customers with cost-based price signals, which encourage the wise and efficient use of energy. Rate design proposals for the residential and small commercial customers included inclining block rates for both summer and non-summer seasons. These block rates encourage customers to use fewer kWh each month and thereby save a larger increment on their electricity bills than if they did not have block rates. Rate design proposals for the larger commercial and industrial customers included time-of-use rates, which encourage customers to reduce or shift electricity usage from peak times of the day. The rate design proposal for the irrigation customer centered around encouraging energy efficiency through load-factor pricing.

## Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, incenting, and educating its customers. In 2008, Idaho Power constructed a new operations facility in Lake Fork, Idaho. Almost 99% complete as of December 2008, it is the first facility built by Idaho Power to use an integrated approach to maximize expertise and coordination throughout the process. Many companies, including Idaho Power, are concentrating their efforts towards LEED certification.

The Long Valley Operations Center is certain to qualify for Silver LEED certification, and will most likely have enough points for the Gold level.

In 2008, Idaho Power successfully retrofitted the entire fifth floor of the Corporate Headquarters (CHQ). Included in this retrofit was the use of low volatile organic compounds (VOC) paint, recycled carpet tile, and low VOC glue to adhere them. The new window shading and the use of T5 lighting and ballasts are projected to save approximately 40% of the energy expended by the old lighting packages. Additionally, shorter, 53" wall panels are used for cubical partitions, allowing more daylight and reducing lighting costs. The plan is to use the fifth floor as the standard for office space in the CHQ and other office areas as budget dollars are approved. Lighting and HVAC upgrades were also made at the Mini-Cassia Operations Center.

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# APPENDICES

This report includes four appendices. Appendix 1 contains financial information for 2008, showing the beginning balance, ending balance, and the expenditures for the Idaho Energy Efficiency Rider, the Oregon Energy Efficiency Rider, BPA funding, and NEEA payments and credits. Appendix 2 also contains financial information. This second appendix shows expenses by funding source for each of Idaho Power's energy efficiency programs or activities. Appendix 3 shows participation, utility cost, total resource cost, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2008. Appendix 4 shows similar data as Appendix 3, but also includes data for past years' program performance, benefit-cost ratios from the utility perspective, and from the total resource cost perspectives for active programs.

## **Appendix 1.** Idaho Rider, Oregon Rider, BPA, and NEEA Funding Balances

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2008 Beginning Balance | $ | 1,483,074.58 |
| 2008 Funding plus Accrued Interest | | 13,454,883.09 |
| Total 2008 Funds | | 14,937,957.67 |
| 2008 Expenses | | (18,880,275.73) |
| **2008 Year-End Balance** | **$** | **(3,942,318.06)** |
| **Oregon Energy Efficiency Rider** | | |
| 2008 Beginning Balance | $ | 410,225.46 |
| 2008 Funding plus Accrued Interest | | 411,602.13 |
| Total 2008 Funds | | 821,827.59 |
| 2008 Expenses | | (625,000.31) |
| **2008 Year-End Balance** | **$** | **196,827.28** |
| **BPA Funding** | | |
| Total Funding and Accrued Interest October 2001–December 2007 | $ | 3,156,889.59 |
| 2008 Accrued Interest | | 2,152.12 |
| Total Funds May 2002–December 2008 | | 3,159,041.71 |
| Total Expenses—Inception through December 2007 | | (3,109,843.04) |
| 2008 Expenses | | (6,950.35) |
| Total BPA Funded Expenses | | (3,116,793.39) |
| **2008 Year-End Balance [(a)]** | **$** | **42,248.32** |
| **NEEA Payments and Escrow Credit Funds Balance** | | |
| 2008 IPC Contractual Obligation | $ | 1,300,000.00 |
| Credit Applied to 2008 Contractual Obligation | | (325,588.00) |
| Interest Credit Applied to 2008 Contract Obligation (b) | | (27,337.00) |
| Interest Credit Applied to 2009 Contract Obligation (c) | | (5,061.00) |
| Total 2008 Cash Payments by IPC | | 942,014.00 |
| Credit Balance | | |
| Beginning Balance Funds Held by NEEA | | (2,115,153.00) |
| 2005-2007 Credit Applied to Contract Obligation | | 1,463,970.00 |
| 2008 Credit Applied to Contract Obligation | | 325,588.00 |
| **2008 Year-End Credit Balance** | **$** | **(325,595.00)** |

[(a)] The 2008 balance of BPA funds was committed to two Solar 4R Schools projects prior to the suspension of BPA funding in 2007. These projects were scheduled for completion in 2008 but have been delayed to 2009.

[(b)] The first quarter invoice for the Idaho Power 2008 contractual obligation to NEEA was processed in December 2007 with the amount scheduled to be amortized over the first quarter. Interest credit of $14,781 was immediately recognized in 2007.

[(c)] The first quarter invoice for the Idaho Power 2009 contractual obligation to NEEA was processed in December 2008 with the amount scheduled to be amortized over the first quarter. Interest credit of $5,061 was immediately recognized in 2008.

## **Appendix 2.** 2008 DSM Expenses by Funding Source (Dollars)

| Sector/Program | Rider Idaho | Rider Oregon | BPA | IPC | Total Program |
|---|---|---|---|---|---|
| ***Energy Efficiency/Demand Response*** | | | | | |
| Residential | | | | | |
| A/C Cool Credit | $ 2,922,985 | $ 45,404 | $ 0 | $ 988 | **$ 2,969,377** |
| Attic Insulation Pilot | 123,454 | 0 | 0 | 0 | **$ 123,454** |
| Energy Efficient Lighting | 1,011,850 | 6,242 | 0 | 200 | **$ 1,018,292** |
| Energy House Calls | 448,992 | 35,388 | 0 | 0 | **$ 484,379** |
| ENERGY STAR® Homes Northwest | 294,579 | 6,388 | 0 | 1,094 | **$ 302,061** |
| Heating & Cooling Efficiency Program | 466,094 | 6,959 | 0 | 498 | **$ 473,551** |
| Home Products Program | 245,219 | 5,541 | 0 | 100 | **$ 250,860** |
| Home Weatherization Pilot | 51,670 | 0 | 0 | 1,138 | **$ 52,807** |
| Oregon Residential Weatherization | 0 | 1,908 | 0 | 5,509 | **$ 7,417** |
| Rebate Advantage | 79,547 | 11,341 | 0 | 0 | **$ 90,888** |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 0 | 1,419,475 | **$ 1,419,475** |
| Commercial/Industrial | | | | | |
| Building Efficiency | 1,006,025 | 47,550 | 0 | 1,434 | **$ 1,055,009** |
| Easy Upgrades | 2,922,340 | 52,556 | 0 | 17,364 | **$ 2,992,261** |
| Holiday Lighting Program | 28,782 | 0 | 0 | 0 | **$ 28,782** |
| Oregon Commercial Audit | 0 | 0 | 0 | 58 | **$ 58** |
| Custom Efficiency | 3,948,617 | 86,858 | 0 | 10,196 | **$ 4,045,671** |
| Irrigation | | | | | |
| Irrigation Efficiency Rewards | 1,878,960 | 193,276 | 0 | 31,466 | **$ 2,103,702** |
| Irrigation Peak Rewards | 1,373,855 | 17,570 | 0 | 40,415 | **$ 1,431,840** |
| **Energy Efficiency Total** | **16,802,969** | **516,981** | **0** | **1,529,934** | **$ 18,849,884** |
| ***Market Transformation*** | | | | | |
| Northwest Energy Efficiency Alliance | 894,913 | 47,101 | 0 | 0 | **$ 942,014** |
| **Market Transformation Total** | **894,913** | **47,101** | **0** | **0** | **$ 942,014** |
| ***Other Programs and Activities*** | | | | | |
| Residential | | | | | |
| Residential Education Initiative | 142,969 | 7,818 | 0 | 130 | **$ 150,917** |
| Commercial | | | | | |
| Commercial Education Initiative | 69,059 | 3,632 | 0 | 46 | **$ 72,738** |
| Other | | | | | |
| CRC Renewables | 0 | 0 | 6,950 | 0 | **$ 6,950** |
| Distribution Efficiency Initiative[(a)] | 0 | 0 | 0 | -1,913 | **$ -1,913** |
| DSM Direct Program Overhead | 135,788 | 6,945 | 0 | 27,178 | **$ 169,911** |
| Local Energy Efficiency Funds | 22,714 | 0 | 0 | 0 | **$ 22,714** |
| **Other Programs and Activities Total** | **370,530** | **18,396** | **6,950** | **25,441** | **$ 421,317** |
| ***Indirect Program Expenses*** | | | | | |
| DSM Accounting and Analysis | 792,478 | 41,483 | 0 | 123,942 | **$ 957,904** |
| Energy Efficiency Advisory Group | 2,148 | 63 | 0 | 0 | **$ 2,211** |
| Special Accounting Entries | 17,236 | 977 | 0 | 1,977 | **$ 20,191** |
| **Indirect Program Expenses Total** | **811,863** | **42,523** | **0** | **125,919** | **$ 980,305** |
| **Totals** | **$18,880,276** | **$ 625,000** | **$ 6,950** | **$ 1,681,294** | **$ 21,193,520** |

[(a)] 2007 Expenses reversed in 2008.

# **Appendix 3.** 2008 DSM Program Activity

| | | | Total Costs | | Savings | | | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|---|
| | Participants | | Utility[b] | Resource[c] | Annual Energy | Summer Peak Demand[d] | Measure Life | Utility | Total Resource |
| **Program** | *(Number)* | *(Units)* | *(Dollars)* | *(Dollars)* | *(kWh)* | *(MW)* | *(Years)* | *($/kWh)* | *($/kWh)* |
| **Demand Response** | | | | | | | | | |
| A/C Cool Credit | 20,195 | homes | $2,969,377 | $2,616,072 | n/a | 22.60 | n/a | n/a | n/a |
| Irrigation Peak Rewards | 897 | service points | $1,431,840 | $189,492 | n/a | 35.10 | n/a | n/a | n/a |
| **Total** | | | **$4,401,217** | **$2,805,563** | **n/a** | **57.70** | | | |
| **Energy Efficiency** | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Attic Insulation Pilot | 282 | homes | $123,454 | $157,866 | 317,814 | 0.03 | 25 | $0.029 | $0.037 |
| Energy Efficient Lighting | 436,234 | CFL bulbs | $1,018,292 | $793,265 | 14,309,444 | | 7 | $0.011 | $0.009 |
| Energy House Calls | 1,099 | homes | $484,379 | $484,379 | 883,038 | | 20 | $0.045 | $0.045 |
| ENERGY STAR® Homes Northwest | 254 | homes | $302,061 | $375,007 | 468,958 | 0.61 | 25 | $0.048 | $0.059 |
| Heating & Cooling Efficiency Program | 359 | homes | $473,551 | $599,771 | 561,441 | | 18 | $0.073 | $0.092 |
| Home Products Program | 3,034 | appliances/fixtures | $250,860 | $468,056 | 541,615 | | 15 | $0.044 | $0.082 |
| Home Weatherization Pilot | 16 | homes | $52,807 | $48,162 | 71,680 | | 25 | $0.055 | $0.050 |
| Oregon Residential Weatherization | 3 | homes | $7,417 | $28,752 | 22,196 | | 25 | $0.025 | $0.096 |
| Rebate Advantage | 107 | homes | $90,888 | $179,868 | 463,401 | | 45 | $0.012 | $0.025 |
| Weatherization Assistance for Qualified Customers—Idaho | 439 | homes/non-profits | $1,375,632 | $1,755,749 | 4,064,301 | | 25 | $0.025 | $0.032 |
| Weatherization Assistance for Qualified Customers—Oregon | 13 | homes/non-profits | $43,843 | $74,048 | 73,841 | | 25 | $0.040 | $0.068 |
| **Sector Total** | | | **$4,223,185** | **$4,964,924** | **21,777,729** | **0.64** | | | |

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.
c. The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
d. Summer Peak Demand is reported where program MW reduction is documented.

## Appendix 3. 2008 DSM Program Activity (continued)

| Program | Participants (Number) | Participants (Units) | Total Costs: Utility[b] (Dollars) | Total Costs: Resource[c] (Dollars) | Savings: Annual Energy (kWh) | Savings: Summer Peak Demand[d] (MW) | Measure Life (Years) | Nominal Levelized Costs[a]: Utility ($/kWh) | Nominal Levelized Costs[a]: Total Resource ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | |
| Building Efficiency | 60 | projects | $1,055,009 | $1,673,268 | 6,598,123 | 0.96 | 12 | $0.017 | $0.028 |
| Easy Upgrades | 685 | projects | $2,992,261 | $10,096,627 | 25,928,391 | 4.49 | 12 | $0.013 | $0.043 |
| Holiday Lighting Program | 14 | projects | $28,782 | $73,108 | 259,092 | | 10 | $0.014 | $0.035 |
| Oregon Commercial Audit | 0 | audits | $58 | $58 | | | n/a | n/a | n/a |
| **Sector Total** | | | **$4,076,109** | **$11,843,061** | **32,785,606** | **5.45** | | | |
| **Industrial** | | | | | | | | | |
| Custom Efficiency | 101 | projects | $4,045,671 | $16,312,379 | 41,058,639 | 4.77 | 12 | $0.011 | $0.044 |
| **Sector Total** | | | **$4,045,671** | **$16,312,379** | **41,058,639** | **4.77** | | | |
| **Irrigation** | | | | | | | | | |
| Irrigation Efficiency Rewards | 961 | projects | $2,103,702 | $5,850,778 | 11,746,395 | 3.47 | 8 | $0.026 | $0.073 |
| **Sector Total** | | | **$2,103,702** | **$5,850,778** | **11,746,395** | **3.47** | | | |
| **Market Transformation** | | | | | | | | | |
| Northwest Energy Efficiency Alliance[1] | | | $942,014 | $942,014 | 32,671,465 | | | | |
| **Other Programs and Activities** | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Residential Education Initative | | | $150,917 | $150,917 | | | | | |
| **Commercial** | | | | | | | | | |
| Commercial Education Initiative | | | $72,738 | $72,738 | | | | | |

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.
c. The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
d. Summer Peak Demand is reported where program MW reduction is documented.
1. Savings are preliminary estimates provided by the NEEA.

## **Appendix 3.** 2008 DSM Program Activity (continued)

| | | | Total Costs | | Savings | | | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|---|
| | Participants | | Utility[b] | Resource[c] | Annual Energy | Summer Peak Demand[d] | Measure Life | Utility | Total Resource |
| **Program** | *(Number)* | *(Units)* | *(Dollars)* | *(Dollars)* | *(kWh)* | *(MW)* | *(Years)* | *($/kWh)* | *($/kWh)* |
| **Other** | | | | | | | | | |
| CRC Renewables | | | $6,950 | $6,950 | | | | | |
| Distribution Efficiency Initiative [2] | | | -$1,913 | -$1,913 | | | | | |
| DSM Direct Program Overhead | | | $169,911 | $169,911 | | | | | |
| Local Energy Efficiency Funds | 2 | projects | $22,714 | $60,100 | 115,931 | | 15 | $0.019 | $0.049 |
| **Total Program Direct Expense** | | | **$20,213,215** | **$43,177,423** | **140,155,765** | **72.03** | | | |
| **Indirect Program Expense** | | | **$980,305** | | | | | | |
| **Total DSM Expense** | | | **$21,193,520** | | | | | | |

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.
c. The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
d. Summer Peak Demand is reported where program MW reduction is documented.
2. 2007 expenses reversed in 2008.

# Appendix 4. DSM Expense and Performance 2002–2008

| Program/Year | | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | | | |
| | 2003 | 204 | $275,645 | $269,680 | | | 0.00 | | | | | | |
| | 2004 | 420 | $287,253 | $274,686 | | | 0.40 | | | | | | |
| | 2005 | 2,369 | $754,062 | $717,902 | | | 2.70 | | | | | | |
| | 2006 | 5,369 | $1,235,476 | $1,131,439 | | | 5.60 | | | | | | |
| | 2007 | 13,692 | $2,426,154 | $2,199,486 | | | 10.80 | | | | | | |
| | 2008 | 20,195 | $2,969,377 | $2,616,072 | | | 22.60 | | | | | | |
| | **Total** | | **$7,947,966** | **$7,209,266** | | | | | | | **1.38** | **1.38** | |
| Irrigation Peak Rewards | | | | | | | | | | | | | |
| | 2004 | 58 | $344,714 | $185,006 | | | 5.60 | | | | | | (1) |
| | 2005 | 894 | $1,468,282 | $479,484 | | | 40.30 | | | | | | (2) |
| | 2006 | 906 | $1,324,418 | $239,977 | | | 31.80 | | | | | | (3) |
| | 2007 | 947 | $1,615,881 | $239,855 | | | 37.40 | | | | | | (3) |
| | 2008 | 897 | $1,431,840 | $189,492 | | | 35.10 | | | | | | (3) |
| | **Total** | | **$6,185,135** | **$1,333,814** | | | | | | | **1.15** | **1.15** | |
| **Residential Efficiency** | | | | | | | | | | | | | |
| Attic Insulation Pilot | | | | | | | | | | | | | |
| | 2008 | 282 | $123,454 | $157,866 | 317,814 | 0.04 | 0.03 | 25 | $0.029 | $0.037 | | | |
| | **Total** | **282** | **$123,454** | **$157,866** | **317,814** | | | **25** | **$0.029** | **$0.037** | **2.48** | **1.94** | |
| Energy Efficiency Packets | | | | | | | | | | | | | |
| | 2002 | 2,925 | $755 | $755 | 155,757 | 0.02 | | 7 | $0.001 | $0.001 | | | (4) |
| | **Total** | **2,925** | **$755** | **$755** | **155,757** | | | **7** | **$0.001** | **$0.001** | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(1) Utility cost restated from $320,309 in prior historical reporting to reflect all funding sources.

(2) Peak MW achieved based on mid-week load reduction schedule.

(3) Peak MW achieved based on equally distributed weekly load reduction schedule.

(4) Utility Cost restated from previously reported $4,910.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy | Savings and Demand Reduction: Average Demand[e] | Savings and Demand Reduction: Peak Demand[f] | Measure Life | Levelized Costs[a]: Total Utility | Levelized Costs[a]: Total Resource | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *(Number)* | *(dollars)* | *(dollars)* | *(kWh)* | *(aMW)* | *(MW)* | *(Years)* | *($/kWh)* | *($/kWh)* | | | |
| Energy Efficient Lighting | | | | | | | | | | | | | |
| | 2002 | 11,619 | $243,033 | $310,643 | 3,299,654 | 0.38 | | 7 | $0.012 | $0.015 | | | |
| | 2003 | 12,663 | $314,641 | $464,059 | 3,596,150 | 0.41 | | 7 | $0.014 | $0.021 | | | |
| | 2004 | 0 | | | | | | | | | | | |
| | 2005 | 43,760 | $73,152 | $107,810 | 1,734,646 | 0.20 | | 7 | $0.007 | $0.010 | | | |
| | 2006 | 178,514 | $298,754 | $539,877 | 6,302,794 | 0.72 | | 7 | $0.008 | $0.014 | | | |
| | 2007 | 219,739 | $557,646 | $433,626 | 7,207,439 | 0.82 | | 7 | $0.012 | $0.010 | | | |
| | 2008 | 436,234 | $1,018,292 | $793,265 | 14,309,444 | 1.63 | | 7 | $0.011 | $0.009 | | | |
| | **Total** | **902,528** | **$2,505,518** | **$2,649,280** | **36,450,127** | | | **7** | **$0.011** | **$0.012** | **4.56** | **4.31** | |
| Energy House Calls | | | | | | | | | | | | | |
| | 2002 | 17 | $26,053 | $26,053 | 25,989 | 0.00 | | 20 | $0.082 | $0.082 | | | |
| | 2003 | 420 | $167,076 | $167,076 | 602,723 | 0.07 | | 20 | $0.023 | $0.023 | | | (5) |
| | 2004 | 1,708 | $725,981 | $725,981 | 2,349,783 | 0.27 | | 20 | $0.025 | $0.025 | | | (6) |
| | 2005 | 891 | $375,610 | $375,610 | 1,775,770 | 0.20 | | 20 | $0.017 | $0.017 | | | |
| | 2006 | 819 | $336,701 | $336,701 | 777,244 | 0.09 | | 20 | $0.035 | $0.035 | | | |
| | 2007 | 700 | $336,372 | $67,616 | 699,899 | 0.08 | | 20 | $0.039 | $0.039 | | | |
| | 2008 | 1,099 | $484,379 | $484,379 | 883,038 | 0.10 | | 20 | $0.045 | $0.045 | | | |
| | **Total** | **5,654** | **$2,452,172** | **$2,183,416** | **7,088,457** | | | **20** | **$0.028** | **$0.025** | **2.20** | **2.20** | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(5) Utility costs restated from $183,653 for historical reporting prior to the 2006 DSM Annual Report.

(6) Utility costs restated from $725,732 for historical reporting prior to the 2006 DSM Annual Report.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ENERGY STAR® Homes Northwest | | | | | | | | | | | | | |
| | 2003 | 0 | $13,597 | $13,597 | | | | | | | | | |
| | 2004 | 44 | $140,165 | $335,437 | 101,200 | 0.01 | 0.09 | 25 | $0.103 | $0.246 | | | (7) |
| | 2005 | 200 | $253,105 | $315,311 | 415,600 | 0.05 | 0.40 | 25 | $0.045 | $0.056 | | | |
| | 2006 | 439 | $469,609 | $602,651 | 912,242 | 0.10 | 0.88 | 25 | $0.038 | $0.049 | | | |
| | 2007 | 303 | $475,044 | $400,637 | 629,634 | 0.07 | 0.61 | 25 | $0.056 | $0.047 | | | |
| | 2008 | 254 | $302,061 | $375,007 | 468,958 | 0.05 | 0.61 | 25 | $0.048 | $0.059 | | | |
| | **Total** | **1,240** | **$1,653,581** | **$2,042,641** | **2,527,634** | | | **25** | **$0.049** | **$0.060** | **1.76** | **1.43** | |
| Heating & Cooling Efficiency Program | | | | | | | | | | | | | |
| | 2006 | 0 | $17,444 | $17,444 | | | | | | | | | |
| | 2007 | 4 | $488,211 | $494,989 | 1,595 | 0.00 | | 18 | $27.344 | $27.710 | | | |
| | 2008 | 359 | $473,551 | $599,771 | 561,441 | 0.06 | | 18 | $0.073 | $0.092 | | | |
| | **Total** | **363** | **$979,207** | **$1,112,204** | **563,036** | | | **18** | **$0.150** | **$0.170** | **0.53** | **0.28** | |
| Home Products Program | | | | | | | | | | | | | |
| | 2007 | 0 | $9,275 | $9,275 | | | | | | | | | |
| | 2008 | 3,034 | $250,860 | $468,056 | 541,615 | 0.06 | | 15 | $0.044 | $0.082 | | | |
| | **Total** | **3,034** | **$260,135** | **$477,331** | **541,615** | | | **15** | **$0.044** | **$0.082** | **1.42** | **0.77** | |
| Home Weatherization Pilot | | | | | | | | | | | | | |
| | 2008 | 16 | $52,807 | $48,162 | 71,680 | 0.01 | | 25 | $0.055 | $0.050 | | | |
| | **Total** | **16** | **$52,807** | **$48,162** | **71,680** | | | **25** | **$0.055** | **$0.050** | **1.31** | **1.43** | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(7) Energy savings based on NEEA standardized per home kWh savings estimates.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oregon Residential Weatherization | | | | | | | | | | | | | |
| | 2002 | 24 | -$662 | $23,971 | 4,580 | 0.00 | | 25 | $0.010 | $0.389 | | | (8) |
| | 2003 | 0 | -$943 | | | | | | | | | | (9) |
| | 2004 | 4 | $1,057 | $1,057 | | | | | | | | | |
| | 2005 | 4 | $612 | $3,608 | 7,927 | 0.00 | | 25 | $0.006 | $0.034 | | | |
| | 2006 | 0 | $4,126 | $4,126 | | | | | | | | | (10) |
| | 2007 | 1 | $3,781 | $5,589 | 9,971 | 0.00 | | 25 | $0.028 | $0.042 | | | |
| | 2008 | 3 | $7,417 | $28,752 | 22,196 | 0.00 | | 25 | $0.025 | $0.096 | | | |
| | **Total** | **36** | **$15,389** | **$67,103** | **44,674** | | | **25** | **$0.026** | **$0.112** | | | (11) |
| Rebate Advantage | | | | | | | | | | | | | |
| | 2003 | 73 | $27,372 | $79,399 | 227,434 | 0.03 | | 45 | $0.008 | $0.022 | | | (12) |
| | 2004 | 105 | $52,187 | $178,712 | 332,587 | 0.04 | | 45 | $0.010 | $0.034 | | | |
| | 2005 | 98 | $46,173 | $158,462 | 312,311 | 0.04 | | 45 | $0.009 | $0.032 | | | |
| | 2006 | 102 | $52,673 | $140,289 | 333,494 | 0.04 | | 45 | $0.010 | $0.027 | | | |
| | 2007 | 123 | $89,269 | $182,152 | 554,018 | 0.06 | | 45 | $0.010 | $0.021 | | | |
| | 2008 | 107 | $90,888 | $179,868 | 463,401 | 0.05 | | 45 | $0.012 | $0.025 | | | |
| | **Total** | **608** | **$358,563** | **$918,882** | **2,223,245** | | | **45** | **$0.010** | **$0.026** | **7.19** | **2.80** | |
| Window A/C Trade Up Pilot | | | | | | | | | | | | | |
| | 2003 | 99 | $6,687 | $10,492 | 14,454 | 0.00 | | 12 | $0.051 | $0.079 | | | |
| | **Total** | **99** | **$6,687** | **$10,492** | **14,454** | | | **12** | **$0.051** | **$0.079** | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(8) Utility Cost reports reversal of $2778 asset from 2001 expense, this amount is included in levelized cost calculation.
In addition, Utility Cost also reports funds subsequently collected on bad loan writeoff expense. These funds are excluded from the annual levelized cost calculation.

(9) Utility Cost reflects collected funds on previous bad loan writeoffs.

(10) Utility Cost reflects only audit and administration costs; there was no further activity in 2006.

(11) Levelized cost calculation includes bad loan write-off expense and funds collected from previously written-off loans.

(12) Utility Cost restated in 2006 from $37,319 to reflect total expense.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential - Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | | |
| 2002 | 197 | $235,048 | $492,139 | | | | | | | | | |
| 2003 | 208 | $228,134 | $483,369 | | | | | | | | | (13) |
| 2004 | 269 | $516,882 | $859,482 | 1,271,677 | 0.15 | | 25 | $0.029 | $0.050 | | | |
| 2005 | 570 | $1,402,487 | $1,927,424 | 3,179,311 | 0.36 | | 25 | $0.033 | $0.045 | | | |
| 2006 | 540 | $1,449,807 | $2,231,086 | 2,958,024 | 0.34 | | 25 | $0.037 | $0.056 | | | |
| 2007 | 397 | $1,290,017 | $1,757,105 | 3,296,019 | 0.38 | | 25 | $0.029 | $0.040 | | | |
| 2008 | 439 | $1,376,543 | $1,755,749 | 4,064,301 | 0.46 | | 25 | $0.025 | $0.032 | | | |
| **Total** | **2,620** | **$6,498,918** | **$9,506,354** | **14,769,332** | | | **25** | **$0.033** | **$0.048** | **2.17** | **1.50** | |
| WAQC—Oregon | | | | | | | | | | | | |
| 2002 | 31 | $24,773 | $47,221 | 68,323 | 0.01 | | 25 | $0.027 | $0.051 | | | |
| 2003 | 29 | $22,255 | $42,335 | 102,643 | 0.01 | | 25 | $0.016 | $0.031 | | | |
| 2004 | 17 | $14,586 | $25,452 | 28,436 | 0.00 | | 25 | $0.035 | $0.067 | | | |
| 2005 | 28 | $44,348 | $59,443 | 94,279 | 0.01 | | 25 | $0.035 | $0.047 | | | |
| 2006 | 0 | $5,566 | | | | | | | | | | |
| 2007 | 11 | $33,607 | $41,700 | 42,108 | 0.00 | | 25 | $0.054 | $0.074 | | | |
| 2008 | 13 | $42,932 | $74,048 | 73,841 | 0.01 | | 25 | $0.040 | $0.068 | | | |
| **Total** | **130** | **$188,067** | **$290,199** | **409,630** | | | **25** | **$0.033** | **$0.053** | **2.02** | **1.26** | |
| WAQC—BPA Supplemental | | | | | | | | | | | | |
| 2002 | 75 | $55,966 | $118,255 | 311,347 | 0.04 | | 25 | $0.013 | $0.028 | | | (14) |
| 2003 | 57 | $49,895 | $106,915 | 223,591 | 0.03 | | 25 | $0.017 | $0.036 | | | |
| 2004 | 40 | $49,885 | $105,021 | 125,919 | 0.01 | | 25 | $0.041 | $0.062 | | | |
| **Total** | **172** | **$155,746** | **$330,191** | **660,857** | | | **25** | **$0.020** | **$0.037** | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(13) Total Resource Cost restated in 2005 to include federal funding administered by CAP agencies. 2002–2003 savings not reported due to integration of fuel types.

(14) Beginning in 2005, BPA funds were no longer applied to CAP agency payments; BPA expense in subsequent years is reflected in the respective state expenses.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy | Savings and Demand Reduction: Average Demand[e] | Savings and Demand Reduction: Peak Demand[f] | Measure Life | Levelized Costs[a]: Total Utility | Levelized Costs[a]: Total Resource | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *(Number)* | *(dollars)* | *(dollars)* | *(kWh)* | *(aMW)* | *(MW)* | *(Years)* | *($/kWh)* | *($/kWh)* | | |
| **Commercial** | | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | | |
| | 2003 | 4 | $5,764 | $9,061 | 33,976 | 0.00 | | 10 | $0.021 | $0.033 | | |
| | 2004 | 0 | $344 | $344 | | | | | | | | |
| | **Total** | **4** | **$6,108** | **$9,405** | **33,976** | | | **10** | **$0.022** | **$0.034** | | |
| Building Efficiency | | | | | | | | | | | | |
| | 2004 | 0 | $28,821 | $28,821 | | | | | | | | |
| | 2005 | 12 | $194,066 | $233,149 | 494,239 | 0.06 | 0.16 | 12 | $0.043 | $0.052 | | |
| | 2006 | 40 | $374,008 | $463,770 | 704,541 | 0.08 | 0.34 | 12 | $0.058 | $0.072 | | |
| | 2007 | 22 | $669,032 | $829,600 | 2,817,248 | 0.32 | 0.45 | 12 | $0.015 | $0.040 | | |
| | 2008 | 60 | $1,055,009 | $1,673,268 | 6,598,123 | 0.75 | 0.96 | 12 | $0.017 | $0.028 | | |
| | **Total** | **134** | **$2,320,937** | **$3,228,609** | **10,614,151** | | | **12** | **$0.024** | **$0.026** | **2.14** | **1.55** |
| Easy Upgrades | | | | | | | | | | | | |
| | 2006 | 0 | $31,819 | $31,819 | | | | | | | | |
| | 2007 | 104 | $711,494 | $1,882,035 | 5,183,640 | 0.59 | 0.78 | 12 | $0.015 | $0.040 | | |
| | 2008 | 685 | $2,992,261 | $10,096,627 | 25,928,391 | 2.96 | 4.49 | 12 | $0.013 | $0.043 | | |
| | **Total** | **789** | **$3,735,574** | **$12,010,481** | **31,112,031** | | | **12** | **$0.013** | **$0.042** | **3.88** | **1.21** |
| Holiday Lighting Program | | | | | | | | | | | | |
| | 2008 | 14 | $28,782 | $73,108 | 259,092 | 0.03 | | 10 | $0.014 | $0.035 | | |
| | **Total** | **14** | **$28,782** | **$73,108** | **259,092** | | | **10** | **$0.014** | **$0.035** | **2.85** | **1.12** |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oregon Commercial Audits | | | | | | | | | | | | | |
| | 2002 | 24 | $5,200 | $5,200 | | | | | | | | | |
| | 2003 | 21 | $0 | $4,000 | | | | | | | | | |
| | 2004 | 7 | $0 | $0 | | | | | | | | | |
| | 2005 | 7 | $5,450 | $5,450 | | | | | | | | | |
| | 2006 | 6 | | | | | | | | | | | |
| | 2007 | 8 | $1,981 | $1,981 | | | | | | | | | |
| | 2008 | 0 | $58 | $58 | | | | | | | | | |
| | **Total** | **73** | **$12,689** | **$16,689** | | | | | | | | | (15) |
| Oregon School Efficiency | | | | | | | | | | | | | |
| | 2005 | 0 | $86 | $86 | | | | | | | | | |
| | 2006 | 6 | $24,379 | $89,771 | 223,368 | 0.03 | | 12 | $0.012 | $0.044 | | | |
| | **Total** | **6** | **$24,465** | **$89,858** | **223,368** | | | **12** | **$0.012** | **$0.044** | | | |
| **Industrial** | | | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | | | |
| | 2003 | 0 | $1,303 | $1,303 | | | | | | | | | |
| | 2004 | 1 | $112,311 | $133,441 | 211,295 | 0.02 | | 12 | $0.058 | $0.069 | | | |
| | 2005 | 24 | $1,128,076 | $3,653,152 | 12,016,678 | 1.37 | | 12 | $0.010 | $0.033 | | | |
| | 2006 | 40 | $1,625,216 | $4,273,885 | 19,211,605 | 2.19 | | 12 | $0.009 | $0.024 | | | |
| | 2007 | 49 | $3,161,866 | $7,012,686 | 29,789,304 | 3.40 | 3.62 | 12 | $0.012 | $0.026 | | | |
| | 2008 | 100 | $4,045,671 | $16,312,379 | 41,058,639 | 4.68 | 4.77 | 12 | $0.011 | $0.044 | | | |
| | **Total** | **214** | **$10,074,442** | **$31,386,846** | **102,287,521** | | | **12** | **$0.018** | **$0.056** | **4.83** | **1.55** | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(15) Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | | | | | | | |
| Irrigation Efficiency Rewards | | | | | | | | | | | | |
| 2003 | 2 | $41,089 | $54,609 | 36,792 | 0.00 | 0.02 | 15 | $0.106 | $0.141 | | | (16) |
| 2004 | 33 | $120,808 | $402,978 | 802,812 | 0.09 | 0.45 | 15 | $0.014 | $0.048 | | | (17) |
| 2005 | 38 | $150,577 | $657,460 | 1,012,883 | 0.12 | 0.40 | 15 | $0.014 | $0.062 | | | |
| 2006 | 559 | $2,779,620 | $8,514,231 | 16,986,008 | 1.94 | 5.10 | 8 | $0.024 | $0.073 | | | |
| 2007 | 816 | $2,001,961 | $8,694,772 | 12,304,073 | 1.40 | 3.41 | 8 | $0.024 | $0.103 | | | |
| 2008 | 961 | $2,103,702 | $5,850,778 | 11,746,395 | 1.34 | 3.47 | 8 | $0.026 | $0.073 | | | |
| **Total** | **2,409** | **$7,197,758** | **$24,174,827** | **42,888,963** | | | **8** | **$0.024** | **$0.082** | **5.49** | **1.64** | (18) |
| **Other Programs** | | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | | |
| 2003 | 71 | $48,853 | $48,853 | 1,825,000 | 0.21 | | 5 | $0.006 | $0.006 | | | (19) |
| 2004 | 26 | $43,969 | $43,969 | 650,000 | 0.07 | | 5 | $0.014 | $0.014 | | | |
| 2005 | 7 | $1,750 | $4,480 | 434,167 | 0.05 | | 5 | $0.001 | $0.002 | | | |
| **Total** | **104** | **$94,572** | **$97,302** | **2,909,167** | | | **5** | **$0.007** | **$0.007** | | | |
| **Other Programs** | | | | | | | | | | | | |
| Commercial Education Initiative | | | | | | | | | | | | |
| 2005 | | $3,497 | $3,497 | | | | | | | | | |
| 2006 | | $4,663 | $4,663 | | | | | | | | | |
| 2007 | | $26,823 | $26,823 | | | | | | | | | |
| 2008 | | $72,738 | $72,738 | | | | | | | | | |
| **Total** | | **$107,721** | **$107,721** | | | | | | | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(16) Restated from $11,190 in prior reports.

(17) Originally reported expense and energy included accrued amounts, restated here to align with accounting records.

(18) Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

(19) Originally reported expense and energy included accrued amounts: 2003 restated from $36,084, 2004 restated from $48,853.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | $21,552 | $43,969 | | | | | | | | |
| 2006 | | $24,306 | $24,306 | | | | | | | | |
| 2007 | | $8,987 | | | | | | | | | |
| 2008 | | -$1,913 | -$1,913 | | | | | | | | |
| **Total** | | **$52,932** | **$66,362** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | $56,909 | $56,909 | | | | | | | | |
| 2008 | | $169,911 | $169,911 | | | | | | | | |
| **Total** | | **$226,820** | **$226,820** | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | $55,722 | $55,722 | | | | | | | | |
| 2003 | | $67,012 | $67,012 | | | | | | | | |
| 2004 | | $108,191 | $108,191 | | | | | | | | |
| 2005 | | $101,177 | $101,177 | | | | | | | | |
| 2006 | | $124,956 | $124,956 | | | | | | | | |
| 2007 | | $31,645 | $31,645 | | | | | | | | |
| 2008 | | $6,950 | $6,950 | | | | | | | | |
| **Total** | | **$495,654** | **$495,654** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | $7,498 | $7,498 | | | | | | | | |
| 2006 | | $56,727 | $56,727 | | | | | | | | |
| 2007 | | $0 | $0 | | | | | | | | |
| 2008 | | $150,917 | $150,917 | | | | | | | | |
| **Total** | | **$215,142** | **$215,142** | | | | | | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | | Participants (Number) | Total Costs: Utility Cost[c] (dollars) | Total Costs: Resource Cost[d] (dollars) | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Demand[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility Benefit/Cost Ratio | Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Local Energy Efficiency Funds | | | | | | | | | | | | | |
| | 2003 | 56 | $5,100 | $5,100 | | | | | | | | | |
| | 2004 | 0 | $23,449 | $23,449 | | | | | | | | | |
| | 2005 | 2 | $14,896 | $26,756 | 78,000 | 0.01 | | 10 | $0.024 | $0.042 | | | |
| | 2006 | 480 | $3,459 | $3,459 | 19,027 | 0.00 | | 7 | $0.009 | $0.009 | | | |
| | 2007 | 1 | $7,520 | $7,520 | 9,000 | 0.00 | | 7 | $0.135 | $0.135 | | | |
| | 2008 | 2 | $22,714 | $60,100 | 115,931 | 0.01 | | 15 | $0.019 | $0.049 | | | |
| | **Total** | **541** | **$77,138** | **$126,384** | **221,958** | | | **10** | **$0.043** | **$0.070** | | | |
| **Market Transformation** | | | | | | | | | | | | | |
| NEEA | | | | | | | | | | | | | |
| | 2002 | | $1,286,632 | $1,286,632 | 13,251,644 | 1.51 | | | | | | | |
| | 2003 | | $1,292,748 | $1,292,748 | 12,050,157 | 1.38 | | | | | | | |
| | 2004 | | $1,256,611 | $1,256,611 | 13,545,896 | 1.55 | | | | | | | |
| | 2005 | | $476,891 | $476,891 | 16,297,235 | 1.86 | | | | | | | |
| | 2006 | | $930,455 | $930,455 | 22,337,477 | 2.55 | | | | | | | |
| | 2007 | | $893,340 | $893,340 | 28,601,410 | 3.27 | | | | | | | |
| | 2008 | | $942,014 | $942,014 | 32,671,465 | 3.73 | | | | | | | (20) |
| | **Total** | | **$7,078,690** | **$7,078,690** | **138,755,283** | | | | | | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(20) Savings are preliminary estimates provided by the Northwest Energy Efficiency Alliance.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| Program/Year | Participants | Utility Cost[c] | Resource Cost[d] | Annual Energy | Average Demand[e] | Peak Demand[f] | Measure Life | Total Utility | Total Resource | Utility Benefit/Cost Ratio | Total Resource Benefit/Cost Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total Costs | | Savings and Demand Reduction | | | | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | | |
| | (Number) | (dollars) | (dollars) | (kWh) | (aMW) | (MW) | (Years) | ($/kWh) | ($/kWh) | | | |
| **Annual Totals** | | | | | | | | | | | | |
| **2002** | | **$1,932,520** | **$2,366,591** | **17,117,294** | **1.95** | **0.00** | | | | | | |
| **2003** | | **$2,566,229** | **$3,119,609** | **18,712,919** | **2.14** | **0.02** | | | | | | |
| **2004** | | **$3,827,213** | **$4,688,637** | **19,419,605** | **2.22** | **6.54** | | | | | | |
| **2005** | | **$6,523,348** | **$9,358,620** | **37,853,046** | **4.32** | **43.96** | | | | | | |
| **2006** | | **$11,174,181** | **$19,761,633** | **70,765,825** | **8.08** | **43.72** | | | | | | |
| **2007** | | **$14,896,816** | **$25,269,343** | **91,145,357** | **10.40** | **57.07** | | | | | | |
| **2008** | | **$20,213,215** | **$43,177,423** | **140,155,765** | **15.99** | **72.03** | | | | | | |
| **Total Direct Program** | | **$61,133,523** | **$107,741,856** | **395,169,810** | | | | | | | | |
| **Indirect Program Expense** | | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | | |
| 2002 | | $128,855 | | | | | | | | | | (21) |
| 2003 | | -$41,543 | | | | | | | | | | (21) |
| 2004 | | $142,337 | | | | | | | | | | |
| 2005 | | $177,624 | | | | | | | | | | |
| 2006 | | $309,832 | | | | | | | | | | |
| 2007 | | $765,561 | | | | | | | | | | |
| 2008 | | $980,305 | | | | | | | | | | |
| **Total** | | **$2,462,971** | | | | | | | | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(21) Analysis and indirect expense were not separated in the accounting for this reporting period.

## Appendix 4. DSM Expense and Performance 2002–2008 (continued)

| | | Total Costs | | Savings and Demand Reduction | | | | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Program/Year | Participants | Utility Cost[c] | Resource Cost[d] | Annual Energy | Average Demand[e] | Peak Demand[f] | Measure Life | Total Utility | Total Resource | Utility Benefit/Cost Ratio | Total Resource Benefit/Cost Ratio |
| | *(Number)* | *(dollars)* | *(dollars)* | *(kWh)* | *(aMW)* | *(MW)* | *(Years)* | *($/kWh)* | *($/kWh)* | | |
| **Total Expense** | | | | | | | | | | | |
| **2002** | | **$2,061,375** | | | | | | | | | |
| **2003** | | **$2,524,686** | | | | | | | | | |
| **2004** | | **$3,969,550** | | | | | | | | | |
| **2005** | | **$6,700,972** | | | | | | | | | |
| **2006** | | **$11,484,013** | | | | | | | | | |
| **2007** | | **$15,662,377** | | | | | | | | | |
| **2008** | | **$21,193,520** | | | | | | | | | |
| **Total 2002–2008** | **Total** | **$63,596,494** | | | | | | | | | |

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs incurred by Idaho Power to implement and manage a DSM program.

(d) The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

(e) Average Demand = Annual Energy / 8,760 annual hours.

(f) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.




# *Appendix C — Technical Appendix*

For the 2009 Integrated Resource Plan

December 2009

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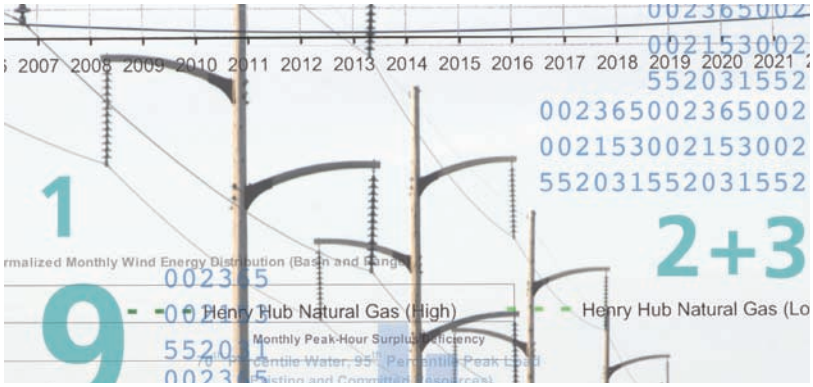
# *Appendix C — Technical Appendix*

For the 2009 Integrated Resource Plan – December 2009

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# TABLE OF CONTENTS

Introduction....1
Near- and Long-Term Action Plan....2
Portfolio Analysis, Results, and Supporting Documentation....4
Initial Resource Portfolios....4
Detailed Portfolio Design Sheets....5
Detailed Resource Portfolio Modeling Assumptions....15
Resource Portfolio Analysis—Base Case, Resource Portfolio Analysis (2010–2019)....16
Resource Portfolio Analysis—Base Case, Coal Curtailment (2010–2019)....17
Resource Portfolio Analysis—$43 $CO_2$, No Coal Curtailment (2010–2019)....18
Resource Portfolio Analysis—Current Operations, No Carbon, No Coal Curtailment (2010–2019)....19
Resource Portfolio Analysis—Base Case, Coal Curtailment (2020–2029)....20
Resource Portfolio Analysis—$43 $CO_2$, No Coal Curtailment (2020–2029)....21
Resource Portfolio Analysis—Current Operations, No Carbon, No Coal Curtailment (2020–2029)....22
Portfolio Incremental Transmission Analysis....23
Loss of Load Analysis....34
Sales and Load Forecast Data....35
Average Annual Forecast Growth Rates....35
Expected Case Load Forecast....36
Monthly Summary....36
Annual Summary....56
70th Percentile Load Forecast....58
Monthly Summary....58
Annual Summary....78
Existing Resource Data....80
Hydroelectric and Thermal Plan Data....80
Qualifying Facility Project Data....81
Power Purchase Agreement Project Data....82
Fuel Data....83
Gas and Coal Forecast—Data and Graphs....83
Natural Gas Price Forecast—Comparison to Other Forecasts....84
Natural Gas Price Forecast—Comparison to Previous Integrated Resource Plans....84

Supply-Side Resource Data ..... 85
Key Financial and Forecast Assumptions ..... 85
Cost Inputs and Operating Assumptions ..... 87
Levelized Cost of Production ..... 88
The Comprehensive Aquifer Management Plan (CAMP) Process and Potential to Impact Power Generation ..... 90
The CAMP Process ..... 90
Potential Impact of CAMP Implementation on Idaho Power ..... 91
Modeled CAMP Scenario ..... 92
Brownlee Reservoir Inflow Record ..... 94
Monthly Wind Energy Distribution ..... 95
Demand-Side Resource Data ..... 96
Cost-Effectiveness ..... 96
Alternate Costs ..... 97
Load and Resource Balance ..... 108
Monthly Average Energy Surplus/Deficiency Data ..... 108
Monthly Average Energy Surpluses and Deficits with Existing Resources ..... 108
Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources ..... 119
Peak Hour Load Surplus/Deficiency Data ..... 120
Peak Hour Deficits with Existing Resources ..... 130
Peak Hour Deficits with 2009 IRP Resources ..... 131
PDR580 Results ..... 132
50th Percentile Water, 50th Percentile Load ..... 132
70th Percentile Water, 70th Percentile Load ..... 142
90th Percentile Water, 70th Percentile Load ..... 152
Oregon Order UM 1056 Planning Criteria ..... 162
Summary of Northwest Utility Planning Criteria ..... 170
IRP Advisory Council Roster ..... 172

# INTRODUCTION

*Appendix C—Technical Appendix* contains some of the supporting and explanatory materials used to develop Idaho Power's *2009 Integrated Resource Plan* (IRP). The Technical Appendix begins with a reprint of the short-term and long-term resource action plans and follows with detailed information concerning various resource planning issues.

The main document, the IRP, contains a full narrative of the Idaho Power resource planning process. Additional information regarding the Idaho Power sales forecast is contained in *Appendix A—Sales and Load Forecast*, and details on Idaho Power's energy efficiency efforts are explained in *Appendix B—Demand-Side Management 2008 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in December 2009.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning
1221 West Idaho Street
Boise, Idaho 83702
208-388-2483

# NEAR- AND LONG-TERM ACTION PLAN

## Near-Term Action Plan

| Year | Action |
|---|---|
| 2010 | Present and gain acceptance of 2009 IRP with regulatory commissions<br>File wind contract resulting from the 2012 Wind RFP with the IPUC<br>File geothermal contract with the IPUC<br>Irrigation Peak Rewards program increases from 160 MW to 220 MW<br>FlexPeak Management program increases from 20 MW to 40 MW<br>Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins<br>Langley Gulch CCCT construction continues<br>Irrigation Peak Rewards program increases from 220 MW to 250 MW<br>FlexPeak Management program increases to from 40 MW to 45 MW<br>File 2011 IRP with regulatory commissions |
| 2012 | Wind project on-line (approximately 150 MW)<br>Langley Gulch CCCT on-line (300 MW)<br>Geothermal project on-line (approximately 20 MW) |
| 2013 | Boardman to Hemingway construction begins<br>Shoshone Falls Upgrade Project construction begins<br>File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls Upgrade Project construction continues |
| 2015 | Shoshone Falls Upgrade Project on-line (49 MW)<br>Boardman to Hemingway completed (250 MW)<br>File 2015 IRP with regulatory commissions |
| 2016 | Geothermal project on-line (approximately 20 MW) |
| 2017 | Boardman to Hemingway additional capacity for market purchases (175 MW)<br>File 2017 IRP with regulatory commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with regulatory commissions |

## Alternate Portfolio Near-Term Action Plan

| Year | Action |
|---|---|
| 2010 | File 2009 IRP with regulatory commissions<br>File wind contract (2012 Wind RFP) with the IPUC<br>File geothermal contract with IPUC<br>Irrigation Peak Rewards Program increases to 220 MW<br>FlexPeak Management program increases to 40 MW<br>Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins<br>Langley Gulch CCCT construction<br>Irrigation Peak Rewards Program increases to 250 MW<br>FlexPeak Management program increases to 45 MW<br>File 2011 IRP with regulatory commissions |
| 2012 | Wind project on line (approximately 150 MW)<br>Langley Gulch CCCT on-line (300 MW)<br>Geothermal generation on-line (approximately 20 MW)<br>***Natural gas generation resource one RFPs*** |
| 2013 | File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls upgrade construction |

| Year | Action |
|---|---|
| | ***Natural gas generation resource two RFPs*** |
| 2015 | Shoshone Falls upgrade on-line (50 MW) |
| | ***Natural gas generation resource one on-line*** |
| | File 2015 IRP with regulatory commissions |
| 2016 | Geothermal Generation on-line (approximately 20 MW) |
| 2017 | ***Natural Gas generation resource two on-line*** |
| | File 2017 IRP with commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with commissions |

## Long-Term Action Plan

| Year | Action |
|---|---|
| 2020 | Natural gas generation project on-line (approximately 100 MW) |
| 2021 | No action |
| 2022 | Wind project on-line (approximately 100 MW) |
| 2023 | No action |
| 2024 | Natural gas generation project on-line (approximately 200 MW) |
| 2025 | No action |
| 2026 | Natural gas generation project on-line (approximately 200 MW) |
| 2027 | Wind project on-line (approximately 400 MW) |
| 2028 | Natural gas generation project on-line (approximately 400 MW) |
| 2029 | Natural gas generation project on-line (approximately 500 MW) |

# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

## Initial Resource Portfolios (2010–2019)

| | 1-1 Solar | | 1-2 Gas Peaker | | 1-3 Gas Peaker & B2H[1] | | 1-4 B2H | |
|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | Resource | MW | Resource | MW | Resource | MW |
| 2012 | Wind* | 150 | Wind* | 150 | Wind* | 150 | Wind* | 150 |
| | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 | CCCT (Langley Gulch)* | 300 |
| | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 |
| 2015 | Shoshone Falls | 49 | Shoshone Falls | 49 | Shoshone Falls | 49 | Shoshone Falls | 49 |
| | SCCT (Large Aero) | 200 | SCCT (Frame Peaker) | 170 | B2H | 250 | B2H | 250 |
| 2016 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 | Geothermal* | 20 |
| 2017 | Solar PT w/St | 100 | SCCT (Frame Peaker) | 170 | SCCT (Large Aero) | 100 | B2H | 175 |
| 2019 | Solar PT w/St | 100 | | | SCCT (Large Aero) | 100 | | |

[1] B2H-Boardman to Hemingway
*Committed Resource

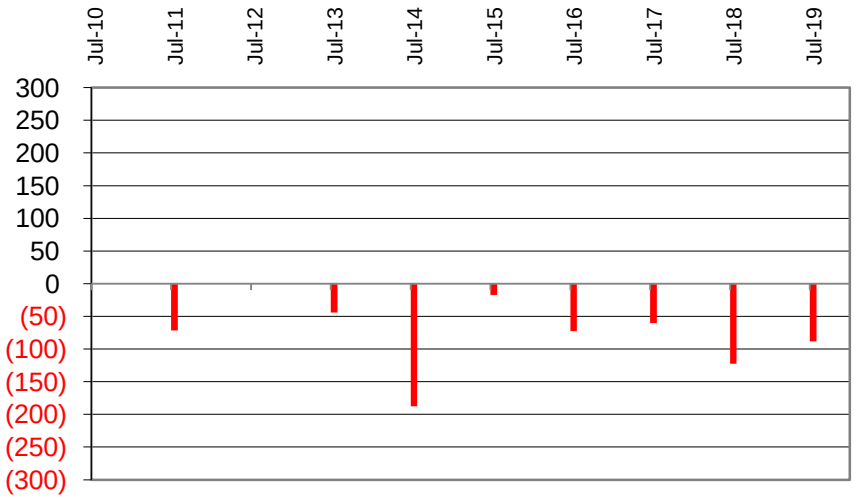
## Initial Resource Portfolios (2020–2029)

| | 2-1 Nuclear/Green | | 2-2 Gateway West | | 2-3 IGCC | | 2-4 Wind & Peakers | | 2-5 Limited Curtailment | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | Resource | MW | Resource | MW | Resource | MW | Resource | MW |
| 2020 | Solar PT w/St | 100 | | | | | SCCT (Large Aero) | 100 | | |
| 2021 | Wind | 100 | Wind | 100 | | | | | Wind | 100 |
| 2022 | Solar PT w/St | 100 | Gateway West | 200 | Solar PT w/St | 100 | Wind | 100 | SCCT (Large Aero) | 100 |
| 2023 | Nuclear | 270 | | | | | | | | |
| 2024 | Geothermal | 52 | | | IGCC w/Seq. | 600 | SCCT (Large Aero) | 200 | | |
| 2025 | Solar PT w/St | 100 | Gateway West | 200 | | | Gateway West | 100 | | |
| 2026 | | | Wind | 100 | | | SCCT (Large Aero) | 200 | SCCT (Large Aero) | 100 |
| 2027 | Geothermal | 52 | Gateway West | 400 | Solar PT w/St | 100 | Wind | 400 | Wind | 200 |
| | | | | | | | | | SCCT (Large Aero) | 100 |
| 2028 | Nuclear | 400 | Gateway West | 600 | SCCT (Large Aero) | 400 | SCCT (Large Aero) | 400 | | |
| 2029 | Gateway West | 250 | | | Solar PT w/St | 100 | SCCT (Large Aero) | 500 | | |

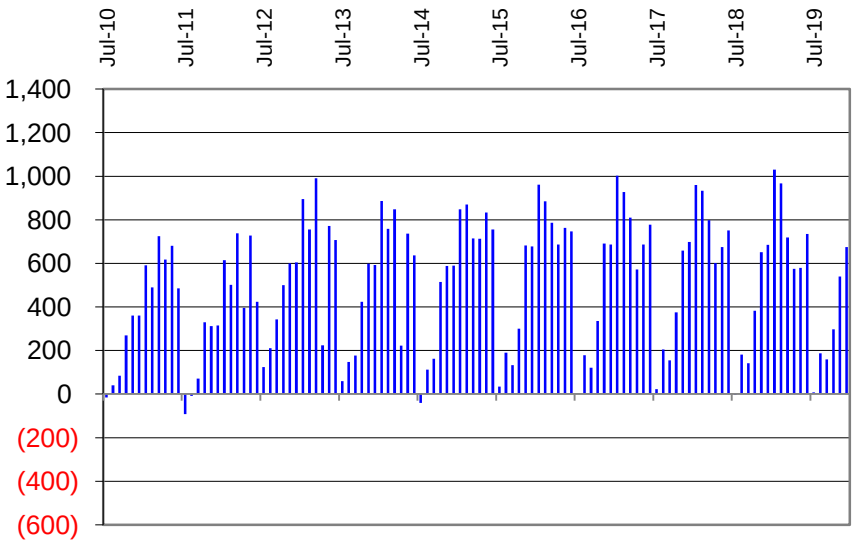
## 1-1 Solar

| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2010 | | | 0 | 0 | 0 | - |
| RES | CR | Wind | 150 | 2011 | | | 0 | 0 | 50 | 438,000 |
| | CR | CCCT (Langley) | 300 | 2012 | | | 0 | 0 | 50 | 438,000 |
| RES | CR | Geothermal | 20 | 2013 | | | 0 | 0 | 68 | 595,680 |
| RES | NR | Shoshone Falls | 49 | 2014 | 7.0 | 0.0 | 7 | 0 | 75 | 657,000 |
| | NR | Large Aero | 200 | 2015 | 100.0 | 200.0 | 107 | 200 | 75 | 657,000 |
| RES | CR | Geothermal | 20 | 2016 | | | 107 | 200 | 93 | 814,680 |
| RES | NR | Solar PT w/St | 100 | 2017 | 28.0 | 92.0 | 135 | 292 | 121 | 1,059,960 |
| | | | | 2018 | | | 135 | 292 | 121 | 1,059,960 |
| RES | NR | Solar PT w/St | 100 | 2019 | 28.0 | 92.0 | 163 | 384 | 149 | 1,305,240 |
| CR = Committed Resource | | | | | | **Min** | **(91)** | **(188)** | | |
| NR = New Resource | | | | | | **STDEV** | **289** | **142** | | |
| MP = Market Purchase | | | | | | **AVG** | **505** | **107** | | |

### Peak-Hour




### Energy

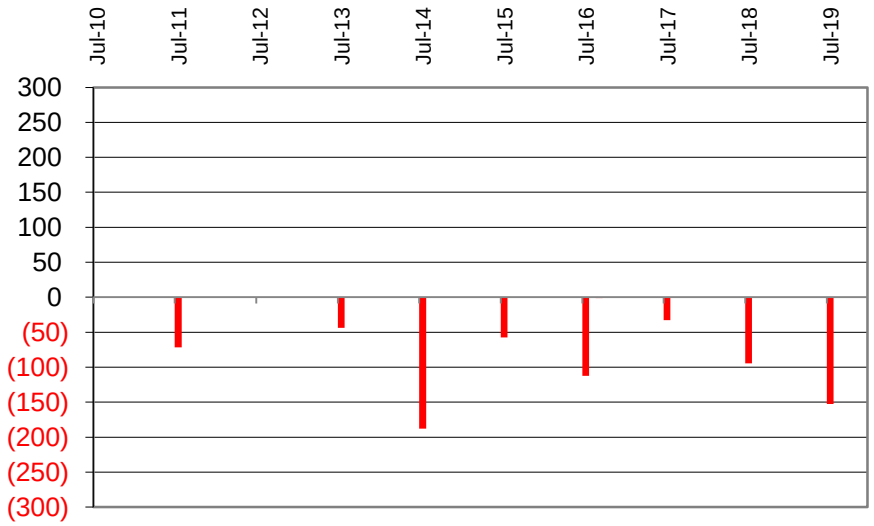


## 1-2 Gas Peaker

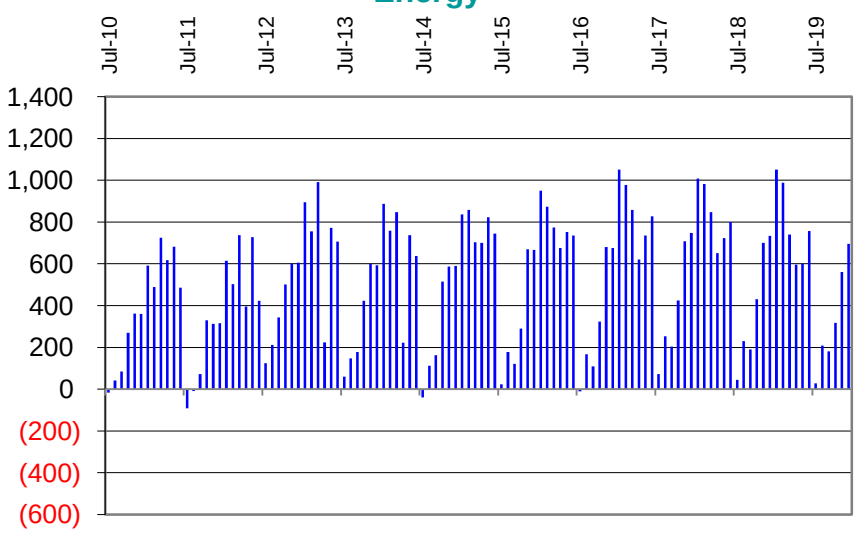
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2010 | | | 0 | 0 | 0 | - |
| RES | CR | Wind | 150 | 2011 | | | 0 | 0 | 50 | 438,000 |
| | CR | CCCT (Langley) | 300 | 2012 | | | 0 | 0 | 50 | 438,000 |
| RES | CR | Geothermal | 20 | 2013 | | | 0 | 0 | 68 | 595,680 |
| RES | NR | Shoshone Falls | 49 | 2014 | 7.0 | 0.0 | 7 | 0 | 75 | 657,000 |
| | NR | Frame Peaker | 170 | 2015 | 88.4 | 159.8 | 95.4 | 159.8 | 75 | 657,000 |
| RES | CR | Geothermal | 20 | 2016 | | | 95.4 | 159.8 | 93 | 814,680 |
| | NR | Frame Peaker | 170 | 2017 | 88.4 | 159.8 | 183.8 | 319.6 | 93 | 814,680 |
| | | | | 2018 | | | 183.8 | 319.6 | 93 | 814,680 |
| | | | | 2019 | | | 183.8 | 319.6 | 93 | 814,680 |
| | | | | | | **Min** | **(91)** | **(188)** | | |
| | | | | | | **STDEV** | **292** | **138** | | |
| | | | | | | **AVG** | **515** | **99** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

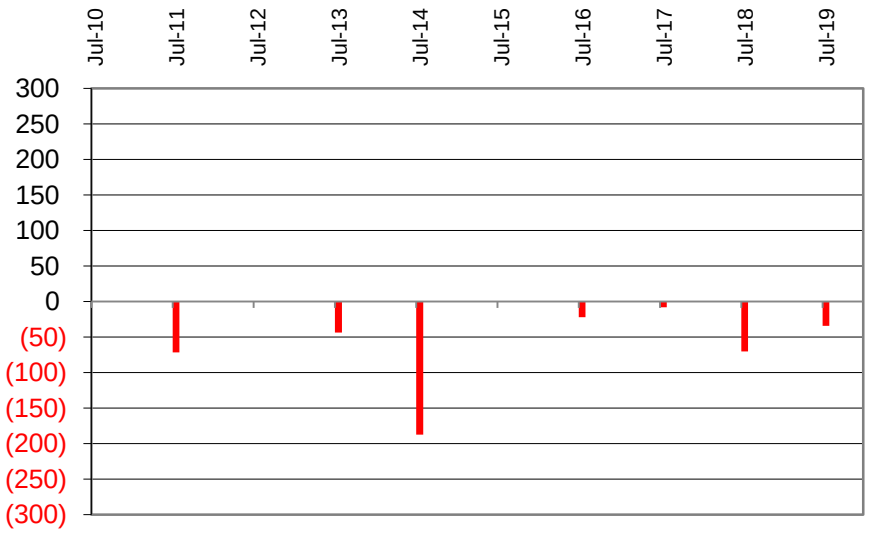


## 1-3 Gas Peaker & B2H

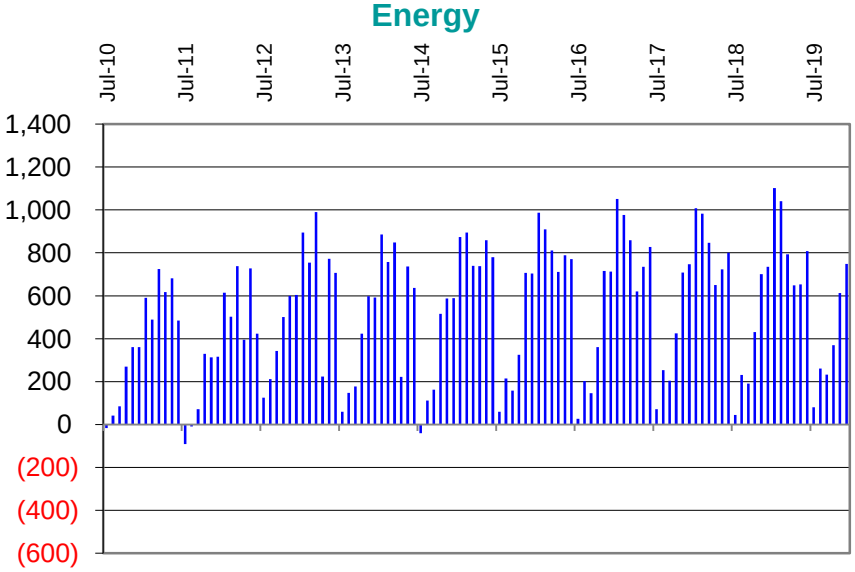
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2010 | | | 0 | 0 | 0 | - |
| RES | CR | Wind | 150 | 2011 | | | 0 | 0 | 50 | 438,000 |
| | CR | CCCT (Langley) | 300 | 2012 | | | 0 | 0 | 50 | 438,000 |
| RES | CR | Geothermal | 20 | 2013 | | | 0 | 0 | 68 | 595,680 |
| RES | NR | Shoshone Falls | 49 | 2014 | 7.0 | 0.0 | 7 | 0 | 75 | 657,000 |
| | MP | B2H | 250 | 2015 | 125.0 | 250.0 | 132 | 250 | 75 | 657,000 |
| RES | CR | Geothermal | 20 | 2016 | | | 132 | 250 | 93 | 814,680 |
| | NR | Large Aero | 100 | 2017 | 52.0 | 94.0 | 184 | 344 | 93 | 814,680 |
| | | | | 2018 | | | 184 | 344 | 93 | 814,680 |
| | NR | Large Aero | 100 | 2019 | 52.0 | 94.0 | 236 | 438 | 93 | 814,680 |
| | | | | | | **Min** | **(91)** | **(188)** | | |
| | | | | | | **STDEV** | **294** | **163** | | |
| | | | | | | **AVG** | **527** | **133** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

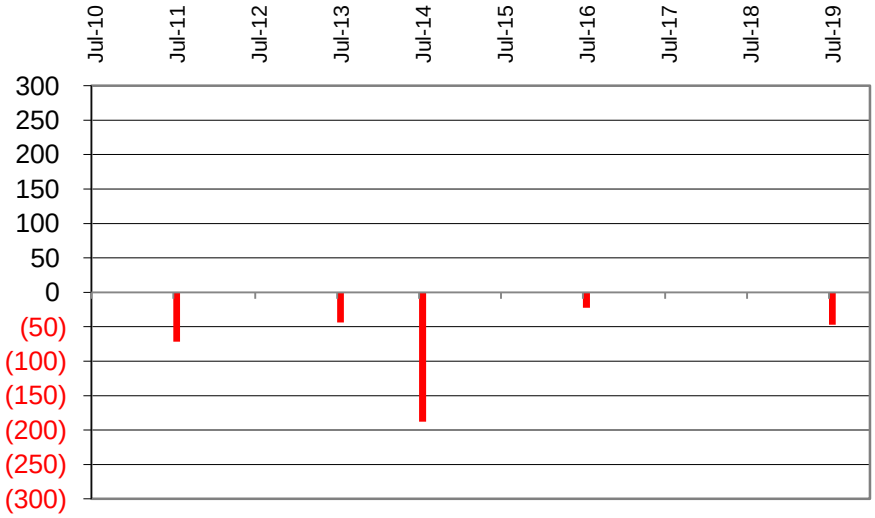


## 1-4 B2H

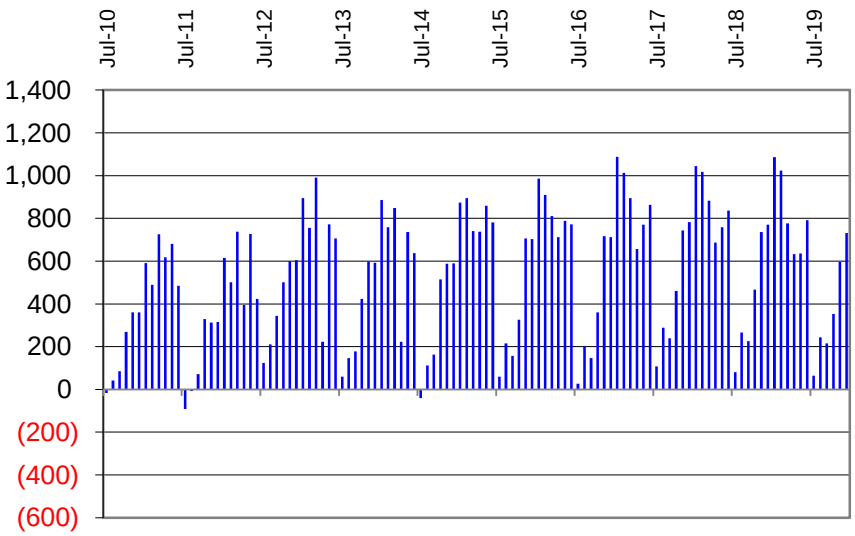
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2010 | | | 0 | 0 | 0 | - |
| RES | CR | Wind | 150 | 2011 | | | 0 | 0 | 50 | 438,000 |
| | CR | CCCT (Langley) | 300 | 2012 | | | 0 | 0 | 50 | 438,000 |
| RES | CR | Geothermal | 20 | 2013 | | | 0 | 0 | 68 | 595,680 |
| RES | NR | Shoshone Falls | 49 | 2014 | 7.0 | 0.0 | 7 | 0 | 75 | 657,000 |
| | MP | B2H | 250 | 2015 | 125.0 | 250.0 | 132 | 250 | 75 | 657,000 |
| RES | CR | Geothermal | 20 | 2016 | | | 132 | 250 | 93 | 814,680 |
| | MP | B2H | 175 | 2017 | 87.5 | 175.0 | 219.5 | 425 | 93 | 814,680 |
| | | | | 2018 | | | 219.5 | 425 | 93 | 814,680 |
| | | | | 2019 | | | 219.5 | 425 | 93 | 814,680 |
| | | | | | | **Min** | **(91)** | **(188)** | | |
| | | | | | | **STDEV** | **297** | **180** | | |
| | | | | | | **AVG** | **533** | **148** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

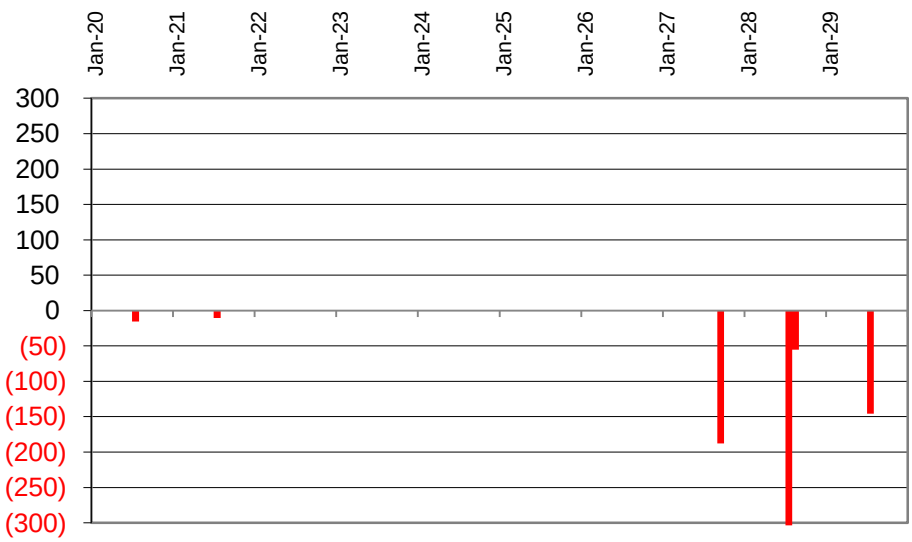


## 2-1 Nuclear/Green

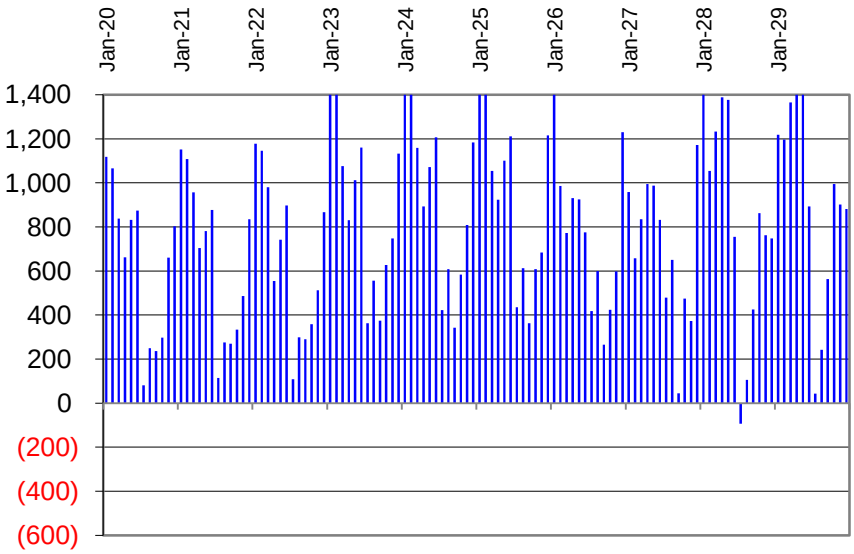
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| RES | NR | Solar PT w/St | 100 | 2020 | 28.0 | 92.0 | 28 | 92 | 28 | 245,280 |
| RES | NR | Wind | 100 | 2021 | 32.0 | 5.0 | 60 | 97 | 60 | 525,600 |
| RES | NR | Solar PT w/St | 100 | 2022 | 28.0 | 92.0 | 88 | 189 | 88 | 770,880 |
| | NR | Nuclear | 270 | 2023 | 270.0 | 270.0 | 358 | 459 | 88 | 770,880 |
| RES | NR | Geothermal | 52 | 2024 | 46.8 | 46.8 | 405 | 506 | 134.8 | 1,180,848 |
| RES | NR | Solar PT w/St | 100 | 2025 | 28.0 | 92.0 | 433 | 598 | 162.8 | 1,426,128 |
| | | | | 2026 | | | 433 | 598 | 162.8 | 1,426,128 |
| RES | NR | Geothermal | 52 | 2027 | 46.8 | 46.8 | 480 | 645 | 209.6 | 1,836,096 |
| | NR | Nuclear | 400 | 2028 | 380.0 | 400.0 | 860 | 1045 | 209.6 | 1,836,096 |
| | | Gateway West | 250 | 2029 | 125.0 | 250.0 | 985 | 1295 | 209.6 | 1,836,096 |
| | | | | | | **Min** | **(93)** | **(380)** | | |
| | | | | | | **STDEV** | **396** | **440** | | |
| | | | | | | **AVG** | **803** | **707** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

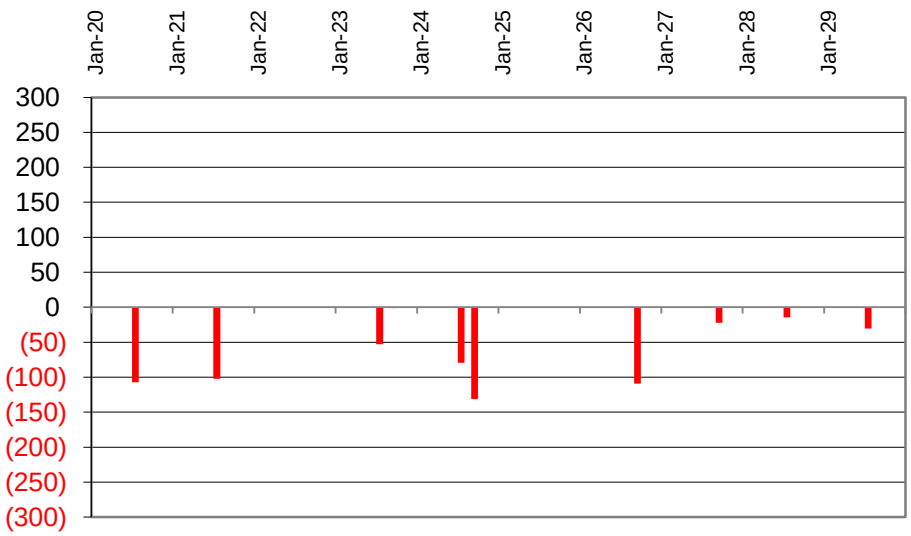


## 2-2 Gateway West

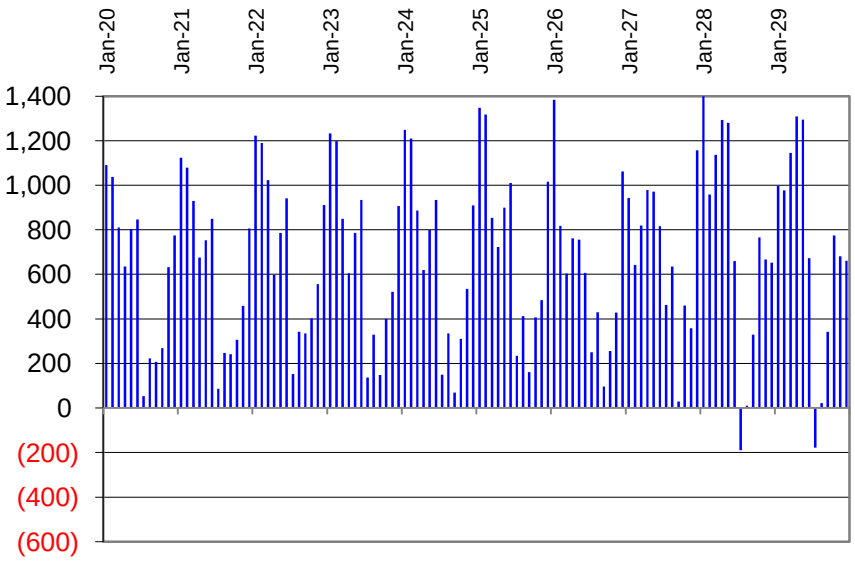
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2020 | | | 0 | 0 | 0 | - |
| RES | NR | Wind | 100 | 2021 | 32 | 5 | 32 | 5 | 32 | 280,320 |
| | | Gateway West | 200 | 2022 | 100 | 200 | 132 | 205 | 32 | 280,320 |
| | | | | 2023 | | | 132 | 205 | 32 | 280,320 |
| | | | | 2024 | | | 132 | 205 | 32 | 280,320 |
| | | Gateway West | 200 | 2025 | 100 | 200 | 232 | 405 | 32 | 280,320 |
| RES | NR | Wind | 100 | 2026 | 32 | 5 | 264 | 410 | 64 | 560,640 |
| | | Gateway West | 400 | 2027 | 200 | 400 | 464 | 810 | 64 | 560,640 |
| | | Gateway West | 600 | 2028 | 300 | 600 | 764 | 1410 | 64 | 560,640 |
| | | | | 2029 | | | 764 | 1410 | 64 | 560,640 |
| | | | | | | **Min** | **(189)** | **(131)** | | |
| | | | | | | **STDEV** | **381** | **506** | | |
| | | | | | | **AVG** | **682** | **661** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour



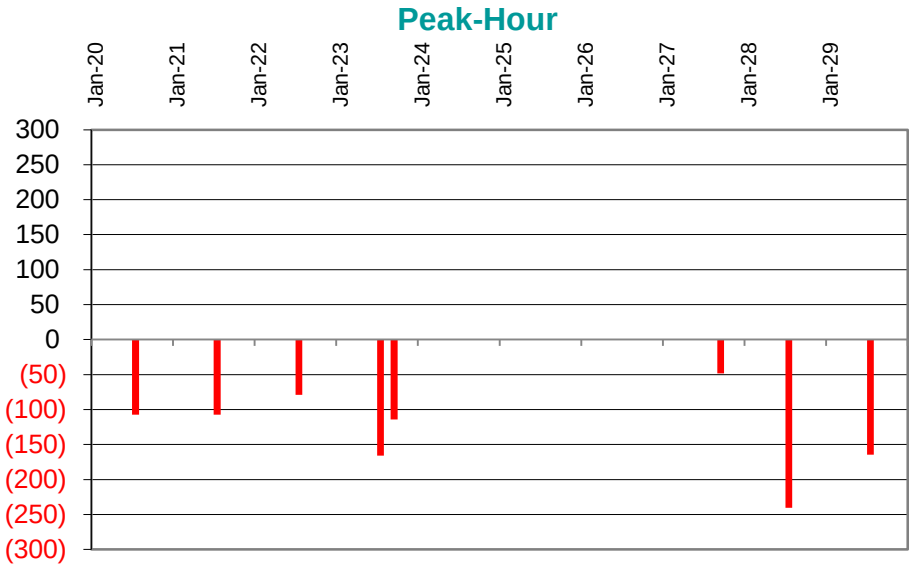

### Energy

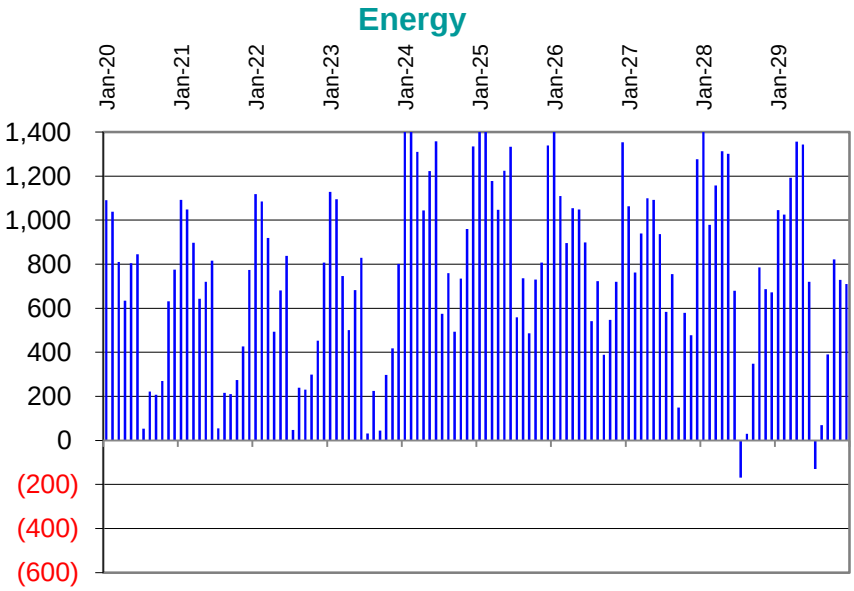


## 2-3 IGCC

| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2020 | | | 0 | 0 | 0 | - |
| | | | | 2021 | | | 0 | 0 | 0 | - |
| RES | NR | Solar PT w/St | 100 | 2022 | 28 | 92 | 28 | 92 | 28 | 245,280 |
| | | | | 2023 | | | 28 | 92 | 28 | 245,280 |
| | NR | IGCC w/Seq. | 600 | 2024 | 528 | 600 | 556 | 692 | 28 | 245,280 |
| | | | | 2025 | | | 556 | 692 | 28 | 245,280 |
| | | | | 2026 | | | 556 | 692 | 28 | 245,280 |
| RES | NR | Solar PT w/St | 100 | 2027 | 28 | 92 | 584 | 784 | 56 | 490,560 |
| | NR | Large Aero | 400 | 2028 | 200 | 400 | 784 | 1184 | 56 | 490,560 |
| RES | NR | Solar PT w/St | 100 | 2029 | 28 | 92 | 812 | 1276 | 84 | 735,840 |
| | | | | | | **Min** | **(169)** | **(240)** | | |
| | | | | | | **STDEV** | **419** | **491** | | |
| | | | | | | **AVG** | **781** | **705** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase



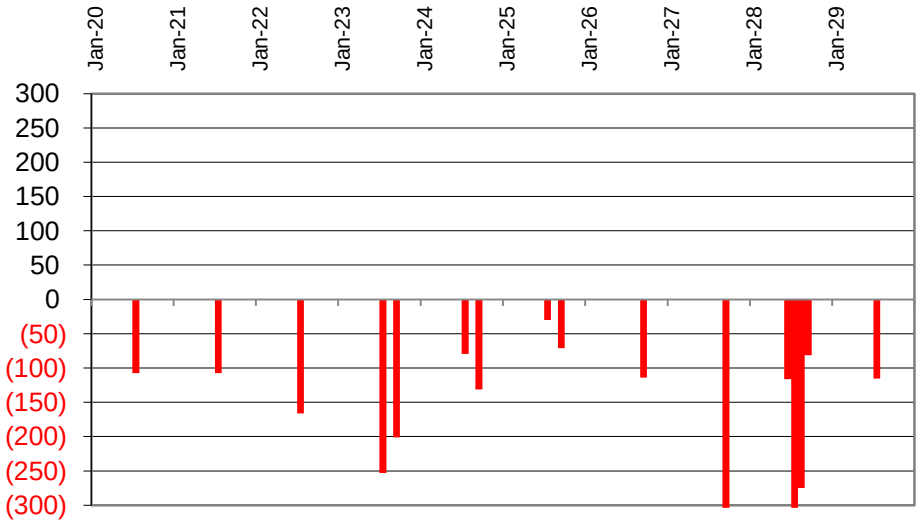



## 2-4 Wind & Peakers

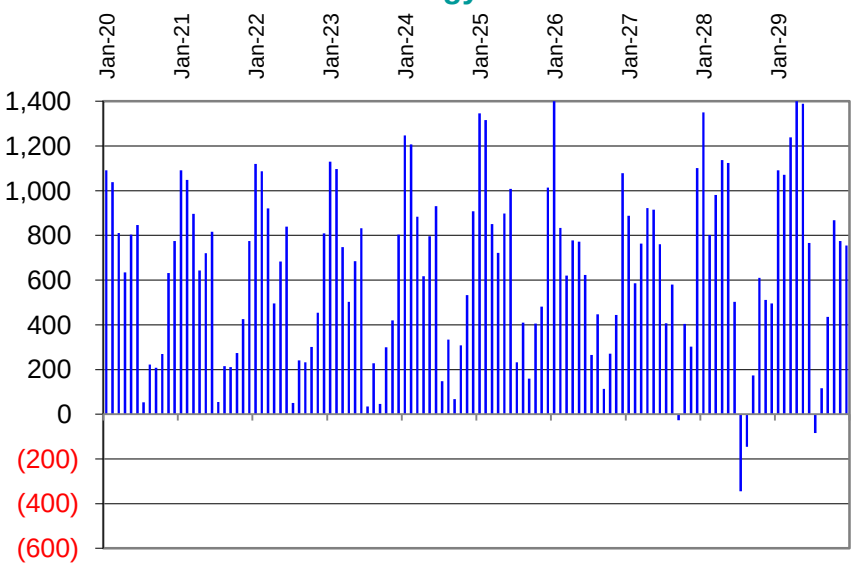
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | NR | Large Aero | 100 | 2020 | | | 0 | 0 | 0 | - |
| | | | | 2021 | | | 0 | 0 | 0 | - |
| RES | NR | Wind | 100 | 2022 | 30 | 5 | 30 | 5 | 30 | 262,800 |
| | | | | 2023 | | | 30 | 5 | 30 | 262,800 |
| | NR | Large Aero | 200 | 2024 | 100 | 200 | 130 | 205 | 30 | 262,800 |
| | | Gateway West | 100 | 2025 | 100 | 100 | 230 | 305 | 30 | 262,800 |
| | NR | Large Aero | 200 | 2026 | 50 | 100 | 280 | 405 | 30 | 262,800 |
| RES | NR | Wind | 400 | 2027 | 128 | 20 | 408 | 425 | 158 | 1,384,080 |
| | NR | Large Aero | 400 | 2028 | 200 | 400 | 608 | 825 | 158 | 1,384,080 |
| | NR | Large Aero | 500 | 2029 | 250 | 500 | 858 | 1325 | 158 | 1,384,080 |
| | | | | | | **Min** | **(345)** | **(599)** | | |
| | | | | | | **STDEV** | **384** | **460** | | |
| | | | | | | **AVG** | **648** | **504** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

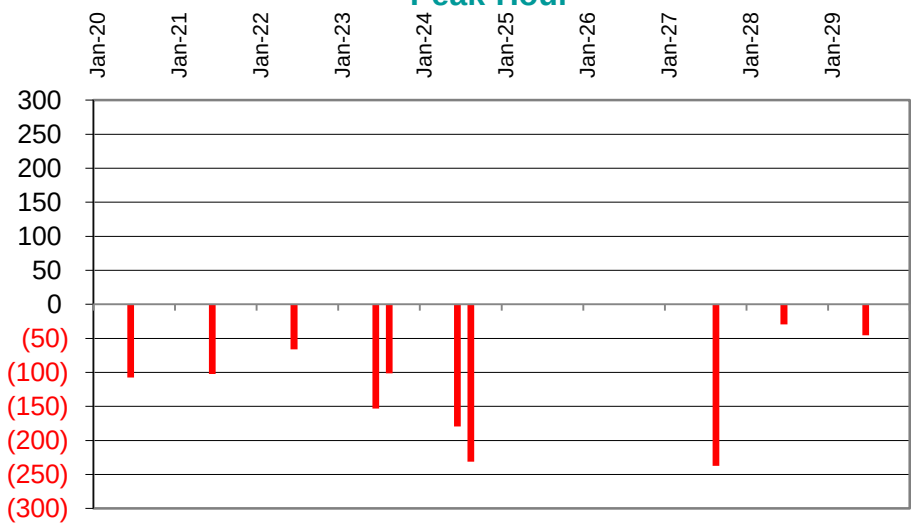


## 2-5 Limited Coal Curtailment

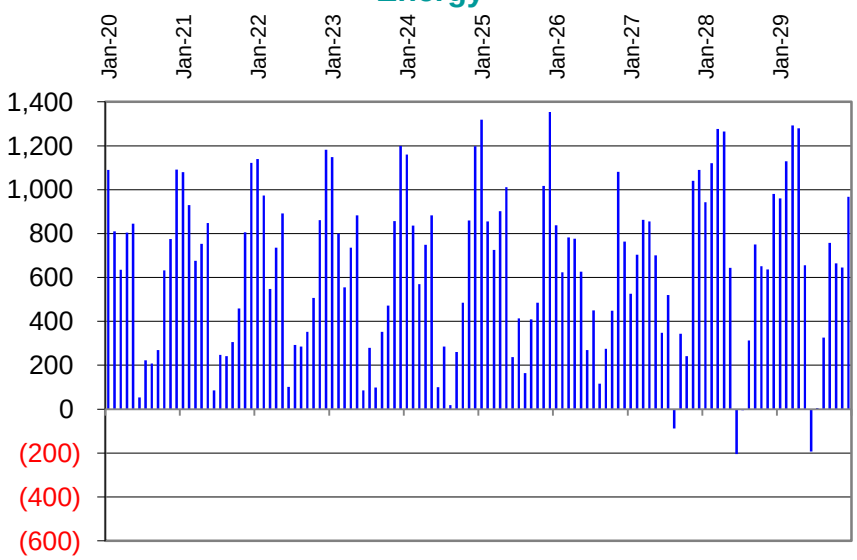
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2020 | | | 0 | 0 | 0 | - |
| RES | NR | Wind | 100 | 2021 | 32 | 5 | 32 | 5 | 32 | 280,320 |
| | NR | Large Aero | 100 | 2022 | 50 | 100 | 82 | 105 | 32 | 280,320 |
| | | | | 2023 | | | 82 | 105 | 32 | 280,320 |
| | | | | 2024 | | | 82 | 105 | 32 | 280,320 |
| | | Existing Coal | 350 | 2025 | 152 | 380 | 234 | 485 | 32 | 280,320 |
| | NR | Large Aero | 100 | 2026 | 50 | 100 | 284 | 585 | 32 | 280,320 |
| RES | NR | Wind | 200 | 2027 | 64 | 10 | 348 | 595 | 96 | 840,960 |
| | NR | Large Aero | 100 | 2027 | 50 | 100 | 398 | 695 | 96 | 840,960 |
| | | Existing Coal | 700 | 2028 | 350 | 700 | 748 | 1395 | 96 | 840,960 |
| | | | | 2029 | | | 748 | 1395 | 96 | 840,960 |
| | | | | | | **Min** | **(205)** | **(237)** | | |
| | | | | | | **STDEV** | **371** | **510** | | |
| | | | | | | **AVG** | **647** | **632** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy

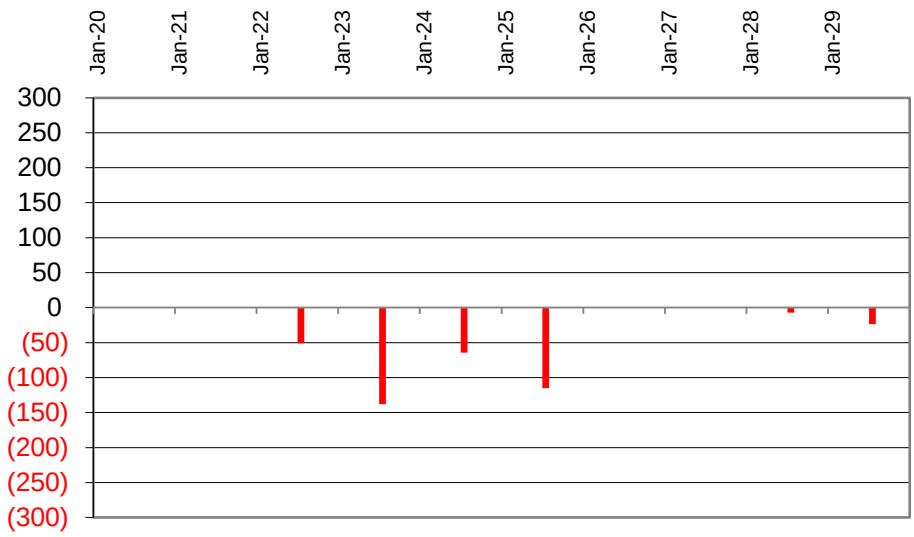


## 2-6 No Coal Curtailment

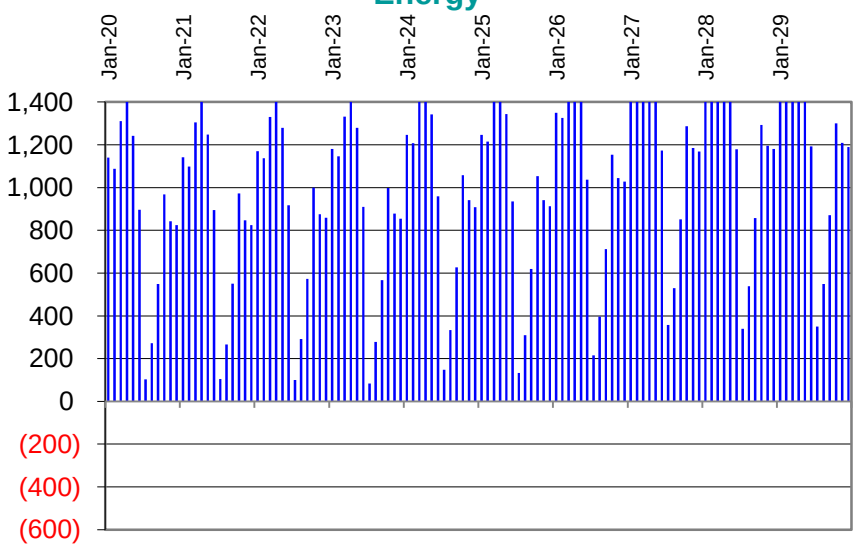
| RES | Type | Resource | Nameplate MW | Year | Energy | Peak | Cum. Energy | Cum. Peak | Cum. RES MW | Cum. RES MWh |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Large Aero | 100 | 2020 | 50 | 100 | 50 | 100 | 0 | - |
| | | | | 2021 | | | 50 | 100 | 32 | 280,320 |
| RES | NR | Wind | 100 | 2022 | 30 | 5 | 80 | 105 | 32 | 280,320 |
| | | | | 2023 | | | 80 | 105 | 32 | 280,320 |
| | | Large Aero | 100 | 2024 | 50 | 100 | 130 | 205 | 32 | 280,320 |
| | | | | 2025 | | | 130 | 205 | 32 | 280,320 |
| | NR | Large Aero | 200 | 2026 | 100 | 200 | 230 | 405 | 32 | 280,320 |
| RES | NR | Wind | 400 | 2027 | 128 | 20 | 358 | 425 | 96 | 840,960 |
| | | | | 2027 | | | 358 | 425 | 96 | 840,960 |
| | | | | 2028 | | | 358 | 425 | 96 | 840,960 |
| | | | | 2029 | | | 358 | 425 | 96 | 840,960 |
| | | | | | | **Min** | **84** | **(138)** | | |
| | | | | | | **STDEV** | **432** | **245** | | |
| | | | | | | **AVG** | **1,029** | **550** | | |

CR = Committed Resource
NR = New Resource
MP = Market Purchase

### Peak-Hour




### Energy



**Resource Portfolio Modeling Assumptions**

| Time Period | Figure Name | Coal Curtailment[1] | Carbon Adder[2] | NTTG Transmission Plan[3] | Only IPC Transmission Share of B2H[4] | Limited Coal Curtailment[5] |
|---|---|---|---|---|---|---|
| 2010–2019 | Base Case, Coal Curtailment *Used in first 10-year Portfolio Selection Process* | X | | | X | |
| 2010–2019 | Base Case, Coal Curtailment | X | | X | | |
| 2010–2019 | $43 CO2, No Coal Curtailment | | X | X | | |
| 2010–2019 | Current Operations, No Carbon, No Coal Curtailment | | | X | | |
| 2020–2029 | Base Case, Coal Curtailment *Used in second 10-Year Portfolio Selection Process* | X | | X | | 2-5 Only |
| 2020–2029 | $43 CO2, No Coal Curtailment | | X | X | | |
| 2020–2029 | Current Operations, No Carbon, No Coal Curtailment | | | X | | |

[1]Idaho Power coal plants are curtailed to comply with HR 2454

[2]$43 per ton added starting in 2012

[3]Includes all NTTG projects at estimated capacity estimate ratings

[4]Transmission paths in the Aurora model are unconstrained to levels of anticipated use by Idaho Power

[5]Coal curtailed to 2020 targets (partial HR 2454 compliance)

**RESOURCE PORTFOLIO ANALYSIS**
**Base Case, Coal Curtailment (2010–2019)**

| Base Case—Coal Curtailment | 1-1 Solar | 1-2 Gas (Peaker) | 1-3 Gas (Peaker & B2H) | 1-4 B2H |
|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 1,264,351,176 | $ 266,751,176 | $ 249,551,176 | $ 96,951,176 |
| Capital Costs NPV ($ 20 Year) | $ 621,711,410 | $ 239,909,076 | $ 178,705,464 | $ 107,198,820 |
| Aurora NPV Portfolio Total Cost | $ 1,963,326,421 | $ 2,066,337,264 | $ 2,032,468,672 | $ 2,063,765,789 |
| **NPV Total = Aurora + Capital** | **$ 2,585,037,830** | **$ 2,306,246,340** | **$ 2,211,174,136** | **$ 2,170,964,609** |
| | | | | |
| $CO_2$ Excess Emissions (Tons) | 117,808 | 288,017 | 429,833 | 258,563 |
| RES Excess Green Tags year 2019 | 684,156 | 193,596 | 193,596 | 193,596 |
| **Carbon Allowances Estimates** | **117,808** | **288,017** | **429,833** | **258,563** |
| | | | | |
| Boxer/Kerry Price Cap Proposal NPV | $ (263,462) | $ 1,467,059 | $ 5,163,204 | $ 1,839,437 |
| **2019 Res Position Estimates** | **684,156** | **193,596** | **193,596** | **193,596** |
| | | | | |
| RES NPV $ Estimates Yr 1–10 | | | | |
| Expected Value (Cost Reduction) | $ (46,921,264) | $ (37,338,255) | $ (37,338,255) | $ (37,338,255) |
| | | | | |
| Transmission | $ 13,163,761 | $ 10,977,415 | $ 55,403,269 | $ 94,451,794 |
| | | | | |
| **Expected Portfolio Cost** | **$ 2,551,016,864** | **$ 2,281,352,560** | **$ 2,234,402,354** | **$ 2,229,917,585** |
| **Rank by Least Cost** | **4** | **3** | **2** | **1** |
| **Difference** | **$ 321,099,279** | **$ 51,434,974** | **$ 4,484,769** | **$ -** |
| | | | | |
| **Risk Factors** | | | | |
| $CO_2$ $43 (Incremental) | $ 4,802,283 | $ 13,851,809 | $ 23,646,013 | $ 12,957,638 |
| | | | | |
| RES NPV $ Estimates Yr 1–10 | | | | |
| High Value (Additional to Expected) | $ (55,685,534) | $ (41,902,289) | $ (41,902,289) | $ (41,902,289) |
| | | | | |
| DSM 50% Realization (Cost Difference) | $ 51,876,928 | $ 38,966,959 | $ 71,495,131 | $ 40,522,318 |
| | | | | |
| High Load Growth (Cost Difference) | $ 290,681,839 | $ 288,768,701 | $ 320,277,146 | $ 289,732,784 |
| | | | | |
| Gas Price | | | | |
| High NG Prices differential from Low | $ (36,516,721) | $ (40,577,759) | $ (7,744,434) | $ (38,094,952) |
| | | | | |
| Transmission B2H | | | | |
| With 3rd-Party Participation NPV | | | ($16,726,745) | ($46,086,195) |
| | | | | |
| **Total Risk Cost** | **$ 255,158,795** | **$ 259,107,422** | **$ 349,044,823** | **$ 217,129,304** |
| **Rank by Least Risk** | **2** | **3** | **4** | **1** |
| **Difference** | **$ 38,029,491** | **$ 41,978,118** | **$ 131,915,519** | **$ -** |
| | | | | |
| **Portfolio Differences w/Cost Risk Adj** | | | | |
| High | $ 631,943,608 | $ 352,444,685 | $ 395,431,881 | $ 259,031,593 |

**RESOURCE PORTFOLIO ANALYSIS**
**Base Case, Coal Curtailment (2010–2019)**

| Base Case—Coal Curtailment | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H | 1-4 B2H |
|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 1,328,502,353 | $ 363,702,353 | $ 346,502,353 | $ 193,902,353 |
| Capital Costs NPV$ 20 Year | $ 621,711,410 | $ 239,909,076 | $ 178,705,464 | $ 107,198,820 |
| Aurora NPV Portfolio Total Cost | $ 1,976,455,828 | $ 2,021,669,045 | $ 2,017,973,554 | $ 2,021,858,588 |
| **NPV Total = Aurora + Capital** | **$ 2,598,167,238** | **$ 2,261,578,121** | **$ 2,196,679,018** | **$ 2,129,057,408** |
| $CO_2$ Excess Emissions (Tons) | (9,258) | 57,787 | 213,135 | 73,737 |
| RES Excess Green Tags year 2019 | 684,156 | 193,596 | 193,596 | 193,596 |
| **Carbon Allowances Needed Estimates** | **(9,258)** | **57,787** | **213,135** | **73,737** |
| Boxer/Kerry Price Cap Proposal NPV | $ (263,462) | $ 1,467,059 | $ 5,163,204 | $ 1,839,437 |
| **2019 Res Position Estimates** | **684,156** | **193,596** | **193,596** | **193,596** |
| RES NPV $ Estimates Yr 1–10 | | | | |
| Expected Value (Cost Reduction) | $ (46,921,264) | $ (37,338,255) | $ (37,338,255) | $ (37,338,255) |
| Transmission | $ 13,163,761 | $ 10,977,415 | $ 55,403,269 | $ 94,451,794 |
| **Expected Portfolio Cost** | **$ 2,564,146,272** | **$ 2,236,684,340** | **$ 2,219,907,236** | **$ 2,188,010,384** |
| **Rank** | **4** | **3** | **2** | **1** |
| **Difference NPV 1–10 Years** | **$ 376,135,888** | **$ 48,673,956** | **$ 31,896,852** | **$ -** |
| **Risk Factors** | | | | |
| $CO_2$ $43 (Incremental) | $ (661,560) | $ 3,951,893 | $ 14,327,997 | $ 5,010,136 |
| RES NPV $ Estimates Yr 1-10 | | | | |
| High Value (Additional to Expected) | $ (55,685,534) | $ (41,902,289) | $ (41,902,289) | $ (41,902,289) |
| DSM 50% Realization (Cost Difference) | $ 27,566,134 | $ 88,116,160 | $ 85,454,235 | $ 87,129,172 |
| High Load Growth (Cost Difference) | $ 267,685,288 | $ 327,202,920 | $ 325,597,765 | $ 327,887,601 |
| Gas Price | | | | |
| High NG Prices differential from Low | $ (49,646,128) | $ 4,090,460 | $ 6,750,684 | $ 3,812,250 |
| Transmission B2H | | | | |
| No resell IPC Outbound NPV | | | ($16,726,745) | ($46,086,195) |
| *No Third Party Participation 1–10 Years (Not Inlcuded in totals below)* | | | *$211,215,269* | *$201,526,193* |
| *11–20 Year Transmission Rev Req IPC Sells Outbound* | | | *$47,299,585* | *$59,148,872* |
| *11–20 Year Transmission Rev Req IPC Does Not Sell Outbound* | | | *$67,755,614* | *$115,510,138.56* |
| *11–20 Year Trans Rev Req IPC No Third Party Participation* | | | *$600,050,525* | *$600,050,525.21* |
| Portfolio Differences w/Cost Risk Adj | | | | |
| High | $ 621,079,622 | $ 472,035,389 | $ 447,300,789 | $ 377,752,964 |
| **High w/Transmission** | **$ 574,993,427** | **$ 425,949,195** | **$ 401,214,594** | **$ 377,752,964** |
| Low | $ 565,394,088 | $ 430,133,100 | $ 405,398,500 | $ 335,850,675 |
| **Low w/Transmission** | **$ 519,307,893** | **$ 384,046,905** | **$ 359,312,305** | **$ 335,850,675** |
| **Rank** | 4 | 3 | 2 | 1 |

**RESOURCE PORTFOLIO ANALYSIS**
**$43 $CO_2$, No Coal Curtailment (2010–2019)**

| $43 CO2—No Coal Curtailment | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H | 1-4 B2H |
|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 1,328,502,353 | $ 363,702,353 | $ 346,502,353 | $ 193,902,353 |
| Capital Costs NPV 20-Year | $ 621,711,410 | $ 239,909,076 | $ 178,705,464 | $ 107,198,820 |
| Aurora NPV Portfolio Total Cost | $ 3,613,437,405 | $ 3,701,347,429 | $ 3,703,473,275 | $ 3,698,952,139 |
| **NPV Total = Aurora + Capital** | **$ 4,235,148,815** | **$ 3,941,256,505** | **$ 3,882,178,739** | **$ 3,806,150,959** |
| $CO_2$ Excess Emissions (Tons) | 7,758,441 | 7,705,353 | 8,323,589 | 7,584,025 |
| RES Excess Green Tags year 2019 | 684,156 | 193,596 | 193,596 | 193,596 |
| 2019 Res Position | 684,156 | 193,596 | 193,596 | 193,596 |
| RES Net Valuation Estimates Yr 1–10 Expected Value (Cost Reduction) | $ (46,921,264) | $ (37,338,255) | $ (37,338,255) | $ (37,338,255) |
| Transmission B2H Fully Subscribed NPV | $ 13,163,761 | $ 10,977,415 | $ 55,403,269 | $ 94,451,794 |
| **Expected Portfolio Cost** | **$ 4,201,391,311** | **$ 3,914,895,665** | **$ 3,900,243,754** | **$ 3,863,264,498** |
| **Rank** | **4** | **3** | **2** | **1** |
| **Difference** | **$ 338,126,813** | **$ 51,631,167** | **$ 36,979,255** | **$ -** |

**RESOURCE PORTFOLIO ANALYSIS**
**Current Operations, No Carbon, No Coal Curtailment (2010–2019)**

| Current Operations, No carbon, No Curtailment | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H | 1-4 B2H |
|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 1,328,502,353 | $ 363,702,353 | $ 346,502,353 | $ 193,902,353 |
| Capital Costs NPV 20-Year | $ 621,711,410 | $ 239,909,076 | $ 178,705,464 | $ 107,198,820 |
| Aurora NPV Portfolio Total Cost | $ 1,907,178,616 | $ 2,001,439,129 | $ 2,000,008,019 | $ 2,001,618,009 |
| **NPV Total = Aurora + Capital** | **$ 2,528,890,026** | **$ 2,241,348,205** | **$ 2,178,713,483** | **$ 2,108,816,829** |
| $CO_2$ Excess Emissions (Tons) | 5,272,549 | 5,312,589 | 5,453,587 | 5,364,722 |
| RES Excess Green Tags year 2019 | 684,156 | 193,596 | 193,596 | 193,596 |
| **Carbon Allowances Needed Estimates** | **5,272,549** | **5,312,589** | **5,453,587** | **5,364,722** |
| Boxer/Kerry Price Cap Proposal NPV | $ 127,454,073 | $ 128,498,367 | $ 131,857,808 | $ 129,738,767 |
| 2019 Res Position | 684,156 | 193,596 | 193,596 | 193,596 |
| RES Net Valuation Estimates Yr 1–10 Expected Value (Cost Reduction) | $ (46,921,264) | $ (37,338,255) | $ (37,338,255) | $ (37,338,255) |
| Transmission B2H Fully Subscribed NPV | $ 13,163,761 | $ 10,977,415 | $ 55,403,269 | $ 94,451,794 |
| **Expected Portfolio Cost** | **$ 2,622,586,596** | **$ 2,343,485,731** | **$ 2,328,636,306** | **$ 2,295,669,136** |
| **Rank** | **4** | **3** | **2** | **1** |
| **Difference** | **$ 326,917,459** | **$ 47,816,595** | **$ 32,967,170** | **$ -** |

**RESOURCE PORTFOLIO ANALYSIS**
**Base Case, Coal Curtailment (2020–2029)**

| Base Case—Coal Curtailment | 2-1 Nuclear Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 5,834,274,000 | $ 355,600,000 | $ 5,123,200,000 | $ 1,957,200,000 | $ 762,300,000 |
| Capital Costs NPV$ 20 Year | $ 2,267,193,086 | $ 150,871,393 | $ 1,724,352,346 | $ 479,620,560 | $ 241,162,616 |
| Aurora NPV Portfolio Total Cost | $ 948,612,021 | $ 1,805,716,731 | $ 1,106,374,123 | $ 1,671,794,651 | $ 1,461,869,774 |
| **NPV Total = Aurora + Capital** | **$ 3,215,805,108** | **$ 1,956,588,124** | **$ 2,830,726,469** | **$ 2,151,415,212** | **$ 1,703,032,390** |
| $CO_2$ Excess Emissions (Tons) | 6,186,401 | 7,268,164 | 6,401,005 | 8,328,556 | 26,657,888 |
| RES Excess Green Tags year 2019 | 1,267,572 | (7,884) | 167,316 | 815,556 | 272,436 |
| Carbon Allowances Needed Estimates | 6,186,401 | 7,268,164 | 6,401,005 | 8,328,556 | 26,657,888 |
| **Boxer/Kerry Price Cap Proposal NPV** | **$ (30,674,006)** | **$ (8,100,874)** | **$ (26,194,772)** | **$ 14,030,419** | **$ 396,574,720** |
| **2029 Res Position Estimates** | **1,267,572** | **(7,884)** | **167,316** | **815,556** | **272,436** |
| RES NPV $ Estimates Yr 1–10 | | | | | |
| Expected Value (Cost Reduction) | $ (99,699,468) | $ (1,485,655) | $ 8,518,747 | $ (17,665,567) | $ (6,796,825) |
| Transmission Estimate NPV | $ 849,733,630 | $ 1,408,824,342 | $768,798,180.04 | $452,114,922 | $207,800,668.18 |
| **Expected Portfolio Cost** | **$ 3,935,165,264** | **$ 3,355,825,937** | **$ 3,581,848,625** | **$ 2,599,894,987** | **$ 2,300,610,952** |
| **Rank by Least Cost** | **5** | **3** | **4** | **2** | **1** |
| **Difference** | **$ 1,634,554,312** | **$ 1,055,214,985** | **$ 1,281,237,672** | **$ 299,284,034** | **$ -** |
| **Risk Factors** | | | | | |
| $CO_2$ $43 (Incremental) | $ 296,689,242 | $ 320,631,927 | $ 301,438,004 | $ 344,097,492 | $ 749,714,446 |
| RES NPV $ Estimates Yr 11–20 | | | | | |
| High Value (Additional to Expected) | $ (149,549,202) | $ (2,228,482) | $ 12,778,121 | $ (26,498,351) | $ (10,195,238) |
| DSM 50% Realization (Cost Difference) | $ 110,191,842 | $ 116,351,682 | $ 113,762,113 | $ 116,777,644 | $ 24,354,437 |
| High Load Growth (Cost Difference) | $ 465,800,512 | $ 486,161,488 | $ 473,734,605 | $ 486,948,952 | $ 392,322,637 |
| Gas Price | | | | | |
| High NG Prices sensitivity | $ (83,134,652) | $ 199,963,861 | $ (96,394,526) | $ 294,198,968 | $ (97,212,291) |
| Transmission B2H | | | | | |
| Zero 3rd-Party Participation NPV | | | | | |
| **Total Risk Cost** | $ 639,997,742 | $ 1,120,880,476 | $ 805,318,318 | $ 1,215,524,706 | $ 1,058,983,991 |
| **Rank by Least Risk** | **1** | **4** | **2** | **5** | **3** |
| **Difference** | **$ -** | **$ 480,882,734** | **$ 165,320,575** | **$ 575,526,964** | **$ 418,986,249** |
| **Portfolio Differences w/Cost Risk Adj** | | | | | |
| High | $ 2,424,101,255 | $ 2,178,323,943 | $ 2,073,777,869 | $ 1,541,307,091 | $ 1,069,179,229 |
| **High w/Transmission** | **$ 2,424,101,255** | **$ 2,178,323,943** | **$ 2,073,777,869** | **$ 1,541,307,091** | **$ 1,069,179,229** |
| Low | $ 2,573,650,457 | $ 2,180,552,425 | $ 2,060,999,748 | $ 1,567,805,441 | $ 1,079,374,467 |
| **Low w/Transmission** | **$ 2,573,650,457** | **$ 2,180,552,425** | **$ 2,060,999,748** | **$ 1,567,805,441** | **$ 1,079,374,467** |
| **Rank** | **5** | **4** | **3** | **2** | **1** |

**RESOURCE PORTFOLIO ANALYSIS**
**$43 $CO_2$, No Coal Curtailment (2020–2029)**

| $43 CO2—No Coal Curtailment | 2-1 Nuclear/Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 5,834,274,000 | $ 355,600,000 | $ 5,123,200,000 | $ 1,957,200,000 | $ 762,300,000 |
| Capital Costs NPV $20 Year | $ 2,267,193,086 | $ 150,871,393 | $ 1,724,352,346 | $ 479,620,560 | $ 241,162,616 |
| Aurora NPV Portfolio Total Cost | $ 1,684,893,917 | $ 2,689,899,037 | $ 1,878,056,113 | $ 2,646,447,583 | $ 2,689,352,379 |
| **NPV Total = Aurora + Capital** | **$ 3,952,087,004** | **$ 2,840,770,430** | **$ 3,602,408,459** | **$ 3,126,068,143** | **$ 2,930,514,994** |
| $CO_2$ Excess Emissions (Tons) | - | - | - | - | - |
| RES Excess Green Tags year 2019 | 1,267,572 | (7,884) | 167,316 | 815,556 | 272,436 |
| Carbon Allowances Needed Estimates | - | - | - | - | - |
| **Boxer/Kerry Price Cap Proposal NPV** | **$ (30,674,006)** | **$ (8,100,874)** | **$ (26,194,772)** | **$ 14,030,419** | **$ 396,574,720** |
| **2029 Res Position Estimates** | **1,267,572** | **(7,884)** | **167,316** | **815,556** | **272,436** |
| RES NPV $ Estimates Yr 1–10 Expected Value (Cost Reduction) | $ (99,699,468) | $ (1,485,655) | $ 8,518,747 | $ (17,665,567) | $ (6,796,825) |
| Transmission Estimate NPV | $ 849,733,630 | $ 1,408,824,342 | $768,798,180.04 | $452,114,922 | $207,800,668.18 |
| **Expected Portfolio Cost** | **$ 4,671,447,160** | **$ 4,240,008,243** | **$ 4,353,530,615** | **$ 3,574,547,918** | **$ 3,528,093,556** |
| **Rank by Least Cost** | **5** | **3** | **4** | **2** | **1** |
| **Difference** | **$ 1,143,353,603** | **$ 711,914,687** | **$ 825,437,058** | **$ 46,454,362** | **$ -** |

**RESOURCE PORTFOLIO ANALYSIS**
**Current Operations, No Carbon, No Coal Curtailment (2020–2029)**

| Current Operations No carbon No curtailment | 2-1 Nuclear/Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| Capital Costs 2009 ($ Total) | $ 5,834,274,000 | $ 355,600,000 | $ 5,123,200,000 | $ 1,957,200,000 | $ - |
| Capital Costs NPV $20 Year | $ 2,267,193,086 | $ 150,871,393 | $ 1,724,352,346 | $ 479,620,560 | $ - |
| Aurora NPV Portfolio Total Cost | $ 664,260,485 | $ 1,331,464,010 | $ 807,979,508 | $ 1,251,035,806 | $ - |
| **NPV Total = Aurora + Capital** | **$ 2,931,453,572** | **$ 1,482,335,403** | **$ 2,532,331,854** | **$ 1,730,656,367** | **$ -** |
| $CO_2$ Excess Emissions (Tons) | 41,437,283 | 42,239,982 | 41,302,614 | 42,968,883 | - |
| RES Excess Green Tags year 2019 | 1,267,572 | (7,884) | 167,316 | 815,556 | - |
| Carbon Allowances Needed Estimates | 41,437,283 | 42,239,982 | 41,302,614 | 42,968,883 | - |
| **Boxer/Kerry Price Cap Proposal NPV** | **$ (30,674,006)** | **$ (8,100,874)** | **$ (26,194,772)** | **$ 14,030,419** | **$ 396,574,720** |
| **2029 Res Position Estimates** | **1,267,572** | **(7,884)** | **167,316** | **815,556** | **-** |
| RES NPV $ Estimates Yr 1–10 Expected Value (Cost Reduction) | $ (99,699,468) | $ (1,485,655) | $ 8,518,747 | $ (17,665,567) | $ (6,796,825) |
| Transmission Estimate NPV | $ 849,733,630 | $ 1,408,824,342 | $768,798,180.04 | $452,114,922 | $207,800,668.18 |
| **Expected Portfolio Cost** | **$ 3,650,813,728** | **$ 2,881,573,215** | **$ 3,283,454,009** | **$ 2,179,136,141** | **$ 597,578,562** |
| **Rank by Least Cost** | **5** | **3** | **4** | **2** | **1** |
| **Difference** | **$ 3,650,813,728** | **$ 2,881,573,215** | **$ 3,283,454,009** | **$ 2,179,136,141** | **$ 597,578,562** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-5

| Project | Capital Cost |
|---|---|
| Gateway 19% owned by IPCo (300/1600) | $ 337,500,000 |
| 300 Wind | Included in GW |
| 1050 Existing Coal | |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **337,500,000** |
| New Revenue Requirements for Project(s) | $ | 54,023,495 |
| New Net Revenue Requirements | $ | 143,079,951 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **300** |
| New System Demand—Including new uses | 5,927 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 24.14 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (9,198,010) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 6,028,365 |
| Long-Term PTP Revenue | $ | 11,250,202 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 119,058,562 |
| **Net change** | **$** | **48,357,798** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 1-2

| Project | Capital Cost |
|---|---|
| Two 170 MW Peakers at Langley | $ 22,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **22,000,000** |
| New Revenue Requirements for Project(s) | $ | 3,521,532 |
| New Net Revenue Requirements | $ | 92,577,988 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **340** |
| New System Demand—Including new uses | 5,967 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 15.52 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | 344,857 |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future** | | |
| BPA Load Ratio Share | $ | 4,154,388 |
| Long-Term PTP Revenue | $ | 7,230,494 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 74,450,284 |
| **Net change** | **$** | **3,749,520** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 1-3 with additional 3rd party subscription

| Project | Capital Cost | |
|---|---|---|
| B2H 11% Owned by IPCo (250/2300) | $ | 65,217,391 |
| Two 100MW Aeros at Langley | $ | 22,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **87,217,391** |
| New Revenue Requirements for Project(s) | $ | 13,960,854 |
| New Net Revenue Requirements | $ | 103,017,310 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **450** |
| New System Demand—Including new uses | 6,077 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 16.95 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (1,244,978) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - B2H with additional participation** | | |
| BPA Load Ratio Share | $ | 4,462,935 |
| Long-Term PTP Revenue | $ | 7,900,174 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 83,911,380 |
| **Net change** | **$** | **13,210,615** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 1-3 without additional 3rd party subscription

| Project | Capital Cost | |
|---|---|---|
| B2H 22% Owned by IPCo (500/2300) | $ | 130,434,783 |
| Two 100MW Aeros at Langley | $ | 22,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **152,434,783** |
| New Revenue Requirements for Project(s) | $ | 24,400,177 |
| New Net Revenue Requirements | $ | 113,456,633 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **450** |
| New System Demand—Including new uses | 6,077 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 18.67 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (3,145,545) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - B2H without additional participation** | | |
| BPA Load Ratio Share | $ | 4,837,378 |
| Long-Term PTP Revenue | $ | 8,700,743 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 93,175,690 |
| **Net change** | **$** | **22,474,926** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 1-4 with additional 3rd party subscription

| Project | Capital Cost |
|---|---|
| B2H 19% owned by IPCo (425/2300) | $ 110,869,565 |
| 450 Market Purchase | included in B2H |

| Annual Revenue Requirements | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **110,869,565** |
| New Revenue Requirements for Project(s) | $ | 17,746,849 |
| New Net Revenue Requirements | $ | 106,803,305 |

| System Use (in MW) | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **425** |
| New System Demand—Including new uses | 6,052 |

| Point-To-Point Transmission Rate | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 17.65 |

| Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits) | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (2,014,578) |

| Network Transmission Revenue Requirements | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - B2H with additional participation** | | |
| BPA Load Ratio Share | $ | 4,615,289 |
| Long-Term PTP Revenue | $ | 8,224,350 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 87,220,844 |
| **Net change** | **$** | **16,520,080** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 1-4 without additional 3rd party subscription

| Project | Capital Cost |
|---|---|
| B2H 37% owned by IPCo (850/2300) | $ 221,739,130 |
| 450 Market Purchase | included in B2H |

| Annual Revenue Requirements | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **221,739,130** |
| New Revenue Requirements for Project(s) | $ | 35,493,697 |
| New Net Revenue Requirements | $ | 124,550,153 |

| System Use (in MW) | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **425** |
| New System Demand—Including new uses | 6,052 |

| Point-To-Point Transmission Rate | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 20.58 |

| Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits) | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (5,258,889) |

| Network Transmission Revenue Requirements | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - B2H without additional participation** | | |
| BPA Load Ratio Share | $ | 5,254,035 |
| Long-Term PTP Revenue | $ | 9,590,940 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 102,962,357 |
| **Net change** | **$** | **32,261,593** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-1

| Project | Capital Cost |
|---|---|
| Gateway 44% owned by IPCo (1020/2300) | $ 1,316,021,739 |
| 250 East Side Purchase | included in GW |
| 670 MW Nuclear | included in GW |
| 300 MW Solar | $ 7,500,000 |
| 104 MW Geothermal | $ 30,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **1,353,521,739** |
| New Revenue Requirements for Project(s) | $ | 216,657,702 |
| New Net Revenue Requirements | $ | 305,714,159 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **1,424** |
| New System Demand—Including new uses | 7,051 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 43.36 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (30,458,820) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 10,321,179 |
| Long-Term PTP Revenue | $ | 20,205,817 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 268,444,341 |
| **Net change** | **$** | **197,743,576** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-2

| Project | Capital Cost |
|---|---|
| Gateway 60% owned by IPCo (900/1500) | $ 1,780,500,000 |
| MSTI 47% owned by IPCo (700/1500) | $ 466,666,667 |
| 700 MW East Side Purchase (Wyoming) | included in GW |
| 200 MW Wind | Included in GW |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **2,247,166,667** |
| New Revenue Requirements for Project(s) | $ | 359,703,101 |
| New Net Revenue Requirements | $ | 448,759,557 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **1,600** |
| New System Demand—Including new uses | 7,227 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 62.10 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (51,188,896) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 14,527,165 |
| Long-Term PTP Revenue | $ | 28,937,873 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 398,551,697 |
| **Net change** | **$** | **327,850,933** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-3

| Project | Capital Cost | |
|---|---|---|
| Gateway 40% owned by IPCo (600/1500) (Aeolus-Hemingway) | $ | 1,187,000,000 |
| 300 MW Solar | $ | 7,500,000 |
| 400 Large Aero (simco Road) | $ | 32,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **1,226,500,000** |
| New Revenue Requirements for Project(s) | $ | 196,325,382 |
| New Net Revenue Requirements | $ | 285,381,838 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **1,300** |
| New System Demand—Including new uses | 6,927 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 41.20 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (28,070,146) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 9,829,717 |
| Long-Term PTP Revenue | $ | 19,199,644 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 249,609,655 |
| **Net change** | **$** | **178,908,891** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-4

| Project | Capital Cost |
|---|---|
| Gateway 31% owned by IPCo (600/1600) | $ 675,000,000 |
| 500 Wind | Included in GW |
| 100 MW East Side Purchase | included in GW |
| 300 MW Aeros at Langley | $ 22,000,000 |
| 1100 MW Aeros At Simco | $ 102,000,000 |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **799,000,000** |
| New Revenue Requirements for Project(s) | $ | 127,895,622 |
| New Net Revenue Requirements | $ | 216,952,078 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **2,000** |
| New System Demand—Including new uses | 7,627 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 28.45 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (13,960,338) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 7,010,667 |
| Long-Term PTP Revenue | $ | 13,256,220 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 189,942,369 |
| **Net change** | **$** | **119,241,605** |

**2009 Integrated Resource Plan**

**Idaho Power Transmission Rate Approximation for 2009 IRP Analysis**

Portfolio 2-5

| Project | Capital Cost |
|---|---|
| Gateway 19% owned by IPCo (300/1600) | $ 337,500,000 |
| 300 Wind | Included in GW |
| 1050 Existing Coal | |

**Annual Revenue Requirements**

| | | |
|---|---|---|
| Existing Revenue Requirements | $ | 106,566,650 |
| Existing Revenue Credits | $ | (17,510,193) |
| Existing Net Revenue Requirements | $ | 89,056,456 |
| **New Project Capital** | **$** | **337,500,000** |
| New Revenue Requirements for Project(s) | $ | 54,023,495 |
| New Net Revenue Requirements | $ | 143,079,951 |

**System Use (in MW)**

| | |
|---|---|
| Existing System Peak Demand | 5,627 |
| **Future additional IPC Network Use** | **300** |
| New System Demand—Including new uses | 5,927 |

**Point-To-Point Transmission Rate**

| | | |
|---|---|---|
| a) Existing Rate—$/kW-yr | $ | 15.83 |
| b) New Rate without 3rd-Party Use—$/kW-yr | $ | 24.14 |

**Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)**

| | | |
|---|---|---|
| Change in existing uses (increase > 100%) | | 100% |
| Existing uses adjusted at new rate b) | $ | (9,198,010) |

**Network Transmission Revenue Requirements**

| | | |
|---|---|---|
| **a) Existing** | | |
| BPA Load Ratio Share | $ | 4,237,114 |
| Long-Term PTP Revenue | $ | 7,375,757 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 70,700,764 |
| **b) Future - New Projects without additional participation** | | |
| BPA Load Ratio Share | $ | 6,028,365 |
| Long-Term PTP Revenue | $ | 11,250,202 |
| Legacy Contract Revenue | $ | 6,742,822 |
| Assigned to IPC Retail Load Service | $ | 119,058,562 |
| **Net change** | **$** | **48,357,798** |

**Loss of Load Expectation Summary Data—Preferred Portfolio (1-4 & 2-4)***

| Year | Annual Preferred | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2010 | 0.66 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.10 | 0.43 | 0.06 | 0.06 | 0.00 | 0.00 | 0.01 |
| 2011 | 2.17 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 | 0.14 | 1.79 | 0.08 | 0.08 | 0.00 | 0.00 | 0.01 |
| 2012 | 1.57 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 | 0.85 | 0.48 | 0.11 | 0.06 | 0.00 | 0.00 | 0.01 |
| 2013 | 1.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.14 | 1.53 | 0.19 | 0.06 | 0.00 | 0.00 | 0.02 |
| 2014 | 1.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.26 | 1.36 | 0.21 | 0.06 | 0.00 | 0.00 | 0.02 |
| 2015 | 1.13 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.11 | 0.81 | 0.11 | 0.07 | 0.00 | 0.00 | 0.01 |
| 2016 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.10 | 1.15 | 0.13 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.57 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.05 | 0.32 | 0.10 | 0.06 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.47 | 0.09 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2019 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.77 | 0.12 | 0.02 | 0.00 | 0.01 | 0.02 |
| 2020 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.02 | 0.64 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.67 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2022 | 1.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.97 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 1.36 | 0.03 | 0.10 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.79 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.21 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.05 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.14 | 0.05 | 0.00 | 0.14 | 0.00 | 0.00 | 0.00 |
| 2028 | 3.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.24 | 2.89 | 0.09 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

*With CBM @ 330 MW and 83 MW & 158 MW east-side purchases in 2013/2014 and 83 MW in 2028

**Loss of Load Expectation Summary Data—Alternate Portfolio 1-2***

| Year | Annual Preferred | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 1.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.26 | 1.36 | 0.21 | 0.06 | 0.00 | 0.00 | 0.02 |
| 2015 | 1.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.95 | 0.07 | 0.07 | 0.00 | 0.00 | 0.00 |
| 2016 | 1.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.12 | 1.34 | 0.14 | 0.08 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.54 | 0.05 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.99 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.81 | 0.07 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2019 | 1.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 1.32 | 0.10 | 0.06 | 0.00 | 0.00 | 0.00 |

* With CBM @ 330 MW and 83 MW & 158 MW east-side purchases in 2013/2014
With CBM @ 330 MW and 83 east-side purchases in 2015 and beyond

**Loss of Load Expectation Summary Data—Alternate Portfolio 2-5***

| Year | Annual Preferred | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2019 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.77 | 0.12 | 0.02 | 0.00 | 0.01 | 0.02 |
| 2020 | 0.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.05 | 0.68 | 0.05 | 0.03 | 0.00 | 0.00 | 0.01 |
| 2021 | 0.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.06 | 0.71 | 0.07 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2022 | 0.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.42 | 0.04 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.08 | 0.57 | 0.05 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.06 | 1.51 | 0.06 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2025 | 1.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.08 | 1.09 | 0.07 | 0.05 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 0.59 | 0.03 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.28 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.89 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.41 | 0.01 | 0.02 | 0.00 | 0.00 | 0.00 |

*With CBM @ 330 MW and 83 MW purchases in 2020–2029

# SALES AND LOAD FORECAST DATA

**Average Annual Growth Rates (%)**

| | 2010–2015 | 2010–2020 | 2010–2029 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.4 | 1.2 | 0.6 |
| Commercial Sales | 1.5 | 1.1 | 0.7 |
| Irrigation Sales | -0.2 | 0.0 | -0.5 |
| Industrial Sales | 3.5 | 1.8 | 1.0 |
| Additional Firm Sales | 3.4 | 1.5 | 2.3 |
| Firm Sales | 1.8 | 1.2 | 0.7 |
| System Sales | 1.8 | 1.2 | 0.7 |
| Total Sales | 1.8 | 1.2 | 0.7 |
| **Loads** | | | |
| Residential Load | 1.4 | 1.2 | 0.6 |
| Commercial Load | 1.5 | 1.1 | 0.7 |
| Irrigation Load | -0.2 | -0.1 | -0.5 |
| Industrial Load | 3.3 | 1.7 | 1.0 |
| Additional Firm Sales | 3.4 | 1.5 | 2.3 |
| Firm Load Losses | 1.5 | 1.0 | 0.5 |
| Firm Load | 1.7 | 1.1 | 0.7 |
| System Load | 1.7 | 1.1 | 0.7 |
| Total Load | 1.7 | 1.1 | 0.7 |
| Firm Requirement Load | 1.7 | 1.1 | 0.6 |
| **Peaks** | | | |
| Firm Peak | 2.1 | 1.8 | 1.5 |
| System Peak | 2.1 | 1.8 | 1.5 |
| Total Peak | 2.1 | 1.8 | 1.5 |
| Firm Requirement Peak | 2.1 | 1.8 | 1.5 |
| Winter Peak | 0.3 | 0.3 | 0.0 |
| Summer Peak | 2.1 | 1.8 | 1.5 |
| **Customers** | | | |
| Residential Customers | 1.6 | 1.7 | 1.7 |
| Commercial Customers | 2.1 | 2.2 | 2.1 |
| Irrigation Customers | 1.5 | 1.4 | 1.4 |
| Industrial Customers | 1.3 | 1.2 | 1.1 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 777 | 688 | 567 | 489 | 440 | 494 | 627 | 607 | 486 | 484 | 620 | 810 |
| Commercial | 458 | 436 | 402 | 388 | 390 | 436 | 503 | 486 | 427 | 407 | 432 | 487 |
| Irrigation | 1 | 1 | 6 | 74 | 258 | 523 | 599 | 483 | 315 | 47 | 3 | 3 |
| Industrial | 248 | 251 | 244 | 239 | 245 | 260 | 255 | 256 | 249 | 255 | 251 | 275 |
| Additional Firm | 152 | 160 | 155 | 150 | 158 | 144 | 147 | 156 | 172 | 182 | 189 | 193 |
| Loss | 159 | 148 | 131 | 128 | 144 | 184 | 214 | 198 | 160 | 129 | 142 | 170 |
| Firm Load | 1,796 | 1,684 | 1,505 | 1,469 | 1,635 | 2,039 | 2,345 | 2,186 | 1,808 | 1,505 | 1,636 | 1,938 |
| Light Load | 1,654 | 1,555 | 1,385 | 1,336 | 1,469 | 1,833 | 2,121 | 1,939 | 1,645 | 1,362 | 1,503 | 1,802 |
| Heavy Load | 1,918 | 1,780 | 1,592 | 1,565 | 1,778 | 2,190 | 2,521 | 2,380 | 1,938 | 1,617 | 1,743 | 2,045 |
| System Load | 1,796 | 1,684 | 1,505 | 1,469 | 1,635 | 2,039 | 2,345 | 2,186 | 1,808 | 1,505 | 1,636 | 1,938 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,796 | 1,684 | 1,505 | 1,469 | 1,635 | 2,039 | 2,345 | 2,186 | 1,808 | 1,505 | 1,636 | 1,938 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -13 | -13 | -13 | -14 | -15 | -16 | -17 | -16 | -14 | -13 | -13 | -13 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,416 | 2,356 | 2,045 | 1,860 | 2,692 | 3,284 | 3,439 | 3,131 | 2,965 | 2,052 | 2,253 | 2,593 |
| System Peak (1 Hour) | 2,416 | 2,356 | 2,045 | 1,860 | 2,692 | 3,284 | 3,439 | 3,131 | 2,965 | 2,052 | 2,253 | 2,593 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,416 | 2,356 | 2,045 | 1,860 | 2,692 | 3,284 | 3,439 | 3,131 | 2,965 | 2,052 | 2,253 | 2,593 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 788 | 696 | 573 | 494 | 446 | 504 | 643 | 623 | 496 | 492 | 630 | 826 |
| Commercial | 464 | 442 | 408 | 393 | 395 | 444 | 513 | 495 | 435 | 413 | 439 | 497 |
| Irrigation | 1 | 1 | 6 | 74 | 259 | 526 | 603 | 486 | 317 | 47 | 3 | 3 |
| Industrial | 269 | 276 | 268 | 266 | 272 | 289 | 285 | 287 | 282 | 288 | 287 | 296 |
| Additional Firm | 206 | 205 | 197 | 191 | 186 | 160 | 153 | 161 | 177 | 182 | 190 | 193 |
| Loss | 165 | 153 | 136 | 133 | 148 | 189 | 219 | 203 | 164 | 133 | 146 | 174 |
| Firm Load | 1,892 | 1,773 | 1,588 | 1,551 | 1,706 | 2,112 | 2,416 | 2,255 | 1,871 | 1,556 | 1,695 | 1,989 |
| Light Load | 1,743 | 1,637 | 1,460 | 1,411 | 1,533 | 1,899 | 2,186 | 2,000 | 1,703 | 1,409 | 1,557 | 1,850 |
| Heavy Load | 2,021 | 1,875 | 1,679 | 1,653 | 1,855 | 2,268 | 2,615 | 2,438 | 2,006 | 1,673 | 1,805 | 2,099 |
| System Load | 1,892 | 1,773 | 1,588 | 1,551 | 1,706 | 2,112 | 2,416 | 2,255 | 1,871 | 1,556 | 1,695 | 1,989 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,892 | 1,773 | 1,588 | 1,551 | 1,706 | 2,112 | 2,416 | 2,255 | 1,871 | 1,556 | 1,695 | 1,989 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -25 | -25 | -25 | -26 | -30 | -33 | -33 | -32 | -28 | -26 | -25 | -25 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,520 | 2,440 | 2,133 | 1,937 | 2,777 | 3,361 | 3,538 | 3,177 | 3,013 | 2,096 | 2,304 | 2,627 |
| System Peak (1 Hour) | 2,520 | 2,440 | 2,133 | 1,937 | 2,777 | 3,361 | 3,538 | 3,177 | 3,013 | 2,096 | 2,304 | 2,627 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,520 | 2,440 | 2,133 | 1,937 | 2,777 | 3,361 | 3,538 | 3,177 | 3,013 | 2,096 | 2,304 | 2,627 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 804 | 709 | 583 | 503 | 455 | 518 | 664 | 644 | 510 | 504 | 643 | 832 |
| Commercial | 474 | 451 | 416 | 401 | 404 | 456 | 527 | 508 | 445 | 422 | 448 | 506 |
| Irrigation | 1 | 1 | 6 | 74 | 256 | 521 | 598 | 483 | 315 | 47 | 3 | 3 |
| Industrial | 289 | 287 | 285 | 282 | 286 | 303 | 298 | 298 | 292 | 297 | 294 | 299 |
| Additional Firm | 205 | 202 | 197 | 191 | 186 | 160 | 153 | 160 | 177 | 188 | 197 | 201 |
| Loss | 169 | 156 | 139 | 135 | 151 | 192 | 223 | 207 | 167 | 136 | 149 | 177 |
| Firm Load | 1,941 | 1,805 | 1,626 | 1,586 | 1,738 | 2,151 | 2,464 | 2,299 | 1,906 | 1,594 | 1,735 | 2,018 |
| Light Load | 1,787 | 1,667 | 1,496 | 1,443 | 1,561 | 1,933 | 2,229 | 2,040 | 1,735 | 1,443 | 1,593 | 1,876 |
| Heavy Load | 2,073 | 1,907 | 1,720 | 1,700 | 1,877 | 2,310 | 2,666 | 2,486 | 2,056 | 1,703 | 1,848 | 2,139 |
| System Load | 1,941 | 1,805 | 1,626 | 1,586 | 1,738 | 2,151 | 2,464 | 2,299 | 1,906 | 1,594 | 1,735 | 2,018 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,941 | 1,805 | 1,626 | 1,586 | 1,738 | 2,151 | 2,464 | 2,299 | 1,906 | 1,594 | 1,735 | 2,018 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -37 | -36 | -37 | -39 | -45 | -48 | -48 | -47 | -42 | -38 | -37 | -37 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,561 | 2,441 | 2,168 | 1,953 | 2,821 | 3,462 | 3,614 | 3,235 | 3,055 | 2,131 | 2,342 | 2,648 |
| System Peak (1 Hour) | 2,561 | 2,441 | 2,168 | 1,953 | 2,821 | 3,462 | 3,614 | 3,235 | 3,055 | 2,131 | 2,342 | 2,648 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,561 | 2,441 | 2,168 | 1,953 | 2,821 | 3,462 | 3,614 | 3,235 | 3,055 | 2,131 | 2,342 | 2,648 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 800 | 704 | 580 | 499 | 454 | 520 | 670 | 649 | 512 | 503 | 642 | 841 |
| Commercial | 480 | 457 | 422 | 407 | 411 | 465 | 538 | 518 | 453 | 429 | 455 | 514 |
| Irrigation | 1 | 1 | 6 | 73 | 254 | 518 | 595 | 479 | 313 | 47 | 3 | 3 |
| Industrial | 290 | 300 | 288 | 284 | 289 | 306 | 300 | 300 | 294 | 300 | 297 | 300 |
| Additional Firm | 205 | 205 | 198 | 191 | 186 | 179 | 189 | 185 | 184 | 189 | 197 | 201 |
| Loss | 169 | 157 | 139 | 136 | 151 | 194 | 226 | 209 | 169 | 137 | 150 | 178 |
| Firm Load | 1,947 | 1,823 | 1,632 | 1,591 | 1,745 | 2,181 | 2,519 | 2,342 | 1,926 | 1,604 | 1,745 | 2,037 |
| Light Load | 1,793 | 1,684 | 1,501 | 1,447 | 1,567 | 1,960 | 2,279 | 2,078 | 1,753 | 1,452 | 1,603 | 1,894 |
| Heavy Load | 2,068 | 1,928 | 1,735 | 1,696 | 1,884 | 2,357 | 2,708 | 2,532 | 2,078 | 1,714 | 1,859 | 2,160 |
| System Load | 1,947 | 1,823 | 1,632 | 1,591 | 1,745 | 2,181 | 2,519 | 2,342 | 1,926 | 1,604 | 1,745 | 2,037 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,947 | 1,823 | 1,632 | 1,591 | 1,745 | 2,181 | 2,519 | 2,342 | 1,926 | 1,604 | 1,745 | 2,037 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -49 | -49 | -49 | -52 | -58 | -63 | -64 | -62 | -56 | -50 | -49 | -50 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,521 | 2,450 | 2,145 | 1,911 | 2,845 | 3,506 | 3,703 | 3,288 | 3,112 | 2,140 | 2,341 | 2,594 |
| System Peak (1 Hour) | 2,521 | 2,450 | 2,145 | 1,911 | 2,845 | 3,506 | 3,703 | 3,288 | 3,112 | 2,140 | 2,341 | 2,594 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,521 | 2,450 | 2,145 | 1,911 | 2,845 | 3,506 | 3,703 | 3,288 | 3,112 | 2,140 | 2,341 | 2,594 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 815 | 715 | 588 | 507 | 462 | 533 | 690 | 669 | 525 | 513 | 654 | 851 |
| Commercial | 485 | 461 | 426 | 412 | 416 | 472 | 547 | 526 | 460 | 435 | 460 | 519 |
| Irrigation | 1 | 1 | 6 | 72 | 253 | 516 | 593 | 478 | 312 | 46 | 3 | 3 |
| Industrial | 291 | 301 | 289 | 285 | 290 | 307 | 302 | 302 | 296 | 301 | 298 | 301 |
| Additional Firm | 206 | 205 | 198 | 192 | 187 | 179 | 189 | 186 | 185 | 190 | 198 | 202 |
| Loss | 172 | 159 | 141 | 137 | 152 | 196 | 229 | 212 | 171 | 138 | 152 | 180 |
| Firm Load | 1,970 | 1,842 | 1,648 | 1,604 | 1,759 | 2,203 | 2,551 | 2,372 | 1,948 | 1,623 | 1,766 | 2,055 |
| Light Load | 1,814 | 1,701 | 1,516 | 1,460 | 1,580 | 1,980 | 2,308 | 2,105 | 1,773 | 1,469 | 1,622 | 1,911 |
| Heavy Load | 2,092 | 1,947 | 1,752 | 1,710 | 1,900 | 2,381 | 2,743 | 2,583 | 2,089 | 1,734 | 1,892 | 2,169 |
| System Load | 1,970 | 1,842 | 1,648 | 1,604 | 1,759 | 2,203 | 2,551 | 2,372 | 1,948 | 1,623 | 1,766 | 2,055 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,970 | 1,842 | 1,648 | 1,604 | 1,759 | 2,203 | 2,551 | 2,372 | 1,948 | 1,623 | 1,766 | 2,055 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -61 | -61 | -61 | -64 | -72 | -78 | -79 | -76 | -68 | -62 | -62 | -61 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,555 | 2,470 | 2,172 | 1,933 | 2,875 | 3,557 | 3,766 | 3,351 | 3,154 | 2,157 | 2,367 | 2,637 |
| System Peak (1 Hour) | 2,555 | 2,470 | 2,172 | 1,933 | 2,875 | 3,557 | 3,766 | 3,351 | 3,154 | 2,157 | 2,367 | 2,637 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,555 | 2,470 | 2,172 | 1,933 | 2,875 | 3,557 | 3,766 | 3,351 | 3,154 | 2,157 | 2,367 | 2,637 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 818 | 717 | 589 | 507 | 464 | 539 | 702 | 681 | 532 | 517 | 658 | 857 |
| Commercial | 488 | 463 | 429 | 414 | 419 | 477 | 554 | 532 | 465 | 438 | 464 | 523 |
| Irrigation | 1 | 1 | 6 | 73 | 253 | 518 | 595 | 480 | 314 | 47 | 3 | 3 |
| Industrial | 292 | 302 | 289 | 286 | 290 | 308 | 302 | 302 | 296 | 302 | 299 | 301 |
| Additional Firm | 206 | 205 | 198 | 192 | 187 | 179 | 189 | 186 | 185 | 190 | 198 | 202 |
| Loss | 172 | 159 | 141 | 137 | 153 | 197 | 232 | 214 | 172 | 139 | 152 | 181 |
| Firm Load | 1,977 | 1,846 | 1,652 | 1,608 | 1,765 | 2,218 | 2,574 | 2,394 | 1,963 | 1,632 | 1,774 | 2,067 |
| Light Load | 1,820 | 1,705 | 1,520 | 1,463 | 1,586 | 1,994 | 2,329 | 2,124 | 1,786 | 1,477 | 1,630 | 1,922 |
| Heavy Load | 2,100 | 1,952 | 1,756 | 1,714 | 1,919 | 2,382 | 2,768 | 2,607 | 2,104 | 1,743 | 1,901 | 2,181 |
| System Load | 1,977 | 1,846 | 1,652 | 1,608 | 1,765 | 2,218 | 2,574 | 2,394 | 1,963 | 1,632 | 1,774 | 2,067 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,977 | 1,846 | 1,652 | 1,608 | 1,765 | 2,218 | 2,574 | 2,394 | 1,963 | 1,632 | 1,774 | 2,067 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -73 | -73 | -73 | -76 | -86 | -92 | -93 | -90 | -81 | -74 | -74 | -73 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,544 | 2,463 | 2,168 | 1,920 | 2,898 | 3,604 | 3,819 | 3,388 | 3,196 | 2,164 | 2,372 | 2,629 |
| System Peak (1 Hour) | 2,544 | 2,463 | 2,168 | 1,920 | 2,898 | 3,604 | 3,819 | 3,388 | 3,196 | 2,164 | 2,372 | 2,629 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,544 | 2,463 | 2,168 | 1,920 | 2,898 | 3,604 | 3,819 | 3,388 | 3,196 | 2,164 | 2,372 | 2,629 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 823 | 720 | 592 | 509 | 467 | 547 | 715 | 694 | 539 | 522 | 664 | 865 |
| Commercial | 490 | 466 | 431 | 416 | 421 | 482 | 561 | 537 | 468 | 440 | 467 | 527 |
| Irrigation | 1 | 1 | 6 | 72 | 253 | 517 | 595 | 479 | 314 | 46 | 3 | 3 |
| Industrial | 293 | 292 | 290 | 286 | 291 | 309 | 303 | 303 | 297 | 302 | 300 | 302 |
| Additional Firm | 204 | 201 | 197 | 191 | 186 | 178 | 189 | 185 | 184 | 189 | 197 | 201 |
| Loss | 173 | 159 | 141 | 137 | 153 | 198 | 234 | 216 | 173 | 140 | 153 | 182 |
| Firm Load | 1,985 | 1,839 | 1,657 | 1,612 | 1,770 | 2,231 | 2,595 | 2,414 | 1,975 | 1,640 | 1,784 | 2,079 |
| Light Load | 1,828 | 1,699 | 1,524 | 1,466 | 1,590 | 2,006 | 2,348 | 2,141 | 1,797 | 1,484 | 1,639 | 1,933 |
| Heavy Load | 2,120 | 1,943 | 1,752 | 1,718 | 1,925 | 2,396 | 2,808 | 2,610 | 2,117 | 1,762 | 1,900 | 2,194 |
| System Load | 1,985 | 1,839 | 1,657 | 1,612 | 1,770 | 2,231 | 2,595 | 2,414 | 1,975 | 1,640 | 1,784 | 2,079 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,985 | 1,839 | 1,657 | 1,612 | 1,770 | 2,231 | 2,595 | 2,414 | 1,975 | 1,640 | 1,784 | 2,079 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -85 | -82 | -85 | -88 | -99 | -106 | -107 | -104 | -94 | -87 | -85 | -84 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,541 | 2,461 | 2,170 | 1,913 | 2,921 | 3,649 | 3,871 | 3,428 | 3,237 | 2,170 | 2,381 | 2,631 |
| System Peak (1 Hour) | 2,541 | 2,461 | 2,170 | 1,913 | 2,921 | 3,649 | 3,871 | 3,428 | 3,237 | 2,170 | 2,381 | 2,631 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,541 | 2,461 | 2,170 | 1,913 | 2,921 | 3,649 | 3,871 | 3,428 | 3,237 | 2,170 | 2,381 | 2,631 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 829 | 723 | 594 | 511 | 471 | 555 | 729 | 707 | 548 | 527 | 670 | 872 |
| Commercial | 493 | 466 | 433 | 417 | 424 | 487 | 567 | 542 | 472 | 443 | 470 | 529 |
| Irrigation | 1 | 1 | 6 | 72 | 252 | 518 | 595 | 480 | 314 | 47 | 3 | 3 |
| Industrial | 293 | 303 | 291 | 287 | 291 | 310 | 303 | 304 | 298 | 303 | 300 | 303 |
| Additional Firm | 204 | 203 | 197 | 191 | 186 | 178 | 188 | 185 | 184 | 188 | 196 | 200 |
| Loss | 173 | 160 | 142 | 138 | 154 | 199 | 236 | 218 | 174 | 140 | 154 | 183 |
| Firm Load | 1,994 | 1,857 | 1,662 | 1,616 | 1,778 | 2,247 | 2,619 | 2,435 | 1,989 | 1,649 | 1,794 | 2,090 |
| Light Load | 1,836 | 1,715 | 1,529 | 1,470 | 1,597 | 2,019 | 2,369 | 2,161 | 1,810 | 1,492 | 1,648 | 1,944 |
| Heavy Load | 2,129 | 1,963 | 1,758 | 1,732 | 1,920 | 2,413 | 2,834 | 2,634 | 2,133 | 1,772 | 1,911 | 2,217 |
| System Load | 1,994 | 1,857 | 1,662 | 1,616 | 1,778 | 2,247 | 2,619 | 2,435 | 1,989 | 1,649 | 1,794 | 2,090 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,994 | 1,857 | 1,662 | 1,616 | 1,778 | 2,247 | 2,619 | 2,435 | 1,989 | 1,649 | 1,794 | 2,090 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -97 | -96 | -96 | -101 | -112 | -120 | -121 | -117 | -106 | -99 | -97 | -97 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,540 | 2,458 | 2,173 | 1,909 | 2,945 | 3,695 | 3,925 | 3,471 | 3,278 | 2,178 | 2,391 | 2,636 |
| System Peak (1 Hour) | 2,540 | 2,458 | 2,173 | 1,909 | 2,945 | 3,695 | 3,925 | 3,471 | 3,278 | 2,178 | 2,391 | 2,636 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,540 | 2,458 | 2,173 | 1,909 | 2,945 | 3,695 | 3,925 | 3,471 | 3,278 | 2,178 | 2,391 | 2,636 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 834 | 726 | 597 | 513 | 474 | 562 | 743 | 721 | 556 | 532 | 676 | 880 |
| Commercial | 495 | 468 | 435 | 419 | 427 | 492 | 573 | 548 | 476 | 446 | 472 | 533 |
| Irrigation | 1 | 1 | 6 | 72 | 252 | 518 | 596 | 480 | 315 | 47 | 3 | 3 |
| Industrial | 294 | 304 | 291 | 287 | 292 | 310 | 304 | 304 | 298 | 304 | 301 | 303 |
| Additional Firm | 204 | 203 | 196 | 190 | 185 | 177 | 188 | 184 | 183 | 188 | 196 | 200 |
| Loss | 174 | 160 | 142 | 138 | 154 | 201 | 238 | 220 | 176 | 141 | 155 | 184 |
| Firm Load | 2,002 | 1,862 | 1,667 | 1,620 | 1,784 | 2,262 | 2,643 | 2,457 | 2,003 | 1,659 | 1,804 | 2,104 |
| Light Load | 1,844 | 1,720 | 1,534 | 1,474 | 1,603 | 2,033 | 2,391 | 2,180 | 1,823 | 1,501 | 1,657 | 1,956 |
| Heavy Load | 2,127 | 1,969 | 1,763 | 1,736 | 1,927 | 2,429 | 2,859 | 2,658 | 2,161 | 1,772 | 1,922 | 2,231 |
| System Load | 2,002 | 1,862 | 1,667 | 1,620 | 1,784 | 2,262 | 2,643 | 2,457 | 2,003 | 1,659 | 1,804 | 2,104 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,002 | 1,862 | 1,667 | 1,620 | 1,784 | 2,262 | 2,643 | 2,457 | 2,003 | 1,659 | 1,804 | 2,104 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -109 | -108 | -108 | -113 | -125 | -134 | -135 | -131 | -120 | -110 | -109 | -109 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,537 | 2,455 | 2,176 | 1,904 | 2,969 | 3,742 | 3,978 | 3,514 | 3,319 | 2,186 | 2,400 | 2,642 |
| System Peak (1 Hour) | 2,537 | 2,455 | 2,176 | 1,904 | 2,969 | 3,742 | 3,978 | 3,514 | 3,319 | 2,186 | 2,400 | 2,642 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,537 | 2,455 | 2,176 | 1,904 | 2,969 | 3,742 | 3,978 | 3,514 | 3,319 | 2,186 | 2,400 | 2,642 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 841 | 731 | 600 | 516 | 478 | 571 | 758 | 736 | 565 | 538 | 683 | 890 |
| Commercial | 497 | 469 | 437 | 421 | 430 | 497 | 580 | 553 | 480 | 449 | 475 | 536 |
| Irrigation | 1 | 1 | 6 | 73 | 253 | 520 | 598 | 481 | 316 | 47 | 3 | 3 |
| Industrial | 295 | 305 | 292 | 288 | 293 | 311 | 305 | 305 | 299 | 305 | 302 | 304 |
| Additional Firm | 201 | 200 | 194 | 188 | 184 | 176 | 186 | 183 | 182 | 186 | 194 | 198 |
| Loss | 175 | 161 | 142 | 138 | 155 | 202 | 240 | 222 | 177 | 142 | 156 | 185 |
| Firm Load | 2,009 | 1,867 | 1,670 | 1,624 | 1,791 | 2,277 | 2,667 | 2,480 | 2,017 | 1,667 | 1,813 | 2,115 |
| Light Load | 1,851 | 1,724 | 1,537 | 1,477 | 1,609 | 2,047 | 2,413 | 2,200 | 1,835 | 1,509 | 1,665 | 1,967 |
| Heavy Load | 2,135 | 1,974 | 1,776 | 1,731 | 1,935 | 2,462 | 2,868 | 2,682 | 2,176 | 1,782 | 1,931 | 2,243 |
| System Load | 2,009 | 1,867 | 1,670 | 1,624 | 1,791 | 2,277 | 2,667 | 2,480 | 2,017 | 1,667 | 1,813 | 2,115 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,009 | 1,867 | 1,670 | 1,624 | 1,791 | 2,277 | 2,667 | 2,480 | 2,017 | 1,667 | 1,813 | 2,115 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -120 | -120 | -121 | -125 | -138 | -148 | -149 | -145 | -132 | -122 | -120 | -121 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,539 | 2,455 | 2,180 | 1,904 | 2,994 | 3,789 | 4,034 | 3,561 | 3,358 | 2,193 | 2,411 | 2,654 |
| System Peak (1 Hour) | 2,539 | 2,455 | 2,180 | 1,904 | 2,994 | 3,789 | 4,034 | 3,561 | 3,358 | 2,193 | 2,411 | 2,654 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,539 | 2,455 | 2,180 | 1,904 | 2,994 | 3,789 | 4,034 | 3,561 | 3,358 | 2,193 | 2,411 | 2,654 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 848 | 736 | 604 | 519 | 482 | 581 | 774 | 752 | 574 | 545 | 690 | 893 |
| Commercial | 498 | 472 | 438 | 423 | 431 | 502 | 586 | 558 | 484 | 451 | 477 | 539 |
| Irrigation | 1 | 1 | 6 | 73 | 253 | 521 | 600 | 483 | 317 | 47 | 4 | 3 |
| Industrial | 296 | 295 | 292 | 288 | 293 | 312 | 305 | 306 | 300 | 306 | 302 | 305 |
| Additional Firm | 201 | 198 | 194 | 188 | 183 | 175 | 186 | 182 | 181 | 186 | 193 | 197 |
| Loss | 176 | 161 | 143 | 139 | 155 | 204 | 243 | 224 | 178 | 143 | 157 | 186 |
| Firm Load | 2,021 | 1,862 | 1,676 | 1,629 | 1,799 | 2,295 | 2,694 | 2,505 | 2,035 | 1,678 | 1,823 | 2,122 |
| Light Load | 1,861 | 1,720 | 1,542 | 1,482 | 1,616 | 2,063 | 2,437 | 2,223 | 1,852 | 1,519 | 1,674 | 1,974 |
| Heavy Load | 2,146 | 1,968 | 1,782 | 1,736 | 1,956 | 2,465 | 2,897 | 2,728 | 2,181 | 1,793 | 1,953 | 2,240 |
| System Load | 2,021 | 1,862 | 1,676 | 1,629 | 1,799 | 2,295 | 2,694 | 2,505 | 2,035 | 1,678 | 1,823 | 2,122 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,021 | 1,862 | 1,676 | 1,629 | 1,799 | 2,295 | 2,694 | 2,505 | 2,035 | 1,678 | 1,823 | 2,122 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -132 | -127 | -133 | -137 | -152 | -162 | -163 | -159 | -144 | -134 | -133 | -132 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,547 | 2,448 | 2,188 | 1,907 | 3,018 | 3,837 | 4,091 | 3,612 | 3,401 | 2,202 | 2,422 | 2,666 |
| System Peak (1 Hour) | 2,547 | 2,448 | 2,188 | 1,907 | 3,018 | 3,837 | 4,091 | 3,612 | 3,401 | 2,202 | 2,422 | 2,666 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,547 | 2,448 | 2,188 | 1,907 | 3,018 | 3,837 | 4,091 | 3,612 | 3,401 | 2,202 | 2,422 | 2,666 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 845 | 731 | 600 | 515 | 481 | 583 | 781 | 758 | 577 | 545 | 689 | 896 |
| Commercial | 498 | 470 | 439 | 423 | 433 | 506 | 591 | 562 | 487 | 453 | 479 | 541 |
| Irrigation | 1 | 1 | 6 | 72 | 252 | 520 | 599 | 482 | 316 | 47 | 4 | 3 |
| Industrial | 295 | 306 | 293 | 289 | 293 | 312 | 306 | 306 | 300 | 306 | 303 | 305 |
| Additional Firm | 200 | 200 | 193 | 188 | 183 | 175 | 186 | 182 | 181 | 186 | 193 | 197 |
| Loss | 175 | 161 | 142 | 138 | 155 | 204 | 244 | 225 | 179 | 143 | 157 | 186 |
| Firm Load | 2,016 | 1,869 | 1,674 | 1,625 | 1,797 | 2,301 | 2,706 | 2,516 | 2,040 | 1,679 | 1,825 | 2,129 |
| Light Load | 1,857 | 1,726 | 1,540 | 1,479 | 1,614 | 2,068 | 2,448 | 2,232 | 1,856 | 1,519 | 1,676 | 1,980 |
| Heavy Load | 2,153 | 1,976 | 1,770 | 1,732 | 1,954 | 2,471 | 2,909 | 2,740 | 2,187 | 1,804 | 1,944 | 2,247 |
| System Load | 2,016 | 1,869 | 1,674 | 1,625 | 1,797 | 2,301 | 2,706 | 2,516 | 2,040 | 1,679 | 1,825 | 2,129 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,016 | 1,869 | 1,674 | 1,625 | 1,797 | 2,301 | 2,706 | 2,516 | 2,040 | 1,679 | 1,825 | 2,129 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -145 | -144 | -143 | -149 | -165 | -176 | -177 | -172 | -157 | -146 | -144 | -144 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,508 | 2,435 | 2,171 | 1,878 | 3,034 | 3,877 | 4,133 | 3,633 | 3,442 | 2,202 | 2,418 | 2,633 |
| System Peak (1 Hour) | 2,508 | 2,435 | 2,171 | 1,878 | 3,034 | 3,877 | 4,133 | 3,633 | 3,442 | 2,202 | 2,418 | 2,633 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,508 | 2,435 | 2,171 | 1,878 | 3,034 | 3,877 | 4,133 | 3,633 | 3,442 | 2,202 | 2,418 | 2,633 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 850 | 734 | 602 | 517 | 484 | 591 | 795 | 772 | 585 | 550 | 695 | 902 |
| Commercial | 499 | 471 | 440 | 424 | 434 | 510 | 596 | 567 | 490 | 454 | 480 | 544 |
| Irrigation | 1 | 1 | 6 | 72 | 251 | 518 | 597 | 480 | 315 | 47 | 4 | 3 |
| Industrial | 296 | 307 | 294 | 289 | 294 | 313 | 307 | 307 | 301 | 307 | 304 | 307 |
| Additional Firm | 200 | 200 | 193 | 187 | 183 | 175 | 185 | 182 | 181 | 185 | 193 | 197 |
| Loss | 176 | 161 | 142 | 138 | 155 | 205 | 246 | 227 | 180 | 143 | 157 | 187 |
| Firm Load | 2,022 | 1,872 | 1,677 | 1,628 | 1,801 | 2,312 | 2,726 | 2,535 | 2,051 | 1,686 | 1,833 | 2,139 |
| Light Load | 1,863 | 1,729 | 1,543 | 1,481 | 1,618 | 2,078 | 2,466 | 2,249 | 1,867 | 1,526 | 1,684 | 1,989 |
| Heavy Load | 2,160 | 1,980 | 1,774 | 1,735 | 1,958 | 2,483 | 2,949 | 2,741 | 2,199 | 1,813 | 1,953 | 2,258 |
| System Load | 2,022 | 1,872 | 1,677 | 1,628 | 1,801 | 2,312 | 2,726 | 2,535 | 2,051 | 1,686 | 1,833 | 2,139 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,022 | 1,872 | 1,677 | 1,628 | 1,801 | 2,312 | 2,726 | 2,535 | 2,051 | 1,686 | 1,833 | 2,139 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -157 | -155 | -155 | -161 | -179 | -190 | -191 | -186 | -170 | -159 | -156 | -155 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,504 | 2,431 | 2,174 | 1,875 | 3,055 | 3,921 | 4,183 | 3,676 | 3,483 | 2,208 | 2,426 | 2,641 |
| System Peak (1 Hour) | 2,504 | 2,431 | 2,174 | 1,875 | 3,055 | 3,921 | 4,183 | 3,676 | 3,483 | 2,208 | 2,426 | 2,641 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,504 | 2,431 | 2,174 | 1,875 | 3,055 | 3,921 | 4,183 | 3,676 | 3,483 | 2,208 | 2,426 | 2,641 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 853 | 735 | 602 | 517 | 486 | 598 | 808 | 785 | 592 | 554 | 699 | 899 |
| Commercial | 500 | 470 | 441 | 424 | 436 | 514 | 601 | 570 | 492 | 456 | 482 | 544 |
| Irrigation | 1 | 1 | 6 | 72 | 251 | 519 | 597 | 481 | 316 | 47 | 4 | 3 |
| Industrial | 297 | 307 | 294 | 290 | 295 | 314 | 307 | 308 | 302 | 308 | 305 | 306 |
| Additional Firm | 198 | 198 | 192 | 186 | 182 | 173 | 184 | 181 | 180 | 184 | 191 | 195 |
| Loss | 176 | 161 | 142 | 138 | 156 | 206 | 247 | 229 | 181 | 144 | 158 | 187 |
| Firm Load | 2,026 | 1,872 | 1,678 | 1,627 | 1,805 | 2,324 | 2,746 | 2,553 | 2,062 | 1,692 | 1,837 | 2,134 |
| Light Load | 1,866 | 1,729 | 1,543 | 1,480 | 1,621 | 2,089 | 2,484 | 2,265 | 1,876 | 1,531 | 1,688 | 1,984 |
| Heavy Load | 2,164 | 1,980 | 1,774 | 1,744 | 1,949 | 2,496 | 2,971 | 2,761 | 2,211 | 1,818 | 1,958 | 2,263 |
| System Load | 2,026 | 1,872 | 1,678 | 1,627 | 1,805 | 2,324 | 2,746 | 2,553 | 2,062 | 1,692 | 1,837 | 2,134 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,026 | 1,872 | 1,678 | 1,627 | 1,805 | 2,324 | 2,746 | 2,553 | 2,062 | 1,692 | 1,837 | 2,134 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -168 | -167 | -167 | -174 | -191 | -204 | -205 | -200 | -182 | -170 | -168 | -169 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,496 | 2,424 | 2,172 | 1,867 | 3,077 | 3,965 | 4,234 | 3,716 | 3,523 | 2,212 | 2,431 | 2,628 |
| System Peak (1 Hour) | 2,496 | 2,424 | 2,172 | 1,867 | 3,077 | 3,965 | 4,234 | 3,716 | 3,523 | 2,212 | 2,431 | 2,628 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,496 | 2,424 | 2,172 | 1,867 | 3,077 | 3,965 | 4,234 | 3,716 | 3,523 | 2,212 | 2,431 | 2,628 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 843 | 725 | 594 | 509 | 480 | 595 | 808 | 785 | 590 | 549 | 692 | 900 |
| Commercial | 499 | 472 | 439 | 424 | 437 | 516 | 605 | 573 | 493 | 456 | 482 | 545 |
| Irrigation | 1 | 1 | 6 | 71 | 248 | 514 | 593 | 477 | 314 | 46 | 4 | 3 |
| Industrial | 299 | 297 | 294 | 290 | 296 | 314 | 308 | 308 | 301 | 309 | 305 | 307 |
| Additional Firm | 198 | 195 | 191 | 186 | 181 | 173 | 184 | 180 | 179 | 184 | 191 | 195 |
| Loss | 175 | 159 | 141 | 137 | 155 | 206 | 247 | 228 | 180 | 143 | 157 | 187 |
| Firm Load | 2,015 | 1,849 | 1,666 | 1,617 | 1,797 | 2,319 | 2,744 | 2,552 | 2,057 | 1,687 | 1,830 | 2,136 |
| Light Load | 1,856 | 1,708 | 1,532 | 1,471 | 1,614 | 2,085 | 2,483 | 2,264 | 1,872 | 1,527 | 1,681 | 1,987 |
| Heavy Load | 2,140 | 1,954 | 1,771 | 1,724 | 1,941 | 2,507 | 2,951 | 2,760 | 2,219 | 1,803 | 1,950 | 2,265 |
| System Load | 2,015 | 1,849 | 1,666 | 1,617 | 1,797 | 2,319 | 2,744 | 2,552 | 2,057 | 1,687 | 1,830 | 2,136 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,015 | 1,849 | 1,666 | 1,617 | 1,797 | 2,319 | 2,744 | 2,552 | 2,057 | 1,687 | 1,830 | 2,136 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -180 | -173 | -180 | -185 | -203 | -218 | -219 | -214 | -196 | -181 | -180 | -181 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,428 | 2,408 | 2,135 | 1,819 | 3,087 | 3,998 | 4,262 | 3,718 | 3,562 | 2,207 | 2,412 | 2,565 |
| System Peak (1 Hour) | 2,428 | 2,408 | 2,135 | 1,819 | 3,087 | 3,998 | 4,262 | 3,718 | 3,562 | 2,207 | 2,412 | 2,565 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,428 | 2,408 | 2,135 | 1,819 | 3,087 | 3,998 | 4,262 | 3,718 | 3,562 | 2,207 | 2,412 | 2,565 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 849 | 728 | 596 | 511 | 484 | 604 | 824 | 800 | 599 | 555 | 699 | 907 |
| Commercial | 499 | 468 | 440 | 424 | 438 | 520 | 610 | 577 | 496 | 458 | 482 | 547 |
| Irrigation | 1 | 1 | 6 | 71 | 246 | 512 | 589 | 474 | 312 | 46 | 4 | 3 |
| Industrial | 298 | 309 | 295 | 291 | 296 | 315 | 309 | 309 | 303 | 310 | 305 | 308 |
| Additional Firm | 198 | 197 | 191 | 185 | 181 | 173 | 184 | 180 | 179 | 184 | 191 | 194 |
| Loss | 175 | 160 | 141 | 137 | 155 | 207 | 249 | 230 | 181 | 144 | 158 | 188 |
| Firm Load | 2,021 | 1,863 | 1,669 | 1,619 | 1,801 | 2,330 | 2,764 | 2,571 | 2,070 | 1,696 | 1,838 | 2,147 |
| Light Load | 1,862 | 1,721 | 1,536 | 1,473 | 1,618 | 2,095 | 2,501 | 2,281 | 1,884 | 1,535 | 1,688 | 1,996 |
| Heavy Load | 2,147 | 1,970 | 1,774 | 1,726 | 1,945 | 2,519 | 2,972 | 2,800 | 2,219 | 1,812 | 1,969 | 2,265 |
| System Load | 2,021 | 1,863 | 1,669 | 1,619 | 1,801 | 2,330 | 2,764 | 2,571 | 2,070 | 1,696 | 1,838 | 2,147 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,021 | 1,863 | 1,669 | 1,619 | 1,801 | 2,330 | 2,764 | 2,571 | 2,070 | 1,696 | 1,838 | 2,147 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -192 | -191 | -192 | -198 | -216 | -232 | -233 | -227 | -208 | -193 | -193 | -192 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,432 | 2,384 | 2,143 | 1,824 | 3,109 | 4,042 | 4,312 | 3,766 | 3,604 | 2,214 | 2,422 | 2,586 |
| System Peak (1 Hour) | 2,432 | 2,384 | 2,143 | 1,824 | 3,109 | 4,042 | 4,312 | 3,766 | 3,604 | 2,214 | 2,422 | 2,586 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,432 | 2,384 | 2,143 | 1,824 | 3,109 | 4,042 | 4,312 | 3,766 | 3,604 | 2,214 | 2,422 | 2,586 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 852 | 729 | 597 | 511 | 486 | 611 | 837 | 813 | 606 | 558 | 702 | 904 |
| Commercial | 499 | 468 | 440 | 424 | 439 | 524 | 615 | 581 | 499 | 459 | 483 | 548 |
| Irrigation | 1 | 1 | 6 | 71 | 247 | 513 | 591 | 476 | 313 | 46 | 4 | 3 |
| Industrial | 299 | 309 | 296 | 291 | 296 | 316 | 309 | 310 | 304 | 311 | 306 | 309 |
| Additional Firm | 196 | 196 | 189 | 184 | 180 | 171 | 182 | 179 | 178 | 182 | 189 | 192 |
| Loss | 176 | 159 | 141 | 137 | 155 | 208 | 251 | 232 | 182 | 144 | 158 | 187 |
| Firm Load | 2,023 | 1,862 | 1,669 | 1,619 | 1,802 | 2,343 | 2,785 | 2,590 | 2,082 | 1,700 | 1,842 | 2,144 |
| Light Load | 1,863 | 1,720 | 1,535 | 1,473 | 1,619 | 2,106 | 2,520 | 2,298 | 1,895 | 1,539 | 1,692 | 1,993 |
| Heavy Load | 2,149 | 1,969 | 1,774 | 1,725 | 1,960 | 2,516 | 2,994 | 2,820 | 2,232 | 1,817 | 1,973 | 2,262 |
| System Load | 2,023 | 1,862 | 1,669 | 1,619 | 1,802 | 2,343 | 2,785 | 2,590 | 2,082 | 1,700 | 1,842 | 2,144 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,023 | 1,862 | 1,669 | 1,619 | 1,802 | 2,343 | 2,785 | 2,590 | 2,082 | 1,700 | 1,842 | 2,144 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -203 | -203 | -204 | -210 | -231 | -246 | -247 | -241 | -219 | -205 | -205 | -203 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,421 | 2,375 | 2,142 | 1,817 | 3,128 | 4,087 | 4,364 | 3,808 | 3,646 | 2,218 | 2,427 | 2,577 |
| System Peak (1 Hour) | 2,421 | 2,375 | 2,142 | 1,817 | 3,128 | 4,087 | 4,364 | 3,808 | 3,646 | 2,218 | 2,427 | 2,577 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,421 | 2,375 | 2,142 | 1,817 | 3,128 | 4,087 | 4,364 | 3,808 | 3,646 | 2,218 | 2,427 | 2,577 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 843 | 719 | 589 | 504 | 481 | 609 | 838 | 814 | 604 | 554 | 697 | 901 |
| Commercial | 498 | 466 | 440 | 424 | 438 | 526 | 618 | 583 | 500 | 459 | 484 | 548 |
| Irrigation | 1 | 1 | 6 | 70 | 245 | 509 | 587 | 473 | 311 | 46 | 4 | 3 |
| Industrial | 299 | 310 | 297 | 292 | 296 | 317 | 310 | 310 | 304 | 311 | 307 | 309 |
| Additional Firm | 195 | 194 | 188 | 182 | 178 | 170 | 181 | 178 | 177 | 180 | 187 | 190 |
| Loss | 174 | 158 | 140 | 136 | 154 | 207 | 251 | 232 | 182 | 144 | 157 | 187 |
| Firm Load | 2,010 | 1,849 | 1,659 | 1,608 | 1,793 | 2,339 | 2,785 | 2,590 | 2,078 | 1,694 | 1,836 | 2,139 |
| Light Load | 1,851 | 1,708 | 1,526 | 1,463 | 1,611 | 2,102 | 2,520 | 2,297 | 1,891 | 1,533 | 1,686 | 1,989 |
| Heavy Load | 2,146 | 1,955 | 1,755 | 1,714 | 1,949 | 2,512 | 2,995 | 2,820 | 2,228 | 1,821 | 1,956 | 2,257 |
| System Load | 2,010 | 1,849 | 1,659 | 1,608 | 1,793 | 2,339 | 2,785 | 2,590 | 2,078 | 1,694 | 1,836 | 2,139 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,010 | 1,849 | 1,659 | 1,608 | 1,793 | 2,339 | 2,785 | 2,590 | 2,078 | 1,694 | 1,836 | 2,139 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -216 | -214 | -214 | -222 | -245 | -260 | -261 | -255 | -233 | -218 | -215 | -215 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,354 | 2,336 | 2,111 | 1,772 | 3,138 | 4,120 | 4,394 | 3,815 | 3,684 | 2,210 | 2,411 | 2,513 |
| System Peak (1 Hour) | 2,354 | 2,336 | 2,111 | 1,772 | 3,138 | 4,120 | 4,394 | 3,815 | 3,684 | 2,210 | 2,411 | 2,513 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,354 | 2,336 | 2,111 | 1,772 | 3,138 | 4,120 | 4,394 | 3,815 | 3,684 | 2,210 | 2,411 | 2,513 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2028 | Feb. 2028 | Mar. 2028 | Apr. 2028 | May. 2028 | Jun. 2028 | Jul. 2028 | Aug. 2028 | Sep. 2028 | Oct. 2028 | Nov. 2028 | Dec. 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 840 | 716 | 585 | 501 | 480 | 612 | 845 | 821 | 607 | 554 | 695 | 891 |
| Commercial | 497 | 469 | 440 | 423 | 440 | 529 | 623 | 586 | 502 | 459 | 484 | 548 |
| Irrigation | 1 | 1 | 6 | 69 | 242 | 504 | 581 | 468 | 308 | 45 | 3 | 3 |
| Industrial | 301 | 300 | 297 | 292 | 297 | 317 | 310 | 311 | 305 | 312 | 308 | 309 |
| Additional Firm | 193 | 190 | 186 | 181 | 177 | 169 | 179 | 176 | 175 | 179 | 186 | 189 |
| Loss | 174 | 157 | 140 | 135 | 154 | 207 | 251 | 232 | 182 | 144 | 157 | 186 |
| Firm Load | 2,005 | 1,833 | 1,654 | 1,600 | 1,789 | 2,338 | 2,790 | 2,594 | 2,079 | 1,693 | 1,834 | 2,126 |
| Light Load | 1,847 | 1,693 | 1,521 | 1,456 | 1,607 | 2,101 | 2,524 | 2,302 | 1,892 | 1,532 | 1,684 | 1,977 |
| Heavy Load | 2,142 | 1,937 | 1,749 | 1,716 | 1,932 | 2,511 | 3,019 | 2,806 | 2,229 | 1,820 | 1,954 | 2,254 |
| System Load | 2,005 | 1,833 | 1,654 | 1,600 | 1,789 | 2,338 | 2,790 | 2,594 | 2,079 | 1,693 | 1,834 | 2,126 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,005 | 1,833 | 1,654 | 1,600 | 1,789 | 2,338 | 2,790 | 2,594 | 2,079 | 1,693 | 1,834 | 2,126 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2028 | Feb. 2028 | Mar. 2028 | Apr. 2028 | May. 2028 | Jun. 2028 | Jul. 2028 | Aug. 2028 | Sep. 2028 | Oct. 2028 | Nov. 2028 | Dec. 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -228 | -218 | -226 | -235 | -257 | -274 | -275 | -269 | -245 | -230 | -227 | -228 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,315 | 2,299 | 2,094 | 1,745 | 3,152 | 4,156 | 4,430 | 3,835 | 3,724 | 2,208 | 2,405 | 2,469 |
| System Peak (1 Hour) | 2,315 | 2,299 | 2,094 | 1,745 | 3,152 | 4,156 | 4,430 | 3,835 | 3,724 | 2,208 | 2,405 | 2,469 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,315 | 2,299 | 2,094 | 1,745 | 3,152 | 4,156 | 4,430 | 3,835 | 3,724 | 2,208 | 2,405 | 2,469 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—50th Percentile

| | Jan. 2029 | Feb. 2029 | Mar. 2029 | Apr. 2029 | May. 2029 | Jun. 2029 | Jul. 2029 | Aug. 2029 | Sep. 2029 | Oct. 2029 | Nov. 2029 | Dec. 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 824 | 700 | 572 | 489 | 471 | 605 | 840 | 816 | 600 | 545 | 684 | 883 |
| Commercial | 496 | 463 | 438 | 421 | 439 | 532 | 626 | 588 | 502 | 460 | 484 | 548 |
| Irrigation | 1 | 1 | 6 | 68 | 237 | 496 | 572 | 460 | 303 | 45 | 3 | 3 |
| Industrial | 300 | 311 | 297 | 292 | 298 | 317 | 310 | 311 | 304 | 312 | 308 | 310 |
| Additional Firm | 191 | 190 | 185 | 180 | 175 | 167 | 178 | 175 | 174 | 177 | 184 | 187 |
| Loss | 172 | 155 | 138 | 133 | 152 | 206 | 250 | 231 | 180 | 142 | 156 | 184 |
| Firm Load | 1,984 | 1,820 | 1,636 | 1,584 | 1,772 | 2,322 | 2,775 | 2,580 | 2,064 | 1,682 | 1,819 | 2,116 |
| Light Load | 1,827 | 1,681 | 1,505 | 1,441 | 1,592 | 2,087 | 2,510 | 2,289 | 1,879 | 1,522 | 1,671 | 1,968 |
| Heavy Load | 2,108 | 1,925 | 1,731 | 1,698 | 1,914 | 2,493 | 3,003 | 2,791 | 2,227 | 1,797 | 1,938 | 2,244 |
| System Load | 1,984 | 1,820 | 1,636 | 1,584 | 1,772 | 2,322 | 2,775 | 2,580 | 2,064 | 1,682 | 1,819 | 2,116 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,984 | 1,820 | 1,636 | 1,584 | 1,772 | 2,322 | 2,775 | 2,580 | 2,064 | 1,682 | 1,819 | 2,116 |

### Peak Load (Megawatts)—90th Percentile

| | Jan. 2029 | Feb. 2029 | Mar. 2029 | Apr. 2029 | May. 2029 | Jun. 2029 | Jul. 2029 | Aug. 2029 | Sep. 2029 | Oct. 2029 | Nov. 2029 | Dec. 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -239 | -238 | -237 | -247 | -270 | -288 | -289 | -282 | -260 | -241 | -238 | -240 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,209 | 2,250 | 2,042 | 1,676 | 3,155 | 4,181 | 4,445 | 3,818 | 3,761 | 2,197 | 2,376 | 2,367 |
| System Peak (1 Hour) | 2,209 | 2,250 | 2,042 | 1,676 | 3,155 | 4,181 | 4,445 | 3,818 | 3,761 | 2,197 | 2,376 | 2,367 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,209 | 2,250 | 2,042 | 1,676 | 3,155 | 4,181 | 4,445 | 3,818 | 3,761 | 2,197 | 2,376 | 2,367 |

## Sales Load Forecast Annual Summary

### Billed Sales (Megawatthours)—50th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,168,469 | 5,256,321 | 5,379,801 | 5,376,155 | 5,489,259 | 5,530,778 | 5,587,128 | 5,645,662 | 5,701,444 | 5,769,695 |
| Commercial | 3,829,818 | 3,890,483 | 3,980,186 | 4,047,917 | 4,100,296 | 4,133,788 | 4,163,623 | 4,192,537 | 4,221,347 | 4,249,770 |
| Irrigation | 1,698,888 | 1,708,444 | 1,695,280 | 1,683,869 | 1,677,836 | 1,683,905 | 1,682,258 | 1,683,643 | 1,685,914 | 1,689,596 |
| Industrial | 2,196,153 | 2,441,884 | 2,567,526 | 2,589,054 | 2,599,655 | 2,604,497 | 2,611,034 | 2,616,668 | 2,622,321 | 2,628,531 |
| Additional Firm | 1,428,995 | 1,604,959 | 1,621,276 | 1,687,195 | 1,689,907 | 1,689,231 | 1,683,727 | 1,678,357 | 1,676,318 | 1,657,486 |
| Firm Sales | 14,322,324 | 14,902,092 | 15,244,069 | 15,384,190 | 15,556,953 | 15,642,199 | 15,727,771 | 15,816,867 | 15,907,344 | 15,995,079 |
| System Sales | 14,322,324 | 14,902,092 | 15,244,069 | 15,384,190 | 15,556,953 | 15,642,199 | 15,727,771 | 15,816,867 | 15,907,344 | 15,995,079 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,322,324 | 14,902,092 | 15,244,069 | 15,384,190 | 15,556,953 | 15,642,199 | 15,727,771 | 15,816,867 | 15,907,344 | 15,995,079 |

### Generation Month Sales (Megawatthours)—50th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,174,855 | 5,264,992 | 5,396,714 | 5,384,048 | 5,492,013 | 5,534,546 | 5,608,557 | 5,649,355 | 5,705,977 | 5,774,417 |
| Commercial | 3,835,231 | 3,897,657 | 3,997,338 | 4,053,044 | 4,104,395 | 4,137,679 | 4,179,510 | 4,196,349 | 4,225,126 | 4,253,450 |
| Irrigation | 1,698,904 | 1,708,441 | 1,695,300 | 1,683,870 | 1,677,845 | 1,683,908 | 1,682,286 | 1,683,649 | 1,685,921 | 1,689,605 |
| Industrial | 2,211,419 | 2,457,547 | 2,569,645 | 2,589,952 | 2,600,158 | 2,605,016 | 2,611,732 | 2,616,883 | 2,622,847 | 2,628,952 |
| Additional Firm | 1,428,995 | 1,604,959 | 1,621,276 | 1,687,195 | 1,689,907 | 1,689,231 | 1,683,727 | 1,678,357 | 1,676,318 | 1,657,486 |
| Firm Sales | 14,349,404 | 14,933,595 | 15,280,274 | 15,398,109 | 15,564,319 | 15,650,380 | 15,765,812 | 15,824,593 | 15,916,190 | 16,003,910 |
| System Sales | 14,349,404 | 14,933,595 | 15,280,274 | 15,398,109 | 15,564,319 | 15,650,380 | 15,765,812 | 15,824,593 | 15,916,190 | 16,003,910 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,349,404 | 14,933,595 | 15,280,274 | 15,398,109 | 15,564,319 | 15,650,380 | 15,765,812 | 15,824,593 | 15,916,190 | 16,003,910 |
| Loss | 1,392,659 | 1,434,513 | 1,465,382 | 1,472,316 | 1,488,589 | 1,496,524 | 1,507,986 | 1,513,222 | 1,521,803 | 1,531,196 |
| Required Generation | 15,742,063 | 16,368,108 | 16,745,655 | 16,870,425 | 17,052,907 | 17,146,904 | 17,273,798 | 17,337,815 | 17,437,993 | 17,535,105 |

### Average Load (Average Megawatts)—50th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 591 | 601 | 614 | 615 | 627 | 632 | 638 | 645 | 651 | 659 |
| Commercial | 438 | 445 | 455 | 463 | 469 | 472 | 476 | 479 | 482 | 486 |
| Irrigation | 194 | 195 | 193 | 192 | 192 | 192 | 192 | 192 | 192 | 193 |
| Industrial | 252 | 281 | 293 | 296 | 297 | 297 | 297 | 299 | 299 | 300 |
| Additional Firm | 163 | 183 | 185 | 193 | 193 | 193 | 192 | 192 | 191 | 189 |
| Loss | 159 | 164 | 167 | 168 | 170 | 171 | 172 | 173 | 174 | 175 |
| Firm Load | 1,797 | 1,869 | 1,906 | 1,926 | 1,947 | 1,957 | 1,967 | 1,979 | 1,991 | 2,002 |
| Light Load | 1,635 | 1,700 | 1,735 | 1,752 | 1,771 | 1,781 | 1,789 | 1,801 | 1,811 | 1,821 |
| Heavy Load | 1,924 | 2,001 | 2,042 | 2,062 | 2,085 | 2,096 | 2,106 | 2,120 | 2,132 | 2,143 |
| System Load | 1,797 | 1,869 | 1,906 | 1,926 | 1,947 | 1,957 | 1,967 | 1,979 | 1,991 | 2,002 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,797 | 1,869 | 1,906 | 1,926 | 1,947 | 1,957 | 1,967 | 1,979 | 1,991 | 2,002 |

### Peak Load (Megawatts)—90th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -17 | -33 | -48 | -64 | -79 | -93 | -107 | -121 | -135 | -149 |
| Demand Response (Mw) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,439 | 3,538 | 3,614 | 3,703 | 3,766 | 3,819 | 3,871 | 3,925 | 3,978 | 4,034 |
| System Peak (1 Hour) | 3,439 | 3,538 | 3,614 | 3,703 | 3,766 | 3,819 | 3,871 | 3,925 | 3,978 | 4,034 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,439 | 3,538 | 3,614 | 3,703 | 3,766 | 3,819 | 3,871 | 3,925 | 3,978 | 4,034 |

## Sales Load Forecast Annual Summary

### Billed Sales (Megawatthours)—50th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,841,011 | 5,841,418 | 5,895,447 | 5,939,934 | 5,890,559 | 5,955,384 | 5,997,074 | 5,957,390 | 5,958,204 | 5,866,848 |
| Commercial | 4,276,547 | 4,293,464 | 4,313,307 | 4,329,757 | 4,334,101 | 4,350,602 | 4,365,073 | 4,370,462 | 4,379,409 | 4,379,364 |
| Irrigation | 1,695,341 | 1,691,409 | 1,685,309 | 1,686,379 | 1,673,258 | 1,663,734 | 1,668,126 | 1,656,601 | 1,638,789 | 1,612,185 |
| Industrial | 2,634,391 | 2,637,943 | 2,644,929 | 2,652,534 | 2,655,893 | 2,661,588 | 2,668,570 | 2,671,916 | 2,678,550 | 2,679,036 |
| Additional Firm | 1,657,426 | 1,651,857 | 1,650,315 | 1,636,705 | 1,638,050 | 1,632,964 | 1,619,435 | 1,605,524 | 1,595,267 | 1,578,775 |
| Firm Sales | 16,104,716 | 16,116,090 | 16,189,308 | 16,245,309 | 16,191,861 | 16,264,271 | 16,318,279 | 16,261,893 | 16,250,219 | 16,116,208 |
| System Sales | 16,104,716 | 16,116,090 | 16,189,308 | 16,245,309 | 16,191,861 | 16,264,271 | 16,318,279 | 16,261,893 | 16,250,219 | 16,116,208 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,104,716 | 16,116,090 | 16,189,308 | 16,245,309 | 16,191,861 | 16,264,271 | 16,318,279 | 16,261,893 | 16,250,219 | 16,116,208 |

### Generation Month Sales (Megawatthours)—50th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,858,867 | 5,844,921 | 5,898,281 | 5,936,364 | 5,912,615 | 5,957,991 | 5,994,165 | 5,957,221 | 5,969,571 | 5,866,154 |
| Commercial | 4,292,409 | 4,296,753 | 4,316,405 | 4,332,205 | 4,350,397 | 4,353,566 | 4,367,548 | 4,373,116 | 4,395,241 | 4,381,980 |
| Irrigation | 1,695,365 | 1,691,408 | 1,685,314 | 1,686,373 | 1,673,278 | 1,663,742 | 1,668,121 | 1,656,591 | 1,638,795 | 1,612,166 |
| Industrial | 2,634,963 | 2,638,631 | 2,645,784 | 2,652,260 | 2,656,430 | 2,662,466 | 2,668,880 | 2,672,483 | 2,678,356 | 2,679,387 |
| Additional Firm | 1,657,426 | 1,651,857 | 1,650,315 | 1,636,705 | 1,638,050 | 1,632,964 | 1,619,435 | 1,605,524 | 1,595,267 | 1,578,775 |
| Firm Sales | 16,139,031 | 16,123,569 | 16,196,100 | 16,243,907 | 16,230,769 | 16,270,729 | 16,318,149 | 16,264,935 | 16,277,230 | 16,118,462 |
| System Sales | 16,139,031 | 16,123,569 | 16,196,100 | 16,243,907 | 16,230,769 | 16,270,729 | 16,318,149 | 16,264,935 | 16,277,230 | 16,118,462 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,139,031 | 16,123,569 | 16,196,100 | 16,243,907 | 16,230,769 | 16,270,729 | 16,318,149 | 16,264,935 | 16,277,230 | 16,118,462 |
| Loss | 1,544,406 | 1,541,615 | 1,548,045 | 1,552,690 | 1,549,724 | 1,552,855 | 1,557,457 | 1,551,223 | 1,551,830 | 1,534,338 |
| Required Generation | 17,683,437 | 17,665,184 | 17,744,145 | 17,796,597 | 17,780,493 | 17,823,583 | 17,875,606 | 17,816,158 | 17,829,060 | 17,652,801 |

### Average Load (Average Megawatts)—50th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 667 | 667 | 673 | 678 | 673 | 680 | 684 | 680 | 680 | 670 |
| Commercial | 489 | 490 | 493 | 495 | 495 | 497 | 499 | 499 | 500 | 500 |
| Irrigation | 193 | 193 | 192 | 193 | 190 | 190 | 190 | 189 | 187 | 184 |
| Industrial | 300 | 301 | 302 | 303 | 302 | 304 | 305 | 305 | 305 | 306 |
| Additional Firm | 189 | 189 | 188 | 187 | 186 | 186 | 185 | 183 | 182 | 180 |
| Loss | 176 | 176 | 177 | 177 | 176 | 177 | 178 | 177 | 177 | 175 |
| Firm Load | 2,013 | 2,017 | 2,026 | 2,032 | 2,024 | 2,035 | 2,041 | 2,034 | 2,030 | 2,015 |
| Light Load | 1,831 | 1,834 | 1,843 | 1,848 | 1,841 | 1,851 | 1,856 | 1,850 | 1,846 | 1,833 |
| Heavy Load | 2,156 | 2,160 | 2,169 | 2,176 | 2,167 | 2,179 | 2,185 | 2,178 | 2,174 | 2,158 |
| System Load | 2,013 | 2,017 | 2,026 | 2,032 | 2,024 | 2,035 | 2,041 | 2,034 | 2,030 | 2,015 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,013 | 2,017 | 2,026 | 2,032 | 2,024 | 2,035 | 2,041 | 2,034 | 2,030 | 2,015 |

### Peak Load (Megawatts)—90th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -163 | -177 | -191 | -205 | -219 | -233 | -247 | -261 | -275 | -289 |
| Demand Response (Mw) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 4,091 | 4,133 | 4,183 | 4,234 | 4,262 | 4,312 | 4,364 | 4,394 | 4,430 | 4,445 |
| System Peak (1 Hour) | 4,091 | 4,133 | 4,183 | 4,234 | 4,262 | 4,312 | 4,364 | 4,394 | 4,430 | 4,445 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 4,091 | 4,133 | 4,183 | 4,234 | 4,262 | 4,312 | 4,364 | 4,394 | 4,430 | 4,445 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 810 | 720 | 586 | 497 | 449 | 512 | 652 | 623 | 495 | 495 | 635 | 835 |
| Commercial | 468 | 447 | 407 | 395 | 397 | 441 | 509 | 490 | 429 | 409 | 436 | 493 |
| Irrigation | 1 | 1 | 7 | 99 | 309 | 577 | 626 | 500 | 332 | 52 | 4 | 3 |
| Industrial | 248 | 251 | 244 | 239 | 245 | 260 | 255 | 256 | 249 | 255 | 251 | 275 |
| Additional Firm | 152 | 160 | 155 | 150 | 158 | 144 | 147 | 156 | 172 | 182 | 189 | 193 |
| Loss | 164 | 153 | 134 | 132 | 151 | 192 | 220 | 202 | 163 | 131 | 144 | 174 |
| Firm Load | 1,844 | 1,730 | 1,533 | 1,512 | 1,709 | 2,126 | 2,409 | 2,226 | 1,838 | 1,525 | 1,658 | 1,972 |
| Light Load | 1,698 | 1,598 | 1,410 | 1,376 | 1,535 | 1,911 | 2,180 | 1,975 | 1,673 | 1,380 | 1,523 | 1,834 |
| Heavy Load | 1,969 | 1,829 | 1,622 | 1,612 | 1,858 | 2,283 | 2,590 | 2,424 | 1,971 | 1,639 | 1,766 | 2,081 |
| System Load | 1,844 | 1,730 | 1,533 | 1,512 | 1,709 | 2,126 | 2,409 | 2,226 | 1,838 | 1,525 | 1,658 | 1,972 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,844 | 1,730 | 1,533 | 1,512 | 1,709 | 2,126 | 2,409 | 2,226 | 1,838 | 1,525 | 1,658 | 1,972 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -13 | -13 | -13 | -14 | -15 | -16 | -17 | -16 | -14 | -13 | -13 | -13 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,455 | 2,402 | 2,103 | 1,871 | 2,761 | 3,318 | 3,460 | 3,138 | 2,978 | 2,088 | 2,302 | 2,695 |
| System Peak (1 Hour) | 2,455 | 2,402 | 2,103 | 1,871 | 2,761 | 3,318 | 3,460 | 3,138 | 2,978 | 2,088 | 2,302 | 2,695 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,455 | 2,402 | 2,103 | 1,871 | 2,761 | 3,318 | 3,460 | 3,138 | 2,978 | 2,088 | 2,302 | 2,695 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 821 | 728 | 592 | 503 | 456 | 523 | 669 | 640 | 506 | 503 | 645 | 850 |
| Commercial | 475 | 452 | 413 | 400 | 403 | 450 | 519 | 499 | 436 | 415 | 442 | 503 |
| Irrigation | 1 | 1 | 7 | 99 | 309 | 580 | 630 | 503 | 334 | 52 | 4 | 3 |
| Industrial | 269 | 276 | 268 | 266 | 272 | 289 | 285 | 287 | 282 | 288 | 287 | 296 |
| Additional Firm | 206 | 205 | 197 | 191 | 186 | 160 | 153 | 161 | 177 | 182 | 190 | 193 |
| Loss | 170 | 158 | 139 | 137 | 155 | 197 | 226 | 207 | 167 | 135 | 148 | 178 |
| Firm Load | 1,941 | 1,820 | 1,616 | 1,595 | 1,781 | 2,200 | 2,482 | 2,296 | 1,902 | 1,577 | 1,716 | 2,024 |
| Light Load | 1,787 | 1,681 | 1,486 | 1,451 | 1,600 | 1,977 | 2,245 | 2,037 | 1,731 | 1,427 | 1,576 | 1,882 |
| Heavy Load | 2,073 | 1,924 | 1,709 | 1,700 | 1,937 | 2,362 | 2,685 | 2,483 | 2,039 | 1,695 | 1,828 | 2,136 |
| System Load | 1,941 | 1,820 | 1,616 | 1,595 | 1,781 | 2,200 | 2,482 | 2,296 | 1,902 | 1,577 | 1,716 | 2,024 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,941 | 1,820 | 1,616 | 1,595 | 1,781 | 2,200 | 2,482 | 2,296 | 1,902 | 1,577 | 1,716 | 2,024 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -25 | -25 | -25 | -26 | -30 | -33 | -33 | -32 | -28 | -26 | -25 | -25 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,559 | 2,486 | 2,191 | 1,948 | 2,846 | 3,395 | 3,560 | 3,185 | 3,027 | 2,133 | 2,353 | 2,733 |
| System Peak (1 Hour) | 2,559 | 2,486 | 2,191 | 1,948 | 2,846 | 3,395 | 3,560 | 3,185 | 3,027 | 2,133 | 2,353 | 2,733 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,559 | 2,486 | 2,191 | 1,948 | 2,846 | 3,395 | 3,560 | 3,185 | 3,027 | 2,133 | 2,353 | 2,733 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 837 | 741 | 602 | 511 | 465 | 538 | 691 | 661 | 520 | 515 | 658 | 857 |
| Commercial | 485 | 462 | 421 | 408 | 412 | 461 | 533 | 512 | 447 | 424 | 452 | 513 |
| Irrigation | 1 | 1 | 7 | 98 | 307 | 576 | 625 | 499 | 332 | 52 | 4 | 3 |
| Industrial | 289 | 287 | 285 | 282 | 286 | 303 | 298 | 298 | 292 | 297 | 294 | 299 |
| Additional Firm | 205 | 202 | 197 | 191 | 186 | 160 | 153 | 160 | 177 | 188 | 197 | 201 |
| Loss | 174 | 161 | 142 | 140 | 158 | 201 | 230 | 211 | 170 | 138 | 151 | 180 |
| Firm Load | 1,990 | 1,853 | 1,655 | 1,630 | 1,814 | 2,239 | 2,531 | 2,341 | 1,937 | 1,615 | 1,756 | 2,053 |
| Light Load | 1,832 | 1,711 | 1,522 | 1,483 | 1,629 | 2,013 | 2,289 | 2,077 | 1,763 | 1,461 | 1,613 | 1,909 |
| Heavy Load | 2,125 | 1,958 | 1,750 | 1,747 | 1,959 | 2,405 | 2,738 | 2,532 | 2,090 | 1,725 | 1,871 | 2,176 |
| System Load | 1,990 | 1,853 | 1,655 | 1,630 | 1,814 | 2,239 | 2,531 | 2,341 | 1,937 | 1,615 | 1,756 | 2,053 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,990 | 1,853 | 1,655 | 1,630 | 1,814 | 2,239 | 2,531 | 2,341 | 1,937 | 1,615 | 1,756 | 2,053 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -37 | -36 | -37 | -39 | -45 | -48 | -48 | -47 | -42 | -38 | -37 | -37 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,600 | 2,487 | 2,225 | 1,964 | 2,891 | 3,496 | 3,636 | 3,242 | 3,069 | 2,168 | 2,391 | 2,756 |
| System Peak (1 Hour) | 2,600 | 2,487 | 2,225 | 1,964 | 2,891 | 3,496 | 3,636 | 3,242 | 3,069 | 2,168 | 2,391 | 2,756 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,600 | 2,487 | 2,225 | 1,964 | 2,891 | 3,496 | 3,636 | 3,242 | 3,069 | 2,168 | 2,391 | 2,756 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 834 | 737 | 599 | 508 | 464 | 540 | 698 | 667 | 522 | 514 | 658 | 866 |
| Commercial | 492 | 468 | 428 | 414 | 419 | 471 | 545 | 522 | 455 | 431 | 459 | 520 |
| Irrigation | 1 | 1 | 7 | 98 | 305 | 572 | 622 | 496 | 330 | 52 | 4 | 3 |
| Industrial | 290 | 300 | 288 | 284 | 289 | 306 | 300 | 300 | 294 | 300 | 297 | 300 |
| Additional Firm | 205 | 205 | 198 | 191 | 186 | 179 | 189 | 185 | 184 | 189 | 197 | 201 |
| Loss | 174 | 162 | 142 | 140 | 158 | 202 | 233 | 213 | 172 | 139 | 152 | 182 |
| Firm Load | 1,997 | 1,872 | 1,661 | 1,635 | 1,821 | 2,270 | 2,587 | 2,385 | 1,957 | 1,625 | 1,767 | 2,073 |
| Light Load | 1,839 | 1,729 | 1,528 | 1,488 | 1,636 | 2,041 | 2,340 | 2,116 | 1,781 | 1,471 | 1,623 | 1,927 |
| Heavy Load | 2,121 | 1,979 | 1,766 | 1,743 | 1,967 | 2,454 | 2,781 | 2,579 | 2,111 | 1,736 | 1,883 | 2,198 |
| System Load | 1,997 | 1,872 | 1,661 | 1,635 | 1,821 | 2,270 | 2,587 | 2,385 | 1,957 | 1,625 | 1,767 | 2,073 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,997 | 1,872 | 1,661 | 1,635 | 1,821 | 2,270 | 2,587 | 2,385 | 1,957 | 1,625 | 1,767 | 2,073 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -49 | -49 | -49 | -52 | -58 | -63 | -64 | -62 | -56 | -50 | -49 | -50 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,560 | 2,496 | 2,203 | 1,922 | 2,915 | 3,541 | 3,726 | 3,296 | 3,127 | 2,177 | 2,389 | 2,703 |
| System Peak (1 Hour) | 2,560 | 2,496 | 2,203 | 1,922 | 2,915 | 3,541 | 3,726 | 3,296 | 3,127 | 2,177 | 2,389 | 2,703 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,560 | 2,496 | 2,203 | 1,922 | 2,915 | 3,541 | 3,726 | 3,296 | 3,127 | 2,177 | 2,389 | 2,703 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 848 | 748 | 608 | 515 | 472 | 554 | 719 | 687 | 535 | 525 | 670 | 876 |
| Commercial | 497 | 472 | 432 | 418 | 424 | 478 | 554 | 530 | 461 | 437 | 464 | 526 |
| Irrigation | 1 | 1 | 7 | 97 | 303 | 570 | 620 | 495 | 329 | 52 | 4 | 3 |
| Industrial | 291 | 301 | 289 | 285 | 290 | 307 | 302 | 302 | 296 | 301 | 298 | 301 |
| Additional Firm | 206 | 205 | 198 | 192 | 187 | 179 | 189 | 186 | 185 | 190 | 198 | 202 |
| Loss | 176 | 163 | 143 | 141 | 160 | 204 | 236 | 216 | 174 | 140 | 154 | 183 |
| Firm Load | 2,020 | 1,891 | 1,677 | 1,649 | 1,836 | 2,294 | 2,620 | 2,416 | 1,980 | 1,644 | 1,788 | 2,091 |
| Light Load | 1,860 | 1,746 | 1,543 | 1,501 | 1,649 | 2,061 | 2,370 | 2,144 | 1,802 | 1,488 | 1,642 | 1,944 |
| Heavy Load | 2,146 | 1,999 | 1,783 | 1,758 | 1,983 | 2,479 | 2,817 | 2,631 | 2,123 | 1,757 | 1,916 | 2,206 |
| System Load | 2,020 | 1,891 | 1,677 | 1,649 | 1,836 | 2,294 | 2,620 | 2,416 | 1,980 | 1,644 | 1,788 | 2,091 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,020 | 1,891 | 1,677 | 1,649 | 1,836 | 2,294 | 2,620 | 2,416 | 1,980 | 1,644 | 1,788 | 2,091 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -61 | -61 | -61 | -64 | -72 | -78 | -79 | -76 | -68 | -62 | -62 | -61 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,594 | 2,516 | 2,230 | 1,944 | 2,946 | 3,593 | 3,789 | 3,359 | 3,169 | 2,193 | 2,415 | 2,748 |
| System Peak (1 Hour) | 2,594 | 2,516 | 2,230 | 1,944 | 2,946 | 3,593 | 3,789 | 3,359 | 3,169 | 2,193 | 2,415 | 2,748 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,594 | 2,516 | 2,230 | 1,944 | 2,946 | 3,593 | 3,789 | 3,359 | 3,169 | 2,193 | 2,415 | 2,748 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 852 | 750 | 609 | 516 | 475 | 561 | 732 | 699 | 542 | 528 | 674 | 883 |
| Commercial | 500 | 475 | 435 | 421 | 427 | 484 | 561 | 536 | 466 | 440 | 468 | 530 |
| Irrigation | 1 | 1 | 7 | 97 | 304 | 572 | 622 | 496 | 330 | 52 | 4 | 3 |
| Industrial | 292 | 302 | 289 | 286 | 290 | 308 | 302 | 302 | 296 | 302 | 299 | 301 |
| Additional Firm | 206 | 205 | 198 | 192 | 187 | 179 | 189 | 186 | 185 | 190 | 198 | 202 |
| Loss | 177 | 164 | 144 | 141 | 160 | 206 | 238 | 218 | 175 | 141 | 155 | 184 |
| Firm Load | 2,028 | 1,896 | 1,682 | 1,653 | 1,842 | 2,310 | 2,645 | 2,438 | 1,994 | 1,652 | 1,797 | 2,103 |
| Light Load | 1,867 | 1,751 | 1,547 | 1,504 | 1,655 | 2,076 | 2,393 | 2,163 | 1,815 | 1,496 | 1,650 | 1,955 |
| Heavy Load | 2,154 | 2,004 | 1,788 | 1,762 | 2,003 | 2,480 | 2,843 | 2,655 | 2,138 | 1,766 | 1,925 | 2,219 |
| System Load | 2,028 | 1,896 | 1,682 | 1,653 | 1,842 | 2,310 | 2,645 | 2,438 | 1,994 | 1,652 | 1,797 | 2,103 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,028 | 1,896 | 1,682 | 1,653 | 1,842 | 2,310 | 2,645 | 2,438 | 1,994 | 1,652 | 1,797 | 2,103 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -73 | -73 | -73 | -76 | -86 | -92 | -93 | -90 | -81 | -74 | -74 | -73 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,583 | 2,509 | 2,226 | 1,931 | 2,970 | 3,640 | 3,843 | 3,396 | 3,211 | 2,200 | 2,421 | 2,742 |
| System Peak (1 Hour) | 2,583 | 2,509 | 2,226 | 1,931 | 2,970 | 3,640 | 3,843 | 3,396 | 3,211 | 2,200 | 2,421 | 2,742 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,583 | 2,509 | 2,226 | 1,931 | 2,970 | 3,640 | 3,843 | 3,396 | 3,211 | 2,200 | 2,421 | 2,742 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 858 | 754 | 611 | 518 | 478 | 570 | 746 | 713 | 550 | 534 | 680 | 890 |
| Commercial | 502 | 478 | 437 | 423 | 430 | 489 | 568 | 542 | 470 | 443 | 471 | 534 |
| Irrigation | 1 | 1 | 7 | 97 | 303 | 572 | 622 | 496 | 330 | 52 | 4 | 3 |
| Industrial | 293 | 292 | 290 | 286 | 291 | 309 | 303 | 303 | 297 | 302 | 300 | 302 |
| Additional Firm | 204 | 201 | 197 | 191 | 186 | 178 | 189 | 185 | 184 | 189 | 197 | 201 |
| Loss | 178 | 164 | 144 | 142 | 161 | 207 | 241 | 220 | 176 | 142 | 156 | 186 |
| Firm Load | 2,037 | 1,889 | 1,687 | 1,657 | 1,848 | 2,324 | 2,667 | 2,459 | 2,007 | 1,661 | 1,807 | 2,115 |
| Light Load | 1,876 | 1,745 | 1,552 | 1,508 | 1,660 | 2,089 | 2,413 | 2,181 | 1,826 | 1,503 | 1,659 | 1,967 |
| Heavy Load | 2,175 | 1,996 | 1,784 | 1,767 | 2,010 | 2,496 | 2,886 | 2,659 | 2,152 | 1,785 | 1,925 | 2,232 |
| System Load | 2,037 | 1,889 | 1,687 | 1,657 | 1,848 | 2,324 | 2,667 | 2,459 | 2,007 | 1,661 | 1,807 | 2,115 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,037 | 1,889 | 1,687 | 1,657 | 1,848 | 2,324 | 2,667 | 2,459 | 2,007 | 1,661 | 1,807 | 2,115 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -85 | -82 | -85 | -88 | -99 | -106 | -107 | -104 | -94 | -87 | -85 | -84 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,580 | 2,507 | 2,228 | 1,924 | 2,993 | 3,686 | 3,895 | 3,437 | 3,252 | 2,207 | 2,430 | 2,745 |
| System Peak (1 Hour) | 2,580 | 2,507 | 2,228 | 1,924 | 2,993 | 3,686 | 3,895 | 3,437 | 3,252 | 2,207 | 2,430 | 2,745 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,580 | 2,507 | 2,228 | 1,924 | 2,993 | 3,686 | 3,895 | 3,437 | 3,252 | 2,207 | 2,430 | 2,745 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 863 | 757 | 614 | 520 | 482 | 578 | 761 | 727 | 558 | 539 | 686 | 898 |
| Commercial | 505 | 478 | 439 | 425 | 433 | 494 | 574 | 547 | 474 | 445 | 474 | 537 |
| Irrigation | 1 | 1 | 7 | 97 | 303 | 572 | 622 | 496 | 331 | 52 | 4 | 3 |
| Industrial | 293 | 303 | 291 | 287 | 291 | 310 | 303 | 304 | 298 | 303 | 300 | 303 |
| Additional Firm | 204 | 203 | 197 | 191 | 186 | 178 | 188 | 185 | 184 | 188 | 196 | 200 |
| Loss | 179 | 165 | 145 | 142 | 161 | 209 | 243 | 222 | 177 | 142 | 156 | 187 |
| Firm Load | 2,046 | 1,908 | 1,693 | 1,662 | 1,856 | 2,340 | 2,692 | 2,481 | 2,022 | 1,670 | 1,817 | 2,127 |
| Light Load | 1,884 | 1,762 | 1,557 | 1,512 | 1,667 | 2,103 | 2,435 | 2,202 | 1,840 | 1,512 | 1,669 | 1,978 |
| Heavy Load | 2,185 | 2,017 | 1,790 | 1,781 | 2,005 | 2,513 | 2,913 | 2,684 | 2,167 | 1,795 | 1,936 | 2,256 |
| System Load | 2,046 | 1,908 | 1,693 | 1,662 | 1,856 | 2,340 | 2,692 | 2,481 | 2,022 | 1,670 | 1,817 | 2,127 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,046 | 1,908 | 1,693 | 1,662 | 1,856 | 2,340 | 2,692 | 2,481 | 2,022 | 1,670 | 1,817 | 2,127 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -97 | -96 | -96 | -101 | -112 | -120 | -121 | -117 | -106 | -99 | -97 | -97 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,578 | 2,504 | 2,231 | 1,920 | 3,018 | 3,733 | 3,949 | 3,480 | 3,293 | 2,215 | 2,439 | 2,751 |
| System Peak (1 Hour) | 2,578 | 2,504 | 2,231 | 1,920 | 3,018 | 3,733 | 3,949 | 3,480 | 3,293 | 2,215 | 2,439 | 2,751 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,578 | 2,504 | 2,231 | 1,920 | 3,018 | 3,733 | 3,949 | 3,480 | 3,293 | 2,215 | 2,439 | 2,751 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 869 | 760 | 616 | 522 | 486 | 587 | 776 | 741 | 566 | 544 | 692 | 906 |
| Commercial | 507 | 480 | 441 | 427 | 435 | 499 | 581 | 553 | 477 | 449 | 477 | 540 |
| Irrigation | 1 | 1 | 7 | 97 | 303 | 573 | 623 | 497 | 331 | 52 | 4 | 3 |
| Industrial | 294 | 304 | 291 | 287 | 292 | 310 | 304 | 304 | 298 | 304 | 301 | 303 |
| Additional Firm | 204 | 203 | 196 | 190 | 185 | 177 | 188 | 184 | 183 | 188 | 196 | 200 |
| Loss | 179 | 165 | 145 | 142 | 162 | 210 | 245 | 224 | 179 | 143 | 157 | 188 |
| Firm Load | 2,054 | 1,914 | 1,698 | 1,666 | 1,863 | 2,356 | 2,717 | 2,504 | 2,035 | 1,680 | 1,827 | 2,141 |
| Light Load | 1,892 | 1,767 | 1,562 | 1,516 | 1,674 | 2,118 | 2,458 | 2,222 | 1,852 | 1,521 | 1,678 | 1,991 |
| Heavy Load | 2,183 | 2,023 | 1,796 | 1,786 | 2,013 | 2,530 | 2,940 | 2,708 | 2,196 | 1,795 | 1,946 | 2,270 |
| System Load | 2,054 | 1,914 | 1,698 | 1,666 | 1,863 | 2,356 | 2,717 | 2,504 | 2,035 | 1,680 | 1,827 | 2,141 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,054 | 1,914 | 1,698 | 1,666 | 1,863 | 2,356 | 2,717 | 2,504 | 2,035 | 1,680 | 1,827 | 2,141 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -109 | -108 | -108 | -113 | -125 | -134 | -135 | -131 | -120 | -110 | -109 | -109 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,576 | 2,501 | 2,233 | 1,915 | 3,042 | 3,780 | 4,003 | 3,523 | 3,334 | 2,223 | 2,448 | 2,759 |
| System Peak (1 Hour) | 2,576 | 2,501 | 2,233 | 1,915 | 3,042 | 3,780 | 4,003 | 3,523 | 3,334 | 2,223 | 2,448 | 2,759 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,576 | 2,501 | 2,233 | 1,915 | 3,042 | 3,780 | 4,003 | 3,523 | 3,334 | 2,223 | 2,448 | 2,759 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 876 | 765 | 620 | 525 | 490 | 597 | 792 | 757 | 576 | 550 | 699 | 916 |
| Commercial | 510 | 482 | 443 | 429 | 439 | 504 | 587 | 558 | 481 | 451 | 479 | 544 |
| Irrigation | 1 | 1 | 7 | 97 | 303 | 574 | 625 | 498 | 332 | 52 | 4 | 3 |
| Industrial | 295 | 305 | 292 | 288 | 293 | 311 | 305 | 305 | 299 | 305 | 302 | 304 |
| Additional Firm | 201 | 200 | 194 | 188 | 184 | 176 | 186 | 183 | 182 | 186 | 194 | 198 |
| Loss | 180 | 166 | 145 | 143 | 163 | 212 | 248 | 227 | 180 | 144 | 158 | 189 |
| Firm Load | 2,062 | 1,918 | 1,701 | 1,670 | 1,871 | 2,373 | 2,743 | 2,528 | 2,050 | 1,689 | 1,836 | 2,153 |
| Light Load | 1,899 | 1,772 | 1,565 | 1,520 | 1,681 | 2,133 | 2,481 | 2,243 | 1,865 | 1,529 | 1,687 | 2,002 |
| Heavy Load | 2,191 | 2,028 | 1,808 | 1,780 | 2,021 | 2,565 | 2,949 | 2,734 | 2,211 | 1,805 | 1,956 | 2,283 |
| System Load | 2,062 | 1,918 | 1,701 | 1,670 | 1,871 | 2,373 | 2,743 | 2,528 | 2,050 | 1,689 | 1,836 | 2,153 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,062 | 1,918 | 1,701 | 1,670 | 1,871 | 2,373 | 2,743 | 2,528 | 2,050 | 1,689 | 1,836 | 2,153 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -120 | -120 | -121 | -125 | -138 | -148 | -149 | -145 | -132 | -122 | -120 | -121 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,578 | 2,501 | 2,238 | 1,915 | 3,067 | 3,827 | 4,060 | 3,570 | 3,374 | 2,230 | 2,459 | 2,773 |
| System Peak (1 Hour) | 2,578 | 2,501 | 2,238 | 1,915 | 3,067 | 3,827 | 4,060 | 3,570 | 3,374 | 2,230 | 2,459 | 2,773 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,578 | 2,501 | 2,238 | 1,915 | 3,067 | 3,827 | 4,060 | 3,570 | 3,374 | 2,230 | 2,459 | 2,773 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 884 | 770 | 624 | 528 | 495 | 607 | 809 | 773 | 585 | 557 | 707 | 919 |
| Commercial | 511 | 485 | 444 | 431 | 441 | 509 | 594 | 563 | 486 | 454 | 481 | 547 |
| Irrigation | 1 | 1 | 8 | 97 | 304 | 576 | 627 | 500 | 334 | 52 | 4 | 3 |
| Industrial | 296 | 295 | 292 | 288 | 293 | 312 | 305 | 306 | 300 | 306 | 302 | 305 |
| Additional Firm | 201 | 198 | 194 | 188 | 183 | 175 | 186 | 182 | 181 | 186 | 193 | 197 |
| Loss | 181 | 166 | 146 | 143 | 163 | 213 | 250 | 229 | 182 | 145 | 159 | 190 |
| Firm Load | 2,074 | 1,915 | 1,707 | 1,676 | 1,879 | 2,392 | 2,772 | 2,554 | 2,068 | 1,699 | 1,846 | 2,160 |
| Light Load | 1,910 | 1,768 | 1,571 | 1,524 | 1,688 | 2,150 | 2,507 | 2,266 | 1,882 | 1,538 | 1,696 | 2,009 |
| Heavy Load | 2,203 | 2,023 | 1,815 | 1,786 | 2,043 | 2,568 | 2,980 | 2,781 | 2,217 | 1,816 | 1,978 | 2,280 |
| System Load | 2,074 | 1,915 | 1,707 | 1,676 | 1,879 | 2,392 | 2,772 | 2,554 | 2,068 | 1,699 | 1,846 | 2,160 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,074 | 1,915 | 1,707 | 1,676 | 1,879 | 2,392 | 2,772 | 2,554 | 2,068 | 1,699 | 1,846 | 2,160 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -132 | -127 | -133 | -137 | -152 | -162 | -163 | -159 | -144 | -134 | -133 | -132 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,586 | 2,494 | 2,246 | 1,918 | 3,092 | 3,876 | 4,118 | 3,621 | 3,417 | 2,239 | 2,470 | 2,786 |
| System Peak (1 Hour) | 2,586 | 2,494 | 2,246 | 1,918 | 3,092 | 3,876 | 4,118 | 3,621 | 3,417 | 2,239 | 2,470 | 2,786 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,586 | 2,494 | 2,246 | 1,918 | 3,092 | 3,876 | 4,118 | 3,621 | 3,417 | 2,239 | 2,470 | 2,786 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 881 | 766 | 620 | 525 | 494 | 610 | 817 | 781 | 588 | 557 | 706 | 923 |
| Commercial | 512 | 483 | 446 | 431 | 442 | 513 | 599 | 567 | 488 | 455 | 483 | 549 |
| Irrigation | 1 | 1 | 8 | 97 | 303 | 574 | 626 | 499 | 333 | 52 | 4 | 3 |
| Industrial | 295 | 306 | 293 | 289 | 293 | 312 | 306 | 306 | 300 | 306 | 303 | 305 |
| Additional Firm | 200 | 200 | 193 | 188 | 183 | 175 | 186 | 182 | 181 | 186 | 193 | 197 |
| Loss | 181 | 166 | 145 | 143 | 163 | 214 | 252 | 230 | 182 | 145 | 159 | 190 |
| Firm Load | 2,070 | 1,922 | 1,705 | 1,673 | 1,878 | 2,398 | 2,785 | 2,565 | 2,073 | 1,700 | 1,848 | 2,167 |
| Light Load | 1,907 | 1,775 | 1,569 | 1,522 | 1,687 | 2,156 | 2,519 | 2,276 | 1,886 | 1,539 | 1,698 | 2,015 |
| Heavy Load | 2,211 | 2,032 | 1,804 | 1,783 | 2,042 | 2,576 | 2,994 | 2,794 | 2,222 | 1,828 | 1,969 | 2,287 |
| System Load | 2,070 | 1,922 | 1,705 | 1,673 | 1,878 | 2,398 | 2,785 | 2,565 | 2,073 | 1,700 | 1,848 | 2,167 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,070 | 1,922 | 1,705 | 1,673 | 1,878 | 2,398 | 2,785 | 2,565 | 2,073 | 1,700 | 1,848 | 2,167 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -145 | -144 | -143 | -149 | -165 | -176 | -177 | -172 | -157 | -146 | -144 | -144 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,547 | 2,481 | 2,229 | 1,889 | 3,109 | 3,916 | 4,160 | 3,642 | 3,458 | 2,239 | 2,466 | 2,754 |
| System Peak (1 Hour) | 2,547 | 2,481 | 2,229 | 1,889 | 3,109 | 3,916 | 4,160 | 3,642 | 3,458 | 2,239 | 2,466 | 2,754 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,547 | 2,481 | 2,229 | 1,889 | 3,109 | 3,916 | 4,160 | 3,642 | 3,458 | 2,239 | 2,466 | 2,754 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 886 | 769 | 622 | 526 | 498 | 619 | 832 | 795 | 596 | 562 | 711 | 929 |
| Commercial | 513 | 484 | 447 | 432 | 444 | 517 | 604 | 572 | 491 | 457 | 485 | 552 |
| Irrigation | 1 | 1 | 8 | 97 | 301 | 572 | 624 | 497 | 332 | 52 | 4 | 3 |
| Industrial | 296 | 307 | 294 | 289 | 294 | 313 | 307 | 307 | 301 | 307 | 304 | 307 |
| Additional Firm | 200 | 200 | 193 | 187 | 183 | 175 | 185 | 182 | 181 | 185 | 193 | 197 |
| Loss | 181 | 166 | 146 | 143 | 163 | 215 | 253 | 232 | 183 | 146 | 160 | 191 |
| Firm Load | 2,077 | 1,926 | 1,709 | 1,675 | 1,883 | 2,411 | 2,806 | 2,585 | 2,085 | 1,708 | 1,857 | 2,178 |
| Light Load | 1,913 | 1,778 | 1,572 | 1,524 | 1,691 | 2,167 | 2,539 | 2,293 | 1,897 | 1,546 | 1,706 | 2,025 |
| Heavy Load | 2,218 | 2,036 | 1,807 | 1,786 | 2,047 | 2,589 | 3,036 | 2,796 | 2,235 | 1,836 | 1,978 | 2,298 |
| System Load | 2,077 | 1,926 | 1,709 | 1,675 | 1,883 | 2,411 | 2,806 | 2,585 | 2,085 | 1,708 | 1,857 | 2,178 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,077 | 1,926 | 1,709 | 1,675 | 1,883 | 2,411 | 2,806 | 2,585 | 2,085 | 1,708 | 1,857 | 2,178 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -157 | -155 | -155 | -161 | -179 | -190 | -191 | -186 | -170 | -159 | -156 | -155 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,543 | 2,477 | 2,232 | 1,886 | 3,131 | 3,961 | 4,210 | 3,685 | 3,500 | 2,245 | 2,474 | 2,763 |
| System Peak (1 Hour) | 2,543 | 2,477 | 2,232 | 1,886 | 3,131 | 3,961 | 4,210 | 3,685 | 3,500 | 2,245 | 2,474 | 2,763 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,543 | 2,477 | 2,232 | 1,886 | 3,131 | 3,961 | 4,210 | 3,685 | 3,500 | 2,245 | 2,474 | 2,763 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 889 | 770 | 623 | 527 | 500 | 626 | 846 | 809 | 604 | 566 | 715 | 926 |
| Commercial | 514 | 484 | 447 | 432 | 446 | 521 | 610 | 576 | 494 | 458 | 486 | 552 |
| Irrigation | 1 | 1 | 8 | 97 | 301 | 573 | 624 | 498 | 333 | 52 | 4 | 3 |
| Industrial | 297 | 307 | 294 | 290 | 295 | 314 | 307 | 308 | 302 | 308 | 305 | 306 |
| Additional Firm | 198 | 198 | 192 | 186 | 182 | 173 | 184 | 181 | 180 | 184 | 191 | 195 |
| Loss | 182 | 166 | 146 | 143 | 164 | 216 | 255 | 234 | 184 | 146 | 160 | 190 |
| Firm Load | 2,081 | 1,926 | 1,709 | 1,674 | 1,887 | 2,424 | 2,827 | 2,604 | 2,096 | 1,714 | 1,862 | 2,173 |
| Light Load | 1,917 | 1,779 | 1,573 | 1,523 | 1,695 | 2,178 | 2,558 | 2,310 | 1,907 | 1,551 | 1,710 | 2,020 |
| Heavy Load | 2,223 | 2,036 | 1,808 | 1,795 | 2,039 | 2,603 | 3,059 | 2,816 | 2,247 | 1,842 | 1,983 | 2,304 |
| System Load | 2,081 | 1,926 | 1,709 | 1,674 | 1,887 | 2,424 | 2,827 | 2,604 | 2,096 | 1,714 | 1,862 | 2,173 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,081 | 1,926 | 1,709 | 1,674 | 1,887 | 2,424 | 2,827 | 2,604 | 2,096 | 1,714 | 1,862 | 2,173 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -168 | -167 | -167 | -174 | -191 | -204 | -205 | -200 | -182 | -170 | -168 | -169 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,535 | 2,470 | 2,230 | 1,878 | 3,153 | 4,006 | 4,261 | 3,726 | 3,540 | 2,249 | 2,479 | 2,751 |
| System Peak (1 Hour) | 2,535 | 2,470 | 2,230 | 1,878 | 3,153 | 4,006 | 4,261 | 3,726 | 3,540 | 2,249 | 2,479 | 2,751 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,535 | 2,470 | 2,230 | 1,878 | 3,153 | 4,006 | 4,261 | 3,726 | 3,540 | 2,249 | 2,479 | 2,751 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 879 | 760 | 614 | 519 | 495 | 625 | 848 | 810 | 602 | 561 | 709 | 927 |
| Commercial | 513 | 485 | 446 | 432 | 447 | 524 | 613 | 578 | 495 | 459 | 486 | 553 |
| Irrigation | 1 | 1 | 8 | 96 | 299 | 569 | 620 | 494 | 330 | 51 | 4 | 3 |
| Industrial | 299 | 297 | 294 | 290 | 296 | 314 | 308 | 308 | 301 | 309 | 305 | 307 |
| Additional Firm | 198 | 195 | 191 | 186 | 181 | 173 | 184 | 180 | 179 | 184 | 191 | 195 |
| Loss | 180 | 164 | 144 | 142 | 163 | 216 | 255 | 234 | 184 | 145 | 159 | 191 |
| Firm Load | 2,071 | 1,903 | 1,698 | 1,665 | 1,880 | 2,420 | 2,827 | 2,604 | 2,091 | 1,709 | 1,855 | 2,176 |
| Light Load | 1,907 | 1,758 | 1,562 | 1,515 | 1,689 | 2,175 | 2,558 | 2,310 | 1,903 | 1,547 | 1,704 | 2,023 |
| Heavy Load | 2,200 | 2,011 | 1,805 | 1,775 | 2,031 | 2,616 | 3,040 | 2,816 | 2,256 | 1,827 | 1,976 | 2,307 |
| System Load | 2,071 | 1,903 | 1,698 | 1,665 | 1,880 | 2,420 | 2,827 | 2,604 | 2,091 | 1,709 | 1,855 | 2,176 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,071 | 1,903 | 1,698 | 1,665 | 1,880 | 2,420 | 2,827 | 2,604 | 2,091 | 1,709 | 1,855 | 2,176 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -180 | -173 | -180 | -185 | -203 | -218 | -219 | -214 | -196 | -181 | -180 | -181 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,467 | 2,454 | 2,193 | 1,830 | 3,164 | 4,039 | 4,290 | 3,728 | 3,580 | 2,244 | 2,461 | 2,688 |
| System Peak (1 Hour) | 2,467 | 2,454 | 2,193 | 1,830 | 3,164 | 4,039 | 4,290 | 3,728 | 3,580 | 2,244 | 2,461 | 2,688 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,467 | 2,454 | 2,193 | 1,830 | 3,164 | 4,039 | 4,290 | 3,728 | 3,580 | 2,244 | 2,461 | 2,688 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 885 | 763 | 617 | 522 | 499 | 634 | 865 | 826 | 611 | 567 | 716 | 934 |
| Commercial | 514 | 483 | 447 | 433 | 448 | 528 | 618 | 582 | 498 | 461 | 487 | 556 |
| Irrigation | 1 | 1 | 7 | 95 | 297 | 566 | 617 | 491 | 329 | 51 | 4 | 3 |
| Industrial | 298 | 309 | 295 | 291 | 296 | 315 | 309 | 309 | 303 | 310 | 305 | 308 |
| Additional Firm | 198 | 197 | 191 | 185 | 181 | 173 | 184 | 180 | 179 | 184 | 191 | 194 |
| Loss | 181 | 165 | 145 | 142 | 163 | 217 | 257 | 235 | 185 | 146 | 160 | 192 |
| Firm Load | 2,078 | 1,918 | 1,702 | 1,668 | 1,885 | 2,433 | 2,849 | 2,624 | 2,104 | 1,718 | 1,863 | 2,186 |
| Light Load | 1,913 | 1,771 | 1,565 | 1,518 | 1,693 | 2,186 | 2,577 | 2,328 | 1,915 | 1,555 | 1,711 | 2,033 |
| Heavy Load | 2,207 | 2,028 | 1,809 | 1,778 | 2,036 | 2,629 | 3,063 | 2,857 | 2,256 | 1,836 | 1,996 | 2,307 |
| System Load | 2,078 | 1,918 | 1,702 | 1,668 | 1,885 | 2,433 | 2,849 | 2,624 | 2,104 | 1,718 | 1,863 | 2,186 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,078 | 1,918 | 1,702 | 1,668 | 1,885 | 2,433 | 2,849 | 2,624 | 2,104 | 1,718 | 1,863 | 2,186 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -192 | -191 | -192 | -198 | -216 | -232 | -233 | -227 | -208 | -193 | -193 | -192 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,471 | 2,430 | 2,201 | 1,835 | 3,186 | 4,084 | 4,341 | 3,776 | 3,622 | 2,251 | 2,471 | 2,710 |
| System Peak (1 Hour) | 2,471 | 2,430 | 2,201 | 1,835 | 3,186 | 4,084 | 4,341 | 3,776 | 3,622 | 2,251 | 2,471 | 2,710 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,471 | 2,430 | 2,201 | 1,835 | 3,186 | 4,084 | 4,341 | 3,776 | 3,622 | 2,251 | 2,471 | 2,710 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 888 | 764 | 617 | 522 | 501 | 642 | 879 | 839 | 618 | 570 | 719 | 931 |
| Commercial | 514 | 482 | 447 | 433 | 449 | 532 | 623 | 586 | 501 | 462 | 488 | 557 |
| Irrigation | 1 | 1 | 8 | 96 | 297 | 567 | 618 | 493 | 330 | 51 | 4 | 3 |
| Industrial | 299 | 309 | 296 | 291 | 296 | 316 | 309 | 310 | 304 | 311 | 306 | 309 |
| Additional Firm | 196 | 196 | 189 | 184 | 180 | 171 | 182 | 179 | 178 | 182 | 189 | 192 |
| Loss | 181 | 165 | 144 | 142 | 163 | 218 | 259 | 237 | 186 | 147 | 160 | 191 |
| Firm Load | 2,080 | 1,918 | 1,701 | 1,668 | 1,887 | 2,446 | 2,871 | 2,644 | 2,117 | 1,723 | 1,866 | 2,183 |
| Light Load | 1,915 | 1,771 | 1,565 | 1,517 | 1,695 | 2,199 | 2,597 | 2,345 | 1,926 | 1,559 | 1,714 | 2,030 |
| Heavy Load | 2,210 | 2,028 | 1,809 | 1,778 | 2,052 | 2,627 | 3,087 | 2,879 | 2,269 | 1,841 | 2,000 | 2,304 |
| System Load | 2,080 | 1,918 | 1,701 | 1,668 | 1,887 | 2,446 | 2,871 | 2,644 | 2,117 | 1,723 | 1,866 | 2,183 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,080 | 1,918 | 1,701 | 1,668 | 1,887 | 2,446 | 2,871 | 2,644 | 2,117 | 1,723 | 1,866 | 2,183 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -203 | -203 | -204 | -210 | -231 | -246 | -247 | -241 | -219 | -205 | -205 | -203 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,460 | 2,421 | 2,199 | 1,828 | 3,206 | 4,129 | 4,393 | 3,818 | 3,664 | 2,254 | 2,475 | 2,702 |
| System Peak (1 Hour) | 2,460 | 2,421 | 2,199 | 1,828 | 3,206 | 4,129 | 4,393 | 3,818 | 3,664 | 2,254 | 2,475 | 2,702 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,460 | 2,421 | 2,199 | 1,828 | 3,206 | 4,129 | 4,393 | 3,818 | 3,664 | 2,254 | 2,475 | 2,702 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 879 | 755 | 610 | 515 | 497 | 641 | 881 | 841 | 617 | 567 | 714 | 927 |
| Commercial | 513 | 481 | 447 | 433 | 449 | 534 | 627 | 589 | 502 | 462 | 489 | 558 |
| Irrigation | 1 | 1 | 7 | 95 | 295 | 563 | 614 | 489 | 328 | 51 | 4 | 3 |
| Industrial | 299 | 310 | 297 | 292 | 296 | 317 | 310 | 310 | 304 | 311 | 307 | 309 |
| Additional Firm | 195 | 194 | 188 | 182 | 178 | 170 | 181 | 178 | 177 | 180 | 187 | 190 |
| Loss | 180 | 164 | 144 | 141 | 162 | 218 | 260 | 237 | 185 | 146 | 160 | 191 |
| Firm Load | 2,067 | 1,905 | 1,692 | 1,658 | 1,878 | 2,443 | 2,873 | 2,644 | 2,113 | 1,716 | 1,861 | 2,179 |
| Light Load | 1,903 | 1,759 | 1,557 | 1,508 | 1,687 | 2,196 | 2,599 | 2,346 | 1,923 | 1,553 | 1,709 | 2,026 |
| Heavy Load | 2,207 | 2,014 | 1,790 | 1,767 | 2,042 | 2,624 | 3,089 | 2,880 | 2,265 | 1,845 | 1,982 | 2,299 |
| System Load | 2,067 | 1,905 | 1,692 | 1,658 | 1,878 | 2,443 | 2,873 | 2,644 | 2,113 | 1,716 | 1,861 | 2,179 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,067 | 1,905 | 1,692 | 1,658 | 1,878 | 2,443 | 2,873 | 2,644 | 2,113 | 1,716 | 1,861 | 2,179 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -216 | -214 | -214 | -222 | -245 | -260 | -261 | -255 | -233 | -218 | -215 | -215 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,393 | 2,382 | 2,168 | 1,783 | 3,216 | 4,163 | 4,424 | 3,825 | 3,703 | 2,247 | 2,460 | 2,639 |
| System Peak (1 Hour) | 2,393 | 2,382 | 2,168 | 1,783 | 3,216 | 4,163 | 4,424 | 3,825 | 3,703 | 2,247 | 2,460 | 2,639 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,393 | 2,382 | 2,168 | 1,783 | 3,216 | 4,163 | 4,424 | 3,825 | 3,703 | 2,247 | 2,460 | 2,639 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2028 | Feb. 2028 | Mar. 2028 | Apr. 2028 | May. 2028 | Jun. 2028 | Jul. 2028 | Aug. 2028 | Sep. 2028 | Oct. 2028 | Nov. 2028 | Dec. 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 876 | 751 | 606 | 511 | 496 | 645 | 890 | 849 | 620 | 566 | 712 | 918 |
| Commercial | 513 | 484 | 447 | 432 | 451 | 538 | 632 | 592 | 504 | 462 | 489 | 557 |
| Irrigation | 1 | 1 | 7 | 94 | 292 | 558 | 608 | 484 | 325 | 50 | 4 | 3 |
| Industrial | 301 | 300 | 297 | 292 | 297 | 317 | 310 | 311 | 305 | 312 | 308 | 309 |
| Additional Firm | 193 | 190 | 186 | 181 | 177 | 169 | 179 | 176 | 175 | 179 | 186 | 189 |
| Loss | 179 | 163 | 143 | 140 | 162 | 218 | 260 | 238 | 185 | 146 | 160 | 189 |
| Firm Load | 2,063 | 1,889 | 1,687 | 1,650 | 1,875 | 2,443 | 2,879 | 2,650 | 2,114 | 1,715 | 1,859 | 2,166 |
| Light Load | 1,900 | 1,745 | 1,552 | 1,501 | 1,684 | 2,196 | 2,605 | 2,351 | 1,924 | 1,553 | 1,707 | 2,014 |
| Heavy Load | 2,203 | 1,996 | 1,784 | 1,769 | 2,025 | 2,624 | 3,115 | 2,866 | 2,266 | 1,844 | 1,980 | 2,297 |
| System Load | 2,063 | 1,889 | 1,687 | 1,650 | 1,875 | 2,443 | 2,879 | 2,650 | 2,114 | 1,715 | 1,859 | 2,166 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,063 | 1,889 | 1,687 | 1,650 | 1,875 | 2,443 | 2,879 | 2,650 | 2,114 | 1,715 | 1,859 | 2,166 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2028 | Feb. 2028 | Mar. 2028 | Apr. 2028 | May. 2028 | Jun. 2028 | Jul. 2028 | Aug. 2028 | Sep. 2028 | Oct. 2028 | Nov. 2028 | Dec. 2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -228 | -218 | -226 | -235 | -257 | -274 | -275 | -269 | -245 | -230 | -227 | -228 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,354 | 2,345 | 2,152 | 1,756 | 3,231 | 4,199 | 4,460 | 3,846 | 3,743 | 2,245 | 2,454 | 2,595 |
| System Peak (1 Hour) | 2,354 | 2,345 | 2,152 | 1,756 | 3,231 | 4,199 | 4,460 | 3,846 | 3,743 | 2,245 | 2,454 | 2,595 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,354 | 2,345 | 2,152 | 1,756 | 3,231 | 4,199 | 4,460 | 3,846 | 3,743 | 2,245 | 2,454 | 2,595 |

## Sales and Load Forecast

### Average Load (Average Megawatts)—70th Percentile

| | Jan. 2029 | Feb. 2029 | Mar. 2029 | Apr. 2029 | May. 2029 | Jun. 2029 | Jul. 2029 | Aug. 2029 | Sep. 2029 | Oct. 2029 | Nov. 2029 | Dec. 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 860 | 735 | 593 | 500 | 487 | 638 | 885 | 844 | 613 | 558 | 701 | 911 |
| Commercial | 512 | 478 | 446 | 431 | 450 | 540 | 635 | 594 | 504 | 463 | 489 | 558 |
| Irrigation | 1 | 1 | 7 | 93 | 288 | 550 | 599 | 477 | 320 | 50 | 4 | 3 |
| Industrial | 300 | 311 | 297 | 292 | 298 | 317 | 310 | 311 | 304 | 312 | 308 | 310 |
| Additional Firm | 191 | 190 | 185 | 180 | 175 | 167 | 178 | 175 | 174 | 177 | 184 | 187 |
| Loss | 177 | 161 | 141 | 138 | 160 | 216 | 259 | 236 | 184 | 145 | 158 | 188 |
| Firm Load | 2,042 | 1,877 | 1,670 | 1,634 | 1,859 | 2,429 | 2,866 | 2,637 | 2,100 | 1,704 | 1,844 | 2,157 |
| Light Load | 1,880 | 1,733 | 1,536 | 1,486 | 1,670 | 2,183 | 2,593 | 2,340 | 1,911 | 1,542 | 1,694 | 2,005 |
| Heavy Load | 2,169 | 1,985 | 1,766 | 1,751 | 2,008 | 2,608 | 3,101 | 2,852 | 2,265 | 1,821 | 1,965 | 2,287 |
| System Load | 2,042 | 1,877 | 1,670 | 1,634 | 1,859 | 2,429 | 2,866 | 2,637 | 2,100 | 1,704 | 1,844 | 2,157 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,042 | 1,877 | 1,670 | 1,634 | 1,859 | 2,429 | 2,866 | 2,637 | 2,100 | 1,704 | 1,844 | 2,157 |

### Peak Load (Megawatts)—95th Percentile

| | Jan. 2029 | Feb. 2029 | Mar. 2029 | Apr. 2029 | May. 2029 | Jun. 2029 | Jul. 2029 | Aug. 2029 | Sep. 2029 | Oct. 2029 | Nov. 2029 | Dec. 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -239 | -238 | -237 | -247 | -270 | -288 | -289 | -282 | -260 | -241 | -238 | -240 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,248 | 2,296 | 2,100 | 1,687 | 3,234 | 4,225 | 4,475 | 3,828 | 3,780 | 2,234 | 2,424 | 2,493 |
| System Peak (1 Hour) | 2,248 | 2,296 | 2,100 | 1,687 | 3,234 | 4,225 | 4,475 | 3,828 | 3,780 | 2,234 | 2,424 | 2,493 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,248 | 2,296 | 2,100 | 1,687 | 3,234 | 4,225 | 4,475 | 3,828 | 3,780 | 2,234 | 2,424 | 2,493 |

## Sales And Load Forecast Annual Summary

### Billed Sales (Megawatthours)—70th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,328,002 | 5,418,985 | 5,545,564 | 5,544,988 | 5,661,123 | 5,705,655 | 5,765,013 | 5,826,541 | 5,885,328 | 5,956,603 |
| Commercial | 3,879,270 | 3,941,139 | 4,032,057 | 4,101,010 | 4,154,617 | 4,189,349 | 4,220,439 | 4,250,624 | 4,280,729 | 4,310,468 |
| Irrigation | 1,843,349 | 1,852,905 | 1,839,741 | 1,828,330 | 1,822,297 | 1,828,366 | 1,826,719 | 1,828,104 | 1,830,375 | 1,834,057 |
| Industrial | 2,196,153 | 2,441,884 | 2,567,526 | 2,589,054 | 2,599,655 | 2,604,497 | 2,611,034 | 2,616,668 | 2,622,321 | 2,628,531 |
| Additional Firm | 1,428,995 | 1,604,959 | 1,621,276 | 1,687,195 | 1,689,907 | 1,689,231 | 1,683,727 | 1,678,357 | 1,676,318 | 1,657,486 |
| Firm Sales | 14,675,769 | 15,259,872 | 15,606,163 | 15,750,577 | 15,927,598 | 16,017,097 | 16,106,932 | 16,200,294 | 16,295,071 | 16,387,145 |
| System Sales | 14,675,769 | 15,259,872 | 15,606,163 | 15,750,577 | 15,927,598 | 16,017,097 | 16,106,932 | 16,200,294 | 16,295,071 | 16,387,145 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,675,769 | 15,259,872 | 15,606,163 | 15,750,577 | 15,927,598 | 16,017,097 | 16,106,932 | 16,200,294 | 16,295,071 | 16,387,145 |

### Generation Month Sales (Megawatthours)—70th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,334,508 | 5,427,771 | 5,563,366 | 5,552,985 | 5,663,976 | 5,709,516 | 5,787,335 | 5,830,320 | 5,889,944 | 5,961,403 |
| Commercial | 3,884,769 | 3,948,400 | 4,049,553 | 4,106,225 | 4,158,805 | 4,193,329 | 4,236,696 | 4,254,529 | 4,284,602 | 4,314,243 |
| Irrigation | 1,843,364 | 1,852,901 | 1,839,761 | 1,828,330 | 1,822,306 | 1,828,368 | 1,826,747 | 1,828,110 | 1,830,382 | 1,834,065 |
| Industrial | 2,211,419 | 2,457,547 | 2,569,645 | 2,589,952 | 2,600,158 | 2,605,016 | 2,611,732 | 2,616,883 | 2,622,847 | 2,628,952 |
| Additional Firm | 1,428,995 | 1,604,959 | 1,621,276 | 1,687,195 | 1,689,907 | 1,689,231 | 1,683,727 | 1,678,357 | 1,676,318 | 1,657,486 |
| Firm Sales | 14,703,056 | 15,291,579 | 15,643,600 | 15,764,687 | 15,935,152 | 16,025,461 | 16,146,238 | 16,208,198 | 16,304,092 | 16,396,149 |
| System Sales | 14,703,056 | 15,291,579 | 15,643,600 | 15,764,687 | 15,935,152 | 16,025,461 | 16,146,238 | 16,208,198 | 16,304,092 | 16,396,149 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,703,056 | 15,291,579 | 15,643,600 | 15,764,687 | 15,935,152 | 16,025,461 | 16,146,238 | 16,208,198 | 16,304,092 | 16,396,149 |
| Loss | 1,431,207 | 1,473,533 | 1,504,984 | 1,512,273 | 1,529,009 | 1,537,408 | 1,549,452 | 1,555,035 | 1,564,084 | 1,573,950 |
| Required Generation | 16,134,263 | 16,765,112 | 17,148,584 | 17,276,961 | 17,464,161 | 17,562,869 | 17,695,690 | 17,763,233 | 17,868,177 | 17,970,099 |

### Average Load (Average Megawatts)—70th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 609 | 620 | 633 | 634 | 647 | 652 | 659 | 666 | 672 | 681 |
| Commercial | 443 | 451 | 461 | 469 | 475 | 479 | 482 | 486 | 489 | 492 |
| Irrigation | 210 | 212 | 209 | 209 | 208 | 209 | 208 | 209 | 209 | 209 |
| Industrial | 252 | 281 | 293 | 296 | 297 | 297 | 297 | 299 | 299 | 300 |
| Additional Firm | 163 | 183 | 185 | 193 | 193 | 193 | 192 | 192 | 191 | 189 |
| Loss | 163 | 168 | 171 | 173 | 175 | 176 | 176 | 178 | 179 | 180 |
| Firm Load | 1,842 | 1,914 | 1,952 | 1,972 | 1,994 | 2,005 | 2,015 | 2,028 | 2,040 | 2,051 |
| Light Load | 1,676 | 1,741 | 1,776 | 1,794 | 1,814 | 1,824 | 1,833 | 1,845 | 1,856 | 1,866 |
| Heavy Load | 1,972 | 2,049 | 2,091 | 2,112 | 2,135 | 2,147 | 2,157 | 2,172 | 2,184 | 2,196 |
| System Load | 1,842 | 1,914 | 1,952 | 1,972 | 1,994 | 2,005 | 2,015 | 2,028 | 2,040 | 2,051 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,842 | 1,914 | 1,952 | 1,972 | 1,994 | 2,005 | 2,015 | 2,028 | 2,040 | 2,051 |

### Peak Load (Megawatts)—95th Percentile

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -17 | -33 | -48 | -64 | -79 | -93 | -107 | -121 | -135 | -149 |
| Demand Response (Mw) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,460 | 3,560 | 3,636 | 3,726 | 3,789 | 3,843 | 3,895 | 3,949 | 4,003 | 4,060 |
| System Peak (1 Hour) | 3,460 | 3,560 | 3,636 | 3,726 | 3,789 | 3,843 | 3,895 | 3,949 | 4,003 | 4,060 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,460 | 3,560 | 3,636 | 3,726 | 3,789 | 3,843 | 3,895 | 3,949 | 4,003 | 4,060 |

## Sales And Load Forecast Annual Summary

### Billed Sales (Megawatthours)—70th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 6,030,952 | 6,034,404 | 6,091,486 | 6,139,032 | 6,092,711 | 6,160,567 | 6,205,253 | 6,168,525 | 6,172,246 | 6,083,732 |
| Commercial | 4,338,582 | 4,356,860 | 4,378,082 | 4,395,931 | 4,401,688 | 4,419,613 | 4,435,517 | 4,442,344 | 4,452,730 | 4,454,123 |
| Irrigation | 1,839,802 | 1,835,870 | 1,829,770 | 1,830,840 | 1,817,719 | 1,808,195 | 1,812,587 | 1,801,062 | 1,783,250 | 1,756,646 |
| Industrial | 2,634,391 | 2,637,943 | 2,644,929 | 2,652,534 | 2,655,893 | 2,661,588 | 2,668,570 | 2,671,916 | 2,678,550 | 2,679,036 |
| Additional Firm | 1,657,426 | 1,651,857 | 1,650,315 | 1,636,705 | 1,638,050 | 1,632,964 | 1,619,435 | 1,605,524 | 1,595,267 | 1,578,775 |
| Firm Sales | 16,501,153 | 16,516,933 | 16,594,582 | 16,655,042 | 16,606,060 | 16,682,926 | 16,741,362 | 16,689,371 | 16,682,043 | 16,552,312 |
| System Sales | 16,501,153 | 16,516,933 | 16,594,582 | 16,655,042 | 16,606,060 | 16,682,926 | 16,741,362 | 16,689,371 | 16,682,043 | 16,552,312 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,501,153 | 16,516,933 | 16,594,582 | 16,655,042 | 16,606,060 | 16,682,926 | 16,741,362 | 16,689,371 | 16,682,043 | 16,552,312 |

### Generation Month Sales (Megawatthours)—70th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 6,049,707 | 6,037,977 | 6,094,385 | 6,135,523 | 6,115,664 | 6,163,222 | 6,202,384 | 6,168,388 | 6,184,488 | 6,083,052 |
| Commercial | 4,354,848 | 4,360,247 | 4,381,280 | 4,398,479 | 4,418,419 | 4,422,680 | 4,438,096 | 4,445,102 | 4,469,029 | 4,456,843 |
| Irrigation | 1,839,826 | 1,835,869 | 1,829,775 | 1,830,833 | 1,817,738 | 1,808,202 | 1,812,581 | 1,801,051 | 1,783,255 | 1,756,627 |
| Industrial | 2,634,963 | 2,638,631 | 2,645,784 | 2,652,260 | 2,656,430 | 2,662,466 | 2,668,880 | 2,672,483 | 2,678,356 | 2,679,387 |
| Additional Firm | 1,657,426 | 1,651,857 | 1,650,315 | 1,636,705 | 1,638,050 | 1,632,964 | 1,619,435 | 1,605,524 | 1,595,267 | 1,578,775 |
| Firm Sales | 16,536,770 | 16,524,581 | 16,601,540 | 16,653,801 | 16,646,300 | 16,689,534 | 16,741,377 | 16,692,548 | 16,710,395 | 16,554,683 |
| System Sales | 16,536,770 | 16,524,581 | 16,601,540 | 16,653,801 | 16,646,300 | 16,689,534 | 16,741,377 | 16,692,548 | 16,710,395 | 16,554,683 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,536,770 | 16,524,581 | 16,601,540 | 16,653,801 | 16,646,300 | 16,689,534 | 16,741,377 | 16,692,548 | 16,710,395 | 16,554,683 |
| Loss | 1,587,760 | 1,585,325 | 1,592,238 | 1,597,369 | 1,595,017 | 1,598,504 | 1,603,588 | 1,597,833 | 1,599,044 | 1,581,886 |
| Required Generation | 18,124,531 | 18,109,906 | 18,193,778 | 18,251,170 | 18,241,317 | 18,288,039 | 18,344,965 | 18,290,381 | 18,309,439 | 18,136,570 |

### Average Load (Average Megawatts)—70th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 689 | 689 | 696 | 700 | 696 | 704 | 708 | 704 | 704 | 694 |
| Commercial | 496 | 498 | 500 | 502 | 503 | 505 | 507 | 507 | 509 | 509 |
| Irrigation | 209 | 210 | 209 | 209 | 207 | 206 | 207 | 206 | 203 | 201 |
| Industrial | 300 | 301 | 302 | 303 | 302 | 304 | 305 | 305 | 305 | 306 |
| Additional Firm | 189 | 189 | 188 | 187 | 186 | 186 | 185 | 183 | 182 | 180 |
| Loss | 181 | 181 | 182 | 182 | 182 | 182 | 183 | 182 | 182 | 181 |
| Firm Load | 2,063 | 2,067 | 2,077 | 2,083 | 2,077 | 2,088 | 2,094 | 2,088 | 2,084 | 2,070 |
| Light Load | 1,877 | 1,881 | 1,889 | 1,895 | 1,889 | 1,899 | 1,905 | 1,899 | 1,896 | 1,883 |
| Heavy Load | 2,209 | 2,214 | 2,224 | 2,232 | 2,223 | 2,236 | 2,243 | 2,236 | 2,233 | 2,217 |
| System Load | 2,063 | 2,067 | 2,077 | 2,083 | 2,077 | 2,088 | 2,094 | 2,088 | 2,084 | 2,070 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,063 | 2,067 | 2,077 | 2,083 | 2,077 | 2,088 | 2,094 | 2,088 | 2,084 | 2,070 |

### Peak Load (Megawatts)—95th Percentile

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -163 | -177 | -191 | -205 | -219 | -233 | -247 | -261 | -275 | -289 |
| Demand Response (Mw) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 4,118 | 4,160 | 4,210 | 4,261 | 4,290 | 4,341 | 4,393 | 4,424 | 4,460 | 4,475 |
| System Peak (1 Hour) | 4,118 | 4,160 | 4,210 | 4,261 | 4,290 | 4,341 | 4,393 | 4,424 | 4,460 | 4,475 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 4,118 | 4,160 | 4,210 | 4,261 | 4,290 | 4,341 | 4,393 | 4,424 | 4,460 | 4,475 |

# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW (4) | Emergency Rating kW (5) |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 108,850 |
| Bliss | 86,250 | 75,000 | 75,000 | 76,470 |
| Brownlee | 650,444 | 585,400 | 585,400 | 746,570 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,800 |
| Clear Lake | 3,125 | 2,500 (1) | 2,420 | 2,420 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 444,830 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 64,340 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 16,520 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,540 |
| Milner | 62,890 | 59,448 | 59,448 | 61,090 |
| Oxbow | 211,112 | 190,000 | 190,000 | 221,410 |
| Shoshone Falls | 14,900 | 12,500 (1) | 12,500 | 14,040 |
| Strike, C.J. | 90,000 | 82,800 | 82,800 | 90,720 |
| Swan Falls | 28,600 | 27,170 | 24,170 (3) | 24,170 |
| Thousand Springs | 11,000 | 8,800 (1) | 6,380 (2) | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 53,060 |
| Upper Salmon "A" | 18,000 | 18,000 | 18,000 | 18,930 |
| Upper Salmon "B" | 18,000 | 16,500 | 16,500 | 17,510 |
| **Total Hydro** | 1,897,046 | 1,709,045 | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC) kW (6) |
|---|---|---|---|
| Bridger (IPC Share) | 811,053 | 770,501 | 706,667 |
| Boardman (IPC Share) | 67,600 | 64,200 | 58,600 |
| Valmy (IPC Share) | 315,000 | 283,500 | 258,250 |
| **Total Thermal** | 1,193,653 | 1,118,201 | 1,023,517 |
| | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 |
| Evander Andrews Unit #1 | 189,994 | 170,955 | 170,955 |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,236 |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,236 |
| **Total Natural Gas** | 483,994 | 435,555 | 425,586 |
| | | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 |
| **Total IPC Generation** | 3,581,573 | 3,267,801 | |

(1) A power factor rating of 0.8 is assumed on four units (Clear Lake, Unit #2 at Shoshone Falls, and Units #1 and #2 at Thousand Springs) with a total kVA rating of 6,127 kVA on which there is no nameplate kW rating.

(2) The two smaller units, #1 and #2, both having nameplate ratings of 1.25 MVA and 1 MW, have been taken out of service due to reduced flows from the springs and penstock integrity.

(3) The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

(4) The Normal Rating is defined as the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

(5) The Emergency Rating is defined as the maximum kW output of the facility with all units on-line. The Emergency Rating is based on allowable generator overloads and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

(6) Net Dependable Capacity (NDC) is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and MDC (Maximum Dependable Capacity) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

**Idaho Power Company**
**Qualifying Facilities**
**Cogeneration and Small Power Production Projects**
**Status as of June 1, 2009**

| Project | | | Contract On-line Date | Contract End Date |
|---|---|---|---|---|
| **Hydro Projects** | | | | |
| Barber Dam | Hydro | 3.70 | Apr-1989 | Apr-2024 |
| Birch Creek | Hydro | 0.05 | Nov-1984 | Oct-2019 |
| Black Canyon #3 | Hydro | 0.14 | Apr-1984 | Apr-2019 |
| Blind Canyon | Hydro | 1.50 | Dec-1994 | Dec-2014 |
| Box Canyon | Hydro | 0.36 | Feb-1984 | Feb-2019 |
| Briggs Creek | Hydro | 0.60 | Oct-1985 | Oct-2020 |
| Bypass | Hydro | 9.96 | Jun-1988 | Jun-2023 |
| Canyon Springs | Hydro | 0.13 | Oct-1984 | Non firm |
| Cedar Draw | Hydro | 1.55 | Jun-1984 | May-2019 |
| Clear Springs Trout | Hydro | 0.52 | Nov-1983 | Oct-2018 |
| Crystal Springs | Hydro | 2.44 | Apr-1986 | Mar-2021 |
| Curry Cattle Company | Hydro | 0.22 | Jun-1983 | Jun-2018 |
| Dietrich Drop | Hydro | 4.50 | Aug-1988 | Aug-2023 |
| Elk Creek | Hydro | 2.00 | May-1986 | May-2021 |
| Falls River | Hydro | 9.10 | Aug-1993 | Aug-2028 |
| Faulkner Ranch | Hydro | 0.87 | Aug-1987 | Aug-2022 |
| Fisheries Development Co | Hydro | 0.26 | Jul-1990 | Non firm |
| Geo Bon #2 | Hydro | 0.93 | Nov-1986 | Nov-2021 |
| Hailey CSPP | Hydro | 0.06 | Jun-1985 | Jun-2020 |
| Hazelton A | Hydro | 7.70 | Jun-1990 | Jun-2010 |
| Hazelton B | Hydro | 7.60 | May-1993 | Apr-2028 |
| Horseshoe Bend Hydroelectric | Hydro | 9.50 | Sep-1995 | Sep-2030 |
| Jim Knight | Hydro | 0.34 | Jun-1985 | Jun-2020 |
| Kasel and Witherspoon | Hydro | 0.90 | Mar-1984 | Feb-2019 |
| Koyle Small Hydro | Hydro | 1.25 | Apr-1984 | Mar-2019 |
| Lateral # 10 | Hydro | 2.06 | May-1985 | Apr-2020 |
| Lemoyne | Hydro | 0.08 | Jun-1985 | Jun-2020 |
| Little Wood Rvr Res | Hydro | 2.85 | Feb-1985 | Feb-2020 |
| Littlewood - Arkoosh | Hydro | 0.87 | Aug-1986 | Jul-2021 |
| Low Line Midway Hydro | Hydro | 7.97 | Aug-2007 | Aug-2027 |
| Lowline #2 | Hydro | 2.79 | Apr-1988 | Apr-2023 |
| Lowline Canal | Hydro | 2.50 | May-1985 | Apr-2005 |
| Magic Reservoir | Hydro | 9.07 | Jun-1989 | May-2024 |
| Malad River | Hydro | 0.62 | May-1984 | Apr-2019 |
| Marco Ranches | Hydro | 1.20 | Aug-1985 | Jul-2020 |
| Mile 28 | Hydro | 1.50 | Jun-1994 | May-2029 |
| Mitchell Butte | Hydro | 2.09 | May-1989 | May-2024 |
| Mora Drop | Hydro | 1.90 | Oct-2006 | Estimated |
| Mud Creek S&S | Hydro | 0.52 | Feb-1982 | Feb-2017 |
| Mud Creek White | Hydro | 0.21 | Jan-1986 | Jan-2021 |
| Owyhee Dam CSPP | Hydro | 5.00 | Aug-1985 | Aug-2015 |
| Pigeon Cove | Hydro | 1.89 | Oct-1984 | Oct-2019 |
| Pristine Springs | Hydro | 0.13 | May-2005 | Apr-2015 |
| Pristine Springs #3 | Hydro | 0.20 | May-2005 | Apr-2015 |
| Reynolds Irrigation | Hydro | 0.26 | May-1986 | May-2021 |
| Rim View | Hydro | 0.20 | Nov-2000 | Non firm |
| Rock Creek #1 | Hydro | 2.05 | Sep-1983 | Sep-2018 |
| Rock Creek #2 | Hydro | 1.90 | Apr-1989 | Mar-2024 |
| Sagebrush | Hydro | 0.43 | Sep-1985 | Aug-2020 |
| Sahko Hydro | Hydro | 0.50 | Jun-2006 | Non firm |
| Schaffner | Hydro | 0.53 | Aug-1986 | Jul-2021 |
| Shingle Creek | Hydro | 0.22 | Aug-1983 | Jul-2018 |
| Shoshone #2 | Hydro | 0.58 | May-1996 | Apr-2031 |
| Shoshone CSPP | Hydro | 0.37 | Jun-1982 | Jun-2017 |
| Snake River Pottery | Hydro | 0.07 | Nov-1984 | Nov-2019 |
| Snedigar | Hydro | 0.54 | Jan-1985 | Dec-2019 |
| Tiber Dam | Hydro | 7.50 | Jun-2004 | May-2024 |
| Trout—Co | Hydro | 0.24 | Dec-1986 | Nov-2021 |
| Tunnel #1 | Hydro | 7.00 | Jun-1993 | May-2028 |
| White Water Ranch | Hydro | 0.16 | Aug-1985 | Jul-2020 |
| Wilson Lake Hydro | Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate MW rating** | | **140.55** | | |
| **Thermal Projects** | | | | |
| Magic Valley | Natural Gas | 10.00 | Nov-1996 | Nov-2016 |
| Magic West | Natural Gas | 10.00 | Dec-1996 | Nov-2016 |
| Simplot Pocatello | Cogen | 12.00 | Mar-2006 | Feb-2016 |
| TASCO—Nampa | Natural Gas | 2.00 | Sep-2003 | Aug-2008 |
| TASCO—Twin Falls | Natural Gas | 3.00 | Aug-2001 | Aug-2006 |
| **Total Thermal Nameplate MW rating** | | **37.00** | | |
| **Biomass Projects** | | | | |
| Bettencourt Dry Creek Biofactory | Biomass | 2.25 | Aug-2008 | Non-firm |
| Big Sky West Dairy Digester | Biomass | 1.50 | Jan-2009 | Jan-2029 |
| CO-GEN CO | Biomass | 9.40 | Jul-2008 | Jul-09 |
| Hidden Hollow Landfill Gas | Biomass | 3.20 | Oct-2006 | Jul-2009 |
| Pocatello Waste | Biomass | 0.46 | Dec-1985 | Dec-2020 |
| Tamarack CSPP | Biomass | 5.00 | Jun-1983 | May-2018 |
| Vaagen Brothers Lumber Inc | Biomass | 4.50 | Sep-1995 | Aug-2010 |
| **Total Biomass Nameplate MW rating** | | **26.31** | | |
| **Wind Projects** | | | | |
| Bennett Creek Wind Farm | Wind | 19.80 | Dec-2008 | Dec. 2028 |
| Burley Butte Wind | Wind | 10.50 | Sep-2010 | Estimated |
| Cassia Farm | Wind | 10.50 | Feb. 2009 | Feb-2029 |
| Cassia Gulch | Wind | 18.90 | Feb. 2009 | Feb. 2029 |
| Fossil Gulch Wind | Wind | 10.50 | Sep-2005 | Sep-2025 |
| Golden Valley Wind | Wind | 12.00 | Sep-2010 | Estimated |
| Horseshoe Bend Wind Park | Wind | 9.00 | Feb-2006 | Feb-2026 |
| Hot Springs Wind Farm | Wind | 19.80 | Mar-2008 | Mar-2028 |
| Lava Beds Wind | Wind | 18.00 | Sep-2010 | Estimated |
| Magic Wind Park | Wind | 19.50 | Sep-2010 | Estimated |
| Milner Dam Wind | Wind | 19.50 | Sep-2010 | Estimated |
| Notch Butte Wind | Wind | 18.00 | Sep-2010 | Estimated |
| Oregon Trail Wind | Wind | 13.50 | Sep-2010 | Estimated |
| Pilgrim Stage Station Wind | Wind | 10.50 | Sep-2010 | Estimated |
| Salmon Falls Wind | Wind | 19.50 | Sep-2010 | Estimated |
| Thousand Springs Wind | Wind | 12.00 | Sep-2010 | Estimated |
| Tuana Gulch Wind | Wind | 10.50 | Sep-2010 | Estimated |
| **Total Wind Nameplate MW rating** | | **252.00** | | |
| **Geothermal Projects** | | | | |
| None | | | | |
| **Total Geothermal Nameplate MW rating** | | **0.00** | | |
| **Total Nameplate MW rating** | | **455.86** | | |

**Cogeneration and Small Power Production Project (CSPP) Generation Information**

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical Generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce. The application of this information to the portfolio of CSPP projects resulted in the average annual MW from CSPP projects being 150 MW beginning in 2011. Projects listed in this appendix are included in the CSPP forecast and were signed and approved contracts as of June 1, 2009.

## Idaho Power Company

## Power Purchase Agreements

## Status as of June 1, 2009

| Project | | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|---|
| **Wind Projects** | | | | |
| Elkhorn Wind Project | Wind | 101 | Dec-2007 | Dec-2027 |
| **Total Wind Nameplate MW Rating*** | | **101** | | |
| **Geothermal Projects** | | | | |
| Raft River Unit #1 | Geothermal | 13 | Apr-2008 | Apr-2033 |
| **Total Geothermal Nameplate MW Rating*** | | **13** | | |
| **Total Nameplate MW Rating** | | **114** | | |

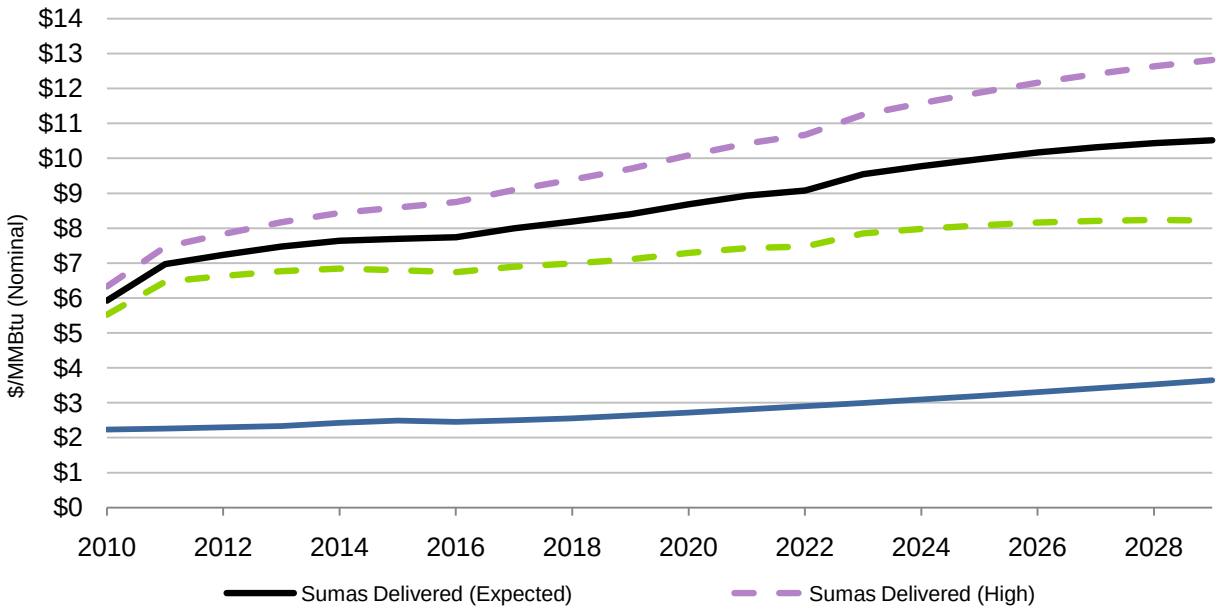
*The above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

# FUEL DATA

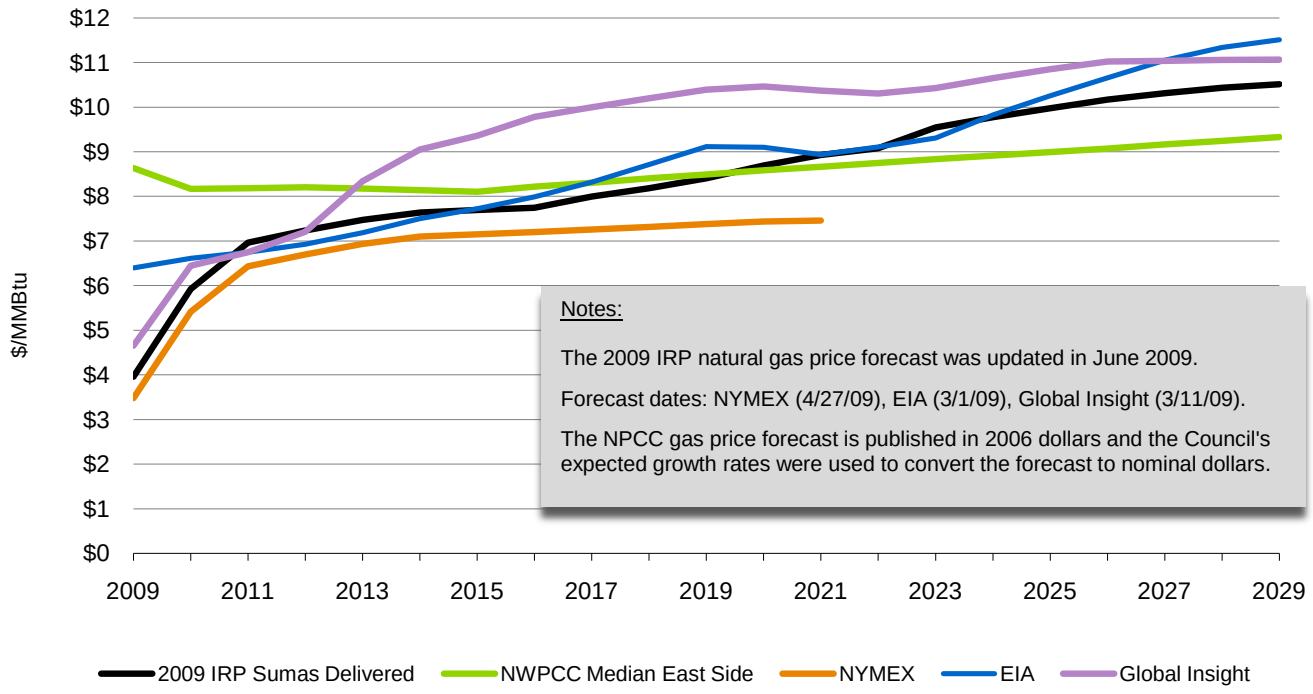
**Gas and Coal Forecast—Data and Graphs**

| Year | Henry Hub | Sumas | Sumas Delivered (Expected) | Sumas Delivered (High) | Sumas Delivered (Low) | Regional Coal |
|---|---|---|---|---|---|---|
| 2010 | $5.81 | $5.41 | $5.93 | $6.33 | $5.53 | $2.23 |
| 2011 | $6.75 | $6.44 | $6.97 | $7.47 | $6.47 | $2.26 |
| 2012 | $7.10 | $6.70 | $7.23 | $7.83 | $6.63 | $2.30 |
| 2013 | $7.23 | $6.93 | $7.47 | $8.17 | $6.77 | $2.34 |
| 2014 | $7.32 | $7.10 | $7.64 | $8.44 | $6.84 | $2.43 |
| 2015 | $7.42 | $7.15 | $7.69 | $8.59 | $6.79 | $2.49 |
| 2016 | $7.51 | $7.20 | $7.74 | $8.74 | $6.74 | $2.46 |
| 2017 | $7.81 | $7.45 | $7.99 | $9.09 | $6.89 | $2.50 |
| 2018 | $8.05 | $7.64 | $8.19 | $9.39 | $6.99 | $2.55 |
| 2019 | $8.31 | $7.86 | $8.40 | $9.70 | $7.10 | $2.63 |
| 2020 | $8.64 | $8.14 | $8.69 | $10.09 | $7.29 | $2.72 |
| 2021 | $8.93 | $8.38 | $8.93 | $10.43 | $7.43 | $2.81 |
| 2022 | $9.10 | $8.48 | $9.08 | $10.68 | $7.48 | $2.90 |
| 2023 | $9.65 | $8.95 | $9.55 | $11.25 | $7.85 | $3.00 |
| 2024 | $9.96 | $9.18 | $9.78 | $11.58 | $7.98 | $3.10 |
| 2025 | $10.26 | $9.37 | $9.98 | $11.88 | $8.08 | $3.20 |
| 2026 | $10.57 | $9.55 | $10.17 | $12.17 | $8.17 | $3.30 |
| 2027 | $10.85 | $9.70 | $10.31 | $12.41 | $8.21 | $3.41 |
| 2028 | $11.14 | $9.81 | $10.43 | $12.63 | $8.23 | $3.53 |
| 2029 | $11.43 | $9.90 | $10.52 | $12.82 | $8.22 | $3.65 |

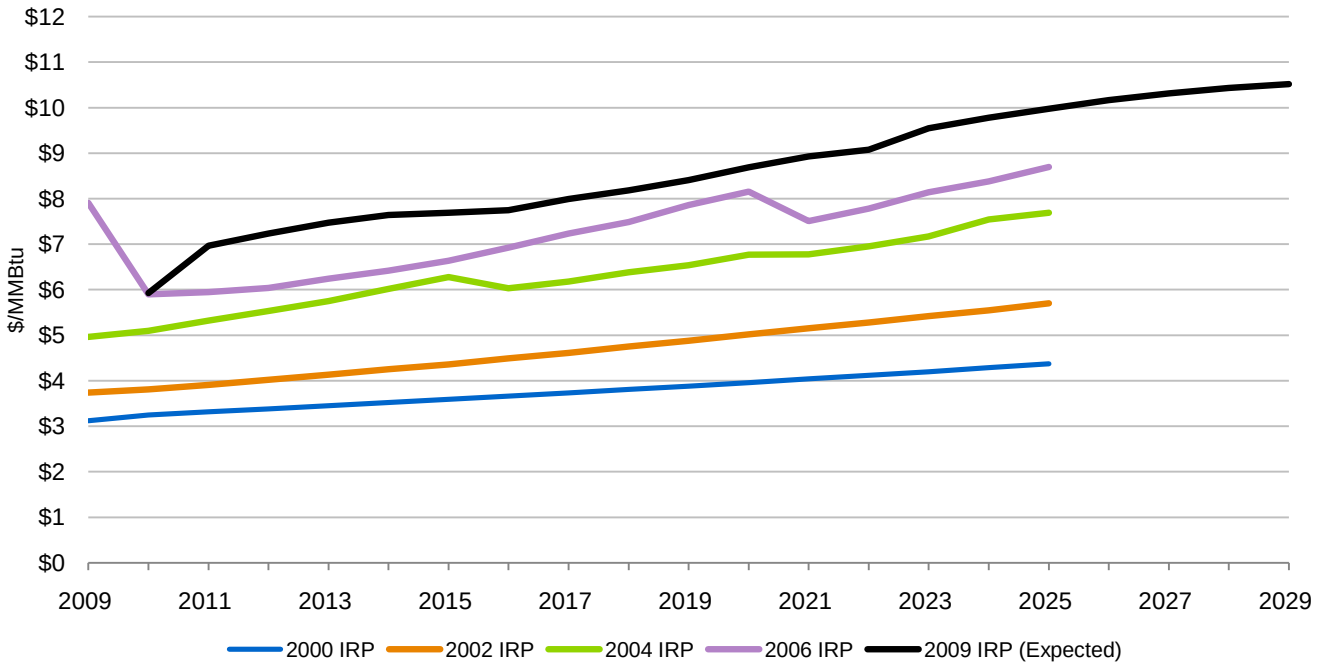
**Natural Gas and Coal Price Forecast**



**Natural Gas Price Forecast—Comparison to Other Forecasts**




**Natural Gas Price Forecast—Comparison to Previous Integrated Resource Plans**



# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.54% |
| Preferred | 0.00% |
| Common | 49.46% |
| Total | 100.00% |
| **Cost** | |
| Debt | 5.65% |
| Preferred | 0.00% |
| Common | 10.60% |
| Average Weighted Cost | 8.10% |

| Financial Assumptions and Factors | |
|---|---|
| Plant Operating (Book) Life | 30 Years |
| Discount Rate (aka WACC) | 6.98% |
| Composite Tax Rate | 39.10% |
| Deferred Rate | 35.00% |
| General O&M Esc Rate | 3.00% |
| Emission Adder Esc Rate | 2.50% |
| Annual Prop Tax Rate (% of Invest) | 0.29% |
| Prop Tax Esc Rate | 3.00% |
| Annual Insurance Prems (% of Invest) | 0.31% |
| Insurance Esc Rate | 2.00% |
| AFUDC Rate (Annual) | 7.00% |
| Prod Tax Credits Esc Rate | 3.00% |

| Tax Credits (2009 $) | |
|---|---|
| Wind, Geothermal and Closed Loop Biomass | $21/MWh first 10 years of operation |
| Open Loop Biomass, Hydro and In-Stream Generation | $10/ MWh first 10 years of operation |
| Solar Investment Tax Credit (ITC) | 30% of depreciable investment |

**Emissions Limits (pounds per MWh by technology)**

(adders are brought into the analysis beginning in 2012)

| | GHG | Nox | Mercury |
|---|---|---|---|
| Small Aeroderavative SCCT | 1,190 | 0.12000 | 0.00000 |
| Large Aeroderavative SCCT | 1,071 | 0.10800 | 0.00000 |
| Large Frame SCCT | 1,119 | 0.11280 | 0.00000 |
| Reciprocating Engines | 1,071 | 0.10800 | 0.00000 |
| CCCT 1x1 | 809 | 0.08160 | 0.00000 |
| CCCT 2x1 | 809 | 0.08160 | 0.00000 |
| Combined Heat and Power (CHP) | 809 | 0.08160 | 0.00000 |
| Distributed Generation—Gas Fired | 1,071 | 0.10800 | 0.00000 |
| Pulverized Coal | 1,886 | 0.44160 | 0.00002 |
| IGCC | 1,797 | 0.21036 | 0.00002 |
| IGCC w/ Carbon Sequestration | 309 | 0.42560 | 0.00002 |
| Biomass—Landfill Gas | 0 | 1.70000 | 0.00000 |
| Biomass—Aneorobic Digesters | 0 | 1.70000 | 0.00000 |

**Emission Adder Rates**

(adders are brought into the analysis beginning in 2012)

| | |
|---|---|
| GHG | $40 per ton (2009 $) |
| NOX | $2,600 per ton during May–September |
| Mercury | $1,443/oz in years 2012–2017; $1,731/oz in year 2018 and beyond |

**Fuel Forecast Base Case (Nominal, $ per MMBtu)**

| Year | Gas | Generic | Nuclear |
|---|---|---|---|
| 2009 | 3.96 | 1.83 | 0.65 |
| 2010 | 5.93 | 2.23 | 0.65 |
| 2011 | 6.97 | 2.26 | 0.66 |
| 2012 | 7.23 | 2.30 | 0.66 |
| 2013 | 7.47 | 2.34 | 0.67 |
| 2014 | 7.64 | 2.43 | 0.67 |
| 2015 | 7.69 | 2.49 | 0.67 |
| 2016 | 7.74 | 2.46 | 0.68 |
| 2017 | 7.99 | 2.50 | 0.68 |
| 2018 | 8.19 | 2.55 | 0.69 |
| 2019 | 8.40 | 2.63 | 0.69 |
| 2020 | 8.69 | 2.72 | 0.69 |
| 2021 | 8.93 | 2.81 | 0.70 |
| 2022 | 9.08 | 2.90 | 0.70 |
| 2023 | 9.55 | 3.00 | 0.71 |
| 2024 | 9.78 | 3.10 | 0.71 |
| 2025 | 9.98 | 3.20 | 0.72 |
| 2026 | 10.17 | 3.30 | 0.72 |
| 2027 | 10.31 | 3.41 | 0.72 |
| 2028 | 10.43 | 3.53 | 0.73 |
| 2029 | 10.52 | 3.65 | 0.73 |
| 2030 | 10.55 | 3.77 | 0.74 |
| 2031 | 10.73 | 3.69 | 0.74 |
| 2032 | 10.84 | 3.77 | 0.75 |
| 2033 | 10.96 | 3.85 | 0.75 |
| 2034 | 11.07 | 3.93 | 0.75 |
| 2035 | 11.19 | 4.01 | 0.76 |
| 2036 | 11.30 | 4.09 | 0.76 |
| 2037 | 11.42 | 4.16 | 0.77 |
| 2038 | 11.53 | 4.24 | 0.77 |

# Cost Inputs and Operating Assumptions Resource Cost Analysis
## (All Costs in 2009 Dollars)

| | Plant Capacity (MW) | Overnight Plant Capital $/kW [1,3] | Overnight Transmission Capital $/kW | Overnight Total Capital $/kW | Total Investment $/kW [2] | Fixed O&M $/kW [3] | Variable O&M $/MWh | Emission Adders $/MWh | Heat Rate (btus/kWH) |
|---|---|---|---|---|---|---|---|---|---|
| Distributed Generation- Gas Fired | 15 | $0 | $163 | $163 | $0 | $3 | $1 | $26 | 12,000 |
| Simple Cycle CT - Industrial Frame | 170 | $470 | $29 | $499 | $529 | $4 | $2 | $27 | 10,000 |
| Boardman to Hemingway | 225 | $0 | $700 | $700 | $0 | $0 | $0 | $0 | 0 |
| Simple Cycle CT - Large Aeroderivative | 100 | $700 | $63 | $763 | $806 | $3 | $3 | $24 | 8,400 |
| Reciprocating Engines | 25 | $673 | $100 | $773 | $815 | $10 | $7 | $24 | 9,700 |
| Simple Cycle CT - Small Aeroderivative | 47 | $850 | $77 | $927 | $982 | $3 | $3 | $27 | 9,200 |
| Gateway West | 275 | $0 | $1,000 | $1,000 | $0 | $0 | $0 | $0 | 0 |
| CCCT (2x1) F Class | 540 | $1,050 | $99 | $1,149 | $0 | $5 | $1 | $18 | 6,800 |
| CHP/Co-Generation | 47 | $1,200 | $133 | $1,333 | $0 | $0 | $3 | $18 | 9,200 |
| CCCT (1x1) F Class | 270 | $1,200 | $93 | $1,293 | $0 | $7 | $1 | $18 | 6,800 |
| Wind | 100 | $1,275 | $503 | $1,778 | $1,887 | $35 | $1 | $0 | 0 |
| Shoshone Falls Upgrade | 64 | $1,779 | $200 | $1,979 | $2,195 | $2 | $0 | $0 | 0 |
| In-Stream Generation | 1 | $2,839 | $442 | $3,281 | $3,398 | $112 | $0 | $0 | 0 |
| Solar - Parabolic Dish Engine | 100 | $3,400 | $10 | $3,410 | $3,739 | $56 | $0 | $0 | 0 |
| Solar - Water Steam Power Tower | 100 | $3,400 | $10 | $3,410 | $3,772 | $56 | $0 | $0 | 0 |
| Solar - Parabolic Trough | 100 | $4,200 | $10 | $4,210 | $4,856 | $55 | $0 | $0 | 0 |
| Biomass - Digesters | 1 | $4,100 | $348 | $4,448 | $0 | $54 | $16 | $0 | 12,407 |
| Biomass - Landfill Gas | 2 | $4,100 | $348 | $4,448 | $0 | $22 | $16 | $0 | 11,556 |
| Conventional Scrubbed Coal | 750 | $3,500 | $675 | $4,175 | $4,947 | $23 | $5 | $43 | 9,200 |
| Low Drop/Small Hydro New | 10 | $4,312 | $400 | $4,712 | $5,436 | $14 | $3 | $0 | 0 |
| Solar - Molten Salt Power Tower, 6.9 Hours Energy Storage | 100 | $4,900 | $10 | $4,910 | $5,602 | $55 | $0 | $0 | 0 |
| IGCC | 600 | $4,025 | $675 | $4,700 | $5,735 | $32 | $3 | $41 | 8,765 |
| Solar - Flat Plate PV | 1 | $6,300 | $0 | $6,300 | $6,411 | $25 | $0 | $0 | 0 |
| IGCC with Carbon Sequestration | 600 | $4,900 | $675 | $5,575 | $6,803 | $38 | $5 | $8 | 10,500 |
| Solar - Parabolic Trough, 6 hours Energy Storage | 100 | $6,300 | $10 | $6,310 | $7,279 | $72 | $0 | $0 | 0 |
| Solar - Concentrating PV | 1 | $7,500 | $0 | $7,500 | $7,768 | $50 | $0 | $0 | 0 |
| Advanced Nuclear | 1,100 | $5,000 | $538 | $5,538 | $0 | $146 | $5 | $0 | 10,400 |
| Geothermal | 26 | $7,200 | $331 | $7,531 | $0 | $76 | $5 | $0 | 0 |

[1] Plant costs include engineering, development costs, generating and ancillary equipment purchase and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

# Levelized Resource Cost Tables

## 30-Year Levelized Cost of Production (at stated capacity factors)

| | Cost of Capital | Non-Fuel O&M [1] | Fuel | Wholesale Energy | Emission Adders | Total Cost per MWh | Capacity Factor |
|---|---|---|---|---|---|---|---|
| Shoshone Falls Upgrade - Hydro (64 MW) | $62 | $0 | $0 | $0 | $0 | $62 | 36% |
| Wind (100 MW) | $60 | $20 | $0 | $0 | $0 | $80 | 32% |
| Biomass - Landfill Gas (2 MW) | $62 | $21 | $0 | $0 | $0 | $83 | 80% |
| Combined Cycle CT 2x1 (540 MW) | $22 | $5 | $58 | $0 | $18 | $103 | 65% |
| Geothermal (26 MW) | $92 | $15 | $0 | $0 | $0 | $107 | 92% |
| Combined Cycle CT 1x1 (270 MW) | $25 | $6 | $58 | $0 | $18 | $107 | 65% |
| Transmission @ 65% - Boardman to Hemingway (225 MW) | $13 | $1 | $0 | $113 | $0 | $126 | 65% |
| Combined Heat and Power (47 MW) | $18 | $6 | $86 | $0 | $18 | $128 | 90% |
| Transmission @ 65% - Gateway West (275 MW) | $18 | $2 | $0 | $113 | $0 | $132 | 65% |
| Biomass - Digesters (1 MW) | $66 | $69 | $0 | $0 | $0 | $136 | 75% |
| Solar - Salt Power Tower (100 MW) | $89 | $50 | $0 | $0 | $0 | $139 | 28% |
| Transmission @ 25.7% - Boardman to Hemingway (225 MW) | $32 | $3 | $0 | $113 | $0 | $147 | 26% |
| Pulverized Coal (750 MW) | $68 | $16 | $26 | $0 | $43 | $153 | 88% |
| Low Drop/Small Hydro New (10 MW) | $140 | $14 | $0 | $0 | $0 | $154 | 45% |
| IGCC with Carbon Sequestration (600 MW) | $96 | $21 | $30 | $0 | $8 | $155 | 85% |
| Solar - Parabolic Dish Engine (100 MW) | $89 | $67 | $0 | $0 | $0 | $156 | 19% |
| Transmission @ 25.7% - Gateway West (275 MW) | $45 | $4 | $0 | $113 | $0 | $162 | 26% |
| IGCC (600 MW) | $81 | $17 | $25 | $0 | $41 | $163 | 85% |
| Advanced Nuclear (1,100 MW) | $114 | $44 | $7 | $0 | $0 | $165 | 85% |
| Solar - Parabolic Trough, with Energy Storage (100 MW) | $115 | $66 | $0 | $0 | $0 | $181 | 28% |
| Solar - Parabolic Trough No Storage (100 MW) | $117 | $73 | $0 | $0 | $0 | $191 | 18% |
| Solar - Water Steam Power Tower (100 MW) | $113 | $85 | $0 | $0 | $0 | $198 | 15% |
| Simple Cycle CT - Large Aero (100 MW) | $93 | $17 | $71 | $0 | $24 | $205 | 10% |
| Distributed Generation - Gas Fired (15 MW) | $68 | $23 | $102 | $0 | $26 | $218 | 3% |
| Solar - Concentrating PV (1 MW) | $159 | $70 | $0 | $0 | $0 | $229 | 22% |
| Solar - Flat Plate PV (1 MW) | $174 | $60 | $0 | $0 | $0 | $234 | 17% |
| Simple Cycle CT - Industrial Frame (170 MW) | $102 | $21 | $85 | $0 | $27 | $234 | 6% |
| In-Stream Generation (1 MW) | $157 | $90 | $0 | $0 | $0 | $247 | 22% |
| Transmission @ 6% - Boardman to Hemingway (225 MW) | $135 | $12 | $0 | $113 | $0 | $260 | 6% |
| Simple Cycle CT - Small Aero (47 MW) | $142 | $22 | $78 | $0 | $27 | $268 | 8% |
| Transmission @ 6% - Gateway West (275 MW) | $193 | $17 | $0 | $113 | $0 | $323 | 6% |
| Reciprocating Engines (25 MW) | $157 | $49 | $109 | $0 | $24 | $339 | 6% |

[1] Non Fuel O&M includes fixed and variable costs, property taxes, and production tax credits.

## 30 Year Levelized Capacity (Fixed) Cost per kW

| | Cost of Capital | Non-Fuel O&M | Fuel | Emission Adders | Total Cost per kW |
|---|---|---|---|---|---|
| Distributed Generation - Gas Fired (15 MW) | $1 | $0 | $0 | $0 | $2 |
| Simple Cycle CT - Industrial Frame (170 MW) | $4 | $1 | $0 | $0 | $5 |
| Transmission - Boardman to Hemingway (275 MW) | $6 | $1 | $0 | $0 | $6 |
| Simple Cycle CT - Large Aero (100 MW) | $7 | $1 | $0 | $0 | $8 |
| Reciprocating Engines (25 MW) | $7 | $2 | $0 | $0 | $9 |
| Transmission - Gateway West (275 MW) | $8 | $1 | $0 | $0 | $9 |
| Simple Cycle CT - Small Aero (47 MW) | $8 | $1 | $0 | $0 | $9 |
| Combined Cycle CT 2x1 (540 MW) | $11 | $1 | $0 | $0 | $12 |
| Combined Heat and Power (47 MW) | $12 | $1 | $0 | $0 | $13 |
| Combined Cycle CT 1x1 (270 MW) | $12 | $2 | $0 | $0 | $14 |
| Shoshone Falls Upgrade - Hydro (64 MW) | $16 | $2 | $0 | $0 | $18 |
| Wind (100 MW) | $14 | $5 | $0 | $0 | $19 |
| Solar - Parabolic Dish Engine (100 MW) | $12 | $9 | $0 | $0 | $21 |
| Solar - Water Steam Power Tower (100 MW) | $12 | $9 | $0 | $0 | $21 |
| Solar - Parabolic Trough No Storage (100 MW) | $16 | $10 | $0 | $0 | $25 |
| Solar - Flat Plate PV (1 MW) | $21 | $7 | $0 | $0 | $28 |
| Solar - Salt Power Tower (100 MW) | $18 | $10 | $0 | $0 | $28 |
| Solar - Concentrating PV (1 MW) | $25 | $11 | $0 | $0 | $36 |
| Solar - Parabolic Trough, with Energy Storage (100 MW) | $24 | $13 | $0 | $0 | $37 |
| In-Stream Generation (1 MW) | $25 | $16 | $0 | $0 | $41 |
| Biomass - Landfill Gas (2 MW) | $36 | $6 | $0 | $0 | $42 |
| Biomass - Digesters (1 MW) | $36 | $10 | $0 | $0 | $46 |
| Pulverized Coal (750 MW) | $43 | $6 | $0 | $0 | $49 |
| Low Drop/Small Hydro New (10 MW) | $46 | $5 | $0 | $0 | $51 |
| IGCC (600 MW) | $50 | $8 | $0 | $0 | $58 |
| IGCC with Carbon Sequestration (600 MW) | $60 | $9 | $0 | $0 | $69 |
| Geothermal (26 MW) | $62 | $15 | $0 | $0 | $76 |
| Advanced Nuclear (1,100 MW) | $71 | $23 | $0 | $0 | $93 |

# The Comprehensive Aquifer Management Plan (CAMP) Process and Potential to Impact Power Generation

## The CAMP Process

The Eastern Snake Plain Aquifer (ESPA) serves nearly one million acres of ground water irrigated land, cities, industries, and thousands of domestic wells. Above American Falls, the ESPA supports spring discharge that provides natural flow for irrigated lands in the Magic Valley. The ESPA has experienced serious declines that began in the late 1970s and appear to be ongoing. Those declines have impacted spring discharge to the Snake River, including springs that provide irrigation water and flows of cold water that support fish hatcheries from Twin Falls to Hagerman. Flow from the ESPA also provides a significant portion of the flow in the Snake River at King Hill and below.

Declining spring discharge has created numerous water shortages resulting in water calls pitting senior spring and surface water users against junior ground water appropriators. Many of those water calls are still pending or have been only partially resolved through orders from the director of the Idaho Department of Water Resources (IDWR). Continued declines in spring flows are likely to exacerbate these ongoing conflicts over water use on the Eastern Snake River Plain (ESRP).

The 2007 Idaho Legislature tasked the Idaho Water Resource Board (IWRB) with developing an ESPA Comprehensive Aquifer Management Plan (CAMP). The charge of the legislature was to "establish public policy as a settlement framework for future management of the ESPA." To meet legislative goals, the IWRB established a 15-member committee representing various water user groups and other parties interested in the management of the ESPA. The goal of the committee was to develop an aquifer management plan to "sustain the economic viability and social and environmental health of the Easter Snake Plain by adaptively managing a balance between water use and supplies."

**Table CAMP-1. Phase I Measures Included in the CAMP**

| Measure | Target (Acft) |
|---|---|
| Ground Water to Surface Water Conversions | 100,000 |
| Managed Aquifer Recharge | 100,000 |
| Demand Reduction | |
| Surface Water Conservation | 50,000 |
| Crop Mix Modification | 5,000 |
| Rotating Fallowing, Dry-Year Lease, CREP | 40,000 |
| Weather Modification | 50,000 |

The committee met monthly starting in May 2007 continuing through September 2008. The CAMP committee first established a goal of producing an annual 600,000 acre-feet adjustment in the water budget of the ESRP. This water balance adjustment was adopted as the long-term hydrologic target; however, committee members recognized this adjustment would be achieved only after many years of implementation. The committee adopted an interim plan called Phase I that targets an annual water budget change of 200,000–300,000 acre-feet/year. The committee's goal is to have Phase I fully implemented in 10 years. Table CAMP-1 shows the measures anticipated under Phase I. The Phase I plan includes the implementation of a variety of measures to change the overall water budget of the ESRP.

CAMP was submitted to the 2009 Idaho Legislature for approval. Upon legislative approval of the plan, the IWRB began a process of selecting an implementation committee. The charge of that committee will be to "assist the Board in the prioritization, development, implementation, and monitoring and evaluation of management actions." The implementation committee will also develop a mechanism to fund measures implemented under CAMP. The successful implementation of any CAMP-recommended measure is dependent upon securing a long-term funding source. As such, the specific practices, their extent or location is unknown at this time. Additionally, some practices are likely to change as the feasibility and impact of specific practices is evaluated over the next five years. The legislative approval of CAMP was only the first step in implementing management practices on the ESPA.

Idaho Power recognizes the potential for declining spring flow below Milner Dam to impact generation capabilities. Idaho Power also recognizes the potential for management practices recommended and implemented through CAMP to impact generation capabilities. Those impacts could be either positive or negative. As such, Idaho Power has been an active member of the CAMP committee. Idaho Power was represented at every CAMP committee meeting, and the company representatives participated in several sub-committees. Idaho Power also developed the appropriate modeling techniques to assess the potential impacts of CAMP on river flows and spring discharge. The results of the modeling was provided to the CAMP committee and used during the decision-making process. Idaho Power has also suggested management alternatives and has agreed to provide technical and material support for a pilot weather modification program in the upper Snake River basin.

CAMP committee members recognize that the failure of proposed management practices to increase aquifer levels or improve spring discharge to the Snake River could result in continued legal action against junior ground water appropriators. Implementation of CAMP was not to supplant the need for litigation but to manage the aquifer such that water calls would be lessened. Ground water appropriators could be subjected to increased mitigation requirements or potential curtailment if CAMP fails to produce desired results.

## Potential Impact of CAMP Implementation on Idaho Power

The implementation of CAMP practices impact hydropower generation in three different ways.

1) Managed recharge can increase spring discharge below Milner Dam, but those increases can occur only if water is diverted above Milner Dam and directed onto the ESRP and recharged to the aquifer. Conversions of ground water supplied irrigated land to surface supplied can also improve spring flow, but would require diversions of water from the Snake River above Milner Dam as well. Diversion for managed recharge and conversion projects have the potential to reduce the volume of water passing through numerous Idaho Power projects. Those diversions may have a negative impact to hydropower production on those facilities located between Milner Dam and King Hill. Additionally, while most of the water diverted for these projects comes back to the river as spring discharge, up to 10% of the water remains in the aquifer as long-term storage. These practices essentially shift water from one compartment, surface water, to another compartment, ground water. The net effect on the overall water budget is zero, but the diversions from the Snake River can have negative impacts to hydropower production.

2) Weather modification and practices that reduce consumptive use of ground water can increase water flowing through those generation facilities located on the Snake River above King Hill. These measures actually change the water budget by reducing consumptive demand or by increasing water supply in the basin. They can increase spring flow or tributary flow into the

Snake River, but, unlike managed recharge or conversion projects, they require no diversions from the Snake River. These projects increase flows in the Snake River and could potentially benefit power generation.

3) Practices described in 1) and 2) are likely to be implemented in some combination. The relative extent of those practices will ultimately determine whether the impact is positive or negative for hydropower production. Diversions and increases in spring discharge may eventually balance, but the first five to ten years of implementation may produce a net negative effect on hydropower production.

The actual impact to hydropower production resulting from the implementation of the CAMP plan is uncertain. The availability of funding could drastically alter the implementation of the CAMP Phase I plan and long-standing water calls may eventually trump any plan proffered. Changing economic conditions may also alter decisions made by agriculture producers and their participation in current mitigation plans and other programs, such as the Conservation Reserve Enhancement Program (CREP). In evaluating the potential impacts of CAMP on hydropower production, the Phase I targets provide a basis for modeling and evaluation.

## Modeled CAMP Scenario

Idaho Power developed modeling capabilities to help determine the potential impacts of CAMP on spring discharge and flows in the Snake River. Idaho Power modeled several different scenarios for the CAMP committee. The modeling incorporates the Enhanced Snake Plain Aquifer Model (ESPAM) and the Snake River Planning Modeling (SRPM). The modeling also incorporates information on canal capacities and sets limits for managed recharge, system conversions, and demand reduction activities. The modeling also includes estimates on increased water from weather-modification activities.

The scenario modeled for the IRP was the Phase I implementation plan proposed in CAMP. The parameters entered into the model were done to try and match the goals of the Phase I plan. Table CAMP-2 compares the results of the Phase I CAMP with the modeled results. The modeled scenario provides close approximation of the planned Phase I and allows for the examination of the impacts of CAMP on spring discharge and flows in the Snake River.

**Table CAMP-2. CAMP Phase I Goals and Results of Modeling**

| Action | CAMP Goal (Average thousand acre-feet/year) | Modeled (Average thousand acre-feet/year) |
|---|---|---|
| Ground to Surface Water Conversions | 100 | 81 |
| Managed Recharge | 100 | 140** |
| Demand Reduction | 95* | 45 |
| Weather Modification | 50 | 50 |

*Some demand reduction includes the purchase of subordination agreements from spring owners that cannot be modeled, but would have no impact on spring flows or Snake River Flows.

**This recharge also includes approximately 20 KAF/yr recharge on the Wood River system.

The SRPM uses a variety of data inputs to determine water availability for irrigation diversions as well as providing information on reservoir storage and river flows. The model allows for present conditioning of historic data. In other words, it applies today's level of development (irrigation diversions and storage), reach gains, and diversions to historic water availability. The model is currently calibrated to

run from 1928 through 2005. This mode of operation allows for the comparison of a base case scenario to a variety of management scenarios. This provides a perspective on the degree to which different management scenarios may impact reservoir storage and river flows.

**Table CAMP-3. Average Difference Between the CAMP Scenario and the Base Case Scenario for Flow at King Hill**

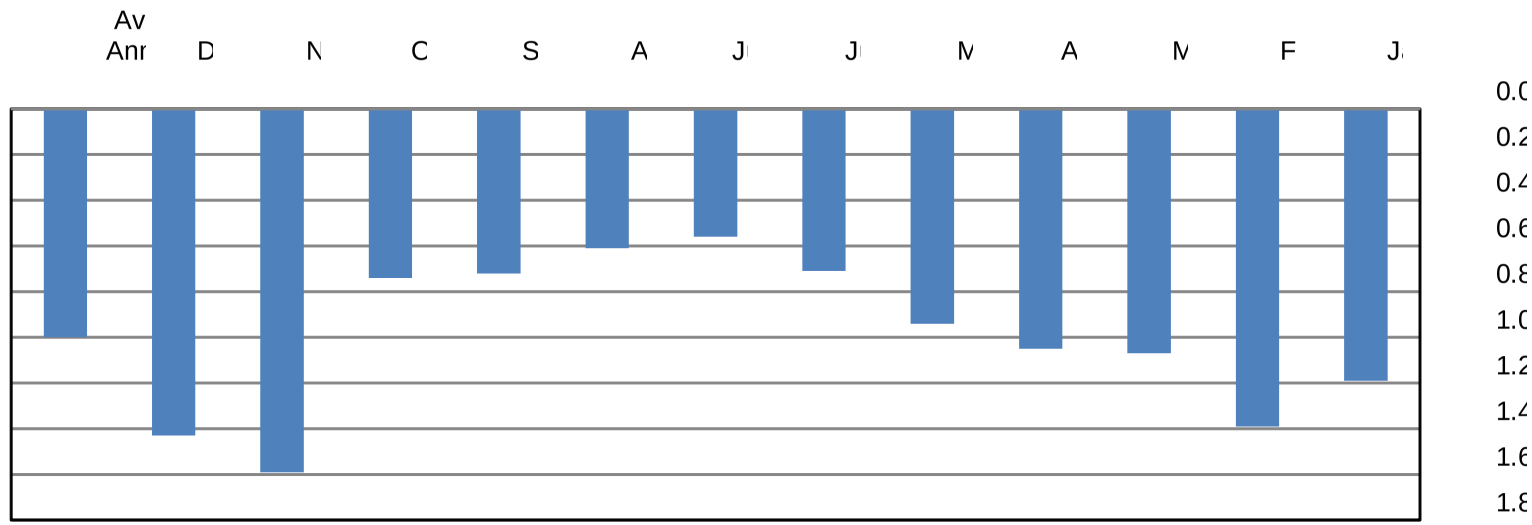
| July (acre-feet) | December (acre-feet) | Yearly (acre-feet) |
|---|---|---|
| 7,700 | 10,900 | 66,600 |

A comparison was made for the months of July and December and total yearly flows for the base case scenario and the CAMP scenario. July and December were selected because they are critical months for power generation. The comparison of modeled data was for the King Hill gage on the Snake River (Table CAMP-3). The average flows for July increased 7,670 acre-feet/month, and December flows increased 10,880 acre-feet/month. The yearly average flows increased by 66,580 acre-feet/year, which is about 1% of the yearly average flow at the King Hill gage. These small increases reflect the nature of changes in the water budget for the upper Snake Basin as proposed through CAMP. The CAMP Phase I plan contains only 95,000 acft in new or additional water to the system. CAMP may increase spring discharge tributary to the Snake River, but those increases are dependent upon large diversion from the Snake River for managed recharge or system conversions. The overall increase in Snake River flow is dependent upon a reduction in consumptive use of water or increases related to water modification activities.

**Brownlee Reservoir Inflow Record (Million Acre-Feet)**
**Record Used for 2009 IRP Modeling of Idaho Power Hydropower System**

| CY | Brownlee April–July Inflow Volume (MAF) | Brownlee Annual Inflow Volume (MAF) | CY | Brownlee April–July Inflow Volume (MAF) | Brownlee Annual Inflow Volume (MAF) |
|---|---|---|---|---|---|
| 1928 | 6.8 | 14.8 | 1967 | 4.9 | 11.3 |
| 1929 | 3.5 | 9.3 | 1968 | 3.5 | 10.8 |
| 1930 | 2.8 | 8.3 | 1969 | 6.9 | 15.4 |
| 1931 | 2.3 | 7.2 | 1970 | 6.3 | 14.9 |
| 1932 | 4.8 | 10.2 | 1971 | 10.4 | 22.9 |
| 1933 | 4.3 | 9.4 | 1972 | 7.8 | 20.2 |
| 1934 | 2.4 | 7.5 | 1973 | 4.0 | 11.3 |
| 1935 | 3.0 | 7.9 | 1974 | 9.7 | 20.1 |
| 1936 | 5.1 | 10.4 | 1975 | 8.2 | 17.6 |
| 1937 | 3.0 | 8.5 | 1976 | 7.3 | 16.3 |
| 1938 | 7.1 | 13.8 | 1977 | 2.2 | 7.8 |
| 1939 | 3.9 | 10.0 | 1978 | 5.2 | 11.9 |
| 1940 | 4.3 | 10.8 | 1979 | 4.0 | 10.8 |
| 1941 | 3.8 | 10.2 | 1980 | 6.1 | 13.2 |
| 1942 | 5.0 | 11.2 | 1981 | 4.4 | 11.5 |
| 1943 | 9.3 | 19.0 | 1982 | 9.4 | 21.2 |
| 1944 | 3.4 | 9.6 | 1983 | 10.0 | 23.6 |
| 1945 | 4.9 | 11.7 | 1984 | 11.4 | 24.4 |
| 1946 | 6.9 | 15.5 | 1985 | 5.5 | 13.5 |
| 1947 | 5.3 | 12.5 | 1986 | 8.4 | 20.6 |
| 1948 | 5.9 | 12.6 | 1987 | 3.0 | 9.2 |
| 1949 | 5.4 | 12.5 | 1988 | 2.7 | 7.9 |
| 1950 | 6.6 | 14.8 | 1989 | 4.4 | 10.7 |
| 1951 | 6.6 | 16.2 | 1990 | 3.1 | 8.6 |
| 1952 | 10.4 | 19.3 | 1991 | 2.9 | 8.2 |
| 1953 | 6.1 | 13.7 | 1992 | 2.0 | 6.8 |
| 1954 | 5.6 | 12.6 | 1993 | 6.3 | 13.0 |
| 1955 | 3.5 | 9.9 | 1994 | 2.8 | 8.5 |
| 1956 | 7.9 | 17.6 | 1995 | 6.9 | 14.2 |
| 1957 | 7.9 | 16.2 | 1996 | 8.3 | 19.1 |
| 1958 | 7.5 | 15.2 | 1997 | 10.1 | 24.0 |
| 1959 | 3.9 | 10.4 | 1998 | 8.6 | 17.6 |
| 1960 | 4.3 | 10.8 | 1999 | 7.9 | 17.8 |
| 1961 | 3.2 | 8.7 | 2000 | 4.6 | 12.1 |
| 1962 | 4.9 | 11.1 | 2001 | 2.6 | 7.8 |
| 1963 | 4.7 | 11.6 | 2002 | 3.5 | 8.8 |
| 1964 | 5.8 | 13.1 | 2003 | 3.7 | 9.2 |
| 1965 | 8.5 | 20.0 | 2004 | 3.2 | 8.8 |
| 1966 | 3.6 | 9.9 | 2005 | 3.6 | 8.8 |

Note: Based on Idaho Department of Water Resources computed Snake River Basin record for 1928–2005.




Normalized Monthly Wind Energy Distri

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | 43 | 48 | 22 | 22 | 18 | 17 | 21 | 28 | 32 | 32 | 42 | 36 |
| A | Dec | Nov | Oct | Sep | Aug | Jul | Jun | May | Apr | Mar | Feb | Jan |
| Ar | | | | | | | | | | | | |

Estimated Monthly Output (aMW)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.00 | 1.43 | 1.59 | 0.74 | 0.72 | 0.61 | 0.56 | 0.71 | 0.94 | 1.05 | 1.07 | 1.39 | 1.19 |
| A | Dec | Nov | Oct | Sep | Aug | Jul | Jun | May | Apr | Mar | Feb | Jan |
| Ar | | | | | | | | | | | | |

Normalized Monthly Wind Energy Distri

| | |
|---|---|
| 30 | Flat M |
| 30% | Annual Ca |
| 100 | Project Size (M |

Monthly Wind Distribution Pro

# DEMAND-SIDE RESOURCE DATA

## Cost-Effectiveness

Most of Idaho Power's energy efficiency programs are preliminarily identified through the integrated resource planning process. A change for the *2009 Integrated Resource Plan* IRP is that a majority of the anticipated new energy efficiency future commitments come through additional measures added into existing programs as opposed to new program offerings.

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power primarily uses the Total Resource Cost (TRC) test and the Utility Cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs.

In the IRP process, specific programs or potential energy savings are screened by sector to determine if the levelized cost of the potential programs is less than supply-side resource alternatives. If the DSM programs are shown to be less costly than supply-side resources as measured by the levelized cost, the potential program is included in the resource plan. Generally, the hourly shaped energy savings are used to compare DSM programs with other supply-side and transmission alternatives.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power creates cost-effectiveness models to assess whether a specific potential program design will be cost-effective from the perspective of Idaho Power and its customers. Incorporated into the cost-effectiveness models are inputs from various sources in order to use the most current and reliable information available. Idaho Power uses a cost-effectiveness model to perform sensitivity analyses in order to determine the appropriate program design. The remaining inputs used in the cost-effectiveness models are obtained from the IRP process.

When possible, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff.

Idaho Power also uses electric industry research organizations, such as E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA), Association of Energy Service Professionals (AESP), Energy Insights, and others, to identify similar programs and expected results. For other assumptions, including estimated costs, savings, and net-to-gross ratio estimates, Idaho Power relies on sources, such as the Northwest Power and Conservation Council (NPCC), the Regional Technical Forum (RTF), Northwest Energy Efficiency Alliance (NEEA), E Source, the Database for Energy Efficiency Resources (DEER), the Energy Trust of Oregon (ETO), Bonneville Power Administration (BPA), third-party consultants, and other regional utilities.

The financial assumptions used in the analysis are consistent with the 2009 IRP, including the discount rate and inflation rate. The IRP is also the source of the DSM alternative costs, which is the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit or forward market prices as determined by the AURORAxmp® Electric Market Model. The avoided capital cost is based on a 170 MW natural gas-fired, simple-cycle combustion turbine.

Idaho Power relies on the Electric Power Research Institute End Use Technical Assessment Guide (TAG) and the California Standard Practice Manual for the cost-effectiveness methodology. As defined in the TAG and California Standard Practice Manual, the TRC and UC tests are most similar to supply-side tests and provide a useful basis to compare demand-side and supply-side resources.

Idaho Power determines cost-effectiveness on a program basis and on a measure-by-measure basis where applicable. To be consistent with the IRP, demand response program B/C ratios for the residential A/C Cool Credit, Irrigation Peak Rewards, and the commercial and industrial FlexPeak program are calculated over a 20-year period. In order for a program to be considered cost-effective, the program must have B/C ratios greater than one for both the TRC and UC tests.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be reexamined after program implementation.

## Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AuroraAxmp model. The Preferred Portfolio module takes into consideration the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward electric market prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy and light load pricing throughout each year of the planning period. The resulting categories are:

- *Summer On-Peak (SONP)*—Average of Idaho Power variable energy and operating costs of a 170 MW simple-cycle combustion turbine, which is the marginal resource for peak hour load deficits during summertime heavy load hours

- *Summer Mid-Peak (SMP)*—Average of heavy load prices from June through August

- *Summer Off-Peak (SOFP)*—Average of light load prices from June through August

- *Non-Summer Mid-Peak (NSMP)*—Average of heavy load prices in January through May and September through December

- *Non-Summer Off-Peak (NSOFP)*—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods. During the SONP, additional purchases from the regional power market are not an option due to currently existing transmission constraints. The marginal resource Idaho Power is trying to avoid with DSM efforts for SONP hours is the construction of simple-cycle combustion turbine. The estimated levelized capacity cost of building a new simple-cycle combustion turbine is approximately $63/kW over a 30-year expected plant life. For demand response or direct load control DSM programs operating during the summer peak, the $63/kW becomes the cost threshold for program cost-effectiveness.

The avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours. The total SONP vary between 512 to 528 hours depending on the calendar. Table DSM-1 lists the financial assumptions used for the cost effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward energy prices over the 20-year planning period that were used to screen new energy efficiency and demand response programs for cost-effectiveness. The cost-effectiveness analysis for measures that have a life longer than 20 years, which is typical for weatherization and building shell measures, prices are escalated at three percent.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 through DSM-7 show the forecast impact of energy efficiency by customer class for existing programs, new energy efficiency commitments, and the total combined impact.

Table DSM-8 shows the annual forecast of utility costs or the costs to administer the new programs and measures to meet the forecast new energy efficiency amounts.

Table DSM-9 shows the 20-year flow of resource costs that combines the program participant costs with the costs to administer the program.

Table DSM-10 outlines the 20-year flow of avoided generation and the benefits attributed to energy efficiency programs.

Table DSM-11 summarizes the cost-effectiveness analysis for new programs and measures through the 20-year IRP planning period.

Table DSM-12 shows the annual forecast impact from all demand response programs.

Tables DSM-13 through DSM-15 show the 20-year flow of utility costs, total resource costs, and value of avoided generation for demand response programs, similar to those presented for new energy efficiency programs.

Table DSM-16 summarizes the cost-effectiveness for demand response programs and the forecast impact through the IRP planning horizon.

**Table DSM-1. IRP Financials**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided Capacity Costs** | |
| Simple-Cycle Combined Turbine | $63/kW |
| **Financial Assumptions** | |
| Weighted Average Cost of Capital (2008 Year Ending After Tax) | 6.98% |
| Financial Escalation Factor | 3.00% |
| **Transmission Losses** | |
| Non-summer Secondary Losses | 10.90% |
| Summer Peak Loss | 13.00% |

**Table DSM-2. DSM Alternate Costs by Pricing Period**

| Year | Summer On-Peak (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2010 | $61.23 | $45.22 | $33.70 | $46.50 | $34.94 |
| 2011 | $71.70 | $53.51 | $40.04 | $55.00 | $42.05 |
| 2012 | $98.56 | $83.99 | $73.25 | $84.85 | $72.70 |
| 2013 | $103.52 | $85.83 | $76.66 | $84.95 | $73.38 |
| 2014 | $105.93 | $88.03 | $78.54 | $87.74 | $75.23 |
| 2015 | $107.21 | $90.65 | $80.59 | $91.35 | $77.69 |
| 2016 | $108.48 | $93.77 | $82.08 | $93.03 | $79.60 |
| 2017 | $111.77 | $95.65 | $84.94 | $95.19 | $82.20 |
| 2018 | $114.49 | $97.48 | $86.37 | $97.66 | $84.64 |
| 2019 | $117.51 | $100.97 | $88.40 | $99.54 | $86.87 |
| 2020 | $121.19 | $102.07 | $89.30 | $101.54 | $89.17 |
| 2021 | $124.46 | $104.48 | $91.76 | $104.64 | $91.87 |
| 2022 | $126.83 | $108.43 | $95.56 | $109.05 | $95.67 |
| 2023 | $132.46 | $111.36 | $98.73 | $111.23 | $98.70 |
| 2024 | $135.69 | $113.45 | $100.73 | $114.15 | $101.27 |
| 2025 | $138.67 | $117.06 | $104.45 | $117.50 | $104.31 |
| 2026 | $141.54 | $120.25 | $107.38 | $121.00 | $107.28 |
| 2027 | $144.00 | $122.37 | $109.98 | $123.58 | $110.04 |
| 2028 | $146.24 | $126.81 | $113.72 | $126.09 | $112.90 |

[1]Estimated variable operations and management costs of a 170 MW capacity simple-cycle combined turbine.

**Table DSM-3. DSM Alternate Cost Summer Pricing Periods (June 1 to August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM Alternate Costs Non-Summer Pricing Periods (September 1 to May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. DSM Existing Energy Efficiency Forecast 2010–2029 (aMW with transmission losses)**

| Year | Industrial | Commercial | Irrigation | Residential | Total |
|---|---|---|---|---|---|
| 2010 | 4.9 | 5.3 | 1.3 | 2.7 | 14.2 |
| 2011 | 9.7 | 11.0 | 2.5 | 4.5 | 27.8 |
| 2012 | 14.2 | 17.2 | 3.7 | 6.0 | 41.1 |
| 2013 | 18.6 | 23.4 | 4.7 | 7.5 | 54.2 |
| 2014 | 23.0 | 29.7 | 5.6 | 9.0 | 67.3 |
| 2015 | 27.5 | 35.9 | 6.2 | 10.3 | 79.8 |
| 2016 | 31.9 | 42.1 | 6.9 | 11.5 | 92.4 |
| 2017 | 36.3 | 48.4 | 7.5 | 12.8 | 105.0 |
| 2018 | 40.8 | 54.6 | 8.2 | 14.0 | 117.6 |
| 2019 | 45.2 | 60.8 | 8.9 | 15.3 | 130.1 |
| 2020 | 49.6 | 67.0 | 9.5 | 16.5 | 142.7 |
| 2021 | 54.1 | 73.3 | 10.2 | 17.8 | 155.3 |
| 2022 | 58.5 | 79.5 | 10.8 | 19.0 | 167.9 |
| 2023 | 62.9 | 85.7 | 11.5 | 20.3 | 180.4 |
| 2024 | 67.4 | 92.0 | 12.2 | 21.6 | 193.0 |
| 2025 | 71.8 | 98.2 | 12.8 | 22.8 | 205.6 |
| 2026 | 76.2 | 104.4 | 13.5 | 24.1 | 218.2 |
| 2027 | 80.6 | 110.6 | 14.1 | 25.3 | 230.7 |
| 2028 | 85.1 | 116.9 | 14.8 | 26.6 | 243.3 |
| 2029 | 89.5 | 123.1 | 15.4 | 27.8 | 255.9 |

**Table DSM-6. New 2009 IRP Energy Efficiency Resources 2010–2029 (aMW with transmission losses)**

| Year | Residential | Commercial | Industrial | Total |
|---|---|---|---|---|
| 2010 | 0.9 | 0.9 | 1.0 | 2.8 |
| 2011 | 2.1 | 1.8 | 3.1 | 7.0 |
| 2012 | 3.4 | 2.9 | 6.1 | 12.4 |
| 2013 | 4.9 | 4.0 | 9.3 | 18.2 |
| 2014 | 6.4 | 5.3 | 12.7 | 24.4 |
| 2015 | 8.0 | 6.6 | 16.2 | 30.8 |
| 2016 | 9.6 | 8.0 | 19.9 | 37.5 |
| 2017 | 11.3 | 9.5 | 23.5 | 44.3 |
| 2018 | 12.9 | 11.1 | 27.3 | 51.3 |
| 2019 | 14.6 | 12.8 | 31.0 | 58.4 |
| 2020 | 16.3 | 14.5 | 34.9 | 65.7 |
| 2021 | 17.7 | 16.4 | 38.8 | 72.9 |
| 2022 | 19.2 | 18.3 | 42.7 | 80.2 |
| 2023 | 20.7 | 20.2 | 46.7 | 87.6 |
| 2024 | 22.2 | 22.3 | 50.8 | 95.3 |
| 2025 | 23.7 | 24.4 | 54.9 | 103.0 |
| 2026 | 25.3 | 26.7 | 59.0 | 110.9 |
| 2027 | 26.9 | 29.0 | 63.2 | 119.0 |
| 2028 | 28.5 | 31.3 | 67.4 | 127.2 |
| 2029 | 28.5 | 31.3 | 67.4 | 127.2 |

**Table DSM-7. Total Energy Efficiency Forecasted Impact Existing and New 2010–2029 (aMW with transmission losses)**

| Year | Industrial | Commercial | Irrigation | Residential | Total |
|---|---|---|---|---|---|
| 2010 | 5.5 | 5.6 | 1.1 | 3.3 | 15.5 |
| 2011 | 12.9 | 12.8 | 2.5 | 6.6 | 34.8 |
| 2012 | 20.3 | 20.1 | 3.7 | 9.5 | 53.5 |
| 2013 | 27.9 | 27.5 | 4.7 | 12.4 | 72.5 |
| 2014 | 35.7 | 35.0 | 5.6 | 15.4 | 91.7 |
| 2015 | 43.7 | 42.5 | 6.2 | 18.2 | 110.7 |
| 2016 | 51.8 | 50.2 | 6.9 | 21.1 | 129.9 |
| 2017 | 59.9 | 57.9 | 7.5 | 24.0 | 149.3 |
| 2018 | 68.0 | 65.7 | 8.2 | 26.9 | 168.9 |
| 2019 | 76.2 | 73.6 | 8.9 | 29.9 | 188.6 |
| 2020 | 84.5 | 81.6 | 9.5 | 32.8 | 208.4 |
| 2021 | 92.8 | 89.6 | 10.2 | 35.5 | 228.2 |
| 2022 | 101.2 | 97.7 | 10.8 | 38.2 | 248.0 |
| 2023 | 109.6 | 106.0 | 11.5 | 41.0 | 268.1 |
| 2024 | 118.1 | 114.2 | 12.2 | 43.7 | 288.3 |
| 2025 | 126.6 | 122.6 | 12.8 | 46.5 | 308.6 |
| 2026 | 135.2 | 131.1 | 13.5 | 49.4 | 329.1 |
| 2027 | 143.8 | 139.6 | 14.1 | 52.2 | 349.7 |
| 2028 | 152.5 | 148.2 | 14.8 | 55.1 | 370.5 |
| 2029 | 156.9 | 154.4 | 15.4 | 56.3 | 383.1 |

**Table DSM-8. New Energy Efficiency Utility Costs 2010–2029**

| Year | Residential | Commercial | Industrial | Total All Sectors |
|---|---|---|---|---|
| 2010 | $2,185,803 | $859,845 | $1,297,023 | $4,342,671 |
| 2011 | $3,060,477 | $969,777 | $3,319,561 | $7,349,814 |
| 2012 | $3,508,588 | $1,067,687 | $4,314,247 | $8,890,522 |
| 2013 | $3,811,045 | $1,158,161 | $4,446,834 | $9,416,040 |
| 2014 | $4,058,383 | $1,243,199 | $4,658,622 | $9,960,205 |
| 2015 | $4,267,066 | $1,325,522 | $4,841,031 | $10,433,618 |
| 2016 | $4,406,327 | $1,405,619 | $4,871,784 | $10,683,730 |
| 2017 | $4,546,267 | $1,484,206 | $4,939,369 | $10,969,841 |
| 2018 | $4,672,279 | $1,561,790 | $5,011,687 | $11,245,755 |
| 2019 | $4,768,785 | $1,638,743 | $5,080,622 | $11,488,151 |
| 2020 | $4,867,634 | $1,715,345 | $5,146,344 | $11,729,324 |
| 2021 | $4,481,009 | $1,791,806 | $5,195,678 | $11,468,493 |
| 2022 | $4,584,723 | $1,868,290 | $5,269,358 | $11,722,371 |
| 2023 | $4,690,963 | $1,944,923 | $5,330,311 | $11,966,196 |
| 2024 | $4,799,793 | $2,021,803 | $5,376,699 | $12,198,295 |
| 2025 | $4,911,279 | $2,099,010 | $5,438,122 | $12,448,410 |
| 2026 | $5,025,489 | $2,176,602 | $5,496,960 | $12,699,051 |
| 2027 | $5,142,493 | $2,254,627 | $5,536,118 | $12,933,238 |
| 2028 | $5,262,362 | $2,333,121 | $5,594,501 | $13,189,985 |
| 2029 | $0 | $0 | $0 | $0 |
| **20-Year NPV** | **$42,646,505** | **$15,206,640** | **$46,583,003** | **$104,436,148** |

**Table DSM-9. New Energy Efficiency Total Resource Costs 2010–2029**

| Year | Residential | Commercial | Industrial | Total All Sectors |
|---|---|---|---|---|
| 2010 | $2,357,175 | $3,636,527 | $1,711,236 | $7,704,938 |
| 2011 | $3,639,396 | $4,162,005 | $4,382,424 | $12,183,825 |
| 2012 | $4,212,132 | $4,635,110 | $5,698,932 | $14,546,174 |
| 2013 | $4,594,083 | $5,075,432 | $5,877,320 | $15,546,835 |
| 2014 | $4,904,362 | $5,492,750 | $6,160,444 | $16,557,556 |
| 2015 | $5,166,365 | $5,896,996 | $6,404,797 | $17,468,157 |
| 2016 | $5,339,158 | $6,291,431 | $6,448,457 | $18,079,045 |
| 2017 | $5,512,736 | $6,679,287 | $6,540,755 | $18,732,777 |
| 2018 | $5,668,296 | $7,062,878 | $6,639,234 | $19,370,408 |
| 2019 | $5,785,396 | $7,443,906 | $6,733,149 | $19,962,451 |
| 2020 | $5,905,291 | $7,823,649 | $6,822,723 | $20,551,663 |
| 2021 | $5,395,175 | $8,203,079 | $6,890,478 | $20,488,732 |
| 2022 | $5,520,874 | $8,582,945 | $6,990,439 | $21,094,258 |
| 2023 | $5,649,585 | $8,963,830 | $7,073,439 | $21,686,855 |
| 2024 | $5,781,384 | $9,346,187 | $7,137,028 | $22,264,599 |
| 2025 | $5,916,347 | $9,730,368 | $7,220,494 | $22,867,209 |
| 2026 | $6,054,554 | $10,116,647 | $7,300,456 | $23,471,657 |
| 2027 | $6,196,088 | $10,505,234 | $7,354,203 | $24,055,525 |
| 2028 | $6,341,030 | $10,896,288 | $7,433,417 | $24,670,736 |
| 2029 | $0 | $0 | $0 | $0 |
| **20-Year NPV** | **$51,412,498** | **$68,482,366** | **$61,693,447** | **$181,588,312** |

**Table DSM-10. New Energy Efficiency Resource Avoided Energy Costs 2010–2029**

| Year | Residential | Commercial | Industrial | Total All Sectors |
|---|---|---|---|---|
| 2010 | $3,709,589 | $5,626,728 | $6,044,209 | $15,380,526 |
| 2011 | $6,188,004 | $6,805,914 | $16,575,769 | $29,569,686 |
| 2012 | $8,371,989 | $7,983,345 | $22,875,049 | $39,230,383 |
| 2013 | $9,735,242 | $8,899,982 | $24,155,131 | $42,790,356 |
| 2014 | $10,921,698 | $9,823,463 | $25,955,488 | $46,700,648 |
| 2015 | $12,019,828 | $10,765,480 | $27,660,310 | $50,445,619 |
| 2016 | $12,895,163 | $11,721,993 | $28,532,458 | $53,149,614 |
| 2017 | $13,807,371 | $12,710,756 | $29,672,368 | $56,190,494 |
| 2018 | $14,673,960 | $13,730,128 | $30,880,008 | $59,284,096 |
| 2019 | $15,459,304 | $14,790,279 | $32,112,014 | $62,361,597 |
| 2020 | $16,257,717 | $15,899,087 | $33,376,505 | $65,533,308 |
| 2021 | $17,119,736 | $17,068,181 | $34,601,987 | $68,789,905 |
| 2022 | $18,070,545 | $18,292,292 | $36,035,764 | $72,398,601 |
| 2023 | $18,998,401 | $19,550,317 | $37,398,739 | $75,947,457 |
| 2024 | $19,943,721 | $20,866,846 | $38,707,298 | $79,517,864 |
| 2025 | $20,959,811 | $22,253,164 | $40,189,732 | $83,402,707 |
| 2026 | $22,003,968 | $23,702,308 | $41,703,823 | $87,410,099 |
| 2027 | $23,035,571 | $25,219,078 | $43,124,470 | $91,379,118 |
| 2028 | $24,124,351 | $26,825,849 | $44,782,746 | $95,732,947 |
| 2029 | $24,876,318 | $26,875,246 | $44,782,746 | $96,534,310 |
| **20-Year NPV** | **$142,492,125** | **$143,365,937** | **$301,075,029** | **$586,933,090** |

**Table DSM-11. New Energy Efficiency Cost Effectiveness Summary**

| | Impact | | 20-Year NPV Costs | | | Utility Costs | | Total Resource Costs | |
|---|---|---|---|---|---|---|---|---|---|
| | 2029 Load (aMW) | 20-Year Energy (kWh) | Utility | Resource | Avoided Energy | Benefit/Cost Ratio | Levelized ($/kWh) | Benefit/Cost Ratio | Levelized ($/kWh) |
| Residential | 29 | 1,096,775,152 | $42,646,505 | $51,412,498 | $142,492,125 | 3.3 | $0.039 | 2.8 | $0.047 |
| Commercial | 31 | 1,042,951,839 | $15,206,640 | $68,482,366 | $143,365,937 | 9.4 | $0.015 | 2.1 | $0.066 |
| Industrial | 67 | 2,391,084,888 | $46,583,003 | $61,693,447 | $301,075,029 | 6.5 | $0.019 | 4.9 | $0.026 |
| **Total** | **127** | **4,530,811,879** | **$104,436,148** | **$181,588,312** | **$586,933,090** | **5.6** | **$0.023** | **3.2** | **$0.040** |

**Table DSM-12. Total Existing and New Demand Response Forecasted Impacts 2010–2029 (MW with transmission losses)**

| Year | Residential | Irrigation | Commercial | Total |
|---|---|---|---|---|
| 2010 | 50.6 | 220.0 | 39.6 | 310.2 |
| 2011 | 50.6 | 250.0 | 45.2 | 345.8 |
| 2012 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2013 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2014 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2015 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2016 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2017 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2018 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2019 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2020 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2021 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2022 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2023 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2024 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2025 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2026 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2027 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2028 | 50.6 | 260.0 | 56.5 | 367.1 |
| 2029 | 50.6 | 260.0 | 56.5 | 367.1 |

**Table DSM-13. Demand Response Utility Costs 2010–2029**

| Year | Residential | Commercial/Industrial | Irrigation | Total All Sectors |
|---|---|---|---|---|
| 2010 | $3,520,710 | $2,081,025 | $10,799,032 | $16,400,767 |
| 2011 | $1,352,143 | $2,760,783 | $11,038,020 | $15,150,946 |
| 2012 | $1,396,152 | $3,415,100 | $11,223,562 | $16,034,815 |
| 2013 | $1,371,927 | $3,448,853 | $11,247,225 | $16,068,005 |
| 2014 | $1,417,031 | $3,482,066 | $11,274,667 | $16,173,763 |
| 2015 | $1,760,923 | $3,489,626 | $11,306,566 | $16,557,115 |
| 2016 | $1,817,247 | $3,498,355 | $11,343,682 | $16,659,284 |
| 2017 | $1,813,491 | $3,507,347 | $11,368,382 | $16,689,220 |
| 2018 | $1,872,482 | $3,516,609 | $11,456,834 | $16,845,925 |
| 2019 | $1,869,268 | $3,526,148 | $11,434,099 | $16,829,515 |
| 2020 | $1,967,417 | $3,535,973 | $11,451,335 | $16,954,725 |
| 2021 | $2,000,416 | $3,546,093 | $11,482,018 | $17,028,527 |
| 2022 | $2,105,980 | $3,556,517 | $11,528,664 | $17,191,161 |
| 2023 | $2,141,187 | $3,567,254 | $11,565,121 | $17,273,562 |
| 2024 | $2,252,091 | $3,578,312 | $11,593,138 | $17,423,542 |
| 2025 | $2,289,700 | $3,589,703 | $11,636,912 | $17,516,315 |
| 2026 | $2,407,865 | $3,601,435 | $11,676,627 | $17,685,927 |
| 2027 | $2,446,881 | $3,613,519 | $11,705,625 | $17,766,024 |
| 2028 | $2,572,782 | $3,625,966 | $11,840,660 | $18,039,408 |
| 2029 | $2,614,977 | $3,638,786 | $11,840,660 | $18,094,423 |
| **20-Year NPV** | **$21,020,406** | **$35,339,272** | **$120,389,467** | **$176,749,144** |

**Table DSM-14. Demand Response Total Resource Costs 2010–2029**

| Year | Residential | Commercial/Industrial | Irrigation | Total All Sectors |
|---|---|---|---|---|
| 2010 | $3,520,710 | $2,081,025 | $10,799,032 | $16,400,767 |
| 2011 | $1,352,143 | $2,760,783 | $11,038,020 | $15,150,946 |
| 2012 | $1,396,152 | $3,415,100 | $11,223,562 | $16,034,815 |
| 2013 | $1,371,927 | $3,448,853 | $11,247,225 | $16,068,005 |
| 2014 | $1,417,031 | $3,482,066 | $11,274,667 | $16,173,763 |
| 2015 | $1,760,923 | $3,489,626 | $11,306,566 | $16,557,115 |
| 2016 | $1,817,247 | $3,498,355 | $11,343,682 | $16,659,284 |
| 2017 | $1,813,491 | $3,507,347 | $11,368,382 | $16,689,220 |
| 2018 | $1,872,482 | $3,516,609 | $11,456,834 | $16,845,925 |
| 2019 | $1,869,268 | $3,526,148 | $11,434,099 | $16,829,515 |
| 2020 | $1,967,417 | $3,535,973 | $11,451,335 | $16,954,725 |
| 2021 | $2,000,416 | $3,546,093 | $11,482,018 | $17,028,527 |
| 2022 | $2,105,980 | $3,556,517 | $11,528,664 | $17,191,161 |
| 2023 | $2,141,187 | $3,567,254 | $11,565,121 | $17,273,562 |
| 2024 | $2,252,091 | $3,578,312 | $11,593,138 | $17,423,542 |
| 2025 | $2,289,700 | $3,589,703 | $11,636,912 | $17,516,315 |
| 2026 | $2,407,865 | $3,601,435 | $11,676,627 | $17,685,927 |
| 2027 | $2,446,881 | $3,613,519 | $11,705,625 | $17,766,024 |
| 2028 | $2,572,782 | $3,625,966 | $11,840,660 | $18,039,408 |
| 2029 | $2,614,977 | $3,638,786 | $11,840,660 | $18,094,423 |
| **20-Year NPV** | **$21,020,406** | **$35,339,272** | **$120,389,467** | **$176,749,144** |

**Table DSM-15. Demand Response Avoided Capacity Costs 2010–2029**

| Year | Residential | Commercial/Industrial | Irrigation | Total All Sectors |
|---|---|---|---|---|
| 2010 | $3,108,304 | $2,636,945 | $16,262,282 | $22,107,531 |
| 2011 | $3,117,340 | $3,042,059 | $17,125,711 | $23,285,110 |
| 2012 | $3,140,508 | $3,893,616 | $17,405,016 | $24,439,140 |
| 2013 | $3,144,787 | $3,910,432 | $17,456,605 | $24,511,824 |
| 2014 | $3,146,863 | $3,918,590 | $17,481,633 | $24,547,086 |
| 2015 | $3,147,966 | $3,922,926 | $17,494,936 | $24,565,828 |
| 2016 | $3,149,066 | $3,927,247 | $17,508,191 | $24,584,503 |
| 2017 | $3,151,905 | $3,938,404 | $17,542,418 | $24,632,727 |
| 2018 | $3,154,249 | $3,947,614 | $17,570,675 | $24,672,538 |
| 2019 | $3,156,852 | $3,957,844 | $17,602,057 | $24,716,752 |
| 2020 | $3,160,032 | $3,970,342 | $17,640,402 | $24,770,776 |
| 2021 | $3,162,847 | $3,981,405 | $17,674,340 | $24,818,592 |
| 2022 | $3,164,891 | $3,989,438 | $17,698,985 | $24,853,315 |
| 2023 | $3,169,750 | $4,008,532 | $17,757,562 | $24,935,844 |
| 2024 | $3,172,541 | $4,019,498 | $17,791,203 | $24,983,242 |
| 2025 | $3,175,111 | $4,029,598 | $17,822,188 | $25,026,896 |
| 2026 | $3,177,585 | $4,039,320 | $17,852,014 | $25,068,919 |
| 2027 | $3,179,706 | $4,047,657 | $17,877,590 | $25,104,953 |
| 2028 | $3,181,640 | $4,055,256 | $17,900,902 | $25,137,798 |
| 2029 | $3,185,424 | $4,070,128 | $17,900,902 | $25,156,455 |
| **20-Year NPV** | **$33,417,991** | **$39,982,107** | **$185,238,997** | **$258,639,09** |

**Table DSM-16. Demand Response Cost-Effectiveness Summary**

| | Impact | | 20-Year NPV Costs | | | Total Resource Costs | |
|---|---|---|---|---|---|---|---|
| | 2029 Load (aMW) | 20-Year Energy (kWh) | Utility | Resource | Avoided Energy | Benefit/Cost Ratio | Levelized ($/kWh) |
| Residential | 51 | 555,495 | $21,020,406 | $21,020,406 | $33,417,991 | 1.6 | $38 |
| Commercial/Industrial | 56 | 573,775 | $35,339,272 | $35,339,272 | $39,982,107 | 1.1 | $62 |
| Irrigation | 260 | 2,748,954 | $120,389,467 | $120,389,467 | $185,238,997 | 1.5 | $44 |
| **Total** | **367** | **3,878,225** | **$176,749,144** | **$176,749,144** | **$258,639,094** | **1.5** | **$46** |

| Monthly Average Energy | 2010 | | | | | | | | | | | | 2011 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-10** | **Feb-10** | **Mar-10** | **Apr-10** | **May-10** | **Jun-10** | **Jul-10** | **Aug-10** | **Sep-10** | **Oct-10** | **Nov-10** | **Dec-10** | **Jan-11** | **Feb-11** | **Mar-11** | **Apr-11** | **May-11** | **Jun-11** | **Jul-11** | **Aug-11** | **Sep-11** | **Oct-11** | **Nov-11** | **Dec-11** |
| **Load Forecast (70th%)—Aug 2009** | (1,857) | (1,743) | (1,546) | (1,526) | (1,724) | (2,143) | (2,426) | (2,242) | (1,853) | (1,538) | (1,671) | (1,985) | (1,966) | (1,845) | (1,641) | (1,621) | (1,811) | (2,232) | (2,515) | (2,328) | (1,930) | (1,602) | (1,741) | (2,049) |
| Existing DSM (Energy Efficiency) | 13 | 13 | 13 | 14 | 15 | 16 | 17 | 16 | 14 | 13 | 13 | 13 | 25 | 25 | 25 | 26 | 30 | 33 | 33 | 32 | 28 | 26 | 25 | 25 |
| **Load Forecast (70th%) w/Existing DSM** | (1,844) | (1,730) | (1,533) | (1,512) | (1,709) | (2,126) | (2,409) | (2,226) | (1,838) | (1,525) | (1,658) | (1,972) | (1,941) | (1,820) | (1,616) | (1,595) | (1,781) | (2,200) | (2,482) | (2,296) | (1,902) | (1,577) | (1,716) | (2,024) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 919 | 919 | 861 | 628 | 587 | 919 | 924 | 924 | 924 | 922 | 924 | 924 | 924 | 924 | 924 | 685 | 712 | 905 | 928 | 928 | 928 | 927 | 928 | 928 |
| Hydro (70th%)—HCC | 610 | 598 | 620 | 697 | 848 | 667 | 477 | 378 | 425 | 434 | 364 | 475 | 669 | 532 | 620 | 697 | 848 | 667 | 477 | 378 | 425 | 434 | 363 | 475 |
| Hydro (70th%)—Other | 221 | 296 | 250 | 248 | 329 | 341 | 252 | 248 | 240 | 227 | 210 | 216 | 221 | 296 | 250 | 248 | 328 | 340 | 252 | 247 | 240 | 227 | 210 | 215 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 831 | 894 | 870 | 945 | 1,177 | 1,008 | 801 | 626 | 665 | 661 | 574 | 691 | 890 | 828 | 869 | 945 | 1,176 | 1,007 | 800 | 625 | 664 | 661 | 574 | 690 |
| **CSPP (PURPA)** | 64 | 68 | 67 | 92 | 137 | 146 | 145 | 136 | 117 | 119 | 112 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 48 | 48 | 46 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 45 | 48 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 29 | 28 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 42 | 42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 42 | 42 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 95 | 166 | 159 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 95 | 134 | 133 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 270 | 325 | 238 | 310 | 301 | 241 | 123 | 187 | 177 | 44 | 364 | 309 | 342 | 389 | 372 | 387 | 343 | 237 | 117 | 183 | 175 | 127 | 363 | 307 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | **2,350** | **2,249** | **2,079** | **2,019** | **2,242** | **2,648** | **2,391** | **2,264** | **1,920** | **1,791** | **2,016** | **2,330** | **2,525** | **2,302** | **2,334** | **2,206** | **2,455** | **2,678** | **2,384** | **2,281** | **1,966** | **1,899** | **2,022** | **2,332** |
| **Monthly Surplus/Deficit** | **506** | **518** | **546** | **507** | **533** | **522** | **(19)** | **38** | **82** | **266** | **358** | **358** | **584** | **482** | **718** | **611** | **674** | **478** | **(98)** | **(15)** | **65** | **322** | **306** | **308** |

| **2006 IRP Resources** | **Jan-10** | **Feb-10** | **Mar-10** | **Apr-10** | **May-10** | **Jun-10** | **Jul-10** | **Aug-10** | **Sep-10** | **Oct-10** | **Nov-10** | **Dec-10** | **Jan-11** | **Feb-11** | **Mar-11** | **Apr-11** | **May-11** | **Jun-11** | **Jul-11** | **Aug-11** | **Sep-11** | **Oct-11** | **Nov-11** | **Dec-11** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Langley Gulch | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **506** | **518** | **546** | **507** | **533** | **522** | **(19)** | **38** | **82** | **266** | **358** | **358** | **584** | **482** | **718** | **611** | **674** | **478** | **(98)** | **(15)** | **65** | **322** | **306** | **308** |

| **2009 IRP DSM** | **Jan-10** | **Feb-10** | **Mar-10** | **Apr-10** | **May-10** | **Jun-10** | **Jul-10** | **Aug-10** | **Sep-10** | **Oct-10** | **Nov-10** | **Dec-10** | **Jan-11** | **Feb-11** | **Mar-11** | **Apr-11** | **May-11** | **Jun-11** | **Jul-11** | **Aug-11** | **Sep-11** | **Oct-11** | **Nov-11** | **Dec-11** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Industrial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Comercial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Residential | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total New DSM Average Energy** | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **Remaining Monthly Surplus/Deficit** | **509** | **521** | **549** | **510** | **536** | **525** | **(16)** | **41** | **85** | **269** | **361** | **361** | **591** | **489** | **725** | **618** | **681** | **485** | **(91)** | **(8)** | **72** | **329** | **313** | **315** |

| **2009 IRP Resources** | **Jan-10** | **Feb-10** | **Mar-10** | **Apr-10** | **May-10** | **Jun-10** | **Jul-10** | **Aug-10** | **Sep-10** | **Oct-10** | **Nov-10** | **Dec-10** | **Jan-11** | **Feb-11** | **Mar-11** | **Apr-11** | **May-11** | **Jun-11** | **Jul-11** | **Aug-11** | **Sep-11** | **Oct-11** | **Nov-11** | **Dec-11** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **509** | **521** | **549** | **510** | **536** | **525** | **(16)** | **41** | **85** | **269** | **361** | **361** | **591** | **489** | **725** | **618** | **681** | **485** | **(91)** | **(8)** | **72** | **329** | **313** | **315** |

| Monthly Average Energy | 2012 | | | | | | | | | | | | 2013 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Nov-13** | **Dec-13** |
| **Load Forecast (70th%)—Aug 2009** | (2,027) | (1,890) | (1,692) | (1,669) | (1,858) | (2,287) | (2,579) | (2,388) | (1,979) | (1,652) | (1,793) | (2,090) | (2,046) | (1,921) | (1,710) | (1,687) | (1,879) | (2,334) | (2,650) | (2,446) | (2,013) | (1,675) | (1,816) | (2,122) |
| Existing DSM (Energy Efficiency) | 37 | 37 | 37 | 39 | 45 | 48 | 48 | 47 | 42 | 38 | 37 | 37 | 49 | 49 | 49 | 52 | 58 | 63 | 64 | 62 | 55 | 50 | 49 | 50 |
| **Load Forecast (70th%) w/Existing DSM** | (1,990) | (1,853) | (1,655) | (1,630) | (1,814) | (2,239) | (2,531) | (2,341) | (1,937) | (1,615) | (1,756) | (2,053) | (1,997) | (1,872) | (1,661) | (1,635) | (1,821) | (2,270) | (2,587) | (2,385) | (1,957) | (1,625) | (1,767) | (2,073) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 928 | 939 | 898 | 543 | 718 | 881 | 934 | 934 | 934 | 768 | 934 | 934 | 934 | 934 | 833 | 0 | 490 | 934 | 940 | 940 | 766 | 646 | 940 | 940 |
| Hydro (70th%)—HCC | 686 | 511 | 619 | 697 | 848 | 667 | 477 | 377 | 425 | 434 | 363 | 475 | 685 | 514 | 615 | 696 | 848 | 666 | 477 | 377 | 424 | 433 | 364 | 474 |
| Hydro (70th%)—Other | 220 | 296 | 249 | 250 | 328 | 340 | 252 | 247 | 240 | 227 | 210 | 215 | 220 | 296 | 249 | 250 | 328 | 339 | 251 | 246 | 239 | 227 | 210 | 215 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 906 | 807 | 869 | 946 | 1,176 | 1,006 | 800 | 624 | 664 | 661 | 573 | 690 | 905 | 810 | 864 | 946 | 1,176 | 1,006 | 799 | 623 | 664 | 660 | 574 | 689 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 48 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 92 | 91 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 340 | 387 | 396 | 287 | 363 | 233 | 114 | 180 | 172 | 172 | 361 | 305 | 337 | 384 | 449 | 388 | 366 | 229 | 110 | 178 | 170 | 222 | 358 | 302 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | **2,543** | **2,294** | **2,332** | **1,965** | **2,481** | **2,602** | **2,344** | **2,241** | **1,969** | **1,785** | **2,025** | **2,326** | **2,555** | **2,290** | **2,315** | **1,523** | **2,256** | **2,641** | **2,310** | **2,195** | **1,798** | **1,712** | **2,029** | **2,328** |
| **Monthly Surplus/Deficit** | **554** | **441** | **677** | **335** | **667** | **363** | **(187)** | **(100)** | **32** | **170** | **269** | **274** | **558** | **418** | **654** | **(113)** | **435** | **371** | **(277)** | **(189)** | **(159)** | **87** | **262** | **256** |
| **2006 IRP Resources** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Nov-13** | **Dec-13** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 0 | 0 | 0 | 0 | 0 | 0 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **602** | **489** | **725** | **383** | **715** | **411** | **112** | **199** | **331** | **488** | **587** | **592** | **876** | **737** | **972** | **205** | **753** | **689** | **41** | **129** | **159** | **405** | **580** | **574** |
| **2009 IRP DSM** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Nov-13** | **Dec-13** |
| Industrial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 9 | 9 | 9 | 9 |
| Comercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Residential | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 5 | 5 | 5 | 5 |
| **Total New DSM Average Energy** | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| **Remaining Monthly Surplus/Deficit** | **614** | **502** | **737** | **396** | **727** | **423** | **125** | **211** | **343** | **501** | **600** | **604** | **895** | **755** | **991** | **223** | **772** | **707** | **59** | **147** | **177** | **423** | **598** | **592** |
| **2009 IRP Resources** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Nov-13** | **Dec-13** |
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **614** | **502** | **737** | **396** | **727** | **423** | **125** | **211** | **343** | **501** | **600** | **604** | **895** | **755** | **991** | **223** | **772** | **707** | **59** | **147** | **177** | **423** | **598** | **592** |

| Monthly Average Energy | 2014 | | | | | | | | | | | | 2015 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-14** | **Feb-14** | **Mar-14** | **Apr-14** | **May-14** | **Jun-14** | **Jul-14** | **Aug-14** | **Sep-14** | **Oct-14** | **Nov-14** | **Dec-14** | **Jan-15** | **Feb-15** | **Mar-15** | **Apr-15** | **May-15** | **Jun-15** | **Jul-15** | **Aug-15** | **Sep-15** | **Oct-15** | **Nov-15** | **Dec-15** |
| **Load Forecast (70th%)—Aug 2009** | (2,081) | (1,952) | (1,739) | (1,714) | (1,908) | (2,371) | (2,699) | (2,492) | (2,048) | (1,706) | (1,850) | (2,152) | (2,101) | (1,969) | (1,755) | (1,730) | (1,928) | (2,402) | (2,737) | (2,528) | (2,075) | (1,727) | (1,870) | (2,176) |
| Existing DSM (Energy Efficiency) | 61 | 61 | 61 | 64 | 72 | 78 | 79 | 76 | 68 | 62 | 62 | 61 | 73 | 73 | 73 | 76 | 86 | 92 | 93 | 90 | 81 | 74 | 74 | 73 |
| **Load Forecast (70th%) w/Existing DSM** | (2,020) | (1,891) | (1,677) | (1,649) | (1,836) | (2,294) | (2,620) | (2,416) | (1,980) | (1,644) | (1,788) | (2,091) | (2,028) | (1,896) | (1,682) | (1,653) | (1,842) | (2,310) | (2,645) | (2,438) | (1,994) | (1,652) | (1,797) | (2,103) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 940 | 932 | 715 | 0 | 491 | 880 | 940 | 940 | 765 | 646 | 940 | 940 | 938 | 938 | 491 | 490 | 490 | 906 | 938 | 938 | 646 | 444 | 938 | 938 |
| Hydro (70th%)—HCC | 684 | 529 | 597 | 695 | 846 | 665 | 475 | 376 | 423 | 432 | 364 | 472 | 683 | 535 | 588 | 694 | 845 | 664 | 474 | 375 | 422 | 430 | 364 | 471 |
| Hydro (70th%)—Other | 219 | 295 | 248 | 249 | 327 | 338 | 249 | 243 | 238 | 226 | 209 | 213 | 218 | 295 | 247 | 247 | 326 | 336 | 248 | 242 | 237 | 225 | 209 | 213 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 903 | 824 | 845 | 944 | 1,173 | 1,003 | 725 | 619 | 661 | 658 | 573 | 685 | 901 | 830 | 835 | 941 | 1,171 | 1,000 | 722 | 617 | 659 | 655 | 573 | 683 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 335 | 381 | 447 | 390 | 334 | 226 | 106 | 174 | 168 | 322 | 356 | 299 | 202 | 379 | 446 | 290 | 335 | 222 | 103 | 172 | 167 | 214 | 354 | 297 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 233 | 0 | 0 | 0 | 233 | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | **2,557** | **2,299** | **2,175** | **1,523** | **2,222** | **2,581** | **2,231** | **2,178** | **1,793** | **1,809** | **2,026** | **2,330** | **2,420** | **2,309** | **1,941** | **1,910** | **2,220** | **2,609** | **2,223** | **2,172** | **1,671** | **1,497** | **2,022** | **2,325** |
| **Monthly Surplus/Deficit** | **537** | **408** | **498** | **(127)** | **387** | **288** | **(389)** | **(238)** | **(187)** | **166** | **238** | **240** | **392** | **414** | **259** | **256** | **377** | **299** | **(421)** | **(266)** | **(324)** | **(155)** | **225** | **222** |
| **2006 IRP Resources** | **Jan-14** | **Feb-14** | **Mar-14** | **Apr-14** | **May-14** | **Jun-14** | **Jul-14** | **Aug-14** | **Sep-14** | **Oct-14** | **Nov-14** | **Dec-14** | **Jan-15** | **Feb-15** | **Mar-15** | **Apr-15** | **May-15** | **Jun-15** | **Jul-15** | **Aug-15** | **Sep-15** | **Oct-15** | **Nov-15** | **Dec-15** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **855** | **727** | **816** | **191** | **705** | **606** | **(71)** | **80** | **131** | **484** | **556** | **558** | **710** | **732** | **577** | **575** | **695** | **618** | **(103)** | **52** | **(6)** | **163** | **543** | **540** |
| **2009 IRP DSM** | **Jan-14** | **Feb-14** | **Mar-14** | **Apr-14** | **May-14** | **Jun-14** | **Jul-14** | **Aug-14** | **Sep-14** | **Oct-14** | **Nov-14** | **Dec-14** | **Jan-15** | **Feb-15** | **Mar-15** | **Apr-15** | **May-15** | **Jun-15** | **Jul-15** | **Aug-15** | **Sep-15** | **Oct-15** | **Nov-15** | **Dec-15** |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 16 | 16 | 16 | 16 | 16 | 17 | 17 | 17 | 16 | 16 | 16 | 16 |
| Comercial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Residential | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 8 | 8 | 8 | 8 |
| **Total New DSM Average Energy** | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 25 | 24 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| **Remaining Monthly Surplus/Deficit** | **879** | **751** | **841** | **216** | **729** | **630** | **(47)** | **105** | **156** | **508** | **580** | **583** | **741** | **763** | **608** | **605** | **726** | **648** | **(72)** | **83** | **25** | **194** | **575** | **571** |
| **2009 IRP Resources** | **Jan-14** | **Feb-14** | **Mar-14** | **Apr-14** | **May-14** | **Jun-14** | **Jul-14** | **Aug-14** | **Sep-14** | **Oct-14** | **Nov-14** | **Dec-14** | **Jan-15** | **Feb-15** | **Mar-15** | **Apr-15** | **May-15** | **Jun-15** | **Jul-15** | **Aug-15** | **Sep-15** | **Oct-15** | **Nov-15** | **Dec-15** |
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **879** | **751** | **841** | **216** | **729** | **630** | **(47)** | **105** | **156** | **508** | **580** | **583** | **741** | **763** | **608** | **605** | **726** | **898** | **178** | **333** | **275** | **444** | **825** | **824** |

| Monthly Average Energy | 2016 | | | | | | | | | | | | 2017 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| **Load Forecast (70th%)—Aug 2009** | (2,122) | (1,974) | (1,771) | (1,746) | (1,948) | (2,430) | (2,774) | (2,562) | (2,101) | (1,747) | (1,892) | (2,200) | (2,142) | (2,004) | (1,789) | (1,762) | (1,968) | (2,460) | (2,813) | (2,599) | (2,128) | (1,769) | (1,914) | (2,225) |
| Existing DSM (Energy Efficiency) | 85 | 85 | 84 | 88 | 99 | 106 | 107 | 104 | 94 | 87 | 85 | 84 | 97 | 96 | 96 | 101 | 112 | 120 | 121 | 117 | 106 | 99 | 97 | 97 |
| **Load Forecast (70th%) w/Existing DSM** | (2,037) | (1,889) | (1,687) | (1,657) | (1,848) | (2,324) | (2,667) | (2,459) | (2,007) | (1,661) | (1,807) | (2,115) | (2,046) | (1,908) | (1,693) | (1,662) | (1,856) | (2,340) | (2,692) | (2,481) | (2,022) | (1,670) | (1,817) | (2,127) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 947 | 560 | 366 | 418 | 909 | 937 | 937 | 645 | 443 | 937 | 937 | 937 | 937 | 560 | 398 | 298 | 909 | 937 | 937 | 645 | 443 | 882 | 937 |
| Hydro (70th%)—HCC | 682 | 531 | 590 | 693 | 844 | 663 | 473 | 374 | 420 | 429 | 363 | 471 | 681 | 551 | 567 | 692 | 843 | 662 | 472 | 373 | 419 | 427 | 364 | 469 |
| Hydro (70th%)—Other | 218 | 295 | 246 | 246 | 326 | 335 | 246 | 241 | 236 | 225 | 208 | 212 | 217 | 295 | 246 | 245 | 325 | 334 | 245 | 240 | 236 | 224 | 207 | 211 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 899 | 826 | 836 | 939 | 1,170 | 998 | 719 | 615 | 657 | 654 | 571 | 683 | 898 | 846 | 813 | 937 | 1,168 | 996 | 717 | 612 | 655 | 651 | 572 | 681 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 328 | 374 | 444 | 193 | 335 | 215 | 94 | 166 | 162 | 252 | 349 | 294 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 233 | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | **2,535** | **2,311** | **2,010** | **1,881** | **2,148** | **2,608** | **2,206** | **2,175** | **1,665** | **1,514** | **2,016** | **2,321** | **2,531** | **2,319** | **1,985** | **1,716** | **2,025** | **2,601** | **2,199** | **2,169** | **1,660** | **1,529** | **1,959** | **2,309** |
| **Monthly Surplus/Deficit** | **499** | **422** | **323** | **224** | **300** | **284** | **(461)** | **(284)** | **(342)** | **(147)** | **209** | **205** | **486** | **411** | **293** | **55** | **169** | **262** | **(493)** | **(312)** | **(361)** | **(141)** | **142** | **182** |
| **2006 IRP Resources** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **817** | **740** | **641** | **542** | **618** | **602** | **(143)** | **34** | **(24)** | **191** | **547** | **543** | **823** | **749** | **630** | **392** | **506** | **599** | **(156)** | **25** | **(24)** | **196** | **480** | **519** |
| **2009 IRP DSM** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| Industrial | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 23 | 23 | 23 | 23 | 23 | 24 | 24 | 24 | 23 | 23 | 23 | 23 |
| Comercial | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 12 | 12 | 12 | 12 | 12 | 10 | 10 | 10 | 12 | 12 | 12 | 12 |
| **Total New DSM Average Energy** | 38 | 37 | 37 | 37 | 38 | 37 | 37 | 37 | 38 | 38 | 38 | 37 | 44 | 44 | 44 | 44 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 45 |
| **Remaining Monthly Surplus/Deficit** | **855** | **777** | **679** | **579** | **656** | **639** | **(105)** | **71** | **14** | **228** | **584** | **580** | **868** | **793** | **675** | **437** | **551** | **643** | **(112)** | **69** | **20** | **241** | **524** | **564** |
| **2009 IRP Resources** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,111** | **1,059** | **941** | **830** | **920** | **907** | **145** | **321** | **264** | **478** | **834** | **833** | **1,299** | **1,249** | **1,112** | **862** | **990** | **1,086** | **313** | **494** | **445** | **666** | **949** | **992** |

| Monthly Average Energy | 2018 | | | | | | | | | | | | 2019 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
| **Load Forecast (70th%)—Aug 2009** | (2,163) | (2,022) | (1,806) | (1,779) | (1,989) | (2,490) | (2,852) | (2,635) | (2,155) | (1,790) | (1,936) | (2,250) | (2,183) | (2,038) | (1,822) | (1,795) | (2,009) | (2,521) | (2,892) | (2,673) | (2,182) | (1,811) | (1,957) | (2,274) |
| Existing DSM (Energy Efficiency) | 109 | 108 | 108 | 113 | 125 | 134 | 135 | 131 | 120 | 110 | 109 | 109 | 120 | 120 | 120 | 125 | 138 | 148 | 149 | 145 | 132 | 122 | 121 | 121 |
| **Load Forecast (70th%) w/Existing DSM** | (2,054) | (1,914) | (1,698) | (1,666) | (1,863) | (2,356) | (2,717) | (2,504) | (2,035) | (1,680) | (1,827) | (2,141) | (2,062) | (1,918) | (1,701) | (1,670) | (1,871) | (2,373) | (2,743) | (2,528) | (2,050) | (1,689) | (1,836) | (2,153) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 937 | 560 | 319 | 288 | 899 | 934 | 934 | 642 | 440 | 879 | 934 | 937 | 937 | 460 | 180 | 168 | 879 | 934 | 934 | 642 | 284 | 746 | 934 |
| Hydro (70th%)—HCC | 680 | 558 | 558 | 691 | 842 | 661 | 471 | 372 | 418 | 426 | 364 | 468 | 679 | 564 | 549 | 689 | 841 | 659 | 470 | 371 | 417 | 425 | 364 | 468 |
| Hydro (70th%)—Other | 216 | 295 | 245 | 244 | 324 | 333 | 243 | 238 | 235 | 223 | 207 | 211 | 216 | 295 | 244 | 244 | 323 | 331 | 242 | 237 | 234 | 223 | 207 | 210 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 896 | 853 | 802 | 935 | 1,166 | 993 | 714 | 610 | 653 | 649 | 571 | 679 | 894 | 859 | 793 | 933 | 1,164 | 991 | 712 | 608 | 650 | 648 | 571 | 678 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 279 | 371 | 441 | 301 | 336 | 211 | 90 | 164 | 160 | 266 | 348 | 292 | 324 | 369 | 440 | 385 | 336 | 208 | 86 | 161 | 159 | 312 | 344 | 260 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | **2,490** | **2,323** | **1,972** | **1,744** | **2,014** | **2,584** | **2,189** | **2,162** | **1,653** | **1,539** | **1,955** | **2,302** | **2,533** | **2,327** | **1,862** | **1,687** | **1,892** | **2,549** | **2,192** | **2,157** | **1,650** | **1,427** | **1,817** | **2,269** |
| **Monthly Surplus/Deficit** | **435** | **409** | **274** | **78** | **151** | **228** | **(528)** | **(342)** | **(382)** | **(141)** | **128** | **161** | **471** | **408** | **161** | **17** | **21** | **177** | **(551)** | **(371)** | **(400)** | **(262)** | **(19)** | **116** |
| **2006 IRP Resources** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **773** | **747** | **612** | **415** | **488** | **565** | **(190)** | **(5)** | **(45)** | **196** | **465** | **499** | **808** | **746** | **498** | **354** | **358** | **514** | **(214)** | **(34)** | **(62)** | **75** | **319** | **454** |
| **2009 IRP DSM** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
| Industrial | 27 | 27 | 27 | 27 | 27 | 28 | 28 | 28 | 27 | 27 | 27 | 27 | 31 | 31 | 31 | 31 | 31 | 32 | 32 | 32 | 31 | 31 | 31 | 31 |
| Comercial | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Residential | 13 | 13 | 13 | 13 | 13 | 12 | 12 | 12 | 13 | 13 | 13 | 13 | 15 | 15 | 15 | 15 | 15 | 13 | 13 | 13 | 15 | 15 | 15 | 15 |
| **Total New DSM Average Energy** | 51 | 51 | 51 | 51 | 52 | 51 | 51 | 51 | 52 | 51 | 51 | 52 | 59 | 58 | 59 | 58 | 59 | 58 | 58 | 58 | 59 | 58 | 59 | 59 |
| **Remaining Monthly Surplus/Deficit** | **824** | **798** | **663** | **467** | **540** | **616** | **(139)** | **46** | **7** | **247** | **517** | **550** | **866** | **804** | **556** | **413** | **417** | **572** | **(155)** | **25** | **(4)** | **134** | **377** | **512** |
| **2009 IRP Resources** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,256** | **1,254** | **1,100** | **892** | **979** | **1,059** | **286** | **471** | **432** | **672** | **942** | **978** | **1,298** | **1,261** | **993** | **838** | **856** | **1,015** | **270** | **450** | **421** | **559** | **802** | **941** |

| Monthly Average Energy | 2020 | | | | | | | | | | | | 2021 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| **Load Forecast (70th%)—Aug 2009** | (2,207) | (2,047) | (1,840) | (1,813) | (2,031) | (2,554) | (2,934) | (2,712) | (2,211) | (1,833) | (1,980) | (2,293) | (2,215) | (2,065) | (1,848) | (1,821) | (2,043) | (2,574) | (2,961) | (2,738) | (2,230) | (1,847) | (1,992) | (2,311) |
| Existing DSM (Energy Efficiency) | 132 | 132 | 132 | 137 | 152 | 162 | 163 | 159 | 144 | 134 | 133 | 132 | 145 | 144 | 143 | 149 | 165 | 176 | 177 | 172 | 157 | 146 | 144 | 144 |
| **Load Forecast (70th%) w/Existing DSM** | (2,074) | (1,915) | (1,707) | (1,676) | (1,879) | (2,392) | (2,772) | (2,554) | (2,068) | (1,699) | (1,846) | (2,160) | (2,070) | (1,922) | (1,705) | (1,673) | (1,878) | (2,398) | (2,785) | (2,565) | (2,073) | (1,700) | (1,848) | (2,167) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 937 | 487 | 180 | 338 | 926 | 934 | 934 | 642 | 284 | 773 | 934 | 937 | 937 | 578 | 180 | 248 | 898 | 934 | 934 | 644 | 284 | 563 | 934 |
| Hydro (70th%)—HCC | 677 | 561 | 551 | 688 | 839 | 658 | 468 | 370 | 416 | 423 | 364 | 468 | 676 | 571 | 538 | 687 | 838 | 657 | 467 | 368 | 415 | 422 | 364 | 468 |
| Hydro (70th%)—Other | 220 | 295 | 244 | 244 | 322 | 330 | 241 | 236 | 232 | 222 | 210 | 210 | 219 | 294 | 243 | 243 | 322 | 330 | 240 | 235 | 231 | 221 | 210 | 209 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 897 | 855 | 794 | 932 | 1,162 | 989 | 709 | 606 | 648 | 645 | 574 | 677 | 895 | 865 | 781 | 931 | 1,160 | 987 | 707 | 603 | 646 | 643 | 574 | 677 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 | 224 | 0 | 0 | 0 | 0 | 240 | 242 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | **2,542** | **2,330** | **1,895** | **1,688** | **2,060** | **2,615** | **2,203** | **2,154** | **1,653** | **1,346** | **1,855** | **2,313** | **2,531** | **2,340** | **1,973** | **1,687** | **1,968** | **2,585** | **2,209** | **2,151** | **1,653** | **1,344** | **1,645** | **2,312** |
| **Monthly Surplus/Deficit** | **468** | **415** | **187** | **12** | **181** | **223** | **(569)** | **(400)** | **(415)** | **(353)** | **9** | **152** | **461** | **418** | **268** | **14** | **90** | **187** | **(575)** | **(414)** | **(420)** | **(356)** | **(204)** | **144** |
| **2006 IRP Resources** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **805** | **752** | **525** | **350** | **518** | **561** | **(232)** | **(63)** | **(77)** | **(16)** | **346** | **490** | **799** | **756** | **605** | **351** | **428** | **524** | **(238)** | **(77)** | **(82)** | **(19)** | **134** | **482** |
| **2009 IRP DSM** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| Industrial | 35 | 34 | 35 | 34 | 35 | 36 | 36 | 36 | 34 | 34 | 35 | 35 | 39 | 38 | 38 | 38 | 39 | 40 | 40 | 40 | 38 | 38 | 38 | 38 |
| Comercial | 14 | 14 | 14 | 14 | 15 | 15 | 15 | 15 | 14 | 14 | 15 | 14 | 16 | 16 | 16 | 16 | 16 | 17 | 17 | 17 | 16 | 16 | 16 | 16 |
| Residential | 17 | 17 | 17 | 17 | 17 | 15 | 15 | 15 | 17 | 17 | 17 | 17 | 18 | 18 | 18 | 18 | 18 | 16 | 16 | 16 | 18 | 18 | 18 | 18 |
| **Total New DSM Average Energy** | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 73 | 73 | 73 | 73 | 74 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| **Remaining Monthly Surplus/Deficit** | **871** | **818** | **591** | **415** | **584** | **626** | **(166)** | **3** | **(12)** | **50** | **412** | **555** | **872** | **828** | **677** | **424** | **501** | **597** | **(165)** | **(4)** | **(9)** | **54** | **207** | **555** |
| **2009 IRP Resources** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 56 | 0 | 0 | 0 | 0 | 58 | 56 | 56 | 0 | 0 | 0 | 56 | 54 | 0 | 0 | 0 | 0 | 58 | 58 | 56 | 0 | 0 | 0 | 56 |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,359** | **1,274** | **1,028** | **840** | **1,023** | **1,126** | **315** | **484** | **413** | **475** | **838** | **1,039** | **1,357** | **1,285** | **1,115** | **849** | **940** | **1,097** | **318** | **477** | **416** | **479** | **632** | **1,039** |

| Monthly Average Energy | 2022 | | | | | | | | | | | | 2023 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
| **Load Forecast (70th%)—Aug 2009** | (2,234) | (2,081) | (1,864) | (1,836) | (2,062) | (2,601) | (2,997) | (2,771) | (2,254) | (1,867) | (2,013) | (2,333) | (2,249) | (2,093) | (1,876) | (1,849) | (2,078) | (2,627) | (3,032) | (2,804) | (2,278) | (1,884) | (2,029) | (2,341) |
| Existing DSM (Energy Efficiency) | 157 | 155 | 155 | 161 | 179 | 190 | 191 | 186 | 170 | 159 | 156 | 155 | 168 | 167 | 167 | 174 | 191 | 204 | 205 | 200 | 182 | 170 | 168 | 169 |
| **Load Forecast (70th%) w/Existing DSM** | (2,077) | (1,926) | (1,709) | (1,675) | (1,883) | (2,411) | (2,806) | (2,585) | (2,085) | (1,708) | (1,857) | (2,178) | (2,081) | (1,926) | (1,709) | (1,674) | (1,887) | (2,424) | (2,827) | (2,604) | (2,096) | (1,714) | (1,862) | (2,173) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 937 | 578 | 0 | 180 | 898 | 934 | 934 | 644 | 284 | 563 | 934 | 937 | 937 | 403 | 0 | 180 | 898 | 934 | 934 | 464 | 284 | 526 | 934 |
| Hydro (70th%)—HCC | 675 | 577 | 529 | 686 | 837 | 656 | 466 | 367 | 414 | 420 | 364 | 468 | 674 | 579 | 525 | 685 | 836 | 655 | 465 | 366 | 412 | 418 | 364 | 468 |
| Hydro (70th%)—Other | 219 | 294 | 242 | 243 | 321 | 329 | 239 | 235 | 229 | 220 | 209 | 208 | 218 | 294 | 242 | 242 | 320 | 328 | 238 | 234 | 228 | 219 | 209 | 208 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 894 | 871 | 771 | 929 | 1,158 | 985 | 705 | 602 | 642 | 640 | 573 | 676 | 892 | 873 | 766 | 927 | 1,156 | 982 | 703 | 600 | 640 | 638 | 573 | 676 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 242 | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | **2,530** | **2,346** | **1,964** | **1,505** | **1,898** | **2,583** | **2,189** | **2,159** | **1,650** | **1,342** | **1,644** | **2,320** | **2,537** | **2,348** | **1,783** | **1,503** | **1,896** | **2,581** | **2,187** | **2,157** | **1,468** | **1,339** | **1,607** | **2,302** |
| **Monthly Surplus/Deficit** | **453** | **420** | **255** | **(171)** | **16** | **172** | **(617)** | **(426)** | **(435)** | **(367)** | **(212)** | **142** | **456** | **422** | **74** | **(172)** | **9** | **157** | **(640)** | **(447)** | **(628)** | **(375)** | **(255)** | **129** |
| **2006 IRP Resources** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **790** | **757** | **592** | **167** | **353** | **510** | **(279)** | **(89)** | **(97)** | **(29)** | **125** | **480** | **793** | **759** | **411** | **166** | **346** | **495** | **(303)** | **(110)** | **(291)** | **(37)** | **83** | **467** |
| **2009 IRP DSM** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
| Industrial | 43 | 42 | 42 | 42 | 43 | 44 | 44 | 44 | 42 | 42 | 42 | 42 | 46 | 46 | 46 | 46 | 47 | 48 | 48 | 48 | 46 | 46 | 46 | 47 |
| Comercial | 18 | 18 | 18 | 18 | 18 | 19 | 19 | 19 | 18 | 18 | 18 | 18 | 20 | 20 | 20 | 20 | 20 | 21 | 21 | 21 | 20 | 20 | 20 | 20 |
| Residential | 20 | 20 | 20 | 20 | 20 | 17 | 17 | 17 | 20 | 20 | 20 | 20 | 21 | 21 | 21 | 21 | 21 | 19 | 19 | 19 | 21 | 21 | 21 | 21 |
| **Total New DSM Average Energy** | 81 | 80 | 80 | 80 | 81 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 88 | 87 | 87 | 88 | 88 | 88 | 87 | 88 | 88 | 88 | 88 | 88 |
| **Remaining Monthly Surplus/Deficit** | **871** | **838** | **672** | **247** | **434** | **590** | **(199)** | **(9)** | **(17)** | **51** | **205** | **560** | **881** | **847** | **498** | **253** | **434** | **582** | **(215)** | **(22)** | **(203)** | **50** | **170** | **555** |
| **2009 IRP Resources** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 54 | 0 | 0 | 0 | 0 | 58 | 54 | 58 | 0 | 0 | 0 | 58 | 56 | 0 | 0 | 0 | 0 | 58 | 54 | 58 | 0 | 0 | 0 | 54 |
| 2022 Wind (100 MW) | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,388** | **1,326** | **1,141** | **704** | **905** | **1,122** | **311** | **506** | **440** | **508** | **662** | **1,078** | **1,400** | **1,335** | **967** | **710** | **905** | **1,114** | **295** | **493** | **254** | **507** | **627** | **1,068** |

| Monthly Average Energy | 2024 | | | | | | | | | | | | 2025 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| **Load Forecast (70th%)—Aug 2009** | (2,250) | (2,082) | (1,877) | (1,851) | (2,083) | (2,638) | (3,046) | (2,817) | (2,287) | (1,891) | (2,034) | (2,356) | (2,269) | (2,109) | (1,893) | (1,866) | (2,101) | (2,664) | (3,082) | (2,851) | (2,312) | (1,911) | (2,056) | (2,378) |
| Existing DSM (Energy Efficiency) | 180 | 179 | 180 | 185 | 203 | 218 | 219 | 214 | 196 | 181 | 180 | 181 | 192 | 191 | 192 | 198 | 216 | 232 | 233 | 227 | 208 | 193 | 193 | 192 |
| **Load Forecast (70th%) w/Existing DSM** | (2,071) | (1,903) | (1,698) | (1,665) | (1,880) | (2,420) | (2,827) | (2,604) | (2,091) | (1,709) | (1,855) | (2,176) | (2,078) | (1,918) | (1,702) | (1,668) | (1,885) | (2,433) | (2,849) | (2,624) | (2,104) | (1,718) | (1,863) | (2,186) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 937 | 403 | 0 | 180 | 898 | 934 | 934 | 374 | 184 | 526 | 934 | 937 | 937 | 285 | 0 | 180 | 898 | 934 | 934 | 374 | 184 | 374 | 934 |
| Hydro (70th%)—HCC | 673 | 561 | 542 | 684 | 835 | 654 | 463 | 365 | 411 | 416 | 364 | 468 | 672 | 576 | 524 | 683 | 834 | 638 | 462 | 364 | 410 | 414 | 364 | 468 |
| Hydro (70th%)—Other | 218 | 294 | 241 | 242 | 320 | 327 | 237 | 233 | 227 | 218 | 208 | 207 | 217 | 294 | 241 | 242 | 319 | 323 | 236 | 232 | 226 | 218 | 207 | 206 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 890 | 854 | 783 | 926 | 1,154 | 980 | 700 | 598 | 638 | 635 | 572 | 675 | 889 | 869 | 764 | 924 | 1,152 | 961 | 698 | 596 | 636 | 632 | 572 | 674 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | **2,535** | **2,329** | **1,800** | **1,501** | **1,894** | **2,569** | **2,194** | **2,155** | **1,376** | **1,236** | **1,606** | **2,301** | **2,534** | **2,344** | **1,663** | **1,500** | **1,892** | **2,550** | **2,192** | **2,144** | **1,374** | **1,233** | **1,454** | **2,309** |
| **Monthly Surplus/Deficit** | **465** | **426** | **102** | **(164)** | **14** | **149** | **(634)** | **(449)** | **(716)** | **(473)** | **(249)** | **126** | **456** | **426** | **(39)** | **(168)** | **8** | **118** | **(657)** | **(480)** | **(730)** | **(485)** | **(409)** | **123** |
| **2006 IRP Resources** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **802** | **763** | **439** | **173** | **352** | **487** | **(296)** | **(111)** | **(378)** | **(136)** | **88** | **463** | **794** | **763** | **299** | **169** | **345** | **455** | **(320)** | **(142)** | **(393)** | **(147)** | **(72)** | **461** |
| **2009 IRP DSM** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| Industrial | 50 | 50 | 50 | 50 | 50 | 52 | 52 | 52 | 51 | 50 | 50 | 51 | 54 | 54 | 54 | 54 | 54 | 56 | 56 | 56 | 54 | 54 | 55 | 54 |
| Comercial | 22 | 22 | 22 | 22 | 22 | 23 | 23 | 23 | 22 | 22 | 22 | 22 | 24 | 24 | 24 | 24 | 24 | 25 | 25 | 25 | 24 | 24 | 24 | 24 |
| Residential | 23 | 23 | 23 | 23 | 23 | 20 | 20 | 20 | 23 | 23 | 23 | 23 | 24 | 25 | 24 | 25 | 24 | 22 | 22 | 21 | 24 | 25 | 24 | 24 |
| **Total New DSM Average Energy** | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 96 | 95 | 95 | 96 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 104 | 103 |
| **Remaining Monthly Surplus/Deficit** | **897** | **858** | **535** | **268** | **447** | **582** | **(201)** | **(16)** | **(282)** | **(41)** | **184** | **559** | **897** | **866** | **402** | **272** | **448** | **558** | **(217)** | **(39)** | **(290)** | **(45)** | **32** | **564** |
| **2009 IRP Resources** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 56 | 0 | 0 | 0 | 0 | 56 | 56 | 58 | 0 | 0 | 0 | 54 | 56 | 0 | 0 | 0 | 0 | 56 | 56 | 56 | 0 | 0 | 0 | 56 |
| 2022 Wind (100 MW) | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 2024 Large Aero (2 X 100 MW) | 112 | 0 | 0 | 0 | 0 | 111 | 112 | 116 | 0 | 0 | 0 | 108 | 112 | 0 | 0 | 0 | 0 | 111 | 112 | 112 | 0 | 0 | 0 | 112 |
| 2025 Gateway West Transmission | | | | | | | | | | | | | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,529** | **1,346** | **1,004** | **725** | **918** | **1,223** | **423** | **615** | **175** | **416** | **641** | **1,180** | **1,628** | **1,454** | **971** | **829** | **1,019** | **1,299** | **508** | **685** | **267** | **512** | **589** | **1,292** |

| Monthly Average Energy | 2026 | | | | | | | | | | | | 2027 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| **Load Forecast (70th%)—Aug 2009** | (2,283) | (2,120) | (1,905) | (1,877) | (2,118) | (2,692) | (3,118) | (2,885) | (2,336) | (1,928) | (2,071) | (2,387) | (2,283) | (2,119) | (1,906) | (1,879) | (2,123) | (2,703) | (3,134) | (2,899) | (2,346) | (1,934) | (2,076) | (2,394) |
| Existing DSM (Energy Efficiency) | 203 | 203 | 203 | 210 | 231 | 246 | 247 | 241 | 219 | 205 | 205 | 203 | 216 | 214 | 214 | 222 | 245 | 260 | 261 | 255 | 233 | 218 | 215 | 215 |
| **Load Forecast (70th%) w/Existing DSM** | (2,080) | (1,918) | (1,701) | (1,668) | (1,887) | (2,446) | (2,871) | (2,644) | (2,117) | (1,723) | (1,866) | (2,183) | (2,067) | (1,905) | (1,692) | (1,658) | (1,878) | (2,443) | (2,873) | (2,644) | (2,113) | (1,716) | (1,861) | (2,179) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 937 | 395 | 0 | 0 | 0 | 463 | 934 | 934 | 284 | 0 | 284 | 934 | 285 | 0 | 0 | 0 | 0 | 463 | 934 | 934 | 5 | 0 | 0 | 816 |
| Hydro (70th%)—HCC | 670 | 578 | 519 | 681 | 832 | 637 | 461 | 363 | 409 | 412 | 364 | 468 | 669 | 576 | 519 | 680 | 831 | 636 | 459 | 362 | 408 | 402 | 364 | 468 |
| Hydro (70th%)—Other | 217 | 293 | 240 | 242 | 318 | 321 | 235 | 231 | 226 | 217 | 207 | 210 | 217 | 293 | 240 | 241 | 317 | 320 | 235 | 231 | 225 | 217 | 206 | 210 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 887 | 871 | 759 | 923 | 1,151 | 958 | 696 | 594 | 634 | 629 | 571 | 678 | 886 | 869 | 759 | 921 | 1,149 | 956 | 694 | 592 | 633 | 618 | 571 | 678 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 | 224 | 0 | 0 | 0 | 0 | 240 | 242 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | **2,532** | **1,804** | **1,373** | **1,499** | **1,711** | **2,121** | **2,189** | **2,142** | **1,282** | **1,047** | **1,362** | **2,313** | **1,870** | **1,407** | **1,373** | **1,497** | **1,709** | **2,119** | **2,196** | **2,140** | **1,002** | **1,036** | **1,078** | **2,195** |
| **Monthly Surplus/Deficit** | **452** | **(114)** | **(328)** | **(169)** | **(177)** | **(325)** | **(682)** | **(501)** | **(835)** | **(676)** | **(504)** | **130** | **(197)** | **(498)** | **(320)** | **(161)** | **(170)** | **(324)** | **(677)** | **(504)** | **(1,111)** | **(680)** | **(782)** | **17** |
| **2006 IRP Resources** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **790** | **223** | **9** | **168** | **161** | **13** | **(345)** | **(164)** | **(497)** | **(339)** | **(167)** | **467** | **140** | **(160)** | **18** | **177** | **168** | **14** | **(339)** | **(167)** | **(774)** | **(343)** | **(445)** | **354** |
| **2009 IRP DSM** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| Industrial | 59 | 58 | 59 | 58 | 59 | 61 | 61 | 61 | 58 | 58 | 59 | 59 | 63 | 62 | 62 | 62 | 63 | 65 | 65 | 65 | 63 | 63 | 63 | 63 |
| Comercial | 26 | 26 | 26 | 26 | 27 | 27 | 27 | 27 | 26 | 26 | 27 | 26 | 29 | 29 | 28 | 28 | 29 | 30 | 30 | 30 | 29 | 29 | 29 | 29 |
| Residential | 26 | 26 | 26 | 26 | 26 | 23 | 23 | 23 | 26 | 26 | 26 | 26 | 28 | 28 | 28 | 28 | 27 | 24 | 24 | 24 | 28 | 28 | 28 | 28 |
| **Total New DSM Average Energy** | 111 | 111 | 111 | 111 | 112 | 111 | 111 | 111 | 111 | 110 | 112 | 111 | 119 | 119 | 118 | 118 | 120 | 119 | 119 | 119 | 119 | 119 | 119 | 119 |
| **Remaining Monthly Surplus/Deficit** | **901** | **334** | **120** | **279** | **272** | **123** | **(234)** | **(53)** | **(387)** | **(228)** | **(55)** | **578** | **260** | **(42)** | **136** | **295** | **288** | **133** | **(220)** | **(48)** | **(655)** | **(224)** | **(326)** | **473** |
| **2009 IRP Resources** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 56 | 0 | 0 | 0 | 0 | 58 | 56 | 56 | 0 | 0 | 0 | 56 | 54 | 0 | 0 | 0 | 0 | 58 | 58 | 56 | 0 | 0 | 0 | 56 |
| 2022 Wind (100 MW) | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 2024 Large Aero (2 X 100 MW) | 112 | 0 | 0 | 0 | 0 | 116 | 112 | 112 | 0 | 0 | 0 | 112 | 108 | 0 | 0 | 0 | 0 | 116 | 116 | 112 | 0 | 0 | 0 | 112 |
| 2025 Gateway West Transmission | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | 112 | 0 | 0 | 0 | 0 | 116 | 112 | 112 | 0 | 0 | 0 | 112 | 108 | 0 | 0 | 0 | 0 | 116 | 116 | 112 | 0 | 0 | 0 | 112 |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **1,744** | **923** | **689** | **836** | **843** | **987** | **603** | **783** | **170** | **329** | **502** | **1,418** | **1,156** | **611** | **769** | **916** | **923** | **1,060** | **691** | **852** | **(34)** | **397** | **295** | **1,377** |

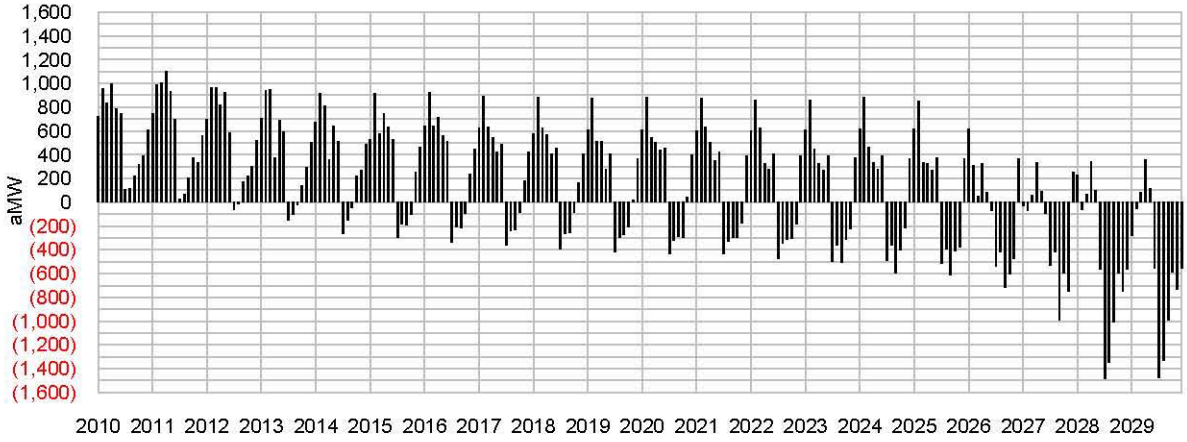
| Monthly Average Energy | 2028 | | | | | | | | | | | | 2029 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-28** | **Feb-28** | **Mar-28** | **Apr-28** | **May-28** | **Jun-28** | **Jul-28** | **Aug-28** | **Sep-28** | **Oct-28** | **Nov-28** | **Dec-28** | **Jan-29** | **Feb-29** | **Mar-29** | **Apr-29** | **May-29** | **Jun-29** | **Jul-29** | **Aug-29** | **Sep-29** | **Oct-29** | **Nov-29** | **Dec-29** |
| **Load Forecast (70th%)—Aug 2009** | (2,291) | (2,115) | (1,912) | (1,885) | (2,132) | (2,717) | (3,154) | (2,919) | (2,359) | (1,946) | (2,085) | (2,394) | (2,280) | (2,115) | (1,907) | (1,881) | (2,129) | (2,716) | (3,155) | (2,920) | (2,359) | (1,945) | (2,083) | (2,397) |
| Existing DSM (Energy Efficiency) | 228 | 226 | 225 | 235 | 257 | 274 | 275 | 269 | 245 | 230 | 227 | 228 | 239 | 238 | 237 | 247 | 270 | 288 | 289 | 282 | 260 | 241 | 239 | 240 |
| **Load Forecast (70th%) w/Existing DSM** | (2,063) | (1,889) | (1,687) | (1,650) | (1,875) | (2,443) | (2,879) | (2,650) | (2,114) | (1,715) | (1,859) | (2,166) | (2,042) | (1,877) | (1,670) | (1,634) | (1,859) | (2,429) | (2,866) | (2,637) | (2,100) | (1,704) | (1,844) | (2,157) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 537 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro (70th%)—HCC | 668 | 570 | 523 | 679 | 830 | 635 | 458 | 360 | 407 | 400 | 364 | 468 | 667 | 576 | 514 | 678 | 829 | 634 | 457 | 359 | 406 | 398 | 364 | 468 |
| Hydro (70th%)—Other | 216 | 292 | 239 | 241 | 317 | 320 | 234 | 229 | 225 | 216 | 206 | 210 | 216 | 292 | 239 | 241 | 316 | 319 | 233 | 229 | 224 | 216 | 205 | 209 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 884 | 862 | 762 | 920 | 1,147 | 954 | 692 | 590 | 631 | 616 | 570 | 677 | 883 | 868 | 753 | 918 | 1,145 | 953 | 690 | 588 | 629 | 613 | 569 | 677 |
| **CSPP (PURPA)** | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 | 102 | 118 | 125 | 144 | 184 | 194 | 180 | 169 | 160 | 139 | 114 | 120 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana - Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 | 44 | 43 | 44 | 45 | 40 | 47 | 47 | 43 | 39 | 45 | 42 | 54 |
| **Firm Pacific NW Import Capability** (Actuals Through Sept 2010) | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 | 330 | 376 | 445 | 387 | 336 | 219 | 99 | 169 | 165 | 234 | 351 | 295 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | **2,120** | **1,400** | **1,376** | **1,495** | **1,707** | **1,655** | **1,242** | **1,213** | **995** | **1,034** | **1,078** | **1,370** | **1,591** | **1,406** | **1,367** | **1,494** | **1,705** | **1,653** | **1,240** | **1,211** | **993** | **1,031** | **1,077** | **1,369** |
| **Monthly Surplus/Deficit** | **57** | **(489)** | **(311)** | **(155)** | **(168)** | **(789)** | **(1,637)** | **(1,438)** | **(1,119)** | **(682)** | **(781)** | **(797)** | **(451)** | **(471)** | **(303)** | **(140)** | **(154)** | **(776)** | **(1,626)** | **(1,426)** | **(1,107)** | **(673)** | **(767)** | **(787)** |

| 2006 IRP Resources | Jan-28 | Feb-28 | Mar-28 | Apr-28 | May-28 | Jun-28 | Jul-28 | Aug-28 | Sep-28 | Oct-28 | Nov-28 | Dec-28 | Jan-29 | Feb-29 | Mar-29 | Apr-29 | May-29 | Jun-29 | Jul-29 | Aug-29 | Sep-29 | Oct-29 | Nov-29 | Dec-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Langley Gulch | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Geothermal | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | **394** | **(152)** | **27** | **183** | **169** | **(451)** | **(1,300)** | **(1,100)** | **(782)** | **(344)** | **(443)** | **(459)** | **(114)** | **(134)** | **35** | **198** | **184** | **(439)** | **(1,288)** | **(1,089)** | **(769)** | **(336)** | **(430)** | **(450)** |

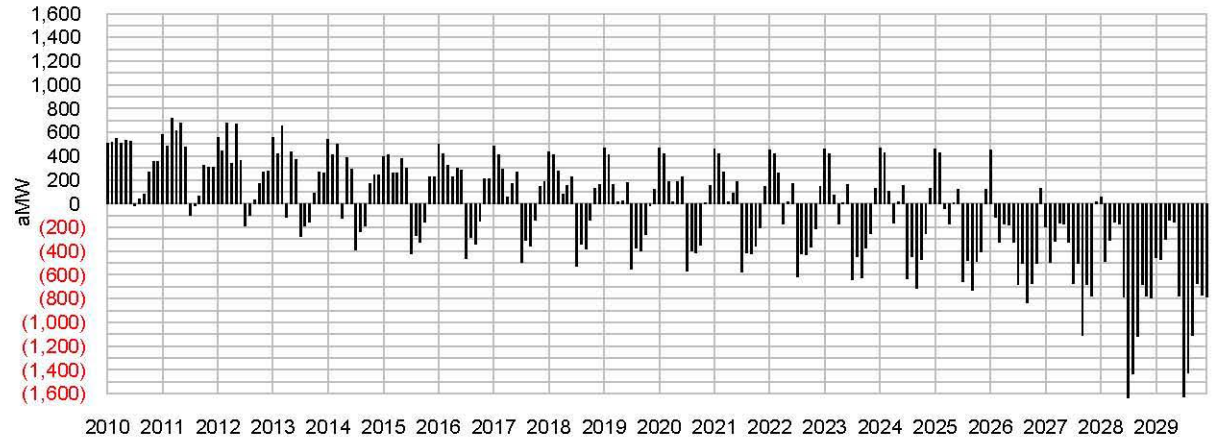
| 2009 IRP DSM | Jan-28 | Feb-28 | Mar-28 | Apr-28 | May-28 | Jun-28 | Jul-28 | Aug-28 | Sep-28 | Oct-28 | Nov-28 | Dec-28 | Jan-29 | Feb-29 | Mar-29 | Apr-29 | May-29 | Jun-29 | Jul-29 | Aug-29 | Sep-29 | Oct-29 | Nov-29 | Dec-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Industrial | 67 | 66 | 66 | 67 | 67 | 69 | 69 | 69 | 67 | 67 | 67 | 67 | 67 | 66 | 66 | 67 | 67 | 69 | 69 | 69 | 67 | 66 | 67 | 67 |
| Comercial | 31 | 31 | 31 | 31 | 31 | 32 | 32 | 32 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 32 | 32 | 32 | 31 | 31 | 31 | 31 |
| Residential | 29 | 29 | 30 | 29 | 29 | 26 | 26 | 26 | 29 | 29 | 29 | 29 | 29 | 29 | 30 | 29 | 29 | 26 | 26 | 26 | 29 | 30 | 29 | 29 |
| **Total New DSM Average Energy** | 128 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 128 | 127 | 127 | 128 |
| **Remaining Monthly Surplus/Deficit** | **522** | **(25)** | **153** | **310** | **297** | **(324)** | **(1,173)** | **(973)** | **(655)** | **(217)** | **(316)** | **(331)** | **14** | **(7)** | **161** | **325** | **311** | **(311)** | **(1,161)** | **(962)** | **(641)** | **(209)** | **(303)** | **(322)** |

| 2009 IRP Resources | Jan-28 | Feb-28 | Mar-28 | Apr-28 | May-28 | Jun-28 | Jul-28 | Aug-28 | Sep-28 | Oct-28 | Nov-28 | Dec-28 | Jan-29 | Feb-29 | Mar-29 | Apr-29 | May-29 | Jun-29 | Jul-29 | Aug-29 | Sep-29 | Oct-29 | Nov-29 | Dec-29 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 | 6 | 31 | 12 | 0 | 14 | 17 | 0 | 0 | 0 | 0 | 0 | 3 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 54 | 0 | 0 | 0 | 0 | 58 | 54 | 58 | 0 | 0 | 0 | 54 | 56 | 0 | 0 | 0 | 0 | 58 | 54 | 58 | 0 | 0 | 0 | 54 |
| 2022 Wind (100 MW) | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 2024 Large Aero (2 X 100 MW) | 108 | 0 | 0 | 0 | 0 | 116 | 108 | 116 | 0 | 0 | 0 | 108 | 112 | 0 | 0 | 0 | 0 | 116 | 108 | 116 | 0 | 0 | 0 | 108 |
| 2025 Gateway West Transmission | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | 108 | 0 | 0 | 0 | 0 | 116 | 108 | 116 | 0 | 0 | 0 | 108 | 112 | 0 | 0 | 0 | 0 | 116 | 108 | 116 | 0 | 0 | 0 | 108 |
| 2027 Wind (2 X 200 MW) | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 | 64 |
| 2028 Large Aero (4 X 100 MW) | 215 | 0 | 0 | 0 | 0 | 231 | 215 | 232 | 0 | 0 | 0 | 215 | 224 | 0 | 0 | 0 | 0 | 231 | 215 | 232 | 0 | 0 | 0 | 215 |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | 280 | 0 | 0 | 0 | 0 | 289 | 269 | 290 | 0 | 0 | 0 | 269 |
| **Monthly Surplus/Deficit** | **1,633** | **627** | **786** | **931** | **932** | **834** | **(68)** | **171** | **(34)** | **404** | **305** | **777** | **1,424** | **645** | **794** | **946** | **946** | **1,136** | **213** | **472** | **(20)** | **412** | **319** | **1,055** |

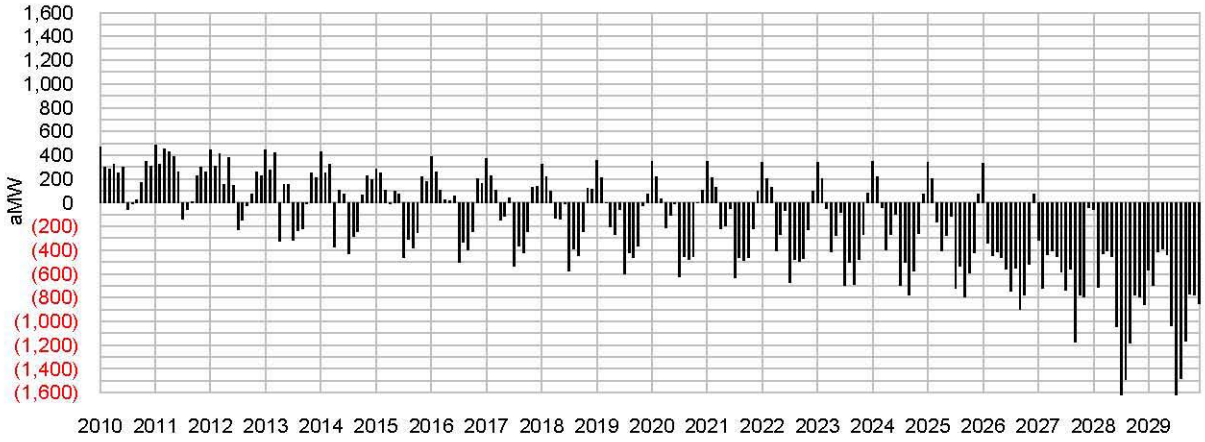
**Monthly Average Energy Surpluses and Deficits with Existing Resources**
(50th Percentile Water and 50th Percentile Load)



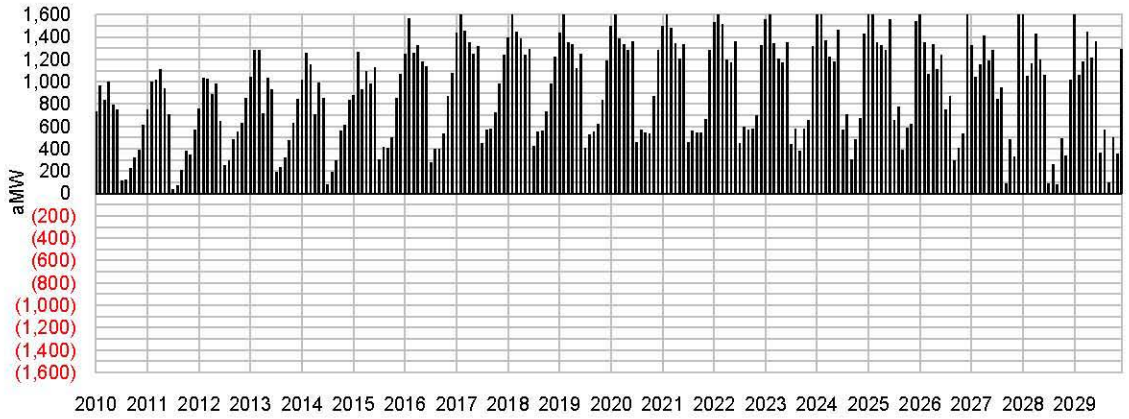

**Monthly Average Energy Surpluses and Deficits with Existing Resources**
(70th Percentile Water and 70th Percentile Load)



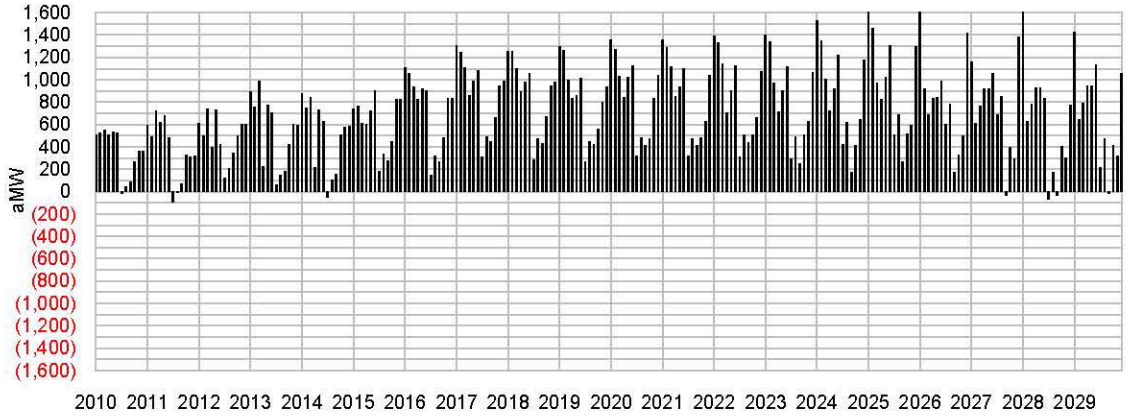

**Monthly Average Energy Surpluses and Deficits with Existing Resources**
(90th Percentile Water and 70th Percentile Load)



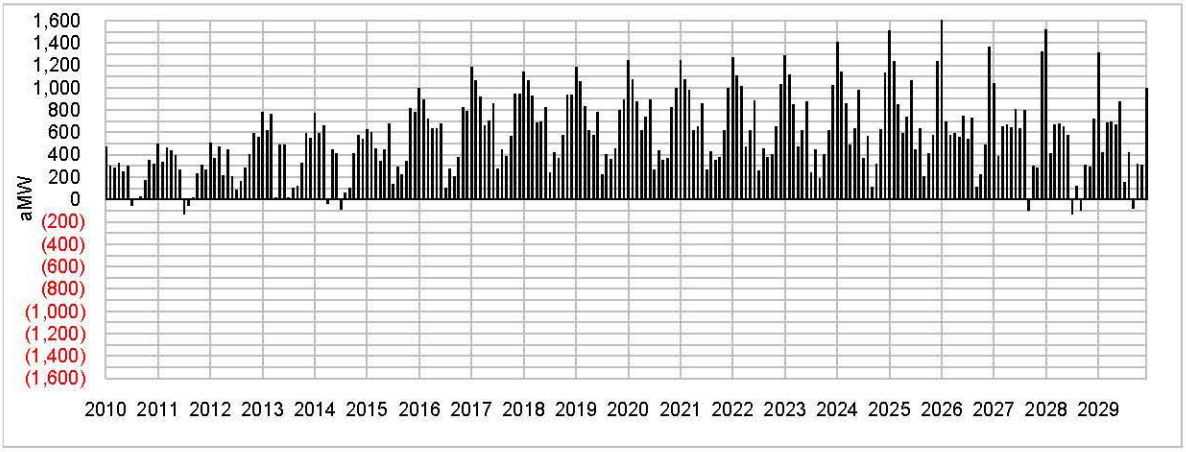
**Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources**
(50th Percentile Water and 50th Percentile Load)




**Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources**
(70th Percentile Water and 70th Percentile Load)




**Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources**
(90th Percentile Water and 70th Percentile Load)



| Peak-Hour | 2010 | | | | | | | | | | | | 2011 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-10** | **Feb-10** | **Mar-10** | **Apr-10** | **May-10** | **Jun-10** | **Jul-10** | **Aug-10** | **Sep-10** | **Oct-10** | **Nov-10** | **Dec-10** | **Jan-11** | **Feb-11** | **Mar-11** | **Apr-11** | **May-11** | **Jun-11** | **Jul-11** | **Aug-11** | **Sep-11** | **Oct-11** | **Nov-11** | **Dec-11** |
| **Load Forecast (95th%)—w/EE DSM** | (2,455) | (2,402) | (2,103) | (1,871) | (2,761) | (3,318) | (3,460) | (3,138) | (2,978) | (2,088) | (2,302) | (2,695) | (2,559) | (2,486) | (2,191) | (1,948) | (2,846) | (3,395) | (3,560) | (3,185) | (3,027) | (2,133) | (2,353) | (2,733) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 8 | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 59 | 59 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,455) | (2,402) | (2,103) | (1,871) | (2,761) | (3,259) | (3,401) | (3,088) | (2,978) | (2,088) | (2,302) | (2,695) | (2,559) | (2,486) | (2,191) | (1,948) | (2,846) | (3,338) | (3,503) | (3,134) | (3,027) | (2,133) | (2,353) | (2,733) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 963 | 963 | 963 | 676 | 621 | 963 | 967 | 967 | 967 | 967 | 967 | 967 | 967 | 967 | 967 | 680 | 790 | 967 | 972 | 972 | 972 | 972 | 972 | 972 |
| Hydro (90th%)—HCC | 1,131 | 945 | 670 | 690 | 1,181 | 1,106 | 1,040 | 945 | 1,035 | 835 | 600 | 785 | 1,107 | 900 | 670 | 690 | 1,179 | 1,110 | 1,035 | 945 | 1,090 | 780 | 600 | 785 |
| Hydro (90th%)—Other | 203 | 207 | 196 | 213 | 289 | 306 | 246 | 236 | 217 | 210 | 198 | 204 | 203 | 206 | 196 | 213 | 289 | 306 | 246 | 236 | 216 | 210 | 198 | 204 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 42 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 47 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,335 | 1,152 | 866 | 903 | 1,470 | 1,413 | 1,328 | 1,181 | 1,252 | 1,045 | 798 | 989 | 1,310 | 1,106 | 866 | 903 | 1,467 | 1,416 | 1,328 | 1,181 | 1,306 | 990 | 798 | 989 |
| **CSPP (PURPA)** | 43 | 42 | 46 | 70 | 121 | 129 | 133 | 124 | 102 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 83 | 83 | 83 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 83 | 83 | 83 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 75 | 75 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 75 | 75 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 15 | 15 | 15 | 15 | 15 | 98 | 223 | 223 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 98 | 173 | 173 | 15 | 15 | 15 | 15 |
| **Firm Pacific NW Import Capability** | 99 | 229 | 212 | 205 | 414 | 302 | 122 | 255 | 291 | 0 | 535 | 443 | 216 | 346 | 288 | 270 | 406 | 287 | 105 | 247 | 287 | 73 | 530 | 440 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,871** | **2,816** | **2,518** | **2,286** | **3,057** | **3,321** | **3,190** | **3,166** | **3,042** | **2,526** | **2,789** | **2,885** | **2,976** | **2,901** | **2,606** | **2,363** | **3,223** | **3,322** | **3,135** | **3,121** | **3,106** | **2,548** | **2,790** | **2,887** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(212)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(17)** | **(368)** | **(13)** | **0** | **0** | **0** | **0** |

| 2006 IRP Resources | Jan-10 | Feb-10 | Mar-10 | Apr-10 | May-10 | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Langley Gulch | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(212)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(17)** | **(368)** | **(13)** | **0** | **0** | **0** | **0** |

| 2009 IRP DSM | Jan-10 | Feb-10 | Mar-10 | Apr-10 | May-10 | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 45 | 45 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 212 | 212 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 244 | 244 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| **Total New DSM Peak Reduction** | 3 | 3 | 3 | 3 | 3 | 254 | 254 | 42 | 3 | 3 | 3 | 3 | 7 | 7 | 7 | 7 | 7 | 296 | 296 | 52 | 7 | 7 | 7 | 7 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(71)** | **0** | **0** | **0** | **0** | **0** |

| 2009 IRP Resources | Jan-10 | Feb-10 | Mar-10 | Apr-10 | May-10 | Jun-10 | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(71)** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2012 | | | | | | | | | | | | 2013 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Nov-13** | **Dec-13** |
| **Load Forecast (95th%)—w/EE DSM** | (2,600) | (2,487) | (2,225) | (1,964) | (2,891) | (3,496) | (3,636) | (3,242) | (3,069) | (2,168) | (2,391) | (2,756) | (2,560) | (2,496) | (2,203) | (1,922) | (2,915) | (3,541) | (3,726) | (3,296) | (3,127) | (2,177) | (2,389) | (2,703) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,600) | (2,487) | (2,225) | (1,964) | (2,891) | (3,440) | (3,579) | (3,192) | (3,069) | (2,168) | (2,391) | (2,756) | (2,560) | (2,496) | (2,203) | (1,922) | (2,915) | (3,484) | (3,669) | (3,246) | (3,127) | (2,177) | (2,389) | (2,703) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 972 | 972 | 933 | 663 | 751 | 972 | 978 | 978 | 978 | 798 | 978 | 978 | 978 | 978 | 907 | 0 | 744 | 978 | 983 | 983 | 789 | 670 | 983 | 983 |
| Hydro (90th%)—HCC | 1,106 | 897 | 670 | 690 | 1,170 | 1,056 | 1,035 | 945 | 1,090 | 780 | 510 | 785 | 1,116 | 870 | 670 | 670 | 1,170 | 1,060 | 1,034 | 945 | 1,035 | 780 | 600 | 870 |
| Hydro (90th%)—Other | 203 | 206 | 196 | 213 | 289 | 306 | 245 | 235 | 216 | 210 | 198 | 203 | 202 | 206 | 195 | 213 | 289 | 306 | 245 | 234 | 216 | 210 | 198 | 203 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,308 | 1,103 | 866 | 903 | 1,459 | 1,363 | 1,328 | 1,180 | 1,306 | 990 | 708 | 988 | 1,319 | 1,076 | 865 | 883 | 1,459 | 1,366 | 1,327 | 1,179 | 1,251 | 990 | 798 | 1,073 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 83 | 83 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 15 | 15 | 15 | 15 | 15 | 15 | 98 | 98 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Firm Pacific NW Import Capability** | 254 | 348 | 317 | 160 | 396 | 263 | 97 | 240 | 284 | 102 | 528 | 437 | 197 | 377 | 290 | 254 | 389 | 248 | 87 | 234 | 278 | 106 | 525 | 443 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **3,017** | **2,904** | **2,601** | **2,236** | **3,166** | **3,166** | **3,059** | **3,045** | **3,109** | **2,403** | **2,704** | **2,889** | **2,977** | **2,913** | **2,547** | **1,647** | **3,151** | **3,161** | **2,969** | **2,960** | **2,859** | **2,279** | **2,795** | **2,985** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(274)** | **(521)** | **(147)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(276)** | **0** | **(324)** | **(700)** | **(286)** | **(268)** | **0** | **0** | **0** |

| 2006 IRP Resources | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Jun-13 | Jul-13 | Aug-13 | Sep-13 | Oct-13 | Nov-13 | Dec-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 0 | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(266)** | **(213)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(373)** | **0** | **0** | **0** | **0** | **0** |

| 2009 IRP DSM | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Jun-13 | Jul-13 | Aug-13 | Sep-13 | Oct-13 | Nov-13 | Dec-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| **Total New DSM Peak Reduction** | 12 | 12 | 12 | 12 | 12 | 323 | 323 | 69 | 12 | 12 | 12 | 12 | 18 | 18 | 18 | 18 | 18 | 329 | 329 | 75 | 18 | 18 | 18 | 18 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(44)** | **0** | **0** | **0** | **0** | **0** |

| 2009 IRP Resources | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Jun-13 | Jul-13 | Aug-13 | Sep-13 | Oct-13 | Nov-13 | Dec-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(44)** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2014 | | | | | | | | | | | | 2015 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-14** | **Feb-14** | **Mar-14** | **Apr-14** | **May-14** | **Jun-14** | **Jul-14** | **Aug-14** | **Sep-14** | **Oct-14** | **Nov-14** | **Dec-14** | **Jan-15** | **Feb-15** | **Mar-15** | **Apr-15** | **May-15** | **Jun-15** | **Jul-15** | **Aug-15** | **Sep-15** | **Oct-15** | **Nov-15** | **Dec-15** |
| **Load Forecast (95th%)—w/EE DSM** | (2,594) | (2,516) | (2,230) | (1,944) | (2,946) | (3,593) | (3,789) | (3,359) | (3,169) | (2,193) | (2,415) | (2,748) | (2,583) | (2,509) | (2,226) | (1,931) | (2,970) | (3,640) | (3,843) | (3,396) | (3,211) | (2,200) | (2,421) | (2,742) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,594) | (2,516) | (2,230) | (1,944) | (2,946) | (3,536) | (3,732) | (3,308) | (3,169) | (2,193) | (2,415) | (2,748) | (2,583) | (2,509) | (2,226) | (1,931) | (2,970) | (3,583) | (3,786) | (3,346) | (3,211) | (2,200) | (2,421) | (2,742) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 983 | 983 | 803 | 0 | 728 | 913 | 983 | 983 | 789 | 670 | 983 | 983 | 982 | 982 | 586 | 676 | 725 | 936 | 982 | 982 | 671 | 470 | 982 | 982 |
| Hydro (90th%)—HCC | 1,122 | 845 | 670 | 585 | 1,135 | 1,066 | 1,005 | 945 | 1,035 | 595 | 600 | 870 | 1,098 | 845 | 670 | 585 | 1,187 | 1,104 | 1,035 | 945 | 1,035 | 780 | 600 | 870 |
| Hydro (90th%)—Other | 202 | 205 | 195 | 213 | 288 | 305 | 243 | 232 | 215 | 209 | 197 | 202 | 201 | 204 | 194 | 212 | 287 | 296 | 240 | 230 | 214 | 209 | 197 | 201 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,323 | 1,050 | 865 | 798 | 1,422 | 1,371 | 1,248 | 1,177 | 1,250 | 804 | 797 | 1,072 | 1,299 | 1,049 | 864 | 797 | 1,473 | 1,400 | 1,275 | 1,175 | 1,249 | 989 | 797 | 1,071 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Firm Pacific NW Import Capability** | 222 | 444 | 523 | 356 | 380 | 237 | 79 | 218 | 276 | 308 | 523 | 439 | 236 | 432 | 517 | 223 | 381 | 242 | 71 | 196 | 267 | 131 | 525 | 439 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **3,011** | **2,959** | **2,676** | **1,663** | **3,090** | **3,090** | **2,882** | **2,941** | **2,856** | **2,295** | **2,793** | **2,980** | **3,000** | **2,944** | **2,452** | **2,206** | **3,139** | **3,146** | **2,900** | **2,916** | **2,728** | **2,103** | **2,793** | **2,978** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **(281)** | **0** | **(447)** | **(850)** | **(367)** | **(313)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(437)** | **(886)** | **(430)** | **(483)** | **(97)** | **0** | **0** |

| 2006 IRP Resources | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(119)** | **(522)** | **(40)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(110)** | **(558)** | **(102)** | **(156)** | **0** | **0** | **0** |

| 2009 IRP DSM | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 25 | 24 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| **Total New DSM Peak Reduction** | 24 | 24 | 24 | 24 | 24 | 335 | 335 | 81 | 24 | 24 | 25 | 24 | 31 | 31 | 31 | 31 | 31 | 341 | 341 | 87 | 31 | 31 | 31 | 31 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(188)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(217)** | **(15)** | **(125)** | **0** | **0** | **0** |

| 2009 IRP Resources | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 | Jan-15 | Feb-15 | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | | | | | | | | | | | | | | | | | | | | | | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(188)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2016 | | | | | | | | | | | | 2017 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| **Load Forecast (95th%)—w/EE DSM** | (2,580) | (2,507) | (2,228) | (1,924) | (2,993) | (3,686) | (3,895) | (3,437) | (3,252) | (2,207) | (2,430) | (2,745) | (2,578) | (2,504) | (2,231) | (1,920) | (3,018) | (3,733) | (3,949) | (3,480) | (3,293) | (2,215) | (2,439) | (2,751) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,580) | (2,507) | (2,228) | (1,924) | (2,993) | (3,629) | (3,838) | (3,386) | (3,252) | (2,207) | (2,430) | (2,745) | (2,578) | (2,504) | (2,231) | (1,920) | (3,018) | (3,676) | (3,893) | (3,429) | (3,293) | (2,215) | (2,439) | (2,751) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 980 | 980 | 586 | 602 | 635 | 936 | 980 | 980 | 671 | 470 | 980 | 980 | 980 | 980 | 586 | 569 | 543 | 936 | 980 | 980 | 671 | 470 | 908 | 980 |
| Hydro (90th%)—HCC | 1,115 | 835 | 585 | 780 | 1,181 | 1,117 | 1,035 | 945 | 1,035 | 780 | 600 | 870 | 1,117 | 845 | 585 | 785 | 1,184 | 1,060 | 1,005 | 945 | 1,085 | 780 | 600 | 870 |
| Hydro (90th%)—Other | 200 | 203 | 193 | 212 | 286 | 294 | 238 | 226 | 213 | 208 | 196 | 201 | 200 | 202 | 192 | 211 | 285 | 292 | 237 | 223 | 212 | 207 | 196 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,315 | 1,038 | 778 | 992 | 1,467 | 1,411 | 1,273 | 1,171 | 1,248 | 988 | 796 | 1,071 | 1,317 | 1,047 | 777 | 996 | 1,469 | 1,353 | 1,242 | 1,168 | 1,297 | 987 | 796 | 1,070 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 219 | 451 | 400 | 259 | 376 | 229 | 65 | 190 | 265 | 141 | 524 | 440 | 215 | 431 | 404 | 0 | 370 | 219 | 58 | 182 | 262 | 150 | 524 | 440 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,997** | **2,951** | **2,249** | **2,363** | **3,038** | **3,144** | **2,891** | **2,905** | **2,725** | **2,112** | **2,790** | **2,977** | **2,980** | **2,925** | **2,237** | **2,060** | **2,927** | **3,061** | **2,838** | **2,879** | **2,756** | **2,105** | **2,701** | **2,960** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(485)** | **(948)** | **(481)** | **(526)** | **(95)** | **0** | **0** | **0** | **0** | **0** | **0** | **(91)** | **(615)** | **(1,054)** | **(550)** | **(537)** | **(110)** | **0** | **0** |
| **2006 IRP Resources** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(158)** | **(620)** | **(154)** | **(199)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(267)** | **(707)** | **(203)** | **(190)** | **0** | **0** | **0** |
| **2009 IRP DSM** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 38 | 37 | 37 | 37 | 38 | 37 | 37 | 37 | 38 | 38 | 38 | 37 | 44 | 44 | 44 | 44 | 45 | 44 | 44 | 44 | 44 | 44 | 44 | 45 |
| **Total New DSM Peak Reduction** | 38 | 37 | 37 | 37 | 38 | 348 | 348 | 94 | 38 | 38 | 38 | 37 | 44 | 44 | 44 | 44 | 45 | 355 | 355 | 101 | 44 | 44 | 44 | 45 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(272)** | **(60)** | **(161)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(352)** | **(102)** | **(145)** | **0** | **0** | **0** |
| **2009 IRP Resources** | **Jan-16** | **Feb-16** | **Mar-16** | **Apr-16** | **May-16** | **Jun-16** | **Jul-16** | **Aug-16** | **Sep-16** | **Oct-16** | **Nov-16** | **Dec-16** | **Jan-17** | **Feb-17** | **Mar-17** | **Apr-17** | **May-17** | **Jun-17** | **Jul-17** | **Aug-17** | **Sep-17** | **Oct-17** | **Nov-17** | **Dec-17** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | | | | | | | | | | | | | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(22)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2018 | | | | | | | | | | | | 2019 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
| **Load Forecast (95th%)—w/EE DSM** | (2,576) | (2,501) | (2,233) | (1,915) | (3,042) | (3,780) | (4,003) | (3,523) | (3,334) | (2,223) | (2,448) | (2,759) | (2,578) | (2,501) | (2,238) | (1,915) | (3,067) | (3,827) | (4,060) | (3,570) | (3,374) | (2,230) | (2,459) | (2,773) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,576) | (2,501) | (2,233) | (1,915) | (3,042) | (3,723) | (3,947) | (3,472) | (3,334) | (2,223) | (2,448) | (2,759) | (2,578) | (2,501) | (2,238) | (1,915) | (3,067) | (3,770) | (4,003) | (3,520) | (3,374) | (2,230) | (2,459) | (2,773) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 980 | 980 | 586 | 376 | 525 | 936 | 977 | 977 | 671 | 470 | 908 | 977 | 977 | 977 | 486 | 237 | 405 | 916 | 977 | 977 | 671 | 314 | 775 | 977 |
| Hydro (90th%)—HCC | 1,113 | 845 | 585 | 585 | 1,175 | 1,041 | 1,005 | 945 | 1,080 | 780 | 510 | 870 | 1,114 | 845 | 700 | 585 | 1,173 | 1,039 | 1,005 | 945 | 1,035 | 760 | 600 | 1,187 |
| Hydro (90th%)—Other | 199 | 201 | 192 | 211 | 284 | 290 | 230 | 222 | 208 | 207 | 195 | 200 | 198 | 201 | 191 | 211 | 284 | 287 | 227 | 221 | 207 | 206 | 195 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,312 | 1,046 | 777 | 796 | 1,460 | 1,331 | 1,235 | 1,167 | 1,288 | 987 | 705 | 1,070 | 1,313 | 1,046 | 891 | 796 | 1,457 | 1,326 | 1,232 | 1,166 | 1,242 | 966 | 795 | 1,387 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 218 | 426 | 406 | 166 | 363 | 206 | 54 | 179 | 256 | 161 | 525 | 439 | 222 | 432 | 300 | 335 | 355 | 193 | 48 | 174 | 249 | 189 | 520 | 312 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,978** | **2,919** | **2,239** | **1,833** | **2,893** | **3,026** | **2,823** | **2,872** | **2,741** | **2,116** | **2,612** | **2,956** | **2,980** | **2,922** | **2,147** | **1,863** | **2,762** | **2,988** | **2,815** | **2,866** | **2,688** | **1,967** | **2,564** | **3,146** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **(82)** | **(150)** | **(697)** | **(1,123)** | **(601)** | **(593)** | **(107)** | **0** | **0** | **0** | **0** | **(91)** | **(52)** | **(305)** | **(783)** | **(1,188)** | **(654)** | **(686)** | **(263)** | **0** | **0** |

| **2006 IRP Resources** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(350)** | **(776)** | **(253)** | **(246)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(435)** | **(841)** | **(306)** | **(339)** | **0** | **0** | **0** |

| **2009 IRP DSM** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 51 | 51 | 51 | 51 | 52 | 51 | 51 | 51 | 52 | 51 | 51 | 52 | 59 | 58 | 59 | 58 | 59 | 58 | 58 | 58 | 59 | 58 | 59 | 59 |
| **Total New DSM Peak Reduction** | 51 | 51 | 51 | 51 | 52 | 362 | 362 | 108 | 52 | 51 | 51 | 52 | 59 | 58 | 59 | 58 | 59 | 369 | 369 | 115 | 59 | 58 | 59 | 59 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(414)** | **(146)** | **(194)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(66)** | **(472)** | **(191)** | **(280)** | **0** | **0** | **0** |

| **2009 IRP Resources** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(47)** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2020 | | | | | | | | | | | | 2021 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| **Load Forecast (95th%)—w/EE DSM** | (2,586) | (2,494) | (2,246) | (1,918) | (3,092) | (3,876) | (4,118) | (3,621) | (3,417) | (2,239) | (2,470) | (2,786) | (2,547) | (2,481) | (2,229) | (1,889) | (3,109) | (3,916) | (4,160) | (3,642) | (3,458) | (2,239) | (2,466) | (2,754) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,586) | (2,494) | (2,246) | (1,918) | (3,092) | (3,819) | (4,061) | (3,570) | (3,417) | (2,239) | (2,470) | (2,786) | (2,547) | (2,481) | (2,229) | (1,889) | (3,109) | (3,860) | (4,103) | (3,592) | (3,458) | (2,239) | (2,466) | (2,754) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 977 | 977 | 513 | 237 | 575 | 977 | 977 | 977 | 671 | 314 | 802 | 977 | 977 | 977 | 605 | 237 | 485 | 935 | 977 | 977 | 673 | 314 | 592 | 977 |
| Hydro (90th%)—HCC | 925 | 965 | 700 | 585 | 1,181 | 1,035 | 1,005 | 945 | 1,035 | 505 | 600 | 785 | 1,064 | 845 | 700 | 585 | 1,178 | 1,035 | 1,050 | 945 | 1,035 | 690 | 600 | 870 |
| Hydro (90th%)—Other | 198 | 200 | 190 | 210 | 283 | 286 | 224 | 220 | 205 | 206 | 194 | 199 | 197 | 200 | 190 | 210 | 282 | 282 | 222 | 219 | 204 | 205 | 193 | 198 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,123 | 1,165 | 890 | 795 | 1,463 | 1,321 | 1,229 | 1,165 | 1,240 | 711 | 794 | 984 | 1,261 | 1,045 | 890 | 795 | 1,461 | 1,317 | 1,272 | 1,164 | 1,239 | 895 | 793 | 1,068 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 452 | 287 | 309 | 339 | 375 | 191 | 41 | 159 | 244 | 481 | 522 | 436 | 243 | 394 | 292 | 313 | 350 | 189 | 34 | 146 | 228 | 269 | 522 | 439 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **3,019** | **2,896** | **2,182** | **1,866** | **2,958** | **3,042** | **2,805** | **2,849** | **2,682** | **2,004** | **2,592** | **2,868** | **2,949** | **2,883** | **2,257** | **1,840** | **2,841** | **2,995** | **2,840** | **2,835** | **2,667** | **1,976** | **2,382** | **2,955** |
| **Monthly Surplus/Deficit** | **0** | **0** | **(64)** | **(53)** | **(134)** | **(777)** | **(1,256)** | **(721)** | **(736)** | **(235)** | **0** | **0** | **0** | **0** | **0** | **(50)** | **(268)** | **(865)** | **(1,263)** | **(757)** | **(791)** | **(262)** | **(84)** | **0** |
| **2006 IRP Resources** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(429)** | **(908)** | **(373)** | **(388)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(518)** | **(915)** | **(409)** | **(444)** | **0** | **0** | **0** |
| **2009 IRP DSM** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 73 | 73 | 73 | 73 | 74 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| **Total New DSM Peak Reduction** | 66 | 66 | 66 | 66 | 66 | 376 | 376 | 122 | 66 | 66 | 66 | 66 | 73 | 73 | 73 | 73 | 74 | 383 | 383 | 129 | 73 | 73 | 73 | 73 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(53)** | **(532)** | **(251)** | **(323)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(134)** | **(532)** | **(280)** | **(371)** | **0** | **0** | **0** |
| **2009 IRP Resources** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2022 Wind (100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(7)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(7)** | **0** | **0** | **0** | **0** | **0** |

| Peak-Hour | 2022 | | | | | | | | | | | | 2023 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
| **Load Forecast (95th%)—w/EE DSM** | (2,543) | (2,477) | (2,232) | (1,886) | (3,131) | (3,961) | (4,210) | (3,685) | (3,500) | (2,245) | (2,474) | (2,763) | (2,535) | (2,470) | (2,230) | (1,878) | (3,153) | (4,006) | (4,261) | (3,726) | (3,540) | (2,249) | (2,479) | (2,751) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,543) | (2,477) | (2,232) | (1,886) | (3,131) | (3,904) | (4,154) | (3,634) | (3,500) | (2,245) | (2,474) | (2,763) | (2,535) | (2,470) | (2,230) | (1,878) | (3,153) | (3,949) | (4,205) | (3,675) | (3,540) | (2,249) | (2,479) | (2,751) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 977 | 977 | 605 | 0 | 417 | 935 | 977 | 977 | 673 | 314 | 592 | 977 | 977 | 977 | 430 | 0 | 417 | 935 | 977 | 977 | 493 | 314 | 555 | 977 |
| Hydro (90th%)—HCC | 1,056 | 815 | 700 | 585 | 1,177 | 1,035 | 1,040 | 945 | 1,035 | 750 | 600 | 785 | 1,048 | 815 | 785 | 585 | 1,104 | 1,035 | 1,005 | 945 | 1,035 | 700 | 600 | 785 |
| Hydro (90th%)—Other | 197 | 199 | 189 | 210 | 282 | 279 | 217 | 218 | 204 | 204 | 193 | 198 | 196 | 198 | 188 | 209 | 281 | 277 | 214 | 218 | 203 | 204 | 192 | 197 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,252 | 1,014 | 889 | 795 | 1,458 | 1,314 | 1,257 | 1,163 | 1,239 | 954 | 793 | 983 | 1,244 | 1,013 | 973 | 794 | 1,385 | 1,312 | 1,219 | 1,163 | 1,238 | 904 | 792 | 982 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 248 | 445 | 296 | 311 | 345 | 185 | 28 | 142 | 222 | 216 | 522 | 439 | 248 | 433 | 210 | 303 | 341 | 176 | 23 | 142 | 217 | 270 | 521 | 439 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,945** | **2,902** | **2,260** | **1,600** | **2,766** | **2,988** | **2,820** | **2,830** | **2,660** | **1,982** | **2,380** | **2,870** | **2,937** | **2,890** | **2,083** | **1,592** | **2,687** | **2,977** | **2,776** | **2,830** | **2,474** | **1,986** | **2,342** | **2,868** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **(287)** | **(365)** | **(916)** | **(1,334)** | **(804)** | **(840)** | **(263)** | **(94)** | **0** | **0** | **0** | **(148)** | **(287)** | **(465)** | **(972)** | **(1,428)** | **(845)** | **(1,066)** | **(263)** | **(137)** | **0** |

| **2006 IRP Resources** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **(17)** | **(569)** | **(987)** | **(456)** | **(492)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(118)** | **(625)** | **(1,081)** | **(498)** | **(719)** | **0** | **0** | **0** |

| **2009 IRP DSM** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 81 | 80 | 80 | 80 | 81 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 88 | 87 | 87 | 88 | 88 | 88 | 87 | 88 | 88 | 88 | 88 | 88 |
| **Total New DSM Peak Reduction** | 81 | 80 | 80 | 80 | 81 | 391 | 390 | 137 | 80 | 80 | 80 | 80 | 88 | 87 | 87 | 88 | 88 | 398 | 398 | 144 | 88 | 88 | 88 | 88 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(178)** | **(596)** | **(320)** | **(412)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(30)** | **(227)** | **(683)** | **(354)** | **(631)** | **0** | **0** | **0** |

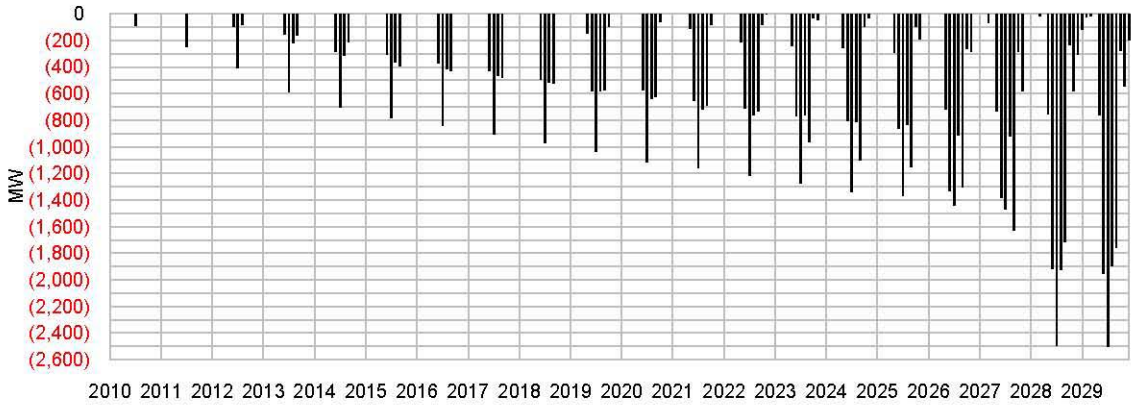
| **2009 IRP Resources** | **Jan-22** | **Feb-22** | **Mar-22** | **Apr-22** | **May-22** | **Jun-22** | **Jul-22** | **Aug-22** | **Sep-22** | **Oct-22** | **Nov-22** | **Dec-22** | **Jan-23** | **Feb-23** | **Mar-23** | **Apr-23** | **May-23** | **Jun-23** | **Jul-23** | **Aug-23** | **Sep-23** | **Oct-23** | **Nov-23** | **Dec-23** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2022 Wind (100 MW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2024 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2025 Gateway West Transmission | | | | | | | | | | | | | | | | | | | | | | | | |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(66)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(153)** | **0** | **(101)** | **0** | **0** | **0** |

| Peak-Hour | 2024 | | | | | | | | | | | | 2025 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| **Load Forecast (95th%)—w/EE DSM** | (2,467) | (2,454) | (2,193) | (1,830) | (3,164) | (4,039) | (4,290) | (3,728) | (3,580) | (2,244) | (2,461) | (2,688) | (2,471) | (2,430) | (2,201) | (1,835) | (3,186) | (4,084) | (4,341) | (3,776) | (3,622) | (2,251) | (2,471) | (2,710) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,467) | (2,454) | (2,193) | (1,830) | (3,164) | (3,983) | (4,234) | (3,678) | (3,580) | (2,244) | (2,461) | (2,688) | (2,471) | (2,430) | (2,201) | (1,835) | (3,186) | (4,027) | (4,284) | (3,726) | (3,622) | (2,251) | (2,471) | (2,710) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 977 | 977 | 430 | 0 | 417 | 935 | 977 | 977 | 403 | 214 | 555 | 977 | 977 | 977 | 311 | 0 | 417 | 935 | 977 | 977 | 403 | 214 | 403 | 977 |
| Hydro (90th%)—HCC | 1,043 | 780 | 700 | 585 | 1,175 | 1,039 | 1,005 | 945 | 1,035 | 615 | 600 | 785 | 968 | 775 | 700 | 585 | 1,173 | 1,035 | 1,005 | 945 | 1,035 | 574 | 600 | 785 |
| Hydro (90th%)—Other | 195 | 198 | 188 | 209 | 281 | 275 | 212 | 217 | 202 | 204 | 191 | 197 | 195 | 197 | 187 | 208 | 280 | 266 | 211 | 216 | 201 | 203 | 190 | 196 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,238 | 978 | 888 | 794 | 1,455 | 1,314 | 1,217 | 1,162 | 1,237 | 819 | 791 | 982 | 1,162 | 972 | 887 | 793 | 1,454 | 1,301 | 1,216 | 1,161 | 1,236 | 777 | 790 | 981 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 186 | 470 | 258 | 255 | 336 | 172 | 19 | 133 | 209 | 366 | 519 | 445 | 266 | 431 | 267 | 261 | 327 | 169 | 13 | 137 | 205 | 466 | 520 | 443 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,869** | **2,891** | **2,046** | **1,544** | **2,754** | **2,974** | **2,771** | **2,820** | **2,375** | **1,897** | **2,339** | **2,874** | **2,873** | **2,847** | **1,935** | **1,549** | **2,743** | **2,959** | **2,763** | **2,823** | **2,370** | **1,955** | **2,188** | **2,872** |
| **Monthly Surplus/Deficit** | **0** | **0** | **(148)** | **(286)** | **(410)** | **(1,009)** | **(1,463)** | **(858)** | **(1,204)** | **(347)** | **(121)** | **0** | **0** | **0** | **(266)** | **(286)** | **(443)** | **(1,068)** | **(1,521)** | **(903)** | **(1,252)** | **(295)** | **(283)** | **0** |
| **2006 IRP Resources** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **(63)** | **(661)** | **(1,115)** | **(510)** | **(857)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(95)** | **(721)** | **(1,173)** | **(556)** | **(904)** | **0** | **0** | **0** |
| **2009 IRP DSM** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 95 | 96 | 95 | 95 | 96 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 103 | 104 | 103 |
| **Total New DSM Peak Reduction** | 95 | 95 | 95 | 95 | 95 | 406 | 406 | 152 | 96 | 95 | 95 | 96 | 103 | 103 | 103 | 103 | 103 | 413 | 413 | 159 | 103 | 103 | 104 | 103 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **(256)** | **(709)** | **(358)** | **(761)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(307)** | **(760)** | **(396)** | **(801)** | **0** | **0** | **0** |
| **2009 IRP Resources** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2022 Wind (100 MW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2024 Large Aero (2 X 100 MW) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2025 Gateway West Transmission | | | | | | | | | | | | | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(31)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

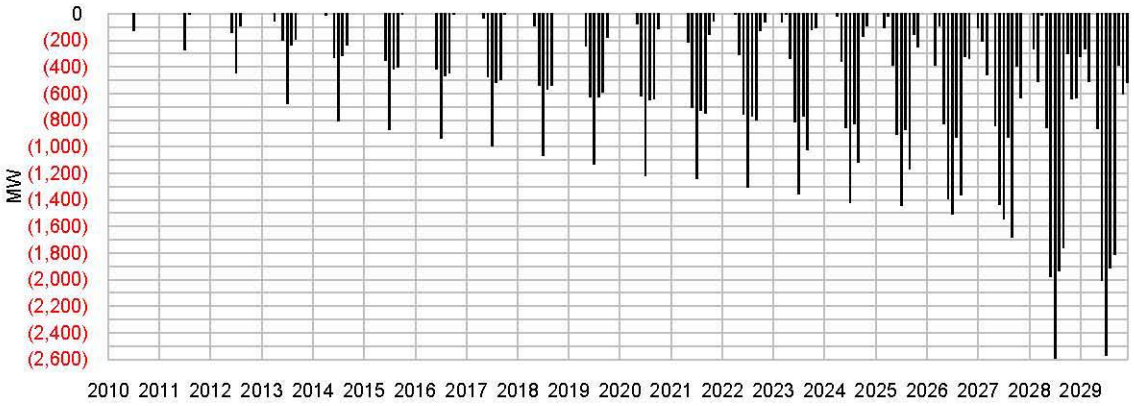
| Peak-Hour | 2026 | | | | | | | | | | | | 2027 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| **Load Forecast (95th%)—w/EE DSM** | (2,460) | (2,421) | (2,199) | (1,828) | (3,206) | (4,129) | (4,393) | (3,818) | (3,664) | (2,254) | (2,475) | (2,702) | (2,393) | (2,382) | (2,168) | (1,783) | (3,216) | (4,163) | (4,424) | (3,825) | (3,703) | (2,247) | (2,460) | (2,639) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,460) | (2,421) | (2,199) | (1,828) | (3,206) | (4,072) | (4,336) | (3,768) | (3,664) | (2,254) | (2,475) | (2,702) | (2,393) | (2,382) | (2,168) | (1,783) | (3,216) | (4,106) | (4,367) | (3,774) | (3,703) | (2,247) | (2,460) | (2,639) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 977 | 421 | 0 | 0 | 0 | 500 | 977 | 977 | 313 | 0 | 313 | 977 | 311 | 0 | 0 | 0 | 0 | 500 | 977 | 977 | 34 | 0 | 0 | 846 |
| Hydro (90th%)—HCC | 895 | 775 | 700 | 585 | 1,173 | 1,035 | 1,005 | 904 | 1,035 | 628 | 605 | 785 | 965 | 690 | 755 | 585 | 1,123 | 1,035 | 1,005 | 945 | 1,035 | 632 | 600 | 785 |
| Hydro (90th%)—Other | 194 | 196 | 186 | 208 | 280 | 261 | 208 | 214 | 201 | 202 | 190 | 195 | 193 | 196 | 186 | 208 | 280 | 241 | 208 | 213 | 200 | 202 | 189 | 195 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,089 | 971 | 886 | 793 | 1,452 | 1,296 | 1,213 | 1,119 | 1,236 | 830 | 795 | 980 | 1,158 | 886 | 941 | 793 | 1,402 | 1,276 | 1,213 | 1,158 | 1,235 | 834 | 789 | 980 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 329 | 412 | 389 | 131 | 329 | 172 | 6 | 125 | 187 | 364 | 522 | 444 | 193 | 504 | 180 | 210 | 327 | 165 | 2 | 126 | 183 | 343 | 523 | 449 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,863** | **2,271** | **1,745** | **1,419** | **2,326** | **2,521** | **2,754** | **2,769** | **2,262** | **1,693** | **2,104** | **2,872** | **2,130** | **1,856** | **1,591** | **1,498** | **2,274** | **2,494** | **2,750** | **2,810** | **1,979** | **1,675** | **1,786** | **2,745** |
| **Monthly Surplus/Deficit** | **0** | **(150)** | **(454)** | **(409)** | **(879)** | **(1,551)** | **(1,582)** | **(999)** | **(1,402)** | **(561)** | **(371)** | **0** | **(263)** | **(526)** | **(577)** | **(285)** | **(942)** | **(1,613)** | **(1,618)** | **(965)** | **(1,724)** | **(572)** | **(674)** | **0** |
| **2006 IRP Resources** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **(107)** | **(62)** | **(532)** | **(1,203)** | **(1,235)** | **(651)** | **(1,055)** | **(214)** | **(24)** | **0** | **0** | **(178)** | **(230)** | **0** | **(594)** | **(1,265)** | **(1,270)** | **(617)** | **(1,376)** | **(224)** | **(326)** | **0** |
| **2009 IRP DSM** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 111 | 111 | 111 | 111 | 112 | 111 | 111 | 111 | 111 | 110 | 112 | 111 | 119 | 119 | 118 | 118 | 120 | 119 | 119 | 119 | 119 | 119 | 119 | 119 |
| **Total New DSM Peak Reduction** | 111 | 111 | 111 | 111 | 112 | 421 | 421 | 167 | 111 | 110 | 112 | 111 | 119 | 119 | 118 | 118 | 120 | 429 | 429 | 175 | 119 | 119 | 119 | 119 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **(420)** | **(782)** | **(813)** | **(484)** | **(944)** | **(103)** | **0** | **0** | **0** | **(59)** | **(111)** | **0** | **(474)** | **(836)** | **(841)** | **(442)** | **(1,257)** | **(105)** | **(207)** | **0** |
| **2009 IRP Resources** | **Jan-26** | **Feb-26** | **Mar-26** | **Apr-26** | **May-26** | **Jun-26** | **Jul-26** | **Aug-26** | **Sep-26** | **Oct-26** | **Nov-26** | **Dec-26** | **Jan-27** | **Feb-27** | **Mar-27** | **Apr-27** | **May-27** | **Jun-27** | **Jul-27** | **Aug-27** | **Sep-27** | **Oct-27** | **Nov-27** | **Dec-27** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2022 Wind (100 MW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2024 Large Aero (2 X 100 MW) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2025 Gateway West Transmission | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2027 Wind (2 X 200 MW) | | | | | | | | | | | | | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| 2028 Large Aero (4 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | | | | | | | | | | | | |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(207)** | **0** | **0** | **0** |

| Peak-Hour | 2028 | | | | | | | | | | | | 2029 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jan-28** | **Feb-28** | **Mar-28** | **Apr-28** | **May-28** | **Jun-28** | **Jul-28** | **Aug-28** | **Sep-28** | **Oct-28** | **Nov-28** | **Dec-28** | **Jan-29** | **Feb-29** | **Mar-29** | **Apr-29** | **May-29** | **Jun-29** | **Jul-29** | **Aug-29** | **Sep-29** | **Oct-29** | **Nov-29** | **Dec-29** |
| **Load Forecast (95th%)—w/EE DSM** | (2,354) | (2,345) | (2,152) | (1,756) | (3,231) | (4,199) | (4,460) | (3,846) | (3,743) | (2,245) | (2,454) | (2,595) | (2,248) | (2,296) | (2,100) | (1,687) | (3,234) | (4,225) | (4,475) | (3,828) | (3,780) | (2,234) | (2,424) | (2,493) |
| Existing DSM (Irrigation Timer) | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 0 | 0 | 0 | 0 | 0 |
| Existing DSM (AC Cool Credit) | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 51 | 51 | 51 | 0 | 0 | 0 | 0 |
| Total Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 51 | 0 | 0 | 0 | 0 |
| **Peak-Hour Load Forecast w/Existing DSM** | (2,354) | (2,345) | (2,152) | (1,756) | (3,231) | (4,143) | (4,403) | (3,795) | (3,743) | (2,245) | (2,454) | (2,595) | (2,248) | (2,296) | (2,100) | (1,687) | (3,234) | (4,169) | (4,419) | (3,778) | (3,780) | (2,234) | (2,424) | (2,493) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Coal (w/Curtailment)** | 563 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro (90th%)—HCC | 962 | 775 | 700 | 575 | 1,171 | 1,035 | 1,005 | 860 | 1,035 | 571 | 600 | 785 | 893 | 775 | 700 | 575 | 1,170 | 1,035 | 1,005 | 945 | 1,035 | 625 | 600 | 785 |
| Hydro (90th%)—Other | 193 | 195 | 185 | 207 | 279 | 239 | 206 | 211 | 200 | 201 | 189 | 194 | 197 | 199 | 184 | 207 | 279 | 237 | 206 | 210 | 199 | 201 | 188 | 193 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,155 | 970 | 885 | 782 | 1,450 | 1,274 | 1,211 | 1,071 | 1,235 | 772 | 789 | 979 | 1,090 | 974 | 884 | 782 | 1,449 | 1,272 | 1,211 | 1,155 | 1,234 | 826 | 788 | 978 |
| **CSPP (PURPA)** | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 | 52 | 51 | 54 | 79 | 129 | 138 | 141 | 132 | 110 | 82 | 58 | 55 |
| **Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PPL Montana—Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| East Side Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Firm Pacific NW Import Capability** | 157 | 333 | 220 | 195 | 324 | 163 | 0 | 120 | 176 | 462 | 518 | 454 | 117 | 280 | 169 | 135 | 321 | 159 | 0 | 129 | 170 | 333 | 526 | 463 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Subtotal** | **2,343** | **1,770** | **1,575** | **1,472** | **2,319** | **1,991** | **1,769** | **1,739** | **1,936** | **1,733** | **1,781** | **1,904** | **1,675** | **1,721** | **1,523** | **1,412** | **2,315** | **1,985** | **1,768** | **1,832** | **1,931** | **1,657** | **1,788** | **1,912** |
| **Monthly Surplus/Deficit** | **(11)** | **(576)** | **(577)** | **(284)** | **(912)** | **(2,152)** | **(2,634)** | **(2,056)** | **(1,806)** | **(512)** | **(673)** | **(691)** | **(573)** | **(575)** | **(577)** | **(276)** | **(919)** | **(2,184)** | **(2,651)** | **(1,946)** | **(1,850)** | **(576)** | **(636)** | **(581)** |
| **2006 IRP Resources** | **Jan-28** | **Feb-28** | **Mar-28** | **Apr-28** | **May-28** | **Jun-28** | **Jul-28** | **Aug-28** | **Sep-28** | **Oct-28** | **Nov-28** | **Dec-28** | **Jan-29** | **Feb-29** | **Mar-29** | **Apr-29** | **May-29** | **Jun-29** | **Jul-29** | **Aug-29** | **Sep-29** | **Oct-29** | **Nov-29** | **Dec-29** |
| 2012 Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | **0** | **(228)** | **(229)** | **0** | **(565)** | **(1,804)** | **(2,287)** | **(1,709)** | **(1,459)** | **(165)** | **(325)** | **(344)** | **(225)** | **(228)** | **(229)** | **0** | **(572)** | **(1,836)** | **(2,303)** | **(1,598)** | **(1,502)** | **(229)** | **(288)** | **(233)** |
| **2009 IRP DSM** | **Jan-28** | **Feb-28** | **Mar-28** | **Apr-28** | **May-28** | **Jun-28** | **Jul-28** | **Aug-28** | **Sep-28** | **Oct-28** | **Nov-28** | **Dec-28** | **Jan-29** | **Feb-29** | **Mar-29** | **Apr-29** | **May-29** | **Jun-29** | **Jul-29** | **Aug-29** | **Sep-29** | **Oct-29** | **Nov-29** | **Dec-29** |
| Commercial (FlexPeak) | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 57 | 57 | 57 | 0 | 0 | 0 | 0 |
| Irrigation Peak Rewards | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 254 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency Peak Reduction | 128 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 128 | 127 | 127 | 128 |
| **Total New DSM Peak Reduction** | 128 | 127 | 127 | 127 | 128 | 438 | 438 | 184 | 127 | 127 | 127 | 128 | 127 | 127 | 127 | 127 | 128 | 438 | 438 | 184 | 128 | 127 | 127 | 128 |
| **Remaining Monthly Surplus/Deficit** | **0** | **(101)** | **(103)** | **0** | **(437)** | **(1,366)** | **(1,849)** | **(1,525)** | **(1,331)** | **(38)** | **(198)** | **(216)** | **(98)** | **(101)** | **(103)** | **0** | **(444)** | **(1,398)** | **(1,866)** | **(1,415)** | **(1,374)** | **(102)** | **(161)** | **(106)** |
| **2009 IRP Resources** | **Jan-28** | **Feb-28** | **Mar-28** | **Apr-28** | **May-28** | **Jun-28** | **Jul-28** | **Aug-28** | **Sep-28** | **Oct-28** | **Nov-28** | **Dec-28** | **Jan-29** | **Feb-29** | **Mar-29** | **Apr-29** | **May-29** | **Jun-29** | **Jul-29** | **Aug-29** | **Sep-29** | **Oct-29** | **Nov-29** | **Dec-29** |
| 2015 Boardman–Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| 2015 Shoshone Falls Upgrade (49 MW) | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 3 | 10 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2017 Boardman–Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| 2020 Large Aero (100 MW) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2022 Wind (100 MW) | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 2024 Large Aero (2 X 100 MW) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2025 Gateway West Transmission | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2026 Large Aero (2 X 100 MW) | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| 2027 Wind (2 X 200 MW) | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| 2028 Large Aero (4 X 100 MW) | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 |
| 2029 Large Aero (5 X 100 MW) | | | | | | | | | | | | | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(399)** | **(75)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

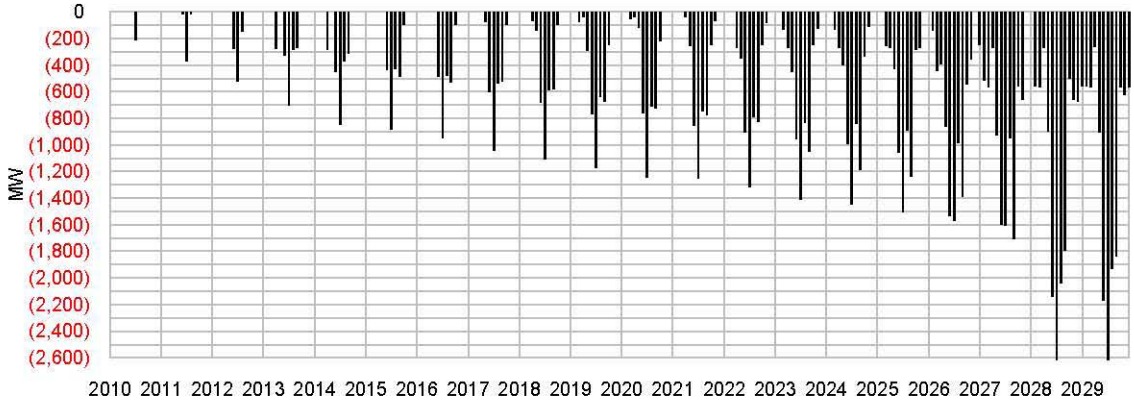
**Peak Hour Deficits with Existing Resources**
(50th Percentile Water and 90th Percentile Load)




**Peak Hour Deficits with Existing Resources**
(70th Percentile Water and 95th Percentile Load)




**Peak Hour Deficits with Existing Resources**
(90th Percentile Water and 95th Percentile Load)



**Peak Hour Deficits with 2009 IRP Resources**
(50th Percentile Water and 90th Percentile Load)




**Peak Hour Deficits with 2009 IRP Resources**
(70th Percentile Water and 95th Percentile Load)




**Peak Hour Deficits with Existing Resources**
(90th Percentile Water and 95th Percentile Load)



## 2009 Integrated Resource Plan

### Average Megawatt Hydro Output from PDR580

### 50th Percentile Water, 50th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2010 | HCC | 290.8 | 405.9 | 352.8 | 427.6 | 424.6 | 352.3 | 250.0 | 179.7 | 225.7 | 191.8 | 152.2 | 250.8 | 291.1 |
| OXBOW | 2010 | HCC | 118.0 | 169.0 | 154.4 | 185.9 | 173.0 | 143.8 | 106.1 | 78.9 | 101.9 | 88.6 | 69.3 | 105.6 | 124.2 |
| HELLS CANYON | 2010 | HCC | 232.4 | 335.5 | 311.2 | 375.4 | 356.1 | 292.1 | 210.3 | 155.4 | 199.1 | 174.8 | 138.0 | 209.3 | 248.4 |
| 1000 SPRINGS | 2010 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2010 | ROR | 24.1 | 26.5 | 23.6 | 57.7 | 80.4 | 86.4 | 79.2 | 60.2 | 36.4 | 16.8 | 0.0 | 19.9 | 42.7 |
| BLISS | 2010 | ROR | 49.7 | 52.2 | 45.5 | 52.0 | 49.6 | 43.3 | 37.5 | 35.4 | 38.9 | 40.6 | 39.8 | 48.9 | 44.4 |
| C.J. STRIKE | 2010 | ROR | 67.0 | 68.6 | 60.2 | 68.7 | 65.8 | 53.6 | 41.0 | 39.3 | 46.8 | 51.9 | 52.7 | 64.2 | 56.6 |
| CASCADE | 2010 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2010 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2010 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2010 | ROR | 35.9 | 37.2 | 30.2 | 35.7 | 34.3 | 29.2 | 24.6 | 22.4 | 24.9 | 26.3 | 25.3 | 34.4 | 30.0 |
| MILNER | 2010 | ROR | 42.4 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 5.0 | 36.7 | 21.6 |
| SHOSHONE FALLS | 2010 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.5 | 11.3 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2010 | ROR | 21.5 | 22.0 | 19.7 | 22.1 | 21.1 | 17.5 | 14.1 | 13.3 | 15.2 | 16.7 | 17.1 | 20.8 | 18.4 |
| TWIN FALLS | 2010 | ROR | 42.4 | 44.3 | 28.9 | 40.8 | 35.3 | 21.9 | 14.0 | 6.6 | 6.6 | 7.3 | 9.5 | 37.3 | 24.5 |
| UPPER MALAD | 2010 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2010 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.8 | 15.3 | 13.8 | 15.4 | 16.4 | 15.6 | 19.1 | 17.0 |
| UPPER SALMON 3&4 | 2010 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 14.3 | 13.0 | 14.4 | 15.2 | 14.6 | 17.7 | 16.0 |
| **HCC TOTAL** | | | **641.2** | **910.4** | **818.4** | **988.9** | **953.7** | **788.2** | **566.4** | **414.0** | **526.6** | **455.2** | **359.5** | **565.7** | **663.7** |
| **ROR TOTAL** | | | **360.5** | **374.8** | **311.1** | **401.3** | **403.7** | **355.3** | **295.0** | **251.9** | **246.6** | **233.4** | **221.3** | **339.8** | **315.9** |
| **TOTAL** | | | **1001.7** | **1285.2** | **1129.5** | **1390.2** | **1357.3** | **1143.5** | **861.4** | **665.9** | **773.2** | **688.6** | **580.8** | **905.5** | **979.5** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2011 | HCC | 290.8 | 405.7 | 352.7 | 427.5 | 424.5 | 352.2 | 249.9 | 179.6 | 225.3 | 192.1 | 152.0 | 250.7 | 291.0 |
| OXBOW | 2011 | HCC | 118.0 | 169.0 | 154.3 | 185.9 | 173.0 | 143.8 | 106.0 | 78.9 | 101.7 | 88.7 | 69.2 | 105.5 | 124.1 |
| HELLS CANYON | 2011 | HCC | 232.3 | 335.4 | 311.1 | 375.3 | 356.1 | 292.1 | 210.2 | 155.2 | 198.7 | 175.0 | 137.9 | 209.3 | 248.3 |
| 1000 SPRINGS | 2011 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2011 | ROR | 23.9 | 26.4 | 23.3 | 57.5 | 79.8 | 85.9 | 78.7 | 59.9 | 36.3 | 16.7 | 0.0 | 19.8 | 42.4 |
| BLISS | 2011 | ROR | 49.7 | 52.1 | 45.5 | 52.0 | 49.6 | 43.2 | 37.4 | 35.4 | 38.9 | 40.6 | 39.8 | 48.9 | 44.4 |
| C.J. STRIKE | 2011 | ROR | 67.0 | 68.5 | 60.2 | 68.7 | 65.7 | 53.6 | 40.9 | 39.2 | 46.7 | 51.8 | 52.7 | 64.1 | 56.5 |
| CASCADE | 2011 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2011 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2011 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2011 | ROR | 35.9 | 37.2 | 30.2 | 35.7 | 34.3 | 29.2 | 24.6 | 22.4 | 24.9 | 26.3 | 25.3 | 34.4 | 30.0 |
| MILNER | 2011 | ROR | 42.3 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 5.0 | 36.7 | 21.5 |
| SHOSHONE FALLS | 2011 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.3 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2011 | ROR | 21.5 | 22.0 | 19.7 | 22.1 | 21.1 | 17.5 | 14.0 | 13.2 | 15.2 | 16.7 | 17.1 | 20.7 | 18.4 |
| TWIN FALLS | 2011 | ROR | 42.4 | 44.3 | 28.9 | 40.8 | 35.3 | 21.9 | 14.0 | 6.6 | 6.6 | 7.3 | 9.5 | 37.3 | 24.5 |
| UPPER MALAD | 2011 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2011 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.8 | 15.3 | 13.8 | 15.4 | 16.4 | 15.6 | 19.1 | 17.0 |
| UPPER SALMON 3&4 | 2011 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 14.2 | 13.0 | 14.4 | 15.2 | 14.5 | 17.7 | 16.0 |
| **HCC TOTAL** | | | **641.1** | **910.1** | **818.1** | **988.7** | **953.5** | **788.1** | **566.1** | **413.7** | **525.7** | **455.8** | **359.1** | **565.5** | **663.4** |
| **ROR TOTAL** | | | **360.2** | **374.5** | **310.8** | **401.1** | **403.0** | **354.7** | **294.1** | **251.4** | **246.3** | **233.2** | **221.2** | **339.5** | **315.5** |
| **TOTAL** | | | **1001.3** | **1284.6** | **1128.9** | **1389.8** | **1356.5** | **1142.8** | **860.2** | **665.1** | **771.9** | **689.0** | **580.3** | **905.0** | **978.9** |

## 2009 Integrated Resource Plan

### Average Megawatt Hydro Output from PDR580
### 50th Percentile Water, 50th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2012 | HCC | 290.7 | 405.7 | 352.6 | 427.4 | 424.4 | 352.1 | 249.8 | 179.5 | 225.0 | 192.3 | 152.0 | 250.6 | 291.2 |
| OXBOW | 2012 | HCC | 118.0 | 169.0 | 154.3 | 185.8 | 173.0 | 143.7 | 106.0 | 78.9 | 101.5 | 88.8 | 69.2 | 105.5 | 124.2 |
| HELLS CANYON | 2012 | HCC | 232.2 | 335.4 | 311.1 | 375.3 | 356.0 | 292.0 | 210.2 | 155.2 | 198.4 | 175.1 | 137.9 | 209.2 | 248.5 |
| 1000 SPRINGS | 2012 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2012 | ROR | 23.9 | 26.3 | 21.9 | 57.4 | 79.6 | 85.4 | 78.3 | 59.4 | 35.9 | 16.6 | 0.0 | 19.7 | 42.1 |
| BLISS | 2012 | ROR | 49.7 | 52.1 | 45.5 | 51.9 | 49.6 | 43.2 | 37.4 | 35.4 | 38.9 | 40.5 | 39.8 | 48.9 | 44.4 |
| C.J. STRIKE | 2012 | ROR | 67.0 | 68.5 | 60.2 | 68.6 | 65.7 | 53.5 | 40.9 | 39.2 | 46.7 | 51.8 | 52.6 | 64.1 | 56.5 |
| CASCADE | 2012 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2012 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2012 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2012 | ROR | 35.9 | 37.2 | 30.2 | 35.7 | 34.2 | 29.2 | 24.5 | 22.4 | 24.8 | 26.3 | 25.3 | 34.3 | 30.0 |
| MILNER | 2012 | ROR | 42.3 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 5.0 | 36.7 | 21.6 |
| SHOSHONE FALLS | 2012 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2012 | ROR | 21.5 | 22.0 | 19.7 | 22.1 | 21.1 | 17.5 | 14.0 | 13.2 | 15.2 | 16.7 | 17.1 | 20.5 | 18.4 |
| TWIN FALLS | 2012 | ROR | 42.4 | 44.3 | 28.9 | 40.8 | 35.3 | 21.9 | 14.0 | 6.6 | 6.6 | 7.3 | 9.5 | 37.3 | 24.5 |
| UPPER MALAD | 2012 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2012 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.8 | 15.2 | 13.7 | 15.4 | 16.4 | 15.6 | 19.1 | 17.0 |
| UPPER SALMON 3&4 | 2012 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 14.2 | 13.0 | 14.4 | 15.2 | 14.5 | 17.7 | 16.0 |
| **HCC TOTAL** | | | **640.9** | **910.1** | **818.0** | **988.5** | **953.3** | **787.8** | **566.0** | **413.6** | **524.9** | **456.2** | **359.1** | **565.3** | **664.0** |
| **ROR TOTAL** | | | **360.2** | **374.4** | **309.4** | **400.8** | **402.7** | **354.1** | **293.5** | **250.8** | **245.8** | **232.9** | **221.1** | **339.1** | **315.2** |
| **TOTAL** | | | **1001.1** | **1284.5** | **1127.4** | **1389.3** | **1355.9** | **1141.9** | **859.5** | **664.4** | **770.7** | **689.1** | **580.2** | **904.4** | **979.2** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2013 | HCC | 290.5 | 405.6 | 352.5 | 427.3 | 424.3 | 352.0 | 249.7 | 179.4 | 225.0 | 192.0 | 152.2 | 250.5 | 290.8 |
| OXBOW | 2013 | HCC | 117.9 | 168.9 | 154.2 | 185.8 | 172.9 | 143.7 | 105.9 | 78.8 | 101.5 | 88.6 | 69.3 | 105.4 | 124.0 |
| HELLS CANYON | 2013 | HCC | 232.1 | 335.3 | 311.0 | 375.2 | 355.9 | 291.9 | 210.0 | 155.1 | 198.3 | 174.8 | 138.1 | 209.1 | 248.2 |
| 1000 SPRINGS | 2013 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2013 | ROR | 23.8 | 26.3 | 21.8 | 57.3 | 79.3 | 84.9 | 78.0 | 59.2 | 35.6 | 16.6 | 0.0 | 19.6 | 42.0 |
| BLISS | 2013 | ROR | 49.7 | 52.1 | 45.5 | 51.9 | 49.6 | 43.2 | 37.3 | 35.4 | 38.9 | 40.5 | 39.8 | 48.8 | 44.3 |
| C.J. STRIKE | 2013 | ROR | 66.9 | 68.5 | 60.2 | 68.6 | 65.7 | 53.5 | 40.8 | 39.2 | 46.7 | 51.7 | 52.6 | 64.1 | 56.5 |
| CASCADE | 2013 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2013 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2013 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2013 | ROR | 35.8 | 37.2 | 30.2 | 35.6 | 34.2 | 29.1 | 24.5 | 22.3 | 24.8 | 26.3 | 25.2 | 34.3 | 29.9 |
| MILNER | 2013 | ROR | 42.2 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 5.0 | 36.7 | 21.5 |
| SHOSHONE FALLS | 2013 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2013 | ROR | 21.5 | 22.0 | 19.7 | 22.1 | 21.1 | 17.5 | 14.0 | 13.2 | 15.2 | 16.7 | 17.1 | 20.5 | 18.4 |
| TWIN FALLS | 2013 | ROR | 42.4 | 44.3 | 28.9 | 40.8 | 35.3 | 21.9 | 14.0 | 6.6 | 6.6 | 7.3 | 9.5 | 37.3 | 24.5 |
| UPPER MALAD | 2013 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2013 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.8 | 15.2 | 13.7 | 15.4 | 16.3 | 15.6 | 19.1 | 17.0 |
| UPPER SALMON 3&4 | 2013 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 14.2 | 12.9 | 14.4 | 15.2 | 14.5 | 17.7 | 16.0 |
| **HCC TOTAL** | | | **640.5** | **909.8** | **817.7** | **988.3** | **953.0** | **787.6** | **565.6** | **413.3** | **524.8** | **455.4** | **359.6** | **565.0** | **663.0** |
| **ROR TOTAL** | | | **359.8** | **374.4** | **309.3** | **400.6** | **402.4** | **353.5** | **293.0** | **250.4** | **245.5** | **232.7** | **221.0** | **338.9** | **314.7** |
| **TOTAL** | | | **1000.3** | **1284.2** | **1127.0** | **1388.9** | **1355.4** | **1141.1** | **858.6** | **663.7** | **770.2** | **688.1** | **580.6** | **903.9** | **977.8** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2014 | HCC | 281.9 | 405.0 | 352.0 | 426.8 | 423.7 | 351.4 | 235.7 | 178.9 | 224.0 | 192.4 | 152.1 | 250.0 | 288.5 |
| OXBOW | 2014 | HCC | 117.7 | 168.7 | 154.0 | 185.6 | 172.7 | 143.5 | 100.0 | 78.6 | 101.0 | 88.8 | 69.2 | 105.2 | 123.4 |
| HELLS CANYON | 2014 | HCC | 233.5 | 334.9 | 310.6 | 374.8 | 355.5 | 291.5 | 198.5 | 154.7 | 197.3 | 175.1 | 137.9 | 208.7 | 247.0 |
| 1000 SPRINGS | 2014 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2014 | ROR | 23.4 | 26.0 | 21.5 | 57.2 | 78.9 | 83.6 | 71.1 | 56.5 | 34.1 | 16.2 | 0.0 | 19.0 | 40.7 |
| BLISS | 2014 | ROR | 49.8 | 52.0 | 45.3 | 51.8 | 49.5 | 43.0 | 33.7 | 35.2 | 38.7 | 40.4 | 39.6 | 48.7 | 43.9 |
| C.J. STRIKE | 2014 | ROR | 66.8 | 68.3 | 60.2 | 68.4 | 65.5 | 53.3 | 36.1 | 39.0 | 46.5 | 51.6 | 52.4 | 63.8 | 55.9 |
| CASCADE | 2014 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2014 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2014 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2014 | ROR | 35.7 | 37.1 | 30.2 | 35.5 | 34.1 | 29.0 | 21.3 | 22.2 | 24.7 | 26.2 | 25.1 | 34.2 | 29.6 |
| MILNER | 2014 | ROR | 42.0 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 35.5 | 20.6 |
| SHOSHONE FALLS | 2014 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2014 | ROR | 21.4 | 21.9 | 19.6 | 22.0 | 21.0 | 17.5 | 12.6 | 13.2 | 15.2 | 16.5 | 17.1 | 20.4 | 18.2 |
| TWIN FALLS | 2014 | ROR | 42.2 | 44.3 | 28.9 | 40.8 | 35.3 | 21.9 | 6.2 | 6.5 | 6.6 | 7.3 | 9.5 | 36.6 | 23.7 |
| UPPER MALAD | 2014 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2014 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.7 | 12.8 | 13.7 | 15.3 | 16.3 | 15.5 | 19.1 | 16.7 |
| UPPER SALMON 3&4 | 2014 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.2 | 12.1 | 12.9 | 14.3 | 15.1 | 14.5 | 17.7 | 15.8 |
| **HCC TOTAL** | | | **633.1** | **908.6** | **816.6** | **987.2** | **951.9** | **786.4** | **534.2** | **412.2** | **522.2** | **456.3** | **359.2** | **563.9** | **658.9** |
| **ROR TOTAL** | | | **358.8** | **373.6** | **308.7** | **400.0** | **401.5** | **351.5** | **249.5** | **247.1** | **243.3** | **231.7** | **220.4** | **335.8** | **309.7** |
| **TOTAL** | | | **991.9** | **1282.2** | **1125.3** | **1387.2** | **1353.3** | **1137.9** | **783.7** | **659.3** | **765.5** | **688.0** | **579.6** | **899.7** | **968.6** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2015 | HCC | 281.4 | 404.5 | 351.5 | 426.3 | 423.2 | 350.9 | 235.2 | 178.5 | 219.0 | 192.5 | 152.3 | 249.4 | 287.8 |
| OXBOW | 2015 | HCC | 117.5 | 168.5 | 153.8 | 185.4 | 172.5 | 143.3 | 99.8 | 78.4 | 100.5 | 88.7 | 69.3 | 105.0 | 123.2 |
| HELLS CANYON | 2015 | HCC | 233.1 | 334.5 | 310.1 | 374.4 | 355.1 | 291.1 | 198.1 | 154.3 | 197.2 | 175.0 | 138.0 | 208.2 | 246.7 |
| 1000 SPRINGS | 2015 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2015 | ROR | 23.1 | 25.9 | 21.3 | 57.6 | 78.3 | 82.3 | 68.7 | 53.6 | 33.5 | 16.2 | 0.0 | 17.5 | 39.9 |
| BLISS | 2015 | ROR | 49.8 | 51.9 | 45.2 | 51.7 | 49.3 | 42.9 | 33.5 | 35.1 | 38.6 | 40.3 | 39.5 | 48.4 | 43.8 |
| C.J. STRIKE | 2015 | ROR | 66.6 | 68.1 | 60.2 | 68.3 | 65.3 | 53.2 | 35.9 | 38.8 | 46.3 | 51.4 | 52.3 | 62.5 | 55.6 |
| CASCADE | 2015 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2015 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2015 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2015 | ROR | 35.6 | 37.0 | 30.2 | 35.4 | 34.0 | 28.9 | 21.2 | 22.1 | 24.6 | 26.1 | 25.0 | 33.6 | 29.4 |
| MILNER | 2015 | ROR | 41.7 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2015 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.0 | 10.3 | 10.4 | 11.1 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2015 | ROR | 21.4 | 21.9 | 19.6 | 21.9 | 21.0 | 17.5 | 12.5 | 13.1 | 15.1 | 16.4 | 17.0 | 20.3 | 18.1 |
| TWIN FALLS | 2015 | ROR | 42.0 | 44.2 | 28.9 | 40.7 | 35.3 | 21.8 | 6.2 | 6.5 | 6.5 | 7.2 | 9.5 | 34.9 | 23.5 |
| UPPER MALAD | 2015 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2015 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.6 | 12.7 | 13.6 | 15.2 | 16.2 | 15.4 | 19.1 | 16.7 |
| UPPER SALMON 3&4 | 2015 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.2 | 12.0 | 12.8 | 14.2 | 15.1 | 14.4 | 17.7 | 15.8 |
| **HCC TOTAL** | | | **632.0** | **907.5** | **815.4** | **986.1** | **950.7** | **785.3** | **533.1** | **411.2** | **516.7** | **456.2** | **359.6** | **562.6** | **657.6** |
| **ROR TOTAL** | | | **357.7** | **373.0** | **308.4** | **399.9** | **400.4** | **349.7** | **246.3** | **243.4** | **241.9** | **230.9** | **219.8** | **328.8** | **307.9** |
| **TOTAL** | | | **989.7** | **1280.5** | **1123.8** | **1386.0** | **1351.1** | **1135.0** | **779.4** | **654.6** | **758.6** | **687.1** | **579.4** | **891.4** | **965.5** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2016 | HCC | 280.9 | 404.0 | 351.0 | 425.8 | 422.7 | 350.4 | 234.7 | 170.8 | 217.8 | 192.5 | 152.5 | 248.9 | 287.0 |
| OXBOW | 2016 | HCC | 117.3 | 168.3 | 153.6 | 185.2 | 172.3 | 143.1 | 99.6 | 78.2 | 99.9 | 88.6 | 69.4 | 104.8 | 123.1 |
| HELLS CANYON | 2016 | HCC | 232.7 | 334.0 | 309.7 | 374.0 | 354.7 | 290.7 | 197.7 | 153.4 | 196.0 | 174.8 | 138.2 | 207.8 | 246.5 |
| 1000 SPRINGS | 2016 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2016 | ROR | 22.8 | 25.9 | 20.7 | 57.2 | 77.5 | 81.6 | 67.8 | 52.2 | 33.4 | 16.2 | 0.0 | 17.6 | 39.4 |
| BLISS | 2016 | ROR | 49.9 | 51.7 | 45.1 | 51.6 | 49.2 | 42.8 | 33.5 | 35.0 | 38.5 | 40.1 | 39.4 | 48.2 | 43.7 |
| C.J. STRIKE | 2016 | ROR | 66.0 | 67.9 | 60.2 | 68.1 | 65.1 | 53.0 | 35.7 | 38.7 | 46.1 | 51.2 | 52.1 | 62.3 | 55.5 |
| CASCADE | 2016 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2016 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2016 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2016 | ROR | 35.5 | 36.9 | 30.2 | 35.3 | 33.9 | 28.8 | 21.1 | 22.0 | 24.5 | 26.0 | 24.9 | 33.5 | 29.4 |
| MILNER | 2016 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2016 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.9 | 10.3 | 10.3 | 11.1 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2016 | ROR | 21.3 | 21.8 | 19.5 | 21.9 | 21.0 | 17.5 | 12.5 | 13.1 | 15.1 | 16.4 | 17.0 | 20.1 | 18.1 |
| TWIN FALLS | 2016 | ROR | 41.4 | 44.2 | 28.9 | 40.7 | 35.2 | 21.8 | 6.1 | 6.4 | 6.5 | 7.2 | 9.5 | 34.9 | 23.5 |
| UPPER MALAD | 2016 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2016 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.6 | 12.6 | 13.5 | 15.2 | 16.1 | 15.3 | 19.1 | 16.7 |
| UPPER SALMON 3&4 | 2016 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.1 | 12.0 | 12.7 | 14.2 | 15.0 | 14.3 | 17.7 | 15.7 |
| **HCC TOTAL** | | | **630.9** | **906.3** | **814.3** | **985.0** | **949.6** | **784.2** | **532.0** | **402.4** | **513.7** | **455.9** | **360.1** | **561.5** | **656.6** |
| **ROR TOTAL** | | | **356.0** | **372.4** | **307.6** | **399.1** | **399.1** | **348.5** | **244.8** | **241.4** | **241.3** | **230.2** | **219.2** | **328.2** | **307.0** |
| **TOTAL** | | | **986.9** | **1278.7** | **1121.9** | **1384.1** | **1348.7** | **1132.7** | **776.8** | **643.8** | **754.9** | **686.1** | **579.3** | **889.7** | **963.6** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2017 | HCC | 280.3 | 403.5 | 350.5 | 425.3 | 422.2 | 349.9 | 234.2 | 170.2 | 216.4 | 192.8 | 152.3 | 248.9 | 286.3 |
| OXBOW | 2017 | HCC | 117.0 | 168.1 | 153.4 | 184.9 | 172.1 | 142.8 | 99.3 | 77.9 | 99.2 | 88.7 | 69.3 | 104.7 | 122.7 |
| HELLS CANYON | 2017 | HCC | 232.2 | 333.7 | 309.3 | 373.5 | 354.3 | 290.3 | 197.3 | 152.9 | 194.6 | 174.9 | 138.0 | 207.7 | 245.8 |
| 1000 SPRINGS | 2017 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2017 | ROR | 22.8 | 25.9 | 20.6 | 57.7 | 76.8 | 81.3 | 67.6 | 52.0 | 33.4 | 16.3 | 4.4 | 17.5 | 39.8 |
| BLISS | 2017 | ROR | 49.9 | 51.6 | 45.0 | 51.4 | 49.1 | 42.7 | 33.4 | 34.9 | 38.4 | 40.0 | 39.2 | 48.1 | 43.6 |
| C.J. STRIKE | 2017 | ROR | 65.9 | 67.8 | 60.2 | 67.9 | 65.0 | 52.8 | 35.5 | 38.5 | 46.0 | 51.1 | 51.9 | 62.1 | 55.3 |
| CASCADE | 2017 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2017 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2017 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2017 | ROR | 35.4 | 36.8 | 30.1 | 35.2 | 33.8 | 28.7 | 21.0 | 21.9 | 24.4 | 25.9 | 24.8 | 33.4 | 29.2 |
| MILNER | 2017 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2017 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.9 | 10.2 | 10.3 | 11.1 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2017 | ROR | 21.3 | 21.8 | 19.5 | 21.8 | 20.9 | 17.5 | 12.4 | 13.0 | 15.0 | 16.3 | 16.9 | 20.0 | 18.0 |
| TWIN FALLS | 2017 | ROR | 41.4 | 44.2 | 28.9 | 40.7 | 35.2 | 21.8 | 6.1 | 6.4 | 6.4 | 7.2 | 9.5 | 34.8 | 23.4 |
| UPPER MALAD | 2017 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2017 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.5 | 12.5 | 13.4 | 15.1 | 16.0 | 15.3 | 19.1 | 16.6 |
| UPPER SALMON 3&4 | 2017 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.0 | 11.9 | 12.7 | 14.1 | 14.9 | 14.2 | 17.7 | 15.7 |
| **HCC TOTAL** | | | **629.5** | **905.3** | **813.2** | **983.7** | **948.5** | **783.0** | **530.8** | **401.0** | **510.2** | **456.4** | **359.6** | **561.3** | **654.8** |
| **ROR TOTAL** | | | **355.8** | **372.1** | **307.3** | **399.0** | **398.0** | **347.6** | **243.9** | **240.5** | **240.6** | **229.7** | **222.9** | **327.5** | **306.6** |
| **TOTAL** | | | **985.3** | **1277.4** | **1120.5** | **1382.7** | **1346.5** | **1130.6** | **774.7** | **641.5** | **750.8** | **686.1** | **582.5** | **888.8** | **961.4** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2018 | HCC | 279.9 | 402.9 | 350.0 | 424.8 | 421.7 | 349.3 | 233.7 | 169.5 | 215.4 | 192.8 | 152.6 | 248.3 | 285.8 |
| OXBOW | 2018 | HCC | 116.8 | 167.9 | 153.2 | 184.7 | 171.9 | 142.6 | 99.1 | 77.6 | 98.6 | 88.6 | 69.3 | 104.5 | 122.5 |
| HELLS CANYON | 2018 | HCC | 231.9 | 333.2 | 308.9 | 373.1 | 353.9 | 289.8 | 196.8 | 152.3 | 193.5 | 174.7 | 138.1 | 207.3 | 245.4 |
| 1000 SPRINGS | 2018 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2018 | ROR | 22.6 | 25.8 | 20.4 | 57.6 | 76.1 | 80.8 | 67.6 | 52.0 | 33.5 | 16.3 | 4.5 | 17.4 | 39.6 |
| BLISS | 2018 | ROR | 49.9 | 51.5 | 44.8 | 51.3 | 49.0 | 42.6 | 33.2 | 34.7 | 38.2 | 39.9 | 39.1 | 48.0 | 43.5 |
| C.J. STRIKE | 2018 | ROR | 65.7 | 67.6 | 60.1 | 67.7 | 64.8 | 52.6 | 35.4 | 38.3 | 45.8 | 50.9 | 51.8 | 61.9 | 55.1 |
| CASCADE | 2018 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2018 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2018 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2018 | ROR | 35.3 | 36.7 | 30.0 | 35.1 | 33.7 | 28.6 | 20.9 | 21.8 | 24.3 | 25.8 | 24.7 | 33.3 | 29.1 |
| MILNER | 2018 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2018 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.8 | 10.2 | 10.2 | 11.0 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2018 | ROR | 21.2 | 21.7 | 19.4 | 21.8 | 20.9 | 17.4 | 12.4 | 13.0 | 15.0 | 16.3 | 16.9 | 20.0 | 18.0 |
| TWIN FALLS | 2018 | ROR | 41.3 | 44.1 | 28.9 | 40.7 | 35.2 | 21.8 | 6.1 | 6.4 | 6.4 | 7.1 | 9.5 | 34.8 | 23.4 |
| UPPER MALAD | 2018 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2018 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.4 | 12.4 | 13.3 | 15.0 | 16.0 | 15.2 | 19.1 | 16.6 |
| UPPER SALMON 3&4 | 2018 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.0 | 11.8 | 12.6 | 14.0 | 14.9 | 14.2 | 17.7 | 15.7 |
| **HCC TOTAL** | | | **628.6** | **904.0** | **812.1** | **982.6** | **947.4** | **781.7** | **529.6** | **399.4** | **507.4** | **456.1** | **360.0** | **560.1** | **653.7** |
| **ROR TOTAL** | | | **355.1** | **371.4** | **306.6** | **398.5** | **396.9** | **346.5** | **243.2** | **239.8** | **239.9** | **229.1** | **222.6** | **327.0** | **305.9** |
| **TOTAL** | | | **983.7** | **1275.4** | **1118.7** | **1381.1** | **1344.3** | **1128.2** | **772.8** | **639.2** | **747.2** | **685.2** | **582.6** | **887.1** | **959.6** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2019 | HCC | 279.4 | 402.4 | 349.5 | 424.3 | 421.1 | 348.8 | 233.1 | 169.3 | 214.7 | 193.0 | 152.4 | 247.9 | 285.4 |
| OXBOW | 2019 | HCC | 116.6 | 167.7 | 153.0 | 184.5 | 171.7 | 142.4 | 98.9 | 77.5 | 98.2 | 88.6 | 69.2 | 104.3 | 122.3 |
| HELLS CANYON | 2019 | HCC | 231.5 | 332.8 | 308.5 | 372.7 | 353.5 | 289.4 | 196.4 | 152.2 | 192.7 | 174.8 | 137.9 | 206.9 | 245.0 |
| 1000 SPRINGS | 2019 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2019 | ROR | 22.6 | 25.8 | 20.3 | 57.8 | 76.1 | 80.9 | 67.7 | 51.9 | 33.5 | 16.4 | 4.6 | 17.5 | 39.7 |
| BLISS | 2019 | ROR | 49.8 | 51.4 | 44.7 | 51.2 | 48.8 | 42.5 | 33.1 | 34.6 | 38.2 | 39.9 | 39.0 | 47.9 | 43.4 |
| C.J. STRIKE | 2019 | ROR | 65.5 | 67.4 | 59.9 | 67.6 | 64.6 | 52.5 | 35.2 | 38.1 | 45.6 | 50.7 | 51.6 | 61.8 | 54.9 |
| CASCADE | 2019 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2019 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2019 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2019 | ROR | 35.2 | 36.6 | 29.9 | 35.0 | 33.6 | 28.5 | 20.8 | 21.7 | 24.2 | 25.7 | 24.6 | 33.2 | 29.0 |
| MILNER | 2019 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2019 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.8 | 10.1 | 10.2 | 11.0 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2019 | ROR | 21.2 | 21.7 | 19.4 | 21.7 | 20.8 | 17.4 | 12.3 | 12.9 | 14.9 | 16.2 | 16.8 | 20.0 | 17.9 |
| TWIN FALLS | 2019 | ROR | 41.3 | 44.1 | 28.9 | 40.6 | 35.1 | 21.7 | 6.0 | 6.3 | 6.4 | 7.1 | 9.5 | 34.8 | 23.4 |
| UPPER MALAD | 2019 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2019 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.3 | 12.4 | 13.3 | 14.9 | 15.9 | 15.1 | 19.1 | 16.5 |
| UPPER SALMON 3&4 | 2019 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.9 | 11.8 | 12.5 | 14.0 | 14.8 | 14.1 | 17.7 | 15.6 |
| **HCC TOTAL** | | | **627.5** | **902.9** | **811.0** | **981.5** | **946.2** | **780.6** | **528.4** | **399.0** | **505.5** | **456.4** | **359.5** | **559.1** | **652.7** |
| **ROR TOTAL** | | | **354.7** | **371.0** | **306.1** | **398.2** | **396.2** | **346.0** | **242.7** | **238.9** | **239.4** | **228.6** | **222.0** | **326.8** | **305.4** |
| **TOTAL** | | | **982.2** | **1273.9** | **1117.1** | **1379.7** | **1342.4** | **1126.6** | **771.1** | **637.9** | **744.8** | **685.0** | **581.5** | **885.9** | **958.1** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2020 | HCC | 278.8 | 401.9 | 349.0 | 423.8 | 420.6 | 348.2 | 232.6 | 169.3 | 213.7 | 193.4 | 152.6 | 247.3 | 285.3 |
| OXBOW | 2020 | HCC | 116.4 | 167.5 | 152.8 | 184.3 | 171.5 | 142.2 | 98.7 | 77.5 | 97.6 | 88.6 | 69.3 | 104.1 | 122.3 |
| HELLS CANYON | 2020 | HCC | 231.0 | 332.4 | 308.1 | 372.3 | 353.0 | 289.0 | 196.0 | 152.2 | 191.6 | 174.8 | 138.1 | 206.4 | 244.9 |
| 1000 SPRINGS | 2020 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2020 | ROR | 22.7 | 25.9 | 20.2 | 57.3 | 76.1 | 80.8 | 67.7 | 51.9 | 33.5 | 16.7 | 4.7 | 17.6 | 39.6 |
| BLISS | 2020 | ROR | 49.7 | 51.3 | 44.6 | 51.1 | 48.7 | 42.4 | 33.0 | 34.5 | 38.1 | 39.8 | 38.9 | 47.7 | 43.3 |
| C.J. STRIKE | 2020 | ROR | 65.3 | 67.3 | 59.7 | 67.4 | 64.5 | 52.3 | 35.0 | 37.9 | 45.5 | 50.5 | 51.4 | 61.6 | 54.8 |
| CASCADE | 2020 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2020 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2020 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2020 | ROR | 35.1 | 36.5 | 29.8 | 34.9 | 33.5 | 28.4 | 20.7 | 21.6 | 24.1 | 25.6 | 24.5 | 33.1 | 29.0 |
| MILNER | 2020 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2020 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.1 | 10.1 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2020 | ROR | 21.1 | 21.7 | 19.3 | 21.7 | 20.8 | 17.3 | 12.2 | 12.9 | 14.9 | 16.2 | 16.8 | 19.9 | 17.9 |
| TWIN FALLS | 2020 | ROR | 41.3 | 44.1 | 28.9 | 40.6 | 35.1 | 21.7 | 6.0 | 6.3 | 6.3 | 7.0 | 9.5 | 34.7 | 23.4 |
| UPPER MALAD | 2020 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2020 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.2 | 12.3 | 13.2 | 14.8 | 15.8 | 15.0 | 19.2 | 16.5 |
| UPPER SALMON 3&4 | 2020 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.8 | 11.7 | 12.5 | 13.9 | 14.7 | 14.0 | 17.7 | 15.6 |
| **HCC TOTAL** | | | **626.2** | **901.8** | **809.9** | **980.4** | **945.1** | **779.4** | **527.3** | **399.0** | **502.9** | **456.8** | **360.0** | **557.8** | **652.5** |
| **ROR TOTAL** | | | **354.3** | **370.8** | **305.5** | **397.3** | **395.9** | **345.2** | **241.9** | **238.4** | **238.7** | **228.1** | **221.5** | **326.3** | **305.0** |
| **TOTAL** | | | **980.5** | **1272.6** | **1115.4** | **1377.7** | **1341.0** | **1124.6** | **769.2** | **637.4** | **741.6** | **684.9** | **581.5** | **884.1** | **957.5** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2021 | HCC | 278.3 | 401.4 | 348.5 | 423.4 | 420.1 | 347.8 | 232.1 | 169.3 | 213.0 | 193.4 | 152.8 | 246.8 | 284.6 |
| OXBOW | 2021 | HCC | 116.2 | 167.2 | 152.6 | 184.1 | 171.3 | 142.0 | 98.5 | 77.5 | 97.2 | 88.6 | 69.4 | 103.9 | 122.0 |
| HELLS CANYON | 2021 | HCC | 230.6 | 332.0 | 307.7 | 371.9 | 352.6 | 288.6 | 195.6 | 152.2 | 190.8 | 174.7 | 138.2 | 206.0 | 244.3 |
| 1000 SPRINGS | 2021 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2021 | ROR | 22.8 | 26.0 | 20.1 | 57.2 | 75.7 | 80.4 | 67.7 | 52.0 | 33.6 | 16.8 | 4.7 | 17.6 | 39.6 |
| BLISS | 2021 | ROR | 49.6 | 51.1 | 44.5 | 51.0 | 48.6 | 42.2 | 32.8 | 34.3 | 37.9 | 39.7 | 38.7 | 47.6 | 43.1 |
| C.J. STRIKE | 2021 | ROR | 65.2 | 67.1 | 59.6 | 67.2 | 64.3 | 52.1 | 34.8 | 37.8 | 45.3 | 50.4 | 51.2 | 61.4 | 54.6 |
| CASCADE | 2021 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2021 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2021 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2021 | ROR | 35.0 | 36.4 | 29.7 | 34.8 | 33.4 | 28.3 | 20.6 | 21.5 | 24.0 | 25.5 | 24.4 | 33.0 | 28.8 |
| MILNER | 2021 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2021 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.0 | 10.1 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2021 | ROR | 21.1 | 21.6 | 19.3 | 21.6 | 20.5 | 17.3 | 12.2 | 12.8 | 14.8 | 16.1 | 16.7 | 19.9 | 17.8 |
| TWIN FALLS | 2021 | ROR | 41.2 | 44.1 | 28.9 | 40.6 | 35.1 | 21.6 | 6.0 | 6.3 | 6.3 | 7.0 | 9.5 | 34.7 | 23.3 |
| UPPER MALAD | 2021 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2021 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 18.2 | 12.2 | 13.1 | 14.8 | 15.7 | 14.9 | 19.2 | 16.5 |
| UPPER SALMON 3&4 | 2021 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.8 | 11.6 | 12.4 | 13.8 | 14.6 | 14.0 | 17.7 | 15.6 |
| **HCC TOTAL** | | | **625.1** | **900.6** | **808.8** | **979.4** | **943.9** | **778.4** | **526.2** | **399.0** | **501.0** | **456.7** | **360.4** | **556.7** | **651.0** |
| **ROR TOTAL** | | | **354.0** | **370.3** | **305.1** | **396.7** | **394.8** | **344.2** | **241.2** | **237.7** | **238.1** | **227.6** | **220.8** | **325.9** | **304.2** |
| **TOTAL** | | | **979.1** | **1270.9** | **1113.9** | **1376.1** | **1338.7** | **1122.6** | **767.4** | **636.7** | **739.1** | **684.3** | **581.2** | **882.6** | **955.2** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2022 | HCC | 280.6 | 396.6 | 348.0 | 422.9 | 419.6 | 347.2 | 231.6 | 169.2 | 212.3 | 193.4 | 152.7 | 246.8 | 284.2 |
| OXBOW | 2022 | HCC | 117.3 | 165.6 | 152.3 | 183.9 | 171.1 | 141.8 | 98.3 | 77.4 | 96.8 | 88.5 | 69.3 | 103.9 | 121.8 |
| HELLS CANYON | 2022 | HCC | 232.8 | 328.7 | 307.3 | 371.5 | 352.3 | 288.2 | 195.1 | 152.0 | 189.9 | 174.5 | 138.1 | 206.0 | 244.0 |
| 1000 SPRINGS | 2022 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2022 | ROR | 22.9 | 26.0 | 20.0 | 57.2 | 75.1 | 79.6 | 67.4 | 52.0 | 33.6 | 17.0 | 4.8 | 17.7 | 39.5 |
| BLISS | 2022 | ROR | 49.5 | 51.0 | 44.3 | 50.9 | 48.5 | 42.1 | 32.7 | 34.2 | 37.8 | 39.6 | 38.6 | 47.5 | 43.0 |
| C.J. STRIKE | 2022 | ROR | 65.0 | 66.9 | 59.4 | 67.0 | 64.1 | 52.1 | 34.7 | 37.6 | 45.1 | 50.2 | 51.0 | 61.2 | 54.4 |
| CASCADE | 2022 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2022 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2022 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2022 | ROR | 34.9 | 36.3 | 29.6 | 34.7 | 33.3 | 28.3 | 20.5 | 21.4 | 23.9 | 25.4 | 24.3 | 32.9 | 28.7 |
| MILNER | 2022 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2022 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.0 | 10.0 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2022 | ROR | 21.1 | 21.6 | 19.2 | 21.6 | 20.4 | 17.2 | 12.1 | 12.8 | 14.8 | 16.1 | 16.5 | 19.8 | 17.7 |
| TWIN FALLS | 2022 | ROR | 41.2 | 44.0 | 28.9 | 40.5 | 35.1 | 21.6 | 5.9 | 6.2 | 6.3 | 7.0 | 9.5 | 34.7 | 23.3 |
| UPPER MALAD | 2022 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2022 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.1 | 12.1 | 13.0 | 14.7 | 15.6 | 14.9 | 19.2 | 16.4 |
| UPPER SALMON 3&4 | 2022 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.7 | 11.6 | 12.3 | 13.8 | 14.6 | 13.9 | 17.7 | 15.5 |
| **HCC TOTAL** | | | **630.7** | **890.9** | **807.6** | **978.3** | **943.0** | **777.2** | **525.0** | **398.6** | **498.9** | **456.4** | **360.1** | **556.7** | **650.0** |
| **ROR TOTAL** | | | **353.7** | **369.8** | **304.5** | **396.2** | **393.7** | **343.0** | **240.3** | **237.0** | **237.5** | **227.3** | **220.2** | **325.5** | **303.6** |
| **TOTAL** | | | **984.4** | **1260.7** | **1112.1** | **1374.5** | **1336.7** | **1120.2** | **765.3** | **635.6** | **736.4** | **683.7** | **580.3** | **882.2** | **953.5** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2023 | HCC | 289.6 | 394.0 | 347.5 | 422.4 | 419.0 | 346.7 | 231.1 | 168.7 | 211.0 | 193.6 | 152.6 | 246.2 | 284.3 |
| OXBOW | 2023 | HCC | 117.8 | 164.6 | 152.1 | 183.7 | 170.9 | 141.6 | 98.1 | 77.2 | 96.2 | 88.5 | 69.2 | 103.6 | 121.6 |
| HELLS CANYON | 2023 | HCC | 231.9 | 326.9 | 306.8 | 371.1 | 351.9 | 287.8 | 194.7 | 151.6 | 188.7 | 174.6 | 137.9 | 205.5 | 243.4 |
| 1000 SPRINGS | 2023 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2023 | ROR | 22.9 | 25.8 | 19.9 | 57.0 | 75.1 | 79.6 | 67.3 | 52.1 | 33.6 | 16.9 | 4.9 | 17.8 | 39.5 |
| BLISS | 2023 | ROR | 49.3 | 50.9 | 44.2 | 50.7 | 48.4 | 42.0 | 32.6 | 34.1 | 37.7 | 39.5 | 38.5 | 47.4 | 42.9 |
| C.J. STRIKE | 2023 | ROR | 64.8 | 66.7 | 59.2 | 66.9 | 63.9 | 52.1 | 34.5 | 37.4 | 44.9 | 50.0 | 50.8 | 61.1 | 54.3 |
| CASCADE | 2023 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2023 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2023 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2023 | ROR | 34.9 | 36.2 | 29.5 | 34.7 | 33.2 | 28.2 | 20.4 | 21.3 | 23.8 | 25.3 | 24.2 | 32.8 | 28.7 |
| MILNER | 2023 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2023 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.6 | 10.0 | 10.0 | 10.8 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2023 | ROR | 21.0 | 21.5 | 19.1 | 21.6 | 20.4 | 17.2 | 12.1 | 12.8 | 14.7 | 16.1 | 16.4 | 19.8 | 17.7 |
| TWIN FALLS | 2023 | ROR | 41.2 | 44.0 | 28.9 | 40.5 | 35.0 | 21.6 | 5.9 | 6.2 | 6.2 | 6.9 | 9.5 | 34.6 | 23.2 |
| UPPER MALAD | 2023 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2023 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.1 | 12.1 | 12.9 | 14.6 | 15.6 | 14.8 | 19.2 | 16.4 |
| UPPER SALMON 3&4 | 2023 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.7 | 11.5 | 12.3 | 13.7 | 14.5 | 13.8 | 17.7 | 15.5 |
| **HCC TOTAL** | | | **639.3** | **885.5** | **806.4** | **977.2** | **941.7** | **776.1** | **523.9** | **397.5** | **495.9** | **456.7** | **359.7** | **555.3** | **649.3** |
| **ROR TOTAL** | | | **353.2** | **369.1** | **303.9** | **395.7** | **393.2** | **342.8** | **239.6** | **236.6** | **236.7** | **226.5** | **219.6** | **325.2** | **303.0** |
| **TOTAL** | | | **992.5** | **1254.6** | **1110.3** | **1372.9** | **1334.9** | **1118.9** | **763.5** | **634.1** | **732.6** | **683.2** | **579.3** | **880.5** | **952.4** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2024 | HCC | 280.5 | 394.2 | 347.0 | 421.9 | 418.5 | 346.1 | 230.6 | 168.3 | 209.8 | 193.7 | 152.8 | 245.7 | 283.5 |
| OXBOW | 2024 | HCC | 117.3 | 164.7 | 151.9 | 183.5 | 170.7 | 141.4 | 97.8 | 77.0 | 95.5 | 88.4 | 69.3 | 103.4 | 121.5 |
| HELLS CANYON | 2024 | HCC | 232.8 | 327.0 | 306.4 | 370.7 | 351.5 | 287.3 | 194.3 | 151.2 | 187.5 | 174.4 | 138.0 | 205.1 | 243.4 |
| 1000 SPRINGS | 2024 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2024 | ROR | 23.0 | 25.8 | 19.9 | 56.9 | 74.4 | 79.1 | 67.4 | 52.1 | 33.7 | 17.1 | 5.0 | 17.8 | 39.4 |
| BLISS | 2024 | ROR | 49.2 | 50.8 | 44.1 | 50.6 | 48.2 | 41.8 | 32.4 | 33.9 | 37.5 | 39.3 | 38.3 | 47.3 | 42.7 |
| C.J. STRIKE | 2024 | ROR | 64.6 | 66.6 | 59.0 | 66.7 | 63.8 | 52.1 | 34.3 | 37.3 | 44.8 | 49.9 | 50.6 | 60.9 | 54.2 |
| CASCADE | 2024 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2024 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2024 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2024 | ROR | 34.8 | 36.1 | 29.4 | 34.5 | 33.1 | 28.1 | 20.3 | 21.2 | 23.7 | 25.2 | 24.1 | 32.7 | 28.6 |
| MILNER | 2024 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2024 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.6 | 9.9 | 10.0 | 10.8 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2024 | ROR | 21.0 | 21.5 | 19.1 | 21.5 | 20.3 | 17.1 | 12.0 | 12.7 | 14.6 | 16.0 | 16.4 | 19.7 | 17.6 |
| TWIN FALLS | 2024 | ROR | 41.2 | 44.0 | 28.9 | 40.5 | 35.0 | 21.6 | 5.8 | 6.1 | 6.2 | 6.9 | 9.5 | 34.6 | 23.3 |
| UPPER MALAD | 2024 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2024 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.0 | 12.0 | 12.9 | 14.5 | 15.5 | 14.7 | 19.2 | 16.4 |
| UPPER SALMON 3&4 | 2024 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.6 | 11.4 | 12.2 | 13.6 | 14.4 | 13.8 | 17.7 | 15.5 |
| **HCC TOTAL** | | | **630.6** | **885.9** | **805.3** | **976.1** | **940.6** | **774.8** | **522.7** | **396.5** | **492.8** | **456.5** | **360.1** | **554.2** | **648.4** |
| **ROR TOTAL** | | | **352.9** | **368.8** | **303.5** | **395.0** | **392.0** | **341.7** | **238.8** | **235.8** | **236.1** | **226.0** | **219.1** | **324.7** | **302.6** |
| **TOTAL** | | | **983.5** | **1254.7** | **1108.8** | **1371.1** | **1332.6** | **1116.5** | **761.5** | **632.3** | **728.8** | **682.5** | **579.2** | **878.9** | **950.9** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2025 | HCC | 291.5 | 388.7 | 346.5 | 421.3 | 418.0 | 345.6 | 230.1 | 167.8 | 208.4 | 194.0 | 152.9 | 245.2 | 283.3 |
| OXBOW | 2025 | HCC | 118.7 | 162.7 | 151.7 | 183.3 | 170.5 | 141.1 | 97.6 | 76.8 | 94.7 | 88.5 | 69.3 | 103.2 | 121.2 |
| HELLS CANYON | 2025 | HCC | 233.7 | 323.2 | 306.0 | 370.2 | 351.1 | 286.9 | 193.9 | 150.8 | 186.0 | 174.5 | 138.1 | 204.7 | 242.6 |
| 1000 SPRINGS | 2025 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2025 | ROR | 23.1 | 25.8 | 19.8 | 57.0 | 74.1 | 78.7 | 67.2 | 52.0 | 33.7 | 17.1 | 5.1 | 17.9 | 39.4 |
| BLISS | 2025 | ROR | 49.1 | 50.7 | 44.0 | 50.5 | 48.1 | 41.7 | 32.3 | 33.8 | 37.4 | 39.2 | 38.2 | 47.1 | 42.6 |
| C.J. STRIKE | 2025 | ROR | 64.5 | 66.4 | 58.9 | 66.5 | 63.6 | 51.4 | 34.2 | 37.1 | 44.6 | 49.7 | 50.5 | 60.7 | 53.9 |
| CASCADE | 2025 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2025 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2025 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2025 | ROR | 34.7 | 36.1 | 29.3 | 34.5 | 33.0 | 28.0 | 20.3 | 21.1 | 23.6 | 25.1 | 24.0 | 32.6 | 28.5 |
| MILNER | 2025 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2025 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.5 | 9.9 | 9.9 | 10.7 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2025 | ROR | 20.9 | 21.4 | 19.1 | 21.5 | 20.3 | 17.0 | 12.0 | 12.6 | 14.6 | 16.0 | 16.3 | 19.7 | 17.6 |
| TWIN FALLS | 2025 | ROR | 41.1 | 43.9 | 28.9 | 40.5 | 35.0 | 21.5 | 5.8 | 6.1 | 6.2 | 6.8 | 9.5 | 34.6 | 23.2 |
| UPPER MALAD | 2025 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2025 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 17.9 | 11.9 | 12.8 | 14.4 | 15.4 | 14.6 | 19.2 | 16.3 |
| UPPER SALMON 3&4 | 2025 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.6 | 11.4 | 12.1 | 13.6 | 14.4 | 13.7 | 17.7 | 15.5 |
| **HCC TOTAL** | | | **643.9** | **874.6** | **804.2** | **974.8** | **939.5** | **773.6** | **521.6** | **395.4** | **489.1** | **457.0** | **360.3** | **553.1** | **647.1** |
| **ROR TOTAL** | | | **352.5** | **368.3** | **303.1** | **394.8** | **391.3** | **340.1** | **238.2** | **235.0** | **235.5** | **225.3** | **218.6** | **324.3** | **301.8** |
| **TOTAL** | | | **996.4** | **1242.9** | **1107.3** | **1369.6** | **1330.8** | **1113.7** | **759.8** | **630.4** | **724.6** | **682.3** | **578.9** | **877.4** | **948.8** |

## 2009 Integrated Resource Plan
### Average Megawatt Hydro Output from PDR580
### 50th Percentile Water, 50th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2026 | HCC | 290.8 | 388.4 | 346.0 | 420.8 | 417.5 | 342.2 | 229.6 | 167.3 | 207.2 | 194.0 | 153.1 | 244.7 | 282.6 |
| OXBOW | 2026 | HCC | 118.4 | 162.6 | 151.5 | 183.1 | 170.3 | 139.8 | 97.4 | 76.5 | 94.1 | 88.4 | 69.4 | 103.0 | 120.9 |
| HELLS CANYON | 2026 | HCC | 233.1 | 323.0 | 305.6 | 369.9 | 350.7 | 284.3 | 193.5 | 150.4 | 184.8 | 174.3 | 138.2 | 204.2 | 242.0 |
| 1000 SPRINGS | 2026 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2026 | ROR | 23.2 | 25.8 | 19.7 | 56.9 | 73.6 | 78.2 | 67.0 | 52.0 | 33.7 | 17.1 | 5.1 | 18.1 | 39.3 |
| BLISS | 2026 | ROR | 49.0 | 50.6 | 43.8 | 50.4 | 48.0 | 41.5 | 32.2 | 33.7 | 37.3 | 39.1 | 38.1 | 47.0 | 42.5 |
| C.J. STRIKE | 2026 | ROR | 64.3 | 66.2 | 58.7 | 66.4 | 63.4 | 51.3 | 34.0 | 36.9 | 44.4 | 49.5 | 50.3 | 60.6 | 53.7 |
| CASCADE | 2026 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2026 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2026 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2026 | ROR | 34.6 | 36.0 | 29.2 | 34.4 | 32.9 | 27.9 | 20.2 | 21.0 | 23.5 | 25.0 | 23.9 | 32.5 | 28.4 |
| MILNER | 2026 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2026 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.5 | 9.8 | 9.9 | 10.7 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2026 | ROR | 20.9 | 21.4 | 19.0 | 21.4 | 20.2 | 17.0 | 11.9 | 12.6 | 14.5 | 15.9 | 16.3 | 19.6 | 17.5 |
| TWIN FALLS | 2026 | ROR | 41.1 | 43.9 | 28.9 | 40.4 | 34.9 | 21.5 | 5.8 | 6.1 | 6.1 | 6.8 | 9.5 | 34.5 | 23.2 |
| UPPER MALAD | 2026 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2026 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 17.8 | 11.8 | 12.7 | 14.4 | 15.4 | 14.5 | 19.2 | 16.3 |
| UPPER SALMON 3&4 | 2026 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.5 | 11.3 | 12.1 | 13.5 | 14.3 | 13.6 | 17.7 | 15.4 |
| **HCC TOTAL** | | | **642.3** | **874.0** | **803.1** | **973.8** | **938.4** | **766.3** | **520.5** | **394.2** | **486.0** | **456.7** | **360.7** | **551.9** | **645.5** |
| **ROR TOTAL** | | | **352.2** | **367.9** | **302.4** | **394.2** | **390.2** | **339.0** | **237.3** | **234.4** | **234.8** | **224.7** | **218.0** | **324.0** | **301.1** |
| **TOTAL** | | | **994.5** | **1241.9** | **1105.5** | **1368.0** | **1328.6** | **1105.3** | **757.8** | **628.6** | **720.8** | **681.4** | **578.7** | **875.9** | **946.6** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2027 | HCC | 290.9 | 387.0 | 345.5 | 420.4 | 417.0 | 329.5 | 229.1 | 166.9 | 206.0 | 194.1 | 153.0 | 244.6 | 281.2 |
| OXBOW | 2027 | HCC | 118.5 | 162.1 | 151.3 | 182.9 | 170.0 | 134.8 | 97.2 | 76.3 | 93.5 | 88.3 | 69.3 | 102.9 | 120.3 |
| HELLS CANYON | 2027 | HCC | 233.3 | 322.0 | 305.2 | 369.5 | 350.3 | 274.5 | 193.1 | 150.0 | 183.5 | 174.2 | 138.0 | 204.2 | 240.8 |
| 1000 SPRINGS | 2027 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2027 | ROR | 23.3 | 25.9 | 19.7 | 56.8 | 73.4 | 77.7 | 66.7 | 52.0 | 33.3 | 17.0 | 5.1 | 18.2 | 39.2 |
| BLISS | 2027 | ROR | 48.9 | 50.4 | 43.7 | 50.3 | 47.9 | 41.4 | 32.0 | 33.5 | 37.1 | 39.0 | 38.0 | 46.9 | 42.4 |
| C.J. STRIKE | 2027 | ROR | 64.1 | 66.0 | 58.5 | 66.2 | 63.2 | 51.1 | 33.8 | 36.7 | 44.3 | 49.3 | 50.1 | 60.4 | 53.5 |
| CASCADE | 2027 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2027 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2027 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2027 | ROR | 34.5 | 35.9 | 29.1 | 34.3 | 32.8 | 27.8 | 20.1 | 20.9 | 23.4 | 24.9 | 23.8 | 32.4 | 28.3 |
| MILNER | 2027 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2027 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.4 | 9.8 | 9.8 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2027 | ROR | 20.8 | 21.3 | 19.0 | 21.4 | 20.2 | 17.0 | 11.9 | 12.5 | 14.5 | 15.9 | 16.2 | 19.6 | 17.5 |
| TWIN FALLS | 2027 | ROR | 41.1 | 43.9 | 28.9 | 40.4 | 34.9 | 21.4 | 5.7 | 6.0 | 6.1 | 6.8 | 9.5 | 34.5 | 23.1 |
| UPPER MALAD | 2027 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2027 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 17.8 | 11.8 | 12.6 | 14.3 | 15.3 | 14.5 | 19.2 | 16.3 |
| UPPER SALMON 3&4 | 2027 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.4 | 11.3 | 12.0 | 13.4 | 14.3 | 13.6 | 17.7 | 15.4 |
| **HCC TOTAL** | | | **642.7** | **871.1** | **802.0** | **972.8** | **937.3** | **738.8** | **519.4** | **393.2** | **482.9** | **456.6** | **360.3** | **551.7** | **642.3** |
| **ROR TOTAL** | | | **351.8** | **367.4** | **302.0** | **393.7** | **389.6** | **337.9** | **236.3** | **233.5** | **233.7** | **224.0** | **217.5** | **323.7** | **300.4** |
| **TOTAL** | | | **994.5** | **1238.5** | **1104.0** | **1366.5** | **1326.8** | **1076.7** | **755.7** | **626.7** | **716.6** | **680.6** | **577.8** | **875.4** | **942.7** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**50th Percentile Water, 50th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2028 | HCC | 293.2 | 382.4 | 345.0 | 419.9 | 416.5 | 329.0 | 228.6 | 166.4 | 204.8 | 194.1 | 153.2 | 244.1 | 280.9 |
| OXBOW | 2028 | HCC | 119.6 | 160.5 | 151.1 | 182.7 | 169.9 | 134.6 | 97.0 | 76.1 | 92.8 | 88.2 | 69.4 | 102.7 | 120.2 |
| HELLS CANYON | 2028 | HCC | 235.4 | 318.8 | 304.8 | 369.1 | 349.9 | 274.1 | 192.6 | 149.6 | 182.3 | 174.0 | 138.2 | 203.8 | 240.6 |
| 1000 SPRINGS | 2028 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2028 | ROR | 23.3 | 25.9 | 19.6 | 56.7 | 73.5 | 77.5 | 66.3 | 51.9 | 32.7 | 16.9 | 5.1 | 18.3 | 39.0 |
| BLISS | 2028 | ROR | 48.7 | 50.3 | 43.6 | 50.1 | 47.8 | 41.3 | 31.9 | 33.4 | 37.0 | 38.8 | 37.8 | 46.8 | 42.3 |
| C.J. STRIKE | 2028 | ROR | 64.0 | 65.9 | 58.4 | 66.0 | 63.1 | 50.9 | 33.6 | 36.5 | 44.1 | 49.2 | 49.9 | 60.2 | 53.4 |
| CASCADE | 2028 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2028 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2028 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2028 | ROR | 34.4 | 35.8 | 29.0 | 34.1 | 32.7 | 27.7 | 19.9 | 20.8 | 23.3 | 24.8 | 23.8 | 32.3 | 28.2 |
| MILNER | 2028 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2028 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.4 | 9.7 | 9.8 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2028 | ROR | 20.8 | 21.3 | 18.9 | 21.3 | 20.1 | 16.9 | 11.8 | 12.5 | 14.4 | 15.8 | 16.2 | 19.5 | 17.4 |
| TWIN FALLS | 2028 | ROR | 41.0 | 43.9 | 28.9 | 40.4 | 34.9 | 21.4 | 5.7 | 6.0 | 6.0 | 6.7 | 9.5 | 34.5 | 23.2 |
| UPPER MALAD | 2028 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2028 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.2 | 17.7 | 11.7 | 12.5 | 14.2 | 15.2 | 14.4 | 19.2 | 16.2 |
| UPPER SALMON 3&4 | 2028 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.3 | 11.2 | 11.9 | 13.4 | 14.2 | 13.5 | 17.7 | 15.3 |
| **HCC TOTAL** | | | **648.2** | **861.7** | **800.9** | **971.7** | **936.2** | **737.7** | **518.2** | **392.1** | **479.8** | **456.3** | **360.8** | **550.6** | **641.7** |
| **ROR TOTAL** | | | **351.3** | **367.1** | **301.5** | **392.9** | **389.4** | **337.0** | **235.1** | **232.7** | **232.4** | **223.1** | **216.9** | **323.3** | **299.9** |
| **TOTAL** | | | **999.5** | **1228.8** | **1102.4** | **1364.6** | **1325.6** | **1074.7** | **753.3** | **624.8** | **712.2** | **679.4** | **577.7** | **873.9** | **941.6** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2029 | HCC | 293.5 | 380.7 | 344.5 | 419.3 | 416.0 | 328.5 | 228.1 | 166.0 | 203.6 | 194.3 | 153.1 | 243.6 | 280.2 |
| OXBOW | 2029 | HCC | 119.7 | 159.9 | 150.9 | 182.5 | 169.7 | 134.3 | 96.8 | 75.9 | 92.2 | 88.3 | 69.3 | 102.5 | 119.8 |
| HELLS CANYON | 2029 | HCC | 235.7 | 317.6 | 304.4 | 368.6 | 349.5 | 273.7 | 192.2 | 149.2 | 181.1 | 174.1 | 138.0 | 203.3 | 240.0 |
| 1000 SPRINGS | 2029 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2029 | ROR | 23.3 | 25.9 | 19.6 | 56.7 | 73.4 | 77.4 | 66.3 | 51.8 | 32.0 | 16.7 | 5.0 | 18.4 | 38.9 |
| BLISS | 2029 | ROR | 48.6 | 50.2 | 43.5 | 50.0 | 47.6 | 40.8 | 31.8 | 33.3 | 36.9 | 38.7 | 37.7 | 46.6 | 42.1 |
| C.J. STRIKE | 2029 | ROR | 63.8 | 65.7 | 58.2 | 65.8 | 62.9 | 50.1 | 33.4 | 36.4 | 43.9 | 49.0 | 49.8 | 60.0 | 53.2 |
| CASCADE | 2029 | ROR | 1.5 | 2.6 | 4.7 | 7.6 | 7.3 | 11.8 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| CLEAR LAKE | 2029 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2029 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2029 | ROR | 34.3 | 35.7 | 28.9 | 34.1 | 32.6 | 27.6 | 19.8 | 20.7 | 23.2 | 24.7 | 23.7 | 32.2 | 28.1 |
| MILNER | 2029 | ROR | 41.6 | 45.2 | 28.4 | 41.0 | 34.5 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 34.0 | 20.5 |
| SHOSHONE FALLS | 2029 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.4 | 9.7 | 9.7 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2029 | ROR | 20.5 | 21.2 | 18.9 | 21.3 | 20.1 | 16.5 | 11.7 | 12.5 | 14.4 | 15.8 | 16.1 | 19.5 | 17.3 |
| TWIN FALLS | 2029 | ROR | 41.0 | 43.8 | 28.9 | 40.3 | 34.8 | 21.4 | 5.7 | 6.0 | 6.0 | 6.7 | 9.5 | 34.5 | 23.1 |
| UPPER MALAD | 2029 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2029 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.2 | 17.6 | 11.6 | 12.5 | 14.1 | 15.1 | 14.4 | 19.2 | 16.2 |
| UPPER SALMON 3&4 | 2029 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 16.3 | 11.1 | 11.9 | 13.3 | 14.2 | 13.5 | 17.7 | 15.3 |
| **HCC TOTAL** | | | **648.9** | **858.2** | **799.8** | **970.4** | **935.1** | **736.5** | **517.1** | **391.1** | **476.9** | **456.7** | **360.4** | **549.4** | **640.0** |
| **ROR TOTAL** | | | **350.6** | **366.5** | **301.1** | **392.5** | **388.7** | **335.0** | **234.4** | **232.3** | **231.0** | **222.4** | **216.4** | **322.9** | **299.0** |
| **TOTAL** | | | **999.5** | **1224.7** | **1100.9** | **1362.9** | **1323.8** | **1071.5** | **751.5** | **623.4** | **707.8** | **679.1** | **576.8** | **872.3** | **939.0** |

## 2009 Integrated Resource Plan

### Average Megawatt Hydro Output from PDR580
### 70th Percentile Water, 70th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2010 | HCC | 269.4 | 261.7 | 270.0 | 311.6 | 382.5 | 301.2 | 224.9 | 160.6 | 180.8 | 186.9 | 156.0 | 211.5 | 243.0 |
| OXBOW | 2010 | HCC | 114.3 | 112.4 | 115.2 | 127.3 | 153.6 | 121.0 | 95.1 | 73.3 | 82.4 | 83.2 | 69.5 | 88.5 | 102.9 |
| HELLS CANYON | 2010 | HCC | 225.9 | 223.8 | 234.6 | 258.1 | 312.3 | 244.8 | 187.7 | 144.0 | 161.7 | 164.0 | 138.1 | 175.4 | 205.8 |
| 1000 SPRINGS | 2010 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2010 | ROR | 0.0 | 14.3 | 13.6 | 37.0 | 71.4 | 87.1 | 80.8 | 59.2 | 34.1 | 15.7 | 0.0 | 0.0 | 34.5 |
| BLISS | 2010 | ROR | 39.3 | 45.2 | 40.2 | 38.3 | 42.0 | 41.1 | 36.8 | 35.0 | 38.0 | 39.5 | 37.9 | 38.2 | 39.2 |
| C.J. STRIKE | 2010 | ROR | 50.9 | 56.0 | 53.0 | 49.4 | 53.5 | 48.1 | 39.8 | 38.3 | 45.6 | 50.8 | 50.1 | 50.3 | 48.8 |
| CASCADE | 2010 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2010 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2010 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2010 | ROR | 24.4 | 30.5 | 25.6 | 23.3 | 28.3 | 28.5 | 24.1 | 22.0 | 24.4 | 25.7 | 24.3 | 24.5 | 25.4 |
| MILNER | 2010 | ROR | 9.0 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 3.5 | 6.5 | 8.8 |
| SHOSHONE FALLS | 2010 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2010 | ROR | 16.7 | 18.3 | 17.6 | 16.9 | 17.5 | 15.8 | 13.6 | 13.0 | 14.7 | 16.1 | 16.2 | 16.2 | 16.0 |
| TWIN FALLS | 2010 | ROR | 12.2 | 28.6 | 16.0 | 8.8 | 20.2 | 21.9 | 14.0 | 6.5 | 6.5 | 7.3 | 8.7 | 10.1 | 13.3 |
| UPPER MALAD | 2010 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2010 | ROR | 15.1 | 18.9 | 13.8 | 14.5 | 18.3 | 18.3 | 14.9 | 13.4 | 15.0 | 15.9 | 14.8 | 15.1 | 15.6 |
| UPPER SALMON 3&4 | 2010 | ROR | 14.1 | 17.7 | 15.1 | 13.6 | 16.9 | 16.9 | 14.0 | 12.7 | 14.1 | 14.8 | 13.9 | 14.1 | 14.8 |
| **HCC TOTAL** | | | **609.6** | **597.9** | **619.8** | **697.0** | **848.4** | **667.0** | **507.7** | **377.9** | **424.8** | **434.1** | **363.6** | **475.4** | **551.7** |
| **ROR TOTAL** | | | **220.9** | **296.1** | **249.8** | **248.0** | **328.8** | **340.8** | **293.0** | **248.0** | **240.2** | **227.4** | **210.3** | **215.7** | **259.6** |
| **TOTAL** | | | **830.5** | **894.0** | **869.6** | **945.0** | **1177.2** | **1007.8** | **800.7** | **625.9** | **665.0** | **661.5** | **573.9** | **691.1** | **811.3** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2011 | HCC | 299.4 | 230.8 | 269.9 | 311.5 | 382.4 | 301.1 | 224.8 | 160.5 | 180.7 | 186.8 | 155.9 | 211.3 | 243.1 |
| OXBOW | 2011 | HCC | 124.8 | 100.5 | 115.2 | 127.3 | 153.5 | 121.0 | 95.1 | 73.3 | 82.4 | 83.2 | 69.5 | 88.4 | 102.9 |
| HELLS CANYON | 2011 | HCC | 244.6 | 200.6 | 234.5 | 258.0 | 312.2 | 244.7 | 187.6 | 143.9 | 161.7 | 164.0 | 138.0 | 175.3 | 205.5 |
| 1000 SPRINGS | 2011 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2011 | ROR | 0.0 | 14.2 | 13.5 | 37.5 | 71.0 | 86.7 | 80.8 | 58.7 | 34.0 | 15.7 | 0.0 | 0.0 | 34.4 |
| BLISS | 2011 | ROR | 39.3 | 45.2 | 40.2 | 38.2 | 41.9 | 41.0 | 36.8 | 35.0 | 38.0 | 39.5 | 37.9 | 38.1 | 39.2 |
| C.J. STRIKE | 2011 | ROR | 50.9 | 56.0 | 52.9 | 49.4 | 53.5 | 48.0 | 39.8 | 38.2 | 45.5 | 50.7 | 50.1 | 50.2 | 48.7 |
| CASCADE | 2011 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2011 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2011 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2011 | ROR | 24.4 | 30.5 | 25.6 | 23.3 | 28.2 | 28.5 | 24.1 | 22.0 | 24.3 | 25.7 | 24.3 | 24.5 | 25.4 |
| MILNER | 2011 | ROR | 9.0 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 3.5 | 6.4 | 8.8 |
| SHOSHONE FALLS | 2011 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2011 | ROR | 16.7 | 18.3 | 17.6 | 16.9 | 17.5 | 15.8 | 13.6 | 12.9 | 14.7 | 16.1 | 16.2 | 16.2 | 16.0 |
| TWIN FALLS | 2011 | ROR | 12.2 | 28.6 | 16.0 | 8.8 | 20.2 | 21.9 | 14.0 | 6.5 | 6.5 | 7.3 | 8.7 | 10.1 | 13.3 |
| UPPER MALAD | 2011 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2011 | ROR | 15.1 | 18.9 | 13.8 | 14.5 | 18.3 | 18.3 | 14.9 | 13.4 | 15.0 | 15.9 | 14.8 | 15.1 | 15.6 |
| UPPER SALMON 3&4 | 2011 | ROR | 14.1 | 17.7 | 15.1 | 13.6 | 16.9 | 16.9 | 14.0 | 12.7 | 14.0 | 14.8 | 13.9 | 14.1 | 14.8 |
| **HCC TOTAL** | | | **668.8** | **531.9** | **619.6** | **696.8** | **848.1** | **666.8** | **507.5** | **377.7** | **424.7** | **434.0** | **363.4** | **475.0** | **551.5** |
| **ROR TOTAL** | | | **220.9** | **296.0** | **249.6** | **248.4** | **328.2** | **340.2** | **293.0** | **247.3** | **239.8** | **227.3** | **210.3** | **215.4** | **259.4** |
| **TOTAL** | | | **889.7** | **827.9** | **869.2** | **945.2** | **1176.3** | **1007.0** | **800.5** | **625.0** | **664.5** | **661.3** | **573.7** | **690.4** | **810.9** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2012 | HCC | 306.3 | 220.9 | 269.8 | 311.4 | 382.3 | 301.0 | 224.7 | 160.4 | 180.6 | 186.7 | 155.8 | 211.1 | 242.8 |
| OXBOW | 2012 | HCC | 128.1 | 96.6 | 115.1 | 127.3 | 153.5 | 121.0 | 95.0 | 73.2 | 82.4 | 83.1 | 69.4 | 88.3 | 102.8 |
| HELLS CANYON | 2012 | HCC | 251.1 | 193.1 | 234.4 | 258.0 | 312.2 | 244.6 | 187.5 | 143.8 | 161.6 | 163.9 | 137.9 | 175.1 | 205.4 |
| 1000 SPRINGS | 2012 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2012 | ROR | 0.0 | 14.2 | 13.5 | 39.1 | 70.9 | 86.4 | 80.6 | 58.3 | 33.8 | 15.8 | 0.0 | 0.0 | 34.4 |
| BLISS | 2012 | ROR | 39.3 | 45.2 | 40.1 | 38.2 | 41.9 | 41.0 | 36.7 | 35.0 | 38.0 | 39.5 | 37.9 | 38.1 | 39.2 |
| C.J. STRIKE | 2012 | ROR | 50.8 | 55.9 | 52.9 | 49.3 | 53.5 | 48.0 | 39.7 | 38.1 | 45.5 | 50.7 | 50.0 | 50.2 | 48.7 |
| CASCADE | 2012 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2012 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2012 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2012 | ROR | 24.4 | 30.5 | 25.6 | 23.2 | 28.2 | 28.5 | 24.1 | 21.9 | 24.3 | 25.6 | 24.3 | 24.4 | 25.4 |
| MILNER | 2012 | ROR | 8.9 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 3.5 | 6.4 | 8.9 |
| SHOSHONE FALLS | 2012 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2012 | ROR | 16.5 | 18.3 | 17.6 | 16.9 | 17.5 | 15.8 | 13.6 | 12.9 | 14.7 | 16.1 | 16.2 | 16.2 | 16.0 |
| TWIN FALLS | 2012 | ROR | 12.1 | 28.6 | 16.0 | 8.8 | 20.2 | 21.9 | 14.0 | 6.5 | 6.5 | 7.3 | 8.7 | 10.0 | 13.3 |
| UPPER MALAD | 2012 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2012 | ROR | 15.1 | 18.9 | 13.8 | 14.4 | 18.3 | 18.3 | 14.9 | 13.4 | 15.0 | 15.8 | 14.8 | 15.0 | 15.6 |
| UPPER SALMON 3&4 | 2012 | ROR | 14.1 | 17.7 | 15.1 | 13.5 | 16.9 | 16.8 | 13.9 | 12.7 | 14.0 | 14.8 | 13.9 | 14.1 | 14.8 |
| **HCC TOTAL** | | | **685.5** | **510.6** | **619.3** | **696.7** | **847.9** | **666.6** | **507.2** | **377.4** | **424.5** | **433.7** | **363.1** | **474.5** | **550.9** |
| **ROR TOTAL** | | | **220.4** | **295.9** | **249.5** | **249.6** | **328.1** | **339.8** | **292.5** | **246.7** | **239.6** | **227.2** | **210.2** | **215.1** | **259.4** |
| **TOTAL** | | | **905.9** | **806.5** | **868.8** | **946.3** | **1176.0** | **1006.4** | **799.7** | **624.1** | **664.1** | **660.9** | **573.3** | **689.6** | **810.3** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2013 | HCC | 306.2 | 222.3 | 267.7 | 311.3 | 382.2 | 300.9 | 224.6 | 160.3 | 180.5 | 186.4 | 156.1 | 210.9 | 242.7 |
| OXBOW | 2013 | HCC | 128.1 | 97.3 | 114.3 | 127.2 | 153.5 | 120.9 | 95.0 | 73.2 | 82.3 | 83.0 | 69.6 | 88.2 | 102.8 |
| HELLS CANYON | 2013 | HCC | 251.0 | 194.5 | 232.9 | 257.9 | 312.1 | 244.6 | 187.4 | 143.7 | 161.5 | 163.6 | 138.1 | 174.9 | 205.3 |
| 1000 SPRINGS | 2013 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2013 | ROR | 0.0 | 14.2 | 13.4 | 39.0 | 70.8 | 86.1 | 80.2 | 57.3 | 33.6 | 15.8 | 0.0 | 0.0 | 34.3 |
| BLISS | 2013 | ROR | 39.3 | 45.2 | 40.1 | 38.2 | 41.9 | 41.0 | 36.7 | 35.0 | 38.0 | 39.4 | 37.8 | 38.1 | 39.2 |
| C.J. STRIKE | 2013 | ROR | 50.6 | 55.8 | 52.9 | 49.3 | 53.4 | 47.9 | 39.7 | 38.1 | 45.5 | 50.7 | 50.0 | 50.1 | 48.6 |
| CASCADE | 2013 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2013 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2013 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2013 | ROR | 24.4 | 30.5 | 25.6 | 23.2 | 28.2 | 28.4 | 24.1 | 21.9 | 24.3 | 25.6 | 24.2 | 24.4 | 25.4 |
| MILNER | 2013 | ROR | 8.9 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 9.4 | 0.0 | 0.0 | 0.0 | 3.5 | 6.3 | 8.8 |
| SHOSHONE FALLS | 2013 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.4 | 10.4 | 11.2 | 12.0 | 12.0 | 11.7 |
| SWAN FALLS | 2013 | ROR | 16.5 | 18.3 | 17.6 | 16.9 | 17.5 | 15.8 | 13.6 | 12.9 | 14.7 | 16.1 | 16.2 | 16.2 | 16.0 |
| TWIN FALLS | 2013 | ROR | 12.0 | 28.6 | 16.0 | 8.8 | 20.2 | 21.9 | 14.0 | 6.5 | 6.5 | 7.3 | 8.7 | 10.0 | 13.3 |
| UPPER MALAD | 2013 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2013 | ROR | 15.1 | 18.9 | 13.8 | 14.4 | 18.3 | 18.3 | 14.9 | 13.4 | 15.0 | 15.8 | 14.8 | 15.0 | 15.6 |
| UPPER SALMON 3&4 | 2013 | ROR | 14.1 | 17.7 | 15.1 | 13.5 | 16.9 | 16.8 | 13.9 | 12.7 | 14.0 | 14.8 | 13.8 | 14.0 | 14.8 |
| **HCC TOTAL** | | | **685.3** | **514.1** | **614.9** | **696.4** | **847.7** | **666.4** | **507.0** | **377.2** | **424.2** | **433.0** | **363.8** | **474.0** | **550.8** |
| **ROR TOTAL** | | | **220.1** | **295.8** | **249.4** | **249.5** | **327.9** | **339.3** | **292.1** | **245.7** | **239.4** | **227.1** | **209.9** | **214.8** | **258.9** |
| **TOTAL** | | | **905.4** | **809.9** | **864.3** | **945.9** | **1175.6** | **1005.7** | **799.1** | **622.9** | **663.6** | **660.1** | **573.7** | **688.8** | **809.7** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2014 | HCC | 305.7 | 228.2 | 259.2 | 310.8 | 381.6 | 300.4 | 210.5 | 159.9 | 179.9 | 185.9 | 156.0 | 209.9 | 240.8 |
| OXBOW | 2014 | HCC | 127.9 | 100.3 | 111.1 | 127.0 | 153.2 | 120.7 | 89.0 | 73.0 | 82.0 | 82.8 | 69.5 | 87.8 | 102.1 |
| HELLS CANYON | 2014 | HCC | 250.6 | 200.3 | 226.6 | 257.5 | 311.6 | 244.2 | 175.8 | 143.3 | 161.0 | 163.2 | 138.0 | 174.2 | 203.9 |
| 1000 SPRINGS | 2014 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2014 | ROR | 0.0 | 14.0 | 12.6 | 38.6 | 70.5 | 85.4 | 74.3 | 55.6 | 33.0 | 15.8 | 0.0 | 0.0 | 33.4 |
| BLISS | 2014 | ROR | 39.1 | 45.2 | 40.0 | 38.1 | 41.8 | 40.9 | 33.1 | 34.8 | 37.8 | 39.3 | 37.7 | 37.9 | 38.8 |
| C.J. STRIKE | 2014 | ROR | 50.4 | 55.5 | 52.7 | 49.1 | 53.3 | 47.8 | 34.9 | 37.9 | 45.3 | 50.5 | 49.8 | 49.8 | 48.0 |
| CASCADE | 2014 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2014 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2014 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2014 | ROR | 24.2 | 30.5 | 25.5 | 23.1 | 28.1 | 28.3 | 20.9 | 21.8 | 24.2 | 25.5 | 24.1 | 24.2 | 25.0 |
| MILNER | 2014 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2014 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 10.0 | 10.3 | 10.3 | 11.1 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2014 | ROR | 16.4 | 18.2 | 17.5 | 16.9 | 17.5 | 15.7 | 12.1 | 12.8 | 14.7 | 16.0 | 16.1 | 16.2 | 15.8 |
| TWIN FALLS | 2014 | ROR | 11.9 | 28.6 | 16.0 | 8.8 | 20.2 | 21.8 | 6.2 | 6.5 | 6.5 | 7.2 | 8.7 | 9.8 | 12.6 |
| UPPER MALAD | 2014 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2014 | ROR | 14.9 | 18.9 | 13.8 | 14.3 | 18.2 | 18.2 | 12.4 | 13.3 | 14.9 | 15.8 | 14.7 | 14.8 | 15.3 |
| UPPER SALMON 3&4 | 2014 | ROR | 14.0 | 17.7 | 15.0 | 13.5 | 16.8 | 16.8 | 11.8 | 12.6 | 14.0 | 14.7 | 13.8 | 13.9 | 14.5 |
| **HCC TOTAL** | | | **684.2** | **528.8** | **596.9** | **695.3** | **846.4** | **665.3** | **475.3** | **376.2** | **422.8** | **431.9** | **363.5** | **471.9** | **546.8** |
| **ROR TOTAL** | | | **218.8** | **295.2** | **248.0** | **248.6** | **327.1** | **338.0** | **249.3** | **243.1** | **238.1** | **226.3** | **209.3** | **213.3** | **254.2** |
| **TOTAL** | | | **903.0** | **824.0** | **844.9** | **943.9** | **1173.5** | **1003.3** | **724.6** | **619.3** | **660.9** | **658.2** | **572.8** | **685.2** | **801.0** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2015 | HCC | 305.2 | 230.6 | 255.1 | 310.2 | 381.1 | 299.8 | 210.0 | 159.4 | 179.3 | 185.1 | 156.3 | 209.4 | 240.2 |
| OXBOW | 2015 | HCC | 127.7 | 101.5 | 109.5 | 126.8 | 153.0 | 120.5 | 88.8 | 72.7 | 81.8 | 82.4 | 69.6 | 87.6 | 101.8 |
| HELLS CANYON | 2015 | HCC | 250.2 | 202.7 | 223.6 | 257.0 | 311.2 | 243.7 | 175.4 | 142.9 | 160.4 | 162.4 | 138.2 | 173.7 | 203.5 |
| 1000 SPRINGS | 2015 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2015 | ROR | 0.0 | 14.0 | 12.2 | 38.0 | 70.0 | 84.4 | 73.2 | 55.0 | 32.8 | 15.6 | 0.0 | 0.0 | 33.0 |
| BLISS | 2015 | ROR | 39.0 | 45.2 | 39.9 | 37.9 | 41.6 | 40.7 | 33.0 | 34.7 | 37.7 | 39.2 | 37.6 | 37.8 | 38.6 |
| C.J. STRIKE | 2015 | ROR | 50.2 | 55.5 | 52.5 | 48.9 | 53.1 | 47.6 | 34.7 | 37.7 | 45.1 | 50.3 | 49.6 | 49.6 | 47.8 |
| CASCADE | 2015 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2015 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2015 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2015 | ROR | 24.1 | 30.5 | 25.4 | 23.0 | 28.0 | 28.3 | 20.8 | 21.7 | 24.1 | 25.4 | 24.0 | 24.1 | 24.9 |
| MILNER | 2015 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2015 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.9 | 10.3 | 10.3 | 11.1 | 12.0 | 12.0 | 11.5 |
| SWAN FALLS | 2015 | ROR | 16.3 | 18.2 | 17.5 | 16.8 | 17.5 | 15.7 | 12.1 | 12.8 | 14.6 | 16.0 | 16.1 | 16.1 | 15.8 |
| TWIN FALLS | 2015 | ROR | 11.9 | 28.6 | 15.9 | 8.7 | 20.1 | 21.8 | 6.1 | 6.4 | 6.4 | 7.2 | 8.7 | 9.8 | 12.5 |
| UPPER MALAD | 2015 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2015 | ROR | 14.8 | 18.9 | 13.8 | 14.3 | 18.1 | 18.1 | 12.4 | 13.2 | 14.8 | 15.7 | 14.6 | 14.8 | 15.3 |
| UPPER SALMON 3&4 | 2015 | ROR | 13.9 | 17.7 | 14.9 | 13.4 | 16.7 | 16.7 | 11.8 | 12.5 | 13.9 | 14.6 | 13.7 | 13.8 | 14.4 |
| **HCC TOTAL** | | | **683.1** | **534.8** | **588.2** | **694.0** | **845.3** | **664.0** | **474.2** | **375.0** | **421.5** | **429.9** | **364.1** | **470.7** | **545.6** |
| **ROR TOTAL** | | | **218.1** | **295.2** | **247.0** | **247.2** | **325.8** | **336.4** | **247.6** | **241.8** | **237.1** | **225.5** | **208.7** | **212.7** | **253.2** |
| **TOTAL** | | | **901.2** | **830.0** | **835.2** | **941.2** | **1171.1** | **1000.4** | **721.8** | **616.8** | **658.6** | **655.4** | **572.8** | **683.4** | **798.8** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2016 | HCC | 304.6 | 229.0 | 256.0 | 309.7 | 380.6 | 299.2 | 209.5 | 159.0 | 178.8 | 184.6 | 155.9 | 209.3 | 239.8 |
| OXBOW | 2016 | HCC | 127.5 | 100.8 | 109.8 | 126.6 | 152.8 | 120.3 | 88.6 | 72.5 | 81.5 | 82.2 | 69.4 | 87.6 | 101.7 |
| HELLS CANYON | 2016 | HCC | 249.8 | 201.2 | 224.2 | 256.6 | 310.9 | 243.3 | 175.0 | 142.5 | 160.0 | 162.0 | 137.9 | 173.6 | 203.1 |
| 1000 SPRINGS | 2016 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2016 | ROR | 0.0 | 14.0 | 12.0 | 37.6 | 70.3 | 84.1 | 72.7 | 54.5 | 32.9 | 15.7 | 0.0 | 0.0 | 32.8 |
| BLISS | 2016 | ROR | 38.9 | 45.2 | 39.7 | 37.8 | 41.5 | 40.6 | 32.8 | 34.6 | 37.5 | 39.1 | 37.4 | 37.7 | 38.5 |
| C.J. STRIKE | 2016 | ROR | 50.0 | 55.5 | 52.4 | 48.8 | 52.9 | 47.4 | 34.5 | 37.5 | 44.9 | 50.1 | 49.5 | 49.5 | 47.7 |
| CASCADE | 2016 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2016 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2016 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2016 | ROR | 24.0 | 30.4 | 25.3 | 22.9 | 27.9 | 28.2 | 20.7 | 21.6 | 24.0 | 25.3 | 23.9 | 24.0 | 24.8 |
| MILNER | 2016 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2016 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.9 | 10.2 | 10.2 | 11.1 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2016 | ROR | 16.3 | 18.2 | 17.4 | 16.8 | 17.5 | 15.6 | 12.0 | 12.8 | 14.6 | 15.9 | 16.0 | 16.1 | 15.8 |
| TWIN FALLS | 2016 | ROR | 11.8 | 28.5 | 15.9 | 8.7 | 20.1 | 21.8 | 6.1 | 6.4 | 6.4 | 7.2 | 8.7 | 9.7 | 12.5 |
| UPPER MALAD | 2016 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2016 | ROR | 14.8 | 18.9 | 13.8 | 14.2 | 18.1 | 18.0 | 12.3 | 13.2 | 14.7 | 15.6 | 14.5 | 14.7 | 15.2 |
| UPPER SALMON 3&4 | 2016 | ROR | 13.8 | 17.7 | 14.9 | 13.3 | 16.7 | 16.6 | 11.7 | 12.5 | 13.8 | 14.5 | 13.6 | 13.8 | 14.4 |
| **HCC TOTAL** | | | **681.9** | **531.0** | **590.0** | **692.9** | **844.2** | **662.8** | **473.1** | **374.0** | **420.3** | **428.8** | **363.2** | **470.5** | **544.6** |
| **ROR TOTAL** | | | **217.5** | **295.0** | **246.3** | **246.3** | **325.7** | **335.4** | **246.3** | **240.8** | **236.4** | **224.9** | **208.0** | **212.2** | **252.6** |
| **TOTAL** | | | **899.4** | **826.0** | **836.3** | **939.2** | **1169.9** | **998.2** | **719.4** | **614.8** | **656.6** | **653.7** | **571.2** | **682.7** | **797.2** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2017 | HCC | 304.1 | 237.1 | 245.2 | 309.1 | 380.0 | 298.7 | 209.0 | 158.5 | 178.3 | 183.9 | 156.3 | 208.8 | 239.1 |
| OXBOW | 2017 | HCC | 127.2 | 104.9 | 105.7 | 126.4 | 152.6 | 120.1 | 88.4 | 72.3 | 81.3 | 81.8 | 69.6 | 87.4 | 101.5 |
| HELLS CANYON | 2017 | HCC | 249.4 | 209.2 | 216.2 | 256.2 | 310.4 | 242.9 | 174.6 | 142.1 | 159.5 | 161.3 | 138.2 | 173.2 | 202.8 |
| 1000 SPRINGS | 2017 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2017 | ROR | 0.0 | 14.0 | 11.9 | 37.3 | 70.3 | 83.5 | 71.7 | 54.0 | 32.6 | 15.6 | 0.0 | 0.0 | 32.7 |
| BLISS | 2017 | ROR | 38.7 | 45.2 | 39.6 | 37.7 | 41.4 | 40.5 | 32.7 | 34.4 | 37.4 | 39.0 | 37.3 | 37.5 | 38.4 |
| C.J. STRIKE | 2017 | ROR | 49.8 | 55.5 | 52.2 | 48.6 | 52.7 | 47.3 | 34.3 | 37.3 | 44.7 | 50.0 | 49.3 | 49.3 | 47.5 |
| CASCADE | 2017 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2017 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2017 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2017 | ROR | 23.9 | 30.3 | 25.2 | 22.8 | 27.8 | 28.1 | 20.6 | 21.5 | 23.9 | 25.2 | 23.8 | 23.9 | 24.7 |
| MILNER | 2017 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2017 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.8 | 10.2 | 10.2 | 11.0 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2017 | ROR | 16.2 | 18.2 | 17.4 | 16.7 | 17.5 | 15.6 | 12.0 | 12.7 | 14.5 | 15.9 | 16.0 | 16.0 | 15.7 |
| TWIN FALLS | 2017 | ROR | 11.8 | 28.5 | 15.9 | 8.7 | 20.1 | 21.7 | 6.1 | 6.4 | 6.4 | 7.1 | 8.6 | 9.7 | 12.5 |
| UPPER MALAD | 2017 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2017 | ROR | 14.7 | 18.9 | 13.8 | 14.1 | 18.0 | 18.0 | 12.2 | 13.1 | 14.7 | 15.5 | 14.5 | 14.6 | 15.1 |
| UPPER SALMON 3&4 | 2017 | ROR | 13.8 | 17.7 | 14.8 | 13.3 | 16.6 | 16.6 | 11.6 | 12.4 | 13.8 | 14.5 | 13.6 | 13.7 | 14.3 |
| **HCC TOTAL** | | | **680.7** | **551.2** | **567.1** | **691.7** | **843.0** | **661.7** | **472.0** | **372.9** | **419.1** | **427.0** | **364.1** | **469.4** | **543.4** |
| **ROR TOTAL** | | | **216.8** | **294.9** | **245.7** | **245.4** | **325.1** | **334.4** | **244.6** | **239.5** | **235.6** | **224.2** | **207.5** | **211.4** | **251.7** |
| **TOTAL** | | | **897.5** | **846.1** | **812.8** | **937.1** | **1168.1** | **996.1** | **716.6** | **612.4** | **654.6** | **651.2** | **571.6** | **680.8** | **795.1** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2018 | HCC | 303.7 | 239.9 | 240.7 | 308.6 | 379.5 | 298.2 | 208.5 | 158.0 | 177.8 | 183.4 | 156.3 | 208.3 | 238.6 |
| OXBOW | 2018 | HCC | 127.1 | 106.3 | 104.0 | 126.1 | 152.4 | 119.9 | 88.1 | 72.1 | 81.0 | 81.6 | 69.6 | 87.1 | 101.3 |
| HELLS CANYON | 2018 | HCC | 249.0 | 212.0 | 212.8 | 255.8 | 310.0 | 242.5 | 174.2 | 141.7 | 159.0 | 160.9 | 138.2 | 172.8 | 202.4 |
| 1000 SPRINGS | 2018 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2018 | ROR | 0.0 | 14.0 | 11.7 | 37.1 | 70.4 | 83.1 | 71.1 | 53.7 | 32.6 | 15.6 | 0.0 | 0.0 | 32.5 |
| BLISS | 2018 | ROR | 38.6 | 45.2 | 39.5 | 37.6 | 41.3 | 40.2 | 32.5 | 34.3 | 37.3 | 38.9 | 37.2 | 37.4 | 38.3 |
| C.J. STRIKE | 2018 | ROR | 49.6 | 55.5 | 52.0 | 48.4 | 52.5 | 47.1 | 34.1 | 37.0 | 44.6 | 49.8 | 49.1 | 49.1 | 47.3 |
| CASCADE | 2018 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2018 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2018 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2018 | ROR | 23.8 | 30.2 | 25.1 | 22.7 | 27.7 | 27.8 | 20.5 | 21.4 | 23.8 | 25.1 | 23.8 | 23.8 | 24.6 |
| MILNER | 2018 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2018 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.8 | 10.1 | 10.1 | 11.0 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2018 | ROR | 16.2 | 18.2 | 17.3 | 16.5 | 17.4 | 15.5 | 11.9 | 12.6 | 14.4 | 15.8 | 15.9 | 16.0 | 15.6 |
| TWIN FALLS | 2018 | ROR | 11.8 | 28.5 | 15.8 | 8.7 | 20.0 | 21.7 | 6.0 | 6.3 | 6.3 | 7.1 | 8.6 | 9.7 | 12.4 |
| UPPER MALAD | 2018 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2018 | ROR | 14.6 | 18.9 | 13.8 | 14.0 | 17.9 | 17.7 | 12.1 | 13.0 | 14.6 | 15.4 | 14.4 | 14.5 | 15.0 |
| UPPER SALMON 3&4 | 2018 | ROR | 13.7 | 17.7 | 14.7 | 13.2 | 16.5 | 16.4 | 11.6 | 12.3 | 13.7 | 14.4 | 13.6 | 13.6 | 14.3 |
| **HCC TOTAL** | | | **679.8** | **558.2** | **557.5** | **690.5** | **841.8** | **660.6** | **470.8** | **371.8** | **417.8** | **425.9** | **364.1** | **468.2** | **542.2** |
| **ROR TOTAL** | | | **216.2** | **294.8** | **244.8** | **244.4** | **324.4** | **332.6** | **243.2** | **238.2** | **234.8** | **223.5** | **207.0** | **210.8** | **250.8** |
| **TOTAL** | | | **896.0** | **853.0** | **802.3** | **934.9** | **1166.2** | **993.2** | **714.0** | **610.0** | **652.6** | **649.4** | **571.1** | **679.0** | **793.0** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2019 | HCC | 303.1 | 242.3 | 236.7 | 308.1 | 379.0 | 297.6 | 208.0 | 157.6 | 177.3 | 182.9 | 156.3 | 208.1 | 238.1 |
| OXBOW | 2019 | HCC | 126.8 | 107.6 | 102.4 | 125.9 | 152.2 | 119.6 | 87.9 | 71.9 | 80.8 | 81.4 | 69.6 | 87.0 | 101.1 |
| HELLS CANYON | 2019 | HCC | 248.6 | 214.5 | 209.8 | 255.4 | 309.6 | 242.1 | 173.8 | 141.2 | 158.6 | 160.5 | 138.2 | 172.6 | 202.0 |
| 1000 SPRINGS | 2019 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2019 | ROR | 0.0 | 14.0 | 11.6 | 37.1 | 70.1 | 82.7 | 70.6 | 53.3 | 32.1 | 15.5 | 0.0 | 0.0 | 32.3 |
| BLISS | 2019 | ROR | 38.5 | 45.2 | 39.3 | 37.4 | 41.1 | 40.1 | 32.4 | 34.2 | 37.2 | 38.8 | 37.1 | 37.3 | 38.2 |
| C.J. STRIKE | 2019 | ROR | 49.6 | 55.5 | 51.8 | 48.2 | 52.4 | 46.9 | 33.9 | 36.8 | 44.4 | 49.6 | 48.9 | 49.0 | 47.2 |
| CASCADE | 2019 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2019 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2019 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2019 | ROR | 23.7 | 30.1 | 25.0 | 22.7 | 27.6 | 27.7 | 20.4 | 21.3 | 23.7 | 25.0 | 23.8 | 23.7 | 24.5 |
| MILNER | 2019 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2019 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.1 | 10.1 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2019 | ROR | 16.1 | 18.2 | 17.3 | 16.4 | 17.4 | 15.4 | 11.8 | 12.5 | 14.4 | 15.8 | 15.9 | 15.9 | 15.6 |
| TWIN FALLS | 2019 | ROR | 11.7 | 28.4 | 15.8 | 8.6 | 20.0 | 21.6 | 6.0 | 6.3 | 6.3 | 7.0 | 8.6 | 9.7 | 12.4 |
| UPPER MALAD | 2019 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2019 | ROR | 14.5 | 18.9 | 13.8 | 14.0 | 17.8 | 17.7 | 12.0 | 12.9 | 14.5 | 15.4 | 14.4 | 14.4 | 15.0 |
| UPPER SALMON 3&4 | 2019 | ROR | 13.6 | 17.7 | 14.7 | 13.2 | 16.4 | 16.3 | 11.5 | 12.3 | 13.6 | 14.4 | 13.5 | 13.5 | 14.2 |
| **HCC TOTAL** | | | **678.5** | **564.4** | **548.9** | **689.4** | **840.7** | **659.3** | **469.7** | **370.7** | **416.7** | **424.8** | **364.1** | **467.7** | **541.1** |
| **ROR TOTAL** | | | **215.6** | **294.6** | **244.2** | **243.8** | **323.5** | **331.5** | **241.9** | **237.2** | **233.7** | **222.8** | **206.6** | **210.2** | **250.1** |
| **TOTAL** | | | **894.1** | **859.0** | **793.1** | **933.2** | **1164.1** | **990.8** | **711.6** | **607.9** | **650.4** | **647.6** | **570.7** | **677.9** | **791.2** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2020 | HCC | 302.6 | 240.8 | 237.5 | 307.6 | 378.4 | 297.1 | 207.4 | 157.1 | 176.8 | 182.3 | 156.3 | 208.1 | 237.7 |
| OXBOW | 2020 | HCC | 126.6 | 106.8 | 102.7 | 125.7 | 152.0 | 119.4 | 87.7 | 71.6 | 80.6 | 81.1 | 69.6 | 87.0 | 100.9 |
| HELLS CANYON | 2020 | HCC | 248.2 | 213.0 | 210.4 | 255.0 | 309.2 | 241.7 | 173.3 | 140.8 | 158.2 | 159.9 | 138.2 | 172.6 | 201.7 |
| 1000 SPRINGS | 2020 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2020 | ROR | 4.7 | 14.1 | 11.5 | 37.1 | 69.7 | 82.2 | 70.2 | 53.0 | 31.0 | 15.2 | 4.1 | 0.0 | 32.8 |
| BLISS | 2020 | ROR | 38.4 | 45.1 | 39.2 | 37.3 | 41.0 | 39.9 | 32.3 | 34.0 | 37.0 | 38.6 | 37.0 | 37.1 | 38.0 |
| C.J. STRIKE | 2020 | ROR | 49.4 | 55.5 | 51.7 | 48.1 | 52.2 | 46.7 | 33.7 | 36.6 | 44.2 | 49.5 | 48.8 | 48.8 | 47.1 |
| CASCADE | 2020 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2020 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2020 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2020 | ROR | 23.6 | 30.0 | 24.9 | 22.7 | 27.5 | 27.6 | 20.3 | 21.2 | 23.6 | 24.9 | 23.7 | 23.6 | 24.4 |
| MILNER | 2020 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2020 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.0 | 10.0 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2020 | ROR | 16.1 | 18.2 | 17.2 | 16.4 | 17.3 | 15.4 | 11.8 | 12.5 | 14.3 | 15.7 | 15.8 | 15.9 | 15.5 |
| TWIN FALLS | 2020 | ROR | 11.7 | 28.4 | 15.8 | 8.6 | 19.9 | 21.6 | 6.0 | 6.3 | 6.3 | 7.0 | 8.5 | 9.6 | 12.4 |
| UPPER MALAD | 2020 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2020 | ROR | 14.4 | 18.9 | 13.8 | 14.0 | 17.7 | 17.6 | 12.0 | 12.8 | 14.5 | 15.3 | 14.3 | 14.4 | 15.0 |
| UPPER SALMON 3&4 | 2020 | ROR | 13.6 | 17.7 | 14.6 | 13.2 | 16.4 | 16.3 | 11.4 | 12.2 | 13.6 | 14.3 | 13.5 | 13.5 | 14.2 |
| **HCC TOTAL** | | | **677.4** | **560.6** | **550.6** | **688.3** | **839.5** | **658.2** | **468.4** | **369.5** | **415.6** | **423.3** | **364.1** | **467.7** | **540.2** |
| **ROR TOTAL** | | | **219.8** | **294.5** | **243.6** | **243.6** | **322.4** | **330.4** | **241.0** | **236.1** | **231.9** | **221.8** | **210.1** | **209.6** | **250.1** |
| **TOTAL** | | | **897.2** | **855.1** | **794.2** | **931.9** | **1161.8** | **988.6** | **709.4** | **605.6** | **647.5** | **645.1** | **574.2** | **677.3** | **790.4** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2021 | HCC | 302.1 | 244.8 | 231.5 | 307.1 | 377.9 | 296.6 | 207.0 | 156.6 | 176.4 | 181.7 | 156.3 | 208.1 | 237.1 |
| OXBOW | 2021 | HCC | 126.4 | 108.9 | 100.4 | 125.5 | 151.8 | 119.2 | 87.5 | 71.4 | 80.4 | 80.8 | 69.6 | 87.0 | 100.7 |
| HELLS CANYON | 2021 | HCC | 247.7 | 217.1 | 205.8 | 254.6 | 308.8 | 241.3 | 172.9 | 140.4 | 157.8 | 159.4 | 138.2 | 172.6 | 201.3 |
| 1000 SPRINGS | 2021 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2021 | ROR | 4.8 | 14.1 | 11.4 | 37.3 | 69.7 | 82.3 | 69.6 | 52.5 | 30.6 | 15.1 | 4.2 | 0.0 | 32.7 |
| BLISS | 2021 | ROR | 38.2 | 44.9 | 39.1 | 37.2 | 40.9 | 39.8 | 32.2 | 33.9 | 36.9 | 38.5 | 36.9 | 37.0 | 37.9 |
| C.J. STRIKE | 2021 | ROR | 49.2 | 55.5 | 51.5 | 47.9 | 52.0 | 46.5 | 33.5 | 36.4 | 44.1 | 49.3 | 48.6 | 48.6 | 46.9 |
| CASCADE | 2021 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2021 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2021 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2021 | ROR | 23.5 | 29.9 | 24.8 | 22.7 | 27.4 | 27.5 | 20.2 | 21.1 | 23.5 | 24.8 | 23.6 | 23.5 | 24.3 |
| MILNER | 2021 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2021 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.7 | 10.0 | 10.0 | 10.9 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2021 | ROR | 16.0 | 18.2 | 17.2 | 16.3 | 17.3 | 15.3 | 11.8 | 12.5 | 14.3 | 15.7 | 15.8 | 15.8 | 15.5 |
| TWIN FALLS | 2021 | ROR | 11.7 | 28.4 | 15.7 | 8.6 | 19.9 | 21.6 | 5.9 | 6.2 | 6.2 | 7.0 | 8.5 | 9.6 | 12.3 |
| UPPER MALAD | 2021 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2021 | ROR | 14.4 | 18.9 | 13.8 | 14.0 | 17.7 | 17.5 | 11.9 | 12.8 | 14.4 | 15.2 | 14.3 | 14.3 | 14.9 |
| UPPER SALMON 3&4 | 2021 | ROR | 13.5 | 17.7 | 14.5 | 13.2 | 16.3 | 16.2 | 11.4 | 12.1 | 13.5 | 14.2 | 13.4 | 13.4 | 14.1 |
| **HCC TOTAL** | | | **676.2** | **570.8** | **537.7** | **687.2** | **838.4** | **657.1** | **467.4** | **368.4** | **414.6** | **421.9** | **364.1** | **467.7** | **539.1** |
| **ROR TOTAL** | | | **219.2** | **294.2** | **242.9** | **243.4** | **321.9** | **329.8** | **239.8** | **235.0** | **230.9** | **221.1** | **209.7** | **208.9** | **249.3** |
| **TOTAL** | | | **895.4** | **865.0** | **780.6** | **930.6** | **1160.3** | **986.9** | **707.2** | **603.4** | **645.5** | **643.0** | **573.8** | **676.6** | **788.5** |

## 2009 Integrated Resource Plan

### Average Megawatt Hydro Output from PDR580
### 70th Percentile Water, 70th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2022 | HCC | 301.6 | 247.2 | 227.5 | 306.5 | 377.3 | 296.0 | 206.4 | 156.2 | 175.9 | 180.9 | 156.4 | 208.1 | 236.6 |
| OXBOW | 2022 | HCC | 126.2 | 110.2 | 98.8 | 125.3 | 151.6 | 119.0 | 87.2 | 71.2 | 80.2 | 80.5 | 69.6 | 87.0 | 100.5 |
| HELLS CANYON | 2022 | HCC | 247.3 | 219.6 | 202.8 | 254.1 | 308.4 | 240.9 | 172.4 | 140.0 | 157.4 | 158.7 | 138.3 | 172.6 | 200.9 |
| 1000 SPRINGS | 2022 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2022 | ROR | 5.0 | 14.2 | 11.3 | 37.3 | 69.5 | 82.3 | 69.7 | 52.5 | 29.3 | 14.8 | 4.3 | 0.0 | 32.6 |
| BLISS | 2022 | ROR | 38.1 | 44.8 | 39.0 | 37.0 | 40.7 | 39.5 | 32.0 | 33.8 | 36.8 | 38.4 | 36.8 | 36.9 | 37.8 |
| C.J. STRIKE | 2022 | ROR | 49.1 | 55.5 | 51.3 | 47.7 | 51.9 | 46.3 | 33.3 | 36.4 | 43.9 | 49.1 | 48.4 | 48.4 | 46.7 |
| CASCADE | 2022 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2022 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2022 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2022 | ROR | 23.4 | 29.8 | 24.7 | 22.7 | 27.3 | 27.4 | 20.1 | 21.0 | 23.4 | 24.8 | 23.5 | 23.4 | 24.2 |
| MILNER | 2022 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2022 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.6 | 10.0 | 10.0 | 10.8 | 12.0 | 12.0 | 11.4 |
| SWAN FALLS | 2022 | ROR | 16.0 | 18.2 | 17.1 | 16.3 | 17.2 | 15.3 | 11.7 | 12.4 | 14.2 | 15.6 | 15.7 | 15.8 | 15.4 |
| TWIN FALLS | 2022 | ROR | 11.7 | 28.3 | 15.7 | 8.6 | 19.9 | 21.5 | 5.9 | 6.2 | 6.2 | 6.9 | 8.5 | 9.6 | 12.3 |
| UPPER MALAD | 2022 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2022 | ROR | 14.3 | 18.9 | 13.8 | 14.0 | 17.6 | 17.4 | 11.8 | 12.7 | 14.3 | 15.2 | 14.2 | 14.2 | 14.8 |
| UPPER SALMON 3&4 | 2022 | ROR | 13.4 | 17.7 | 14.5 | 13.2 | 16.2 | 16.1 | 11.3 | 12.0 | 13.4 | 14.2 | 13.4 | 13.4 | 14.0 |
| **HCC TOTAL** | | | **675.1** | **577.0** | **529.1** | **685.9** | **837.2** | **655.9** | **466.0** | **367.4** | **413.5** | **420.1** | **364.3** | **467.7** | **538.0** |
| **ROR TOTAL** | | | **218.9** | **294.0** | **242.3** | **243.0** | **321.0** | **328.9** | **239.0** | **234.5** | **228.9** | **220.2** | **209.2** | **208.4** | **248.6** |
| **TOTAL** | | | **894.0** | **871.0** | **771.4** | **928.9** | **1158.2** | **984.8** | **705.0** | **601.9** | **642.4** | **640.3** | **573.5** | **676.1** | **786.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2023 | HCC | 301.0 | 248.1 | 225.3 | 305.9 | 376.8 | 295.5 | 205.7 | 155.7 | 175.4 | 180.1 | 156.4 | 208.1 | 236.1 |
| OXBOW | 2023 | HCC | 126.0 | 110.7 | 98.0 | 125.1 | 151.3 | 118.8 | 87.0 | 71.0 | 80.0 | 80.1 | 69.6 | 87.0 | 100.3 |
| HELLS CANYON | 2023 | HCC | 246.9 | 220.5 | 201.2 | 253.7 | 308.0 | 240.4 | 171.9 | 139.6 | 157.0 | 158.0 | 138.2 | 172.6 | 200.5 |
| 1000 SPRINGS | 2023 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2023 | ROR | 5.1 | 14.2 | 11.2 | 37.5 | 69.3 | 82.1 | 69.7 | 52.4 | 28.9 | 14.8 | 4.5 | 0.0 | 32.6 |
| BLISS | 2023 | ROR | 38.0 | 44.7 | 38.8 | 36.9 | 40.6 | 39.4 | 31.9 | 33.6 | 36.6 | 38.2 | 36.6 | 36.8 | 37.6 |
| C.J. STRIKE | 2023 | ROR | 48.9 | 55.5 | 51.1 | 47.5 | 51.7 | 46.2 | 33.1 | 36.3 | 43.7 | 48.9 | 48.2 | 48.3 | 46.5 |
| CASCADE | 2023 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2023 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2023 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2023 | ROR | 23.3 | 29.7 | 24.6 | 22.6 | 27.2 | 27.1 | 20.0 | 20.9 | 23.3 | 24.7 | 23.4 | 23.3 | 24.1 |
| MILNER | 2023 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2023 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.6 | 9.9 | 9.9 | 10.8 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2023 | ROR | 15.9 | 18.2 | 17.1 | 16.2 | 17.2 | 15.2 | 11.6 | 12.4 | 14.2 | 15.6 | 15.7 | 15.7 | 15.4 |
| TWIN FALLS | 2023 | ROR | 11.7 | 28.3 | 15.7 | 8.5 | 19.9 | 21.5 | 5.8 | 6.2 | 6.2 | 6.9 | 8.5 | 9.6 | 12.3 |
| UPPER MALAD | 2023 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2023 | ROR | 14.2 | 18.9 | 13.8 | 13.9 | 17.5 | 17.2 | 11.7 | 12.6 | 14.2 | 15.1 | 14.2 | 14.2 | 14.8 |
| UPPER SALMON 3&4 | 2023 | ROR | 13.3 | 17.7 | 14.4 | 13.1 | 16.2 | 15.9 | 11.2 | 12.0 | 13.4 | 14.1 | 13.3 | 13.3 | 14.0 |
| **HCC TOTAL** | | | **673.9** | **579.3** | **524.5** | **684.7** | **836.0** | **654.7** | **464.6** | **366.3** | **412.4** | **418.2** | **364.2** | **467.7** | **536.9** |
| **ROR TOTAL** | | | **218.3** | **293.8** | **241.6** | **242.4** | **320.3** | **327.7** | **238.2** | **233.8** | **227.8** | **219.5** | **208.8** | **207.9** | **247.9** |
| **TOTAL** | | | **892.2** | **873.1** | **766.1** | **927.1** | **1156.3** | **982.4** | **702.8** | **600.1** | **640.1** | **637.7** | **573.0** | **675.6** | **784.9** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2024 | HCC | 300.5 | 240.6 | 233.4 | 305.4 | 376.2 | 294.9 | 205.1 | 155.2 | 175.0 | 179.3 | 156.2 | 208.1 | 235.8 |
| OXBOW | 2024 | HCC | 125.7 | 106.8 | 101.1 | 124.9 | 151.1 | 118.6 | 86.7 | 70.8 | 79.7 | 79.7 | 69.5 | 87.0 | 100.1 |
| HELLS CANYON | 2024 | HCC | 246.4 | 213.1 | 207.1 | 253.3 | 307.5 | 240.0 | 171.4 | 139.2 | 156.6 | 157.2 | 138.1 | 172.6 | 200.2 |
| 1000 SPRINGS | 2024 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2024 | ROR | 5.2 | 14.3 | 11.1 | 37.6 | 69.4 | 82.2 | 69.3 | 52.2 | 28.5 | 14.7 | 4.5 | 0.0 | 32.4 |
| BLISS | 2024 | ROR | 37.8 | 44.6 | 38.7 | 36.8 | 40.5 | 39.1 | 31.8 | 33.5 | 36.5 | 38.1 | 36.5 | 36.6 | 37.5 |
| C.J. STRIKE | 2024 | ROR | 48.7 | 55.5 | 51.0 | 47.4 | 51.5 | 45.8 | 33.0 | 36.1 | 43.5 | 48.7 | 48.1 | 48.1 | 46.4 |
| CASCADE | 2024 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2024 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2024 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2024 | ROR | 23.2 | 29.6 | 24.6 | 22.5 | 27.1 | 26.9 | 19.9 | 20.8 | 23.2 | 24.6 | 23.3 | 23.2 | 24.0 |
| MILNER | 2024 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2024 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.5 | 9.9 | 9.9 | 10.7 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2024 | ROR | 15.9 | 18.2 | 17.0 | 16.2 | 17.1 | 15.4 | 11.6 | 12.4 | 14.2 | 15.5 | 15.6 | 15.7 | 15.4 |
| TWIN FALLS | 2024 | ROR | 11.7 | 28.3 | 15.6 | 8.5 | 19.8 | 21.5 | 5.8 | 6.1 | 6.1 | 6.8 | 8.4 | 9.5 | 12.3 |
| UPPER MALAD | 2024 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2024 | ROR | 14.1 | 18.9 | 13.8 | 13.9 | 17.4 | 17.0 | 11.6 | 12.5 | 14.1 | 15.0 | 14.1 | 14.1 | 14.7 |
| UPPER SALMON 3&4 | 2024 | ROR | 13.3 | 17.7 | 14.4 | 13.1 | 16.1 | 15.8 | 11.2 | 11.9 | 13.3 | 14.0 | 13.2 | 13.3 | 13.9 |
| **HCC TOTAL** | | | **672.6** | **560.5** | **541.6** | **683.6** | **834.8** | **653.5** | **463.2** | **365.2** | **411.2** | **416.2** | **363.8** | **467.7** | **536.1** |
| **ROR TOTAL** | | | **217.8** | **293.7** | **241.1** | **242.2** | **319.6** | **326.8** | **237.3** | **232.9** | **226.7** | **218.5** | **208.1** | **207.2** | **247.4** |
| **TOTAL** | | | **890.4** | **854.2** | **782.7** | **925.8** | **1154.3** | **980.3** | **700.5** | **598.1** | **637.9** | **634.7** | **571.9** | **674.9** | **783.5** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2025 | HCC | 300.0 | 246.5 | 225.0 | 304.9 | 375.7 | 282.8 | 204.6 | 154.8 | 174.5 | 178.3 | 156.5 | 208.1 | 234.3 |
| OXBOW | 2025 | HCC | 125.5 | 110.0 | 97.8 | 124.7 | 150.9 | 116.9 | 86.5 | 70.6 | 79.5 | 79.2 | 69.6 | 87.0 | 99.8 |
| HELLS CANYON | 2025 | HCC | 246.1 | 219.1 | 200.8 | 252.9 | 307.1 | 238.7 | 170.9 | 138.8 | 156.1 | 156.3 | 138.2 | 172.6 | 199.7 |
| 1000 SPRINGS | 2025 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2025 | ROR | 5.3 | 14.4 | 11.1 | 37.8 | 69.1 | 80.7 | 69.1 | 52.0 | 28.6 | 14.8 | 4.4 | 0.0 | 32.4 |
| BLISS | 2025 | ROR | 37.7 | 44.5 | 38.6 | 36.6 | 40.4 | 38.8 | 31.6 | 33.4 | 36.4 | 38.0 | 36.4 | 36.5 | 37.4 |
| C.J. STRIKE | 2025 | ROR | 48.5 | 55.5 | 50.8 | 47.2 | 51.5 | 45.3 | 32.8 | 35.9 | 43.4 | 48.6 | 47.9 | 47.9 | 46.2 |
| CASCADE | 2025 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2025 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2025 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2025 | ROR | 23.1 | 29.5 | 24.6 | 22.4 | 27.0 | 26.5 | 19.8 | 20.7 | 23.1 | 24.5 | 23.2 | 23.1 | 23.9 |
| MILNER | 2025 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2025 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.5 | 9.8 | 9.8 | 10.7 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2025 | ROR | 15.8 | 18.2 | 17.0 | 16.1 | 17.1 | 15.2 | 11.5 | 12.3 | 14.2 | 15.5 | 15.6 | 15.6 | 15.3 |
| TWIN FALLS | 2025 | ROR | 11.7 | 28.2 | 15.6 | 8.5 | 19.8 | 20.7 | 5.8 | 6.1 | 6.1 | 6.8 | 8.4 | 9.5 | 12.2 |
| UPPER MALAD | 2025 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2025 | ROR | 14.0 | 18.9 | 13.8 | 13.8 | 17.3 | 16.8 | 11.6 | 12.4 | 14.0 | 14.9 | 14.0 | 14.0 | 14.6 |
| UPPER SALMON 3&4 | 2025 | ROR | 13.2 | 17.7 | 14.4 | 13.0 | 16.0 | 15.6 | 11.1 | 11.8 | 13.2 | 14.0 | 13.2 | 13.2 | 13.8 |
| **HCC TOTAL** | | | **671.6** | **575.6** | **523.6** | **682.5** | **833.6** | **638.4** | **462.0** | **364.2** | **410.1** | **413.8** | **364.3** | **467.7** | **533.7** |
| **ROR TOTAL** | | | **217.2** | **293.5** | **240.8** | **241.6** | **318.9** | **322.7** | **236.4** | **231.9** | **226.2** | **218.2** | **207.5** | **206.5** | **246.4** |
| **TOTAL** | | | **888.8** | **869.1** | **764.4** | **924.1** | **1152.5** | **961.1** | **698.4** | **596.1** | **636.3** | **632.0** | **571.8** | **674.2** | **780.1** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2026 | HCC | 299.5 | 247.4 | 222.9 | 304.3 | 375.1 | 282.2 | 204.0 | 154.3 | 174.0 | 177.5 | 156.4 | 208.1 | 233.7 |
| OXBOW | 2026 | HCC | 125.3 | 110.4 | 97.0 | 124.4 | 150.7 | 116.7 | 86.2 | 70.3 | 79.3 | 78.8 | 69.5 | 87.0 | 99.6 |
| HELLS CANYON | 2026 | HCC | 245.6 | 220.0 | 199.2 | 252.5 | 306.7 | 238.2 | 170.5 | 138.3 | 155.7 | 155.5 | 138.1 | 172.6 | 199.3 |
| 1000 SPRINGS | 2026 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2026 | ROR | 5.5 | 14.5 | 11.1 | 38.5 | 68.9 | 80.8 | 68.8 | 52.0 | 28.7 | 14.8 | 4.4 | 4.4 | 32.8 |
| BLISS | 2026 | ROR | 37.6 | 44.3 | 38.4 | 36.5 | 40.2 | 38.7 | 31.5 | 33.2 | 36.2 | 37.8 | 36.2 | 36.4 | 37.2 |
| C.J. STRIKE | 2026 | ROR | 48.3 | 55.5 | 50.6 | 47.0 | 51.3 | 44.3 | 32.6 | 35.8 | 43.2 | 48.4 | 47.7 | 47.7 | 46.0 |
| CASCADE | 2026 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2026 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2026 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2026 | ROR | 23.0 | 29.4 | 24.6 | 22.3 | 26.9 | 26.5 | 19.7 | 20.6 | 23.0 | 24.4 | 23.1 | 23.0 | 23.8 |
| MILNER | 2026 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2026 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.5 | 9.8 | 9.8 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2026 | ROR | 15.8 | 18.1 | 16.9 | 16.1 | 17.1 | 14.9 | 11.4 | 12.2 | 14.1 | 15.4 | 15.5 | 15.6 | 15.2 |
| TWIN FALLS | 2026 | ROR | 11.7 | 28.2 | 15.6 | 8.5 | 19.8 | 20.7 | 5.7 | 6.0 | 6.0 | 6.8 | 8.4 | 9.5 | 12.1 |
| UPPER MALAD | 2026 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2026 | ROR | 14.0 | 18.9 | 13.8 | 13.7 | 17.3 | 16.7 | 11.5 | 12.4 | 14.0 | 14.9 | 13.9 | 13.9 | 14.5 |
| UPPER SALMON 3&4 | 2026 | ROR | 13.1 | 17.6 | 14.4 | 12.9 | 16.0 | 15.5 | 11.0 | 11.8 | 13.1 | 13.9 | 13.1 | 13.1 | 13.8 |
| **HCC TOTAL** | | | **670.4** | **577.8** | **519.1** | **681.2** | **832.4** | **637.1** | **460.7** | **362.9** | **408.9** | **411.8** | **364.0** | **467.7** | **532.6** |
| **ROR TOTAL** | | | **216.9** | **293.1** | **240.3** | **241.7** | **318.2** | **321.2** | **235.3** | **231.3** | **225.5** | **217.4** | **206.7** | **210.3** | **246.1** |
| **TOTAL** | | | **887.3** | **870.9** | **759.4** | **922.9** | **1150.6** | **958.3** | **696.0** | **594.2** | **634.4** | **629.2** | **570.7** | **678.0** | **778.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2027 | HCC | 299.0 | 246.7 | 222.7 | 303.8 | 374.6 | 281.7 | 203.4 | 153.7 | 173.5 | 169.2 | 156.6 | 208.1 | 232.7 |
| OXBOW | 2027 | HCC | 125.1 | 110.1 | 96.9 | 124.2 | 150.5 | 116.5 | 86.0 | 70.0 | 79.1 | 78.3 | 69.6 | 87.0 | 99.4 |
| HELLS CANYON | 2027 | HCC | 245.2 | 219.4 | 199.0 | 252.1 | 306.3 | 237.8 | 170.0 | 137.8 | 155.3 | 154.1 | 138.2 | 172.6 | 198.8 |
| 1000 SPRINGS | 2027 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2027 | ROR | 5.6 | 14.5 | 11.1 | 38.7 | 68.9 | 80.8 | 68.8 | 51.9 | 28.8 | 14.9 | 4.4 | 4.7 | 32.8 |
| BLISS | 2027 | ROR | 37.5 | 44.2 | 38.3 | 36.4 | 40.1 | 38.6 | 31.5 | 33.1 | 36.1 | 37.7 | 36.2 | 36.3 | 37.1 |
| C.J. STRIKE | 2027 | ROR | 48.2 | 55.5 | 50.5 | 46.8 | 51.1 | 44.2 | 32.4 | 35.6 | 43.0 | 48.3 | 47.5 | 47.6 | 45.8 |
| CASCADE | 2027 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2027 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2027 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2027 | ROR | 22.9 | 29.3 | 24.6 | 22.2 | 26.8 | 26.4 | 19.6 | 20.5 | 22.9 | 24.3 | 23.0 | 22.9 | 23.7 |
| MILNER | 2027 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2027 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.4 | 9.7 | 9.8 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2027 | ROR | 15.7 | 18.1 | 16.9 | 16.0 | 17.0 | 14.8 | 11.4 | 12.2 | 14.1 | 15.4 | 15.5 | 15.5 | 15.2 |
| TWIN FALLS | 2027 | ROR | 11.7 | 28.2 | 15.6 | 8.4 | 19.7 | 20.6 | 5.7 | 6.0 | 6.0 | 6.7 | 8.4 | 9.5 | 12.1 |
| UPPER MALAD | 2027 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2027 | ROR | 13.9 | 18.9 | 13.8 | 13.6 | 17.2 | 16.6 | 11.4 | 12.3 | 13.9 | 14.8 | 13.8 | 13.8 | 14.5 |
| UPPER SALMON 3&4 | 2027 | ROR | 13.1 | 17.5 | 14.4 | 12.8 | 15.9 | 15.4 | 11.0 | 11.7 | 13.1 | 13.8 | 13.0 | 13.0 | 13.7 |
| **HCC TOTAL** | | | **669.3** | **576.2** | **518.6** | **680.1** | **831.3** | **636.0** | **459.4** | **361.5** | **407.9** | **401.6** | **364.4** | **467.7** | **530.9** |
| **ROR TOTAL** | | | **216.5** | **292.8** | **240.1** | **241.1** | **317.4** | **320.5** | **234.8** | **230.5** | **225.1** | **216.9** | **206.2** | **210.0** | **245.6** |
| **TOTAL** | | | **885.8** | **869.0** | **758.7** | **921.2** | **1148.6** | **956.5** | **694.2** | **592.0** | **633.0** | **618.5** | **570.6** | **677.7** | **776.5** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**70th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2028 | HCC | 298.4 | 244.0 | 224.8 | 303.2 | 374.0 | 281.2 | 202.8 | 153.1 | 173.0 | 168.4 | 156.5 | 208.1 | 232.3 |
| OXBOW | 2028 | HCC | 124.9 | 108.8 | 97.7 | 124.0 | 150.3 | 116.3 | 85.7 | 69.8 | 78.8 | 77.9 | 69.6 | 87.0 | 99.2 |
| HELLS CANYON | 2028 | HCC | 244.8 | 216.8 | 200.6 | 251.6 | 305.9 | 237.4 | 169.5 | 137.3 | 154.9 | 153.4 | 138.1 | 172.6 | 198.5 |
| 1000 SPRINGS | 2028 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2028 | ROR | 5.7 | 14.5 | 10.9 | 38.9 | 68.8 | 80.7 | 68.7 | 51.8 | 28.8 | 15.0 | 4.4 | 4.9 | 32.8 |
| BLISS | 2028 | ROR | 37.3 | 44.1 | 38.2 | 36.2 | 40.0 | 38.4 | 31.4 | 32.8 | 36.0 | 37.6 | 36.2 | 36.2 | 37.0 |
| C.J. STRIKE | 2028 | ROR | 48.0 | 55.5 | 50.3 | 46.7 | 51.0 | 44.0 | 32.2 | 35.3 | 42.9 | 48.1 | 47.4 | 47.4 | 45.7 |
| CASCADE | 2028 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2028 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2028 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2028 | ROR | 22.8 | 29.2 | 24.5 | 22.1 | 26.7 | 26.2 | 19.5 | 20.4 | 22.8 | 24.1 | 22.9 | 22.8 | 23.6 |
| MILNER | 2028 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2028 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.4 | 9.7 | 9.7 | 10.6 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2028 | ROR | 15.7 | 18.0 | 16.8 | 16.0 | 17.0 | 14.8 | 11.3 | 12.1 | 14.2 | 15.3 | 15.4 | 15.5 | 15.2 |
| TWIN FALLS | 2028 | ROR | 11.7 | 28.1 | 15.6 | 8.4 | 19.7 | 20.6 | 5.7 | 6.0 | 6.0 | 6.7 | 8.3 | 9.4 | 12.1 |
| UPPER MALAD | 2028 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2028 | ROR | 13.8 | 18.9 | 13.8 | 13.5 | 17.1 | 16.5 | 11.3 | 12.2 | 13.8 | 14.7 | 13.8 | 13.8 | 14.4 |
| UPPER SALMON 3&4 | 2028 | ROR | 13.0 | 17.5 | 14.3 | 12.8 | 15.8 | 15.3 | 10.9 | 11.6 | 13.0 | 13.8 | 13.0 | 13.0 | 13.6 |
| **HCC TOTAL** | | | **668.1** | **569.6** | **523.1** | **678.8** | **830.1** | **634.9** | **458.0** | **360.2** | **406.7** | **399.7** | **364.2** | **467.7** | **530.0** |
| **ROR TOTAL** | | | **215.9** | **292.4** | **239.3** | **240.8** | **316.8** | **319.6** | **234.0** | **229.4** | **224.6** | **216.3** | **205.8** | **209.7** | **245.1** |
| **TOTAL** | | | **884.0** | **862.0** | **762.4** | **919.6** | **1146.9** | **954.5** | **692.0** | **589.6** | **631.3** | **616.0** | **570.0** | **677.4** | **775.1** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2029 | HCC | 297.9 | 246.4 | 220.8 | 302.7 | 373.5 | 280.6 | 202.3 | 152.7 | 172.6 | 167.6 | 156.4 | 208.1 | 231.7 |
| OXBOW | 2029 | HCC | 124.7 | 110.0 | 96.1 | 123.8 | 150.1 | 116.0 | 85.5 | 69.6 | 78.6 | 77.5 | 69.5 | 87.0 | 99.0 |
| HELLS CANYON | 2029 | HCC | 244.4 | 219.3 | 197.5 | 251.2 | 305.5 | 236.9 | 169.0 | 136.9 | 154.5 | 152.7 | 138.0 | 172.6 | 198.1 |
| 1000 SPRINGS | 2029 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2029 | ROR | 5.9 | 14.6 | 10.9 | 39.1 | 68.7 | 80.7 | 68.6 | 51.7 | 28.9 | 15.0 | 4.3 | 5.1 | 32.9 |
| BLISS | 2029 | ROR | 37.2 | 44.0 | 38.1 | 36.2 | 39.9 | 38.3 | 31.3 | 32.7 | 35.9 | 37.5 | 36.2 | 36.1 | 36.9 |
| C.J. STRIKE | 2029 | ROR | 47.8 | 55.5 | 50.1 | 46.5 | 50.8 | 43.8 | 32.0 | 35.2 | 42.7 | 47.9 | 47.2 | 47.2 | 45.5 |
| CASCADE | 2029 | ROR | 0.0 | 0.0 | 2.6 | 1.5 | 4.8 | 7.6 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.0 |
| CLEAR LAKE | 2029 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2029 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2029 | ROR | 22.8 | 29.1 | 24.3 | 22.0 | 26.6 | 26.1 | 19.4 | 20.2 | 22.6 | 24.0 | 22.8 | 22.7 | 23.5 |
| MILNER | 2029 | ROR | 8.7 | 26.9 | 12.6 | 4.9 | 17.0 | 17.6 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 | 6.0 | 8.0 |
| SHOSHONE FALLS | 2029 | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 9.3 | 9.7 | 9.7 | 10.5 | 12.0 | 12.0 | 11.3 |
| SWAN FALLS | 2029 | ROR | 15.6 | 18.0 | 16.8 | 15.9 | 16.9 | 14.7 | 11.2 | 12.0 | 14.1 | 15.3 | 15.4 | 15.4 | 15.1 |
| TWIN FALLS | 2029 | ROR | 11.7 | 28.1 | 15.6 | 8.4 | 19.6 | 20.6 | 5.6 | 5.9 | 5.9 | 6.7 | 8.3 | 9.4 | 12.0 |
| UPPER MALAD | 2029 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2029 | ROR | 13.8 | 18.9 | 13.8 | 13.5 | 17.0 | 16.5 | 11.3 | 12.1 | 13.7 | 14.6 | 13.7 | 13.7 | 14.3 |
| UPPER SALMON 3&4 | 2029 | ROR | 13.0 | 17.4 | 14.2 | 12.7 | 15.8 | 15.3 | 10.8 | 11.6 | 12.9 | 13.7 | 12.9 | 12.9 | 13.6 |
| **HCC TOTAL** | | | **667.0** | **575.7** | **514.4** | **677.7** | **829.0** | **633.5** | **456.8** | **359.2** | **405.6** | **397.8** | **363.9** | **467.7** | **528.7** |
| **ROR TOTAL** | | | **215.7** | **292.2** | **238.7** | **240.5** | **316.0** | **319.1** | **233.1** | **228.6** | **223.8** | **215.6** | **205.2** | **209.2** | **244.4** |
| **TOTAL** | | | **882.7** | **867.9** | **753.1** | **918.2** | **1145.0** | **952.6** | **689.9** | **587.8** | **629.4** | **613.4** | **569.1** | **676.9** | **773.1** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2010 | HCC | 259.6 | 199.2 | 173.4 | 242.2 | 266.2 | 213.5 | 210.2 | 146.5 | 166.2 | 149.9 | 158.2 | 195.8 | 198.4 |
| OXBOW | 2010 | HCC | 111.7 | 88.9 | 77.7 | 100.7 | 110.1 | 88.0 | 88.5 | 66.6 | 75.6 | 68.5 | 69.7 | 81.5 | 85.6 |
| HELLS CANYON | 2010 | HCC | 219.9 | 176.4 | 158.7 | 204.6 | 226.2 | 177.0 | 173.9 | 130.9 | 148.1 | 135.3 | 138.0 | 161.2 | 170.8 |
| 1000 SPRINGS | 2010 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2010 | ROR | 0.0 | 0.0 | 5.7 | 33.7 | 71.3 | 83.8 | 83.5 | 54.7 | 25.7 | 9.2 | 0.0 | 0.0 | 30.8 |
| BLISS | 2010 | ROR | 35.8 | 36.3 | 34.7 | 34.2 | 38.2 | 37.9 | 36.0 | 33.9 | 36.5 | 38.4 | 36.5 | 36.4 | 36.2 |
| C.J. STRIKE | 2010 | ROR | 45.6 | 45.8 | 45.3 | 42.7 | 45.4 | 41.3 | 36.4 | 35.6 | 42.8 | 47.9 | 46.3 | 45.8 | 43.4 |
| CASCADE | 2010 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2010 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2010 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2010 | ROR | 22.9 | 23.5 | 21.6 | 21.3 | 25.8 | 25.7 | 23.5 | 21.3 | 23.2 | 24.9 | 23.4 | 23.4 | 23.4 |
| MILNER | 2010 | ROR | 6.4 | 6.8 | 2.0 | 0.0 | 8.8 | 13.1 | 9.4 | 0.0 | 0.0 | 0.0 | 1.8 | 5.5 | 4.5 |
| SHOSHONE FALLS | 2010 | ROR | 12.0 | 12.0 | 10.2 | 8.0 | 12.0 | 12.0 | 12.0 | 9.7 | 7.3 | 9.5 | 11.5 | 12.0 | 10.7 |
| SWAN FALLS | 2010 | ROR | 15.3 | 15.2 | 15.3 | 14.6 | 15.3 | 14.6 | 12.7 | 12.1 | 14.2 | 15.4 | 15.3 | 15.2 | 14.6 |
| TWIN FALLS | 2010 | ROR | 9.8 | 9.7 | 6.4 | 4.3 | 12.0 | 16.9 | 13.2 | 6.0 | 3.8 | 5.8 | 7.5 | 9.4 | 8.7 |
| UPPER MALAD | 2010 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2010 | ROR | 13.9 | 14.5 | 13.1 | 12.9 | 16.4 | 16.1 | 14.4 | 12.9 | 14.1 | 15.3 | 14.1 | 14.2 | 14.3 |
| UPPER SALMON 3&4 | 2010 | ROR | 13.1 | 13.6 | 12.4 | 12.2 | 15.3 | 15.0 | 13.5 | 12.3 | 13.3 | 14.3 | 13.3 | 13.4 | 13.5 |
| **HCC TOTAL** | | | **591.2** | **464.5** | **409.8** | **547.5** | **602.5** | **478.5** | **472.6** | **344.0** | **389.9** | **353.7** | **365.9** | **438.5** | **454.9** |
| **ROR TOTAL** | | | **203.4** | **206.5** | **195.8** | **213.0** | **288.9** | **306.5** | **288.3** | **235.7** | **216.5** | **210.4** | **198.5** | **204.0** | **230.8** |
| **TOTAL** | | | **794.6** | **671.0** | **605.6** | **760.5** | **891.4** | **785.0** | **760.9** | **579.7** | **606.4** | **564.1** | **564.4** | **642.5** | **685.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2011 | HCC | 259.4 | 199.0 | 173.3 | 242.2 | 266.1 | 213.5 | 210.1 | 146.4 | 166.1 | 149.8 | 158.1 | 195.6 | 198.3 |
| OXBOW | 2011 | HCC | 111.6 | 88.8 | 77.6 | 100.7 | 110.1 | 88.0 | 88.5 | 66.6 | 75.6 | 68.5 | 69.6 | 81.5 | 85.6 |
| HELLS CANYON | 2011 | HCC | 219.8 | 176.3 | 158.6 | 204.6 | 226.1 | 177.0 | 173.8 | 130.8 | 148.0 | 135.2 | 137.9 | 161.0 | 170.8 |
| 1000 SPRINGS | 2011 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2011 | ROR | 0.0 | 0.0 | 5.7 | 33.7 | 71.3 | 83.8 | 83.2 | 54.7 | 25.7 | 9.2 | 0.0 | 0.0 | 30.8 |
| BLISS | 2011 | ROR | 35.8 | 36.2 | 34.7 | 34.2 | 38.2 | 37.8 | 36.0 | 33.9 | 36.5 | 38.3 | 36.5 | 36.3 | 36.2 |
| C.J. STRIKE | 2011 | ROR | 45.5 | 45.8 | 45.3 | 42.7 | 45.4 | 41.3 | 36.4 | 35.6 | 42.7 | 47.9 | 46.3 | 45.7 | 43.4 |
| CASCADE | 2011 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2011 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2011 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2011 | ROR | 22.8 | 23.5 | 21.6 | 21.3 | 25.8 | 25.7 | 23.4 | 21.3 | 23.2 | 24.9 | 23.3 | 23.4 | 23.3 |
| MILNER | 2011 | ROR | 6.4 | 6.7 | 2.0 | 0.0 | 8.8 | 13.1 | 9.4 | 0.0 | 0.0 | 0.0 | 1.8 | 5.5 | 4.5 |
| SHOSHONE FALLS | 2011 | ROR | 12.0 | 12.0 | 10.2 | 8.0 | 12.0 | 12.0 | 12.0 | 9.7 | 7.3 | 9.5 | 11.5 | 12.0 | 10.7 |
| SWAN FALLS | 2011 | ROR | 15.2 | 15.2 | 15.3 | 14.6 | 15.3 | 14.6 | 12.7 | 12.1 | 14.2 | 15.4 | 15.3 | 15.2 | 14.6 |
| TWIN FALLS | 2011 | ROR | 9.8 | 9.7 | 6.4 | 4.3 | 12.0 | 16.9 | 13.2 | 5.9 | 3.8 | 5.8 | 7.5 | 9.4 | 8.7 |
| UPPER MALAD | 2011 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2011 | ROR | 13.8 | 14.5 | 13.1 | 12.9 | 16.4 | 16.1 | 14.4 | 12.9 | 14.1 | 15.3 | 14.1 | 14.2 | 14.3 |
| UPPER SALMON 3&4 | 2011 | ROR | 13.0 | 13.6 | 12.4 | 12.2 | 15.3 | 15.0 | 13.5 | 12.3 | 13.3 | 14.3 | 13.3 | 13.4 | 13.5 |
| **HCC TOTAL** | | | **590.8** | **464.1** | **409.5** | **547.5** | **602.2** | **478.5** | **472.4** | **343.8** | **389.7** | **353.5** | **365.6** | **438.1** | **454.7** |
| **ROR TOTAL** | | | **202.9** | **206.3** | **195.8** | **213.0** | **288.9** | **306.4** | **287.9** | **235.6** | **216.4** | **210.3** | **198.4** | **203.8** | **230.6** |
| **TOTAL** | | | **793.7** | **670.4** | **605.3** | **760.5** | **891.1** | **784.9** | **760.3** | **579.4** | **606.1** | **563.8** | **564.0** | **641.9** | **685.3** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2012 | HCC | 259.2 | 198.8 | 173.2 | 242.2 | 266.0 | 213.5 | 209.9 | 146.3 | 166.0 | 149.4 | 158.4 | 195.4 | 198.2 |
| OXBOW | 2012 | HCC | 111.5 | 88.7 | 77.6 | 100.7 | 110.1 | 88.0 | 88.4 | 66.5 | 75.5 | 68.2 | 69.7 | 81.4 | 85.5 |
| HELLS CANYON | 2012 | HCC | 219.6 | 176.1 | 158.6 | 204.6 | 226.1 | 177.0 | 173.8 | 130.7 | 147.9 | 134.8 | 138.1 | 160.9 | 170.7 |
| 1000 SPRINGS | 2012 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2012 | ROR | 0.0 | 0.0 | 5.7 | 33.7 | 71.2 | 83.9 | 82.9 | 54.4 | 25.7 | 9.2 | 0.0 | 0.0 | 30.7 |
| BLISS | 2012 | ROR | 35.7 | 36.2 | 34.7 | 34.2 | 38.2 | 37.8 | 36.0 | 33.9 | 36.5 | 38.3 | 36.4 | 36.3 | 36.2 |
| C.J. STRIKE | 2012 | ROR | 45.4 | 45.7 | 45.3 | 42.7 | 45.4 | 41.2 | 36.3 | 35.5 | 42.7 | 47.8 | 46.2 | 45.6 | 43.3 |
| CASCADE | 2012 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2012 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2012 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2012 | ROR | 22.8 | 23.4 | 21.5 | 21.3 | 25.8 | 25.6 | 23.4 | 21.3 | 23.2 | 24.9 | 23.3 | 23.4 | 23.3 |
| MILNER | 2012 | ROR | 6.3 | 6.7 | 2.0 | 0.0 | 8.8 | 13.1 | 9.4 | 0.0 | 0.0 | 0.0 | 1.8 | 5.4 | 4.5 |
| SHOSHONE FALLS | 2012 | ROR | 12.0 | 12.0 | 10.2 | 8.0 | 12.0 | 12.0 | 12.0 | 9.7 | 7.3 | 9.5 | 11.4 | 12.0 | 10.7 |
| SWAN FALLS | 2012 | ROR | 15.2 | 15.2 | 15.2 | 14.6 | 15.3 | 14.6 | 12.7 | 12.1 | 14.2 | 15.4 | 15.3 | 15.2 | 14.6 |
| TWIN FALLS | 2012 | ROR | 9.7 | 9.6 | 6.4 | 4.3 | 12.0 | 16.9 | 13.2 | 5.9 | 3.8 | 5.8 | 7.5 | 9.3 | 8.7 |
| UPPER MALAD | 2012 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2012 | ROR | 13.8 | 14.4 | 13.1 | 12.9 | 16.4 | 16.1 | 14.4 | 12.9 | 14.1 | 15.3 | 14.1 | 14.2 | 14.3 |
| UPPER SALMON 3&4 | 2012 | ROR | 13.0 | 13.5 | 12.4 | 12.2 | 15.2 | 14.9 | 13.5 | 12.2 | 13.3 | 14.3 | 13.2 | 13.3 | 13.4 |
| **HCC TOTAL** | | | **590.3** | **463.6** | **409.4** | **547.5** | **602.1** | **478.5** | **472.1** | **343.5** | **389.4** | **352.4** | **366.2** | **437.7** | **454.4** |
| **ROR TOTAL** | | | **202.5** | **205.8** | **195.6** | **213.0** | **288.8** | **306.2** | **287.5** | **235.1** | **216.4** | **210.2** | **198.0** | **203.4** | **230.3** |
| **TOTAL** | | | **792.8** | **669.4** | **605.0** | **760.5** | **890.9** | **784.7** | **759.6** | **578.6** | **605.8** | **562.6** | **564.2** | **641.1** | **684.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2013 | HCC | 259.0 | 198.7 | 189.3 | 230.3 | 265.9 | 213.5 | 209.9 | 146.2 | 165.9 | 149.3 | 158.3 | 195.2 | 198.5 |
| OXBOW | 2013 | HCC | 111.4 | 88.6 | 82.0 | 96.2 | 110.0 | 88.0 | 88.4 | 66.5 | 75.5 | 68.2 | 69.7 | 81.3 | 85.5 |
| HELLS CANYON | 2013 | HCC | 219.4 | 176.0 | 167.3 | 195.8 | 226.0 | 177.0 | 173.7 | 130.6 | 147.8 | 134.7 | 138.0 | 160.7 | 170.6 |
| 1000 SPRINGS | 2013 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2013 | ROR | 0.0 | 0.0 | 5.7 | 33.8 | 71.2 | 84.0 | 82.5 | 54.0 | 25.7 | 9.2 | 0.0 | 0.0 | 30.7 |
| BLISS | 2013 | ROR | 35.7 | 36.1 | 34.6 | 34.2 | 38.1 | 37.8 | 35.9 | 33.8 | 36.4 | 38.3 | 36.4 | 36.3 | 36.1 |
| C.J. STRIKE | 2013 | ROR | 45.4 | 45.6 | 45.2 | 42.6 | 45.3 | 41.2 | 36.3 | 35.4 | 42.6 | 47.8 | 46.2 | 45.6 | 43.2 |
| CASCADE | 2013 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2013 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2013 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2013 | ROR | 22.8 | 23.4 | 21.5 | 21.3 | 25.8 | 25.6 | 23.4 | 21.2 | 23.2 | 24.9 | 23.3 | 23.3 | 23.3 |
| MILNER | 2013 | ROR | 6.2 | 6.6 | 2.0 | 0.0 | 8.8 | 13.1 | 9.4 | 0.0 | 0.0 | 0.0 | 1.8 | 5.3 | 4.4 |
| SHOSHONE FALLS | 2013 | ROR | 12.0 | 12.0 | 10.2 | 8.0 | 12.0 | 12.0 | 12.0 | 9.7 | 7.3 | 9.5 | 11.4 | 12.0 | 10.7 |
| SWAN FALLS | 2013 | ROR | 15.2 | 15.4 | 15.2 | 14.6 | 15.3 | 14.5 | 12.7 | 12.1 | 14.2 | 15.4 | 15.3 | 15.4 | 14.6 |
| TWIN FALLS | 2013 | ROR | 9.7 | 9.6 | 6.4 | 4.3 | 12.0 | 16.9 | 13.2 | 5.9 | 3.8 | 5.8 | 7.5 | 9.3 | 8.7 |
| UPPER MALAD | 2013 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2013 | ROR | 13.8 | 14.4 | 13.1 | 12.9 | 16.4 | 16.1 | 14.3 | 12.9 | 14.1 | 15.2 | 14.1 | 14.2 | 14.3 |
| UPPER SALMON 3&4 | 2013 | ROR | 13.0 | 13.5 | 12.4 | 12.2 | 15.2 | 14.9 | 13.5 | 12.2 | 13.3 | 14.2 | 13.2 | 13.3 | 13.4 |
| **HCC TOTAL** | | | **589.8** | **463.3** | **438.6** | **522.3** | **601.8** | **478.5** | **472.0** | **343.3** | **389.2** | **352.2** | **366.0** | **437.2** | **454.6** |
| **ROR TOTAL** | | | **202.4** | **205.7** | **195.4** | **213.0** | **288.6** | **306.2** | **286.9** | **234.4** | **216.2** | **210.0** | **198.0** | **203.4** | **230.2** |
| **TOTAL** | | | **792.2** | **669.0** | **634.0** | **735.3** | **890.4** | **784.7** | **758.9** | **577.7** | **605.4** | **562.2** | **564.0** | **640.6** | **684.8** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2014 | HCC | 258.4 | 198.0 | 202.7 | 211.8 | 265.4 | 213.5 | 195.8 | 145.7 | 165.4 | 148.2 | 158.6 | 194.8 | 196.6 |
| OXBOW | 2014 | HCC | 111.2 | 88.4 | 88.5 | 89.1 | 109.8 | 88.0 | 82.4 | 66.2 | 75.3 | 67.7 | 69.8 | 81.1 | 84.8 |
| HELLS CANYON | 2014 | HCC | 219.0 | 175.4 | 180.1 | 182.2 | 225.6 | 177.0 | 162.1 | 130.2 | 147.4 | 133.7 | 138.2 | 160.4 | 169.3 |
| 1000 SPRINGS | 2014 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2014 | ROR | 0.0 | 0.0 | 5.6 | 33.8 | 71.0 | 83.5 | 76.9 | 52.4 | 25.6 | 9.4 | 0.0 | 0.0 | 30.0 |
| BLISS | 2014 | ROR | 35.5 | 36.0 | 34.5 | 34.0 | 38.0 | 37.6 | 32.3 | 33.7 | 36.3 | 38.1 | 36.3 | 36.1 | 35.7 |
| C.J. STRIKE | 2014 | ROR | 45.2 | 45.5 | 45.1 | 42.5 | 45.2 | 41.0 | 31.5 | 35.2 | 42.5 | 47.6 | 46.0 | 45.4 | 42.7 |
| CASCADE | 2014 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2014 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2014 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2014 | ROR | 22.8 | 23.3 | 21.4 | 21.2 | 25.7 | 25.5 | 20.3 | 21.1 | 23.1 | 24.8 | 23.2 | 23.2 | 23.0 |
| MILNER | 2014 | ROR | 6.2 | 6.4 | 2.0 | 0.0 | 8.8 | 13.1 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.2 | 3.6 |
| SHOSHONE FALLS | 2014 | ROR | 12.0 | 12.0 | 10.2 | 8.0 | 12.0 | 12.0 | 8.9 | 9.6 | 7.2 | 9.4 | 11.4 | 12.0 | 10.4 |
| SWAN FALLS | 2014 | ROR | 15.4 | 15.4 | 15.2 | 14.5 | 15.3 | 14.5 | 11.1 | 12.0 | 14.1 | 15.3 | 15.2 | 15.4 | 14.4 |
| TWIN FALLS | 2014 | ROR | 9.4 | 9.3 | 6.4 | 4.3 | 11.9 | 16.9 | 5.3 | 5.9 | 3.7 | 5.7 | 7.4 | 9.1 | 7.9 |
| UPPER MALAD | 2014 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2014 | ROR | 13.8 | 14.3 | 13.0 | 12.9 | 16.3 | 16.0 | 11.9 | 12.8 | 14.0 | 15.2 | 14.0 | 14.0 | 14.0 |
| UPPER SALMON 3&4 | 2014 | ROR | 13.0 | 13.5 | 12.3 | 12.2 | 15.2 | 14.9 | 11.4 | 12.1 | 13.2 | 14.2 | 13.2 | 13.2 | 13.2 |
| **HCC TOTAL** | | | **588.6** | **461.8** | **471.3** | **483.1** | **600.7** | **478.5** | **440.3** | **342.1** | **388.0** | **349.6** | **366.6** | **436.3** | **450.7** |
| **ROR TOTAL** | | | **201.9** | **204.8** | **194.8** | **212.5** | **287.8** | **305.1** | **243.3** | **232.0** | **215.4** | **209.4** | **197.3** | **202.3** | **225.6** |
| **TOTAL** | | | **790.5** | **666.6** | **666.1** | **695.6** | **888.5** | **783.6** | **683.6** | **574.1** | **603.4** | **559.0** | **563.9** | **638.6** | **676.4** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2015 | HCC | 258.0 | 197.5 | 207.5 | 204.3 | 264.8 | 213.5 | 195.3 | 145.1 | 165.0 | 147.5 | 158.5 | 194.8 | 196.1 |
| OXBOW | 2015 | HCC | 111.0 | 88.1 | 90.9 | 86.2 | 109.6 | 88.0 | 82.2 | 65.9 | 75.1 | 67.3 | 69.7 | 81.1 | 84.6 |
| HELLS CANYON | 2015 | HCC | 218.6 | 175.0 | 184.7 | 176.5 | 225.2 | 177.0 | 161.6 | 129.6 | 147.0 | 133.0 | 138.1 | 160.4 | 168.9 |
| 1000 SPRINGS | 2015 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2015 | ROR | 0.0 | 0.0 | 5.5 | 34.3 | 70.6 | 80.5 | 74.1 | 51.0 | 25.1 | 9.4 | 0.0 | 0.0 | 29.4 |
| BLISS | 2015 | ROR | 35.4 | 35.9 | 34.4 | 33.9 | 37.9 | 37.1 | 32.1 | 33.6 | 36.0 | 38.0 | 36.2 | 36.0 | 35.5 |
| C.J. STRIKE | 2015 | ROR | 45.0 | 45.3 | 44.9 | 42.3 | 45.0 | 40.5 | 31.3 | 35.0 | 42.3 | 47.4 | 45.8 | 45.2 | 42.5 |
| CASCADE | 2015 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2015 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2015 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2015 | ROR | 22.7 | 23.2 | 21.3 | 21.1 | 25.6 | 25.3 | 20.1 | 21.0 | 22.9 | 24.7 | 23.1 | 23.1 | 22.8 |
| MILNER | 2015 | ROR | 5.9 | 6.0 | 2.0 | 0.0 | 8.8 | 10.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.3 |
| SHOSHONE FALLS | 2015 | ROR | 12.0 | 12.0 | 10.1 | 7.9 | 12.0 | 12.0 | 8.9 | 9.6 | 7.2 | 9.4 | 11.3 | 12.0 | 10.4 |
| SWAN FALLS | 2015 | ROR | 15.3 | 15.3 | 15.1 | 14.4 | 15.2 | 14.4 | 11.0 | 12.0 | 14.1 | 15.3 | 15.2 | 15.4 | 14.4 |
| TWIN FALLS | 2015 | ROR | 9.4 | 9.3 | 6.3 | 4.2 | 11.9 | 15.1 | 5.3 | 5.9 | 3.7 | 5.7 | 7.4 | 9.0 | 7.8 |
| UPPER MALAD | 2015 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2015 | ROR | 13.7 | 14.2 | 12.9 | 12.8 | 16.2 | 15.8 | 11.8 | 12.7 | 13.9 | 15.1 | 13.9 | 14.0 | 13.9 |
| UPPER SALMON 3&4 | 2015 | ROR | 12.9 | 13.4 | 12.2 | 12.1 | 15.1 | 14.7 | 11.3 | 12.0 | 13.1 | 14.1 | 13.1 | 13.1 | 13.1 |
| **HCC TOTAL** | | | **587.6** | **460.6** | **483.1** | **467.0** | **599.5** | **478.5** | **439.1** | **340.6** | **387.0** | **347.8** | **366.3** | **436.3** | **449.6** |
| **ROR TOTAL** | | | **200.9** | **203.7** | **193.8** | **212.1** | **286.7** | **296.0** | **239.6** | **230.0** | **214.0** | **208.8** | **196.6** | **201.5** | **223.7** |
| **TOTAL** | | | **788.5** | **664.3** | **676.9** | **679.1** | **886.2** | **774.5** | **678.7** | **570.6** | **601.0** | **556.6** | **562.9** | **637.8** | **673.4** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2016 | HCC | 257.5 | 197.1 | 183.8 | 234.3 | 264.3 | 213.5 | 194.8 | 144.5 | 164.5 | 146.4 | 158.8 | 194.1 | 196.2 |
| OXBOW | 2016 | HCC | 110.8 | 87.9 | 79.4 | 97.6 | 109.4 | 88.0 | 82.0 | 65.7 | 74.9 | 66.8 | 69.8 | 80.8 | 84.4 |
| HELLS CANYON | 2016 | HCC | 218.2 | 174.6 | 162.4 | 198.7 | 224.7 | 177.0 | 161.2 | 129.1 | 146.7 | 132.0 | 138.3 | 159.8 | 168.6 |
| 1000 SPRINGS | 2016 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2016 | ROR | 0.0 | 0.0 | 5.4 | 34.6 | 70.6 | 79.1 | 73.7 | 48.2 | 25.1 | 9.2 | 0.0 | 0.0 | 28.9 |
| BLISS | 2016 | ROR | 35.3 | 35.7 | 34.2 | 33.8 | 37.7 | 37.1 | 31.8 | 33.3 | 35.9 | 37.9 | 36.2 | 35.9 | 35.4 |
| C.J. STRIKE | 2016 | ROR | 44.8 | 45.1 | 44.7 | 42.1 | 44.8 | 40.3 | 31.2 | 34.8 | 42.1 | 47.3 | 45.7 | 45.0 | 42.3 |
| CASCADE | 2016 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2016 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2016 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2016 | ROR | 22.5 | 23.1 | 21.2 | 21.0 | 25.5 | 25.1 | 20.0 | 20.9 | 22.8 | 24.6 | 23.0 | 23.0 | 22.7 |
| MILNER | 2016 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 10.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.3 |
| SHOSHONE FALLS | 2016 | ROR | 12.0 | 12.0 | 10.1 | 7.9 | 12.0 | 12.0 | 8.9 | 9.6 | 7.2 | 9.4 | 11.3 | 12.0 | 10.4 |
| SWAN FALLS | 2016 | ROR | 15.2 | 15.3 | 15.1 | 14.4 | 15.1 | 14.4 | 11.0 | 11.9 | 14.0 | 15.3 | 15.4 | 15.3 | 14.4 |
| TWIN FALLS | 2016 | ROR | 9.4 | 9.3 | 6.3 | 4.2 | 11.9 | 15.0 | 5.3 | 5.8 | 3.7 | 5.7 | 7.3 | 9.0 | 7.7 |
| UPPER MALAD | 2016 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2016 | ROR | 13.6 | 14.2 | 12.8 | 12.7 | 16.2 | 15.6 | 11.7 | 12.6 | 13.8 | 15.0 | 13.8 | 13.9 | 13.8 |
| UPPER SALMON 3&4 | 2016 | ROR | 12.8 | 13.3 | 12.2 | 12.1 | 15.0 | 14.6 | 11.2 | 12.0 | 13.0 | 14.0 | 13.0 | 13.1 | 13.0 |
| **HCC TOTAL** | | | **586.5** | **459.6** | **425.6** | **530.6** | **598.3** | **478.5** | **438.0** | **339.3** | **386.0** | **345.2** | **366.9** | **434.7** | **449.1** |
| **ROR TOTAL** | | | **200.1** | **203.0** | **193.1** | **211.9** | **286.1** | **293.8** | **238.5** | **226.3** | **213.2** | **208.1** | **196.3** | **200.9** | **222.7** |
| **TOTAL** | | | **786.6** | **662.6** | **618.7** | **742.5** | **884.4** | **772.3** | **676.5** | **565.6** | **599.2** | **553.3** | **563.2** | **635.6** | **671.8** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2017 | HCC | 257.0 | 196.6 | 185.4 | 231.0 | 263.8 | 213.5 | 194.2 | 143.9 | 164.0 | 145.6 | 158.3 | 193.8 | 195.6 |
| OXBOW | 2017 | HCC | 110.6 | 87.7 | 80.2 | 96.4 | 109.2 | 88.0 | 81.7 | 65.4 | 74.6 | 66.4 | 69.6 | 80.7 | 84.2 |
| HELLS CANYON | 2017 | HCC | 217.8 | 174.2 | 163.9 | 196.2 | 224.3 | 177.0 | 160.8 | 128.5 | 146.2 | 131.3 | 137.8 | 159.6 | 168.1 |
| 1000 SPRINGS | 2017 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2017 | ROR | 0.0 | 0.0 | 5.4 | 34.8 | 70.5 | 78.5 | 73.6 | 45.9 | 24.9 | 9.2 | 0.0 | 0.0 | 28.7 |
| BLISS | 2017 | ROR | 35.1 | 35.6 | 34.1 | 33.7 | 37.6 | 36.9 | 31.5 | 33.1 | 35.8 | 37.8 | 36.0 | 35.7 | 35.2 |
| C.J. STRIKE | 2017 | ROR | 44.6 | 44.9 | 44.5 | 41.9 | 44.6 | 40.1 | 31.0 | 34.6 | 41.9 | 47.1 | 45.7 | 44.9 | 42.1 |
| CASCADE | 2017 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2017 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2017 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2017 | ROR | 22.5 | 23.0 | 21.1 | 20.9 | 25.4 | 24.9 | 19.9 | 20.8 | 22.7 | 24.5 | 22.9 | 22.9 | 22.6 |
| MILNER | 2017 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 10.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.3 |
| SHOSHONE FALLS | 2017 | ROR | 12.0 | 12.0 | 10.1 | 7.8 | 12.0 | 12.0 | 8.8 | 9.5 | 7.1 | 9.3 | 11.3 | 12.0 | 10.3 |
| SWAN FALLS | 2017 | ROR | 15.2 | 15.2 | 15.0 | 14.3 | 15.1 | 14.3 | 10.9 | 11.8 | 13.9 | 15.3 | 15.3 | 15.3 | 14.3 |
| TWIN FALLS | 2017 | ROR | 9.4 | 9.3 | 6.3 | 4.2 | 11.8 | 15.0 | 5.2 | 5.8 | 3.6 | 5.6 | 7.3 | 9.0 | 7.7 |
| UPPER MALAD | 2017 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2017 | ROR | 13.5 | 14.1 | 12.7 | 12.6 | 16.1 | 15.5 | 11.6 | 12.5 | 13.8 | 14.9 | 13.7 | 13.8 | 13.7 |
| UPPER SALMON 3&4 | 2017 | ROR | 12.8 | 13.3 | 12.1 | 12.0 | 15.0 | 14.5 | 11.2 | 11.9 | 13.0 | 14.0 | 13.0 | 13.0 | 13.0 |
| **HCC TOTAL** | | | **585.4** | **458.5** | **429.5** | **523.6** | **597.2** | **478.5** | **436.7** | **337.8** | **384.8** | **343.3** | **365.7** | **434.1** | **447.9** |
| **ROR TOTAL** | | | **199.6** | **202.4** | **192.4** | **211.3** | **285.3** | **292.3** | **237.4** | **223.1** | **212.4** | **207.4** | **195.8** | **200.3** | **221.7** |
| **TOTAL** | | | **785.0** | **660.9** | **621.9** | **734.9** | **882.5** | **770.8** | **674.1** | **560.9** | **597.2** | **550.7** | **561.5** | **634.4** | **669.7** |

## 2009 Integrated Resource Plan

### Average Megawatt Hydro Output from PDR580

### 90th Percentile Water, 70th Percentile Load

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2018 | HCC | 256.4 | 196.1 | 188.2 | 226.2 | 263.3 | 209.2 | 193.7 | 143.4 | 163.5 | 144.5 | 158.6 | 193.3 | 194.7 |
| OXBOW | 2018 | HCC | 110.3 | 87.5 | 81.6 | 94.5 | 108.9 | 86.2 | 81.5 | 65.1 | 74.4 | 65.9 | 69.7 | 80.5 | 83.8 |
| HELLS CANYON | 2018 | HCC | 217.3 | 173.7 | 166.5 | 192.7 | 223.9 | 173.6 | 160.4 | 128.1 | 145.8 | 130.3 | 138.0 | 159.1 | 167.4 |
| 1000 SPRINGS | 2018 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2018 | ROR | 0.0 | 0.0 | 5.3 | 35.1 | 70.1 | 77.6 | 66.8 | 45.8 | 25.0 | 9.1 | 0.0 | 0.0 | 28.1 |
| BLISS | 2018 | ROR | 35.0 | 35.5 | 34.0 | 33.6 | 37.5 | 36.7 | 31.5 | 33.0 | 35.6 | 37.6 | 35.9 | 35.7 | 35.1 |
| C.J. STRIKE | 2018 | ROR | 44.5 | 44.6 | 44.4 | 41.8 | 44.5 | 39.8 | 30.8 | 34.4 | 41.7 | 46.9 | 45.7 | 44.9 | 42.0 |
| CASCADE | 2018 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2018 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2018 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2018 | ROR | 22.4 | 22.8 | 21.0 | 20.8 | 25.3 | 24.7 | 19.8 | 20.7 | 22.6 | 24.4 | 22.8 | 22.8 | 22.5 |
| MILNER | 2018 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 10.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.3 |
| SHOSHONE FALLS | 2018 | ROR | 12.0 | 12.0 | 10.0 | 7.8 | 12.0 | 12.0 | 8.8 | 9.5 | 7.1 | 9.3 | 11.2 | 12.0 | 10.3 |
| SWAN FALLS | 2018 | ROR | 15.1 | 15.1 | 15.0 | 14.3 | 15.0 | 14.1 | 10.8 | 11.8 | 13.9 | 15.2 | 15.3 | 15.2 | 14.2 |
| TWIN FALLS | 2018 | ROR | 9.4 | 9.2 | 6.2 | 4.2 | 11.8 | 15.0 | 5.2 | 5.7 | 0.0 | 5.6 | 7.3 | 9.0 | 7.4 |
| UPPER MALAD | 2018 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2018 | ROR | 13.5 | 14.0 | 12.7 | 12.5 | 16.0 | 15.3 | 11.6 | 12.4 | 13.7 | 14.9 | 13.7 | 13.7 | 13.7 |
| UPPER SALMON 3&4 | 2018 | ROR | 12.7 | 13.2 | 12.0 | 11.9 | 14.9 | 14.3 | 11.1 | 11.8 | 12.9 | 13.9 | 12.9 | 12.9 | 12.9 |
| **HCC TOTAL** | | | **584.0** | **457.3** | **436.3** | **513.4** | **596.0** | **469.0** | **435.6** | **336.6** | **383.7** | **340.7** | **366.3** | **432.9** | **446.0** |
| **ROR TOTAL** | | | **199.1** | **201.4** | **191.7** | **211.1** | **284.3** | **290.1** | **230.1** | **222.3** | **208.2** | **206.6** | **195.4** | **199.9** | **220.1** |
| **TOTAL** | | | **783.1** | **658.7** | **628.0** | **724.5** | **880.3** | **759.1** | **665.7** | **558.9** | **591.8** | **547.3** | **561.7** | **632.8** | **666.1** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2019 | HCC | 256.0 | 195.6 | 190.5 | 222.0 | 262.7 | 208.7 | 193.1 | 142.9 | 163.1 | 143.5 | 158.9 | 192.8 | 194.2 |
| OXBOW | 2019 | HCC | 110.1 | 87.3 | 82.7 | 92.9 | 108.7 | 86.0 | 81.3 | 64.9 | 74.2 | 65.3 | 69.8 | 80.3 | 83.6 |
| HELLS CANYON | 2019 | HCC | 216.9 | 173.3 | 168.8 | 189.5 | 223.5 | 173.1 | 159.9 | 127.6 | 145.4 | 129.3 | 138.2 | 158.7 | 167.0 |
| 1000 SPRINGS | 2019 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2019 | ROR | 0.0 | 0.0 | 5.3 | 35.4 | 69.9 | 77.0 | 64.6 | 45.4 | 24.9 | 9.2 | 0.0 | 0.0 | 27.8 |
| BLISS | 2019 | ROR | 34.9 | 35.3 | 33.9 | 33.4 | 37.4 | 36.5 | 31.2 | 32.8 | 35.5 | 37.5 | 35.8 | 35.6 | 35.0 |
| C.J. STRIKE | 2019 | ROR | 44.3 | 44.4 | 44.2 | 41.6 | 44.3 | 39.6 | 30.6 | 34.4 | 41.5 | 46.7 | 45.5 | 44.9 | 41.8 |
| CASCADE | 2019 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2019 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2019 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2019 | ROR | 22.2 | 22.7 | 20.9 | 20.7 | 25.2 | 24.6 | 19.7 | 20.6 | 22.5 | 24.3 | 22.7 | 22.7 | 22.4 |
| MILNER | 2019 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 9.6 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.2 |
| SHOSHONE FALLS | 2019 | ROR | 12.0 | 12.0 | 10.0 | 7.7 | 12.0 | 12.0 | 8.8 | 9.4 | 7.0 | 9.2 | 11.2 | 12.0 | 10.3 |
| SWAN FALLS | 2019 | ROR | 15.1 | 15.1 | 15.0 | 14.2 | 15.0 | 14.1 | 10.8 | 11.7 | 13.8 | 15.2 | 15.2 | 15.2 | 14.2 |
| TWIN FALLS | 2019 | ROR | 9.3 | 9.2 | 6.2 | 4.1 | 11.8 | 14.0 | 5.2 | 5.7 | 0.0 | 5.6 | 7.2 | 9.0 | 7.3 |
| UPPER MALAD | 2019 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2019 | ROR | 13.4 | 13.9 | 12.6 | 12.5 | 15.9 | 15.3 | 11.5 | 12.4 | 13.6 | 14.8 | 13.6 | 13.6 | 13.6 |
| UPPER SALMON 3&4 | 2019 | ROR | 12.6 | 13.1 | 12.0 | 11.9 | 14.8 | 14.3 | 11.0 | 11.8 | 12.8 | 13.8 | 12.8 | 12.9 | 12.8 |
| **HCC TOTAL** | | | **583.0** | **456.2** | **442.0** | **504.4** | **594.8** | **467.8** | **434.3** | **335.4** | **382.6** | **338.1** | **366.9** | **431.8** | **444.8** |
| **ROR TOTAL** | | | **198.3** | **200.7** | **191.2** | **210.6** | **283.5** | **287.1** | **227.1** | **221.4** | **207.3** | **206.0** | **194.6** | **199.6** | **219.0** |
| **TOTAL** | | | **781.3** | **656.9** | **633.2** | **715.0** | **878.3** | **754.9** | **661.4** | **556.8** | **589.9** | **544.1** | **561.5** | **631.4** | **663.9** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2020 | HCC | 255.5 | 195.1 | 193.3 | 217.3 | 262.2 | 208.1 | 192.7 | 142.3 | 162.6 | 142.7 | 158.8 | 192.2 | 193.6 |
| OXBOW | 2020 | HCC | 109.9 | 87.1 | 84.0 | 91.1 | 108.5 | 85.8 | 81.1 | 64.6 | 74.0 | 64.9 | 69.7 | 80.0 | 83.4 |
| HELLS CANYON | 2020 | HCC | 216.5 | 172.9 | 171.4 | 186.0 | 223.1 | 172.7 | 159.5 | 127.1 | 145.0 | 128.5 | 138.1 | 158.3 | 166.6 |
| 1000 SPRINGS | 2020 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2020 | ROR | 0.0 | 0.0 | 5.3 | 35.7 | 69.8 | 76.9 | 62.6 | 44.6 | 23.6 | 9.3 | 0.0 | 0.0 | 27.4 |
| BLISS | 2020 | ROR | 34.8 | 35.2 | 33.7 | 33.3 | 37.2 | 36.4 | 31.1 | 32.7 | 35.4 | 37.4 | 35.6 | 35.5 | 34.9 |
| C.J. STRIKE | 2020 | ROR | 44.1 | 44.2 | 44.0 | 41.4 | 44.1 | 39.4 | 30.5 | 34.4 | 41.3 | 46.5 | 45.3 | 44.7 | 41.6 |
| CASCADE | 2020 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2020 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2020 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2020 | ROR | 22.1 | 22.6 | 20.8 | 20.6 | 25.1 | 24.5 | 19.6 | 20.5 | 22.3 | 24.2 | 22.6 | 22.6 | 22.3 |
| MILNER | 2020 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 9.6 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.2 |
| SHOSHONE FALLS | 2020 | ROR | 12.0 | 12.0 | 9.9 | 7.7 | 12.0 | 12.0 | 8.7 | 9.4 | 7.0 | 9.2 | 11.1 | 12.0 | 10.2 |
| SWAN FALLS | 2020 | ROR | 15.0 | 15.0 | 15.0 | 14.2 | 14.9 | 14.0 | 10.8 | 11.7 | 13.8 | 15.4 | 15.2 | 15.1 | 14.2 |
| TWIN FALLS | 2020 | ROR | 9.3 | 9.2 | 6.1 | 4.1 | 11.8 | 13.9 | 5.1 | 5.7 | 0.0 | 5.5 | 7.2 | 9.0 | 7.2 |
| UPPER MALAD | 2020 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2020 | ROR | 13.3 | 13.8 | 12.5 | 12.4 | 15.8 | 15.2 | 11.4 | 12.3 | 13.5 | 14.7 | 13.5 | 13.6 | 13.5 |
| UPPER SALMON 3&4 | 2020 | ROR | 12.6 | 13.0 | 11.9 | 11.8 | 14.7 | 14.2 | 11.0 | 11.7 | 12.7 | 13.8 | 12.8 | 12.8 | 12.7 |
| **HCC TOTAL** | | | **581.9** | **455.1** | **448.7** | **494.4** | **593.7** | **466.6** | **433.3** | **334.0** | **381.5** | **336.1** | **366.6** | **430.5** | **443.6** |
| **ROR TOTAL** | | | **197.7** | **200.0** | **190.3** | **210.3** | **282.7** | **286.2** | **224.5** | **220.2** | **205.2** | **205.7** | **193.9** | **199.0** | **218.0** |
| **TOTAL** | | | **779.6** | **655.1** | **639.0** | **704.7** | **876.4** | **752.8** | **657.8** | **554.2** | **586.7** | **541.8** | **560.5** | **629.5** | **661.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2021 | HCC | 254.9 | 194.6 | 193.5 | 215.8 | 261.7 | 207.6 | 192.2 | 141.7 | 158.6 | 141.6 | 158.7 | 192.2 | 192.8 |
| OXBOW | 2021 | HCC | 109.7 | 86.8 | 84.2 | 90.5 | 108.3 | 85.5 | 80.9 | 64.3 | 73.8 | 64.4 | 69.7 | 80.0 | 83.2 |
| HELLS CANYON | 2021 | HCC | 216.0 | 172.5 | 171.7 | 184.8 | 222.6 | 172.3 | 159.1 | 126.6 | 144.4 | 127.5 | 138.0 | 158.2 | 166.2 |
| 1000 SPRINGS | 2021 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2021 | ROR | 0.0 | 0.0 | 5.2 | 36.0 | 69.7 | 76.3 | 60.6 | 44.3 | 23.5 | 9.4 | 0.0 | 0.0 | 27.2 |
| BLISS | 2021 | ROR | 34.7 | 35.1 | 33.6 | 33.2 | 37.2 | 36.3 | 30.9 | 32.5 | 35.2 | 37.2 | 35.5 | 35.4 | 34.7 |
| C.J. STRIKE | 2021 | ROR | 44.0 | 44.0 | 43.9 | 41.2 | 44.0 | 39.2 | 30.3 | 34.2 | 41.2 | 46.4 | 45.2 | 44.5 | 41.5 |
| CASCADE | 2021 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2021 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2021 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2021 | ROR | 22.0 | 22.6 | 20.7 | 20.5 | 25.0 | 24.3 | 19.5 | 20.4 | 22.2 | 24.1 | 22.5 | 22.5 | 22.2 |
| MILNER | 2021 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 8.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.1 |
| SHOSHONE FALLS | 2021 | ROR | 12.0 | 12.0 | 9.9 | 7.6 | 12.0 | 12.0 | 8.7 | 9.3 | 6.9 | 9.1 | 11.1 | 12.0 | 10.2 |
| SWAN FALLS | 2021 | ROR | 15.0 | 15.0 | 15.0 | 14.1 | 14.9 | 14.0 | 10.7 | 11.6 | 13.7 | 15.3 | 15.1 | 15.1 | 14.1 |
| TWIN FALLS | 2021 | ROR | 9.3 | 9.2 | 6.1 | 4.0 | 11.8 | 12.1 | 5.1 | 5.6 | 0.0 | 5.5 | 7.2 | 9.0 | 7.1 |
| UPPER MALAD | 2021 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2021 | ROR | 13.2 | 13.8 | 12.4 | 12.3 | 15.8 | 15.0 | 11.3 | 12.2 | 13.4 | 14.6 | 13.4 | 13.5 | 13.4 |
| UPPER SALMON 3&4 | 2021 | ROR | 12.5 | 13.0 | 11.8 | 11.7 | 14.7 | 14.1 | 10.9 | 11.6 | 12.6 | 13.7 | 12.7 | 12.7 | 12.7 |
| **HCC TOTAL** | | | **580.6** | **453.9** | **449.4** | **491.1** | **592.5** | **465.4** | **432.2** | **332.6** | **376.7** | **333.5** | **366.4** | **430.4** | **442.1** |
| **ROR TOTAL** | | | **197.2** | **199.7** | **189.7** | **209.7** | **282.3** | **281.9** | **221.7** | **218.9** | **204.3** | **205.0** | **193.3** | **198.4** | **216.9** |
| **TOTAL** | | | **777.8** | **653.6** | **639.1** | **700.8** | **874.8** | **747.3** | **653.9** | **551.5** | **581.0** | **538.5** | **559.7** | **628.8** | **659.1** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2022 | HCC | 254.4 | 194.2 | 195.8 | 211.6 | 261.2 | 207.0 | 191.7 | 141.2 | 158.1 | 140.9 | 158.7 | 191.7 | 192.3 |
| OXBOW | 2022 | HCC | 109.5 | 86.6 | 85.3 | 88.9 | 108.1 | 85.3 | 80.6 | 64.1 | 73.5 | 64.0 | 69.6 | 79.8 | 82.9 |
| HELLS CANYON | 2022 | HCC | 215.6 | 172.1 | 173.9 | 181.7 | 222.2 | 171.8 | 158.7 | 126.2 | 143.9 | 126.8 | 137.9 | 157.8 | 165.7 |
| 1000 SPRINGS | 2022 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2022 | ROR | 0.0 | 0.0 | 5.2 | 36.3 | 69.5 | 75.6 | 56.8 | 44.2 | 23.3 | 9.5 | 0.0 | 0.0 | 26.8 |
| BLISS | 2022 | ROR | 34.6 | 34.9 | 33.5 | 33.0 | 37.2 | 35.7 | 30.8 | 32.4 | 35.1 | 37.1 | 35.4 | 35.2 | 34.6 |
| C.J. STRIKE | 2022 | ROR | 43.8 | 43.8 | 43.7 | 41.1 | 43.8 | 38.7 | 30.1 | 34.0 | 41.0 | 46.3 | 45.0 | 44.4 | 41.3 |
| CASCADE | 2022 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2022 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2022 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2022 | ROR | 21.9 | 22.5 | 20.6 | 20.4 | 24.9 | 24.2 | 19.4 | 20.3 | 22.1 | 23.9 | 22.4 | 22.4 | 22.1 |
| MILNER | 2022 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 8.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.1 |
| SHOSHONE FALLS | 2022 | ROR | 12.0 | 12.0 | 9.8 | 7.6 | 12.0 | 12.0 | 8.7 | 9.3 | 6.9 | 9.1 | 11.0 | 12.0 | 10.2 |
| SWAN FALLS | 2022 | ROR | 14.9 | 14.9 | 15.0 | 14.1 | 14.8 | 13.7 | 10.6 | 11.5 | 13.6 | 15.3 | 15.1 | 15.1 | 14.0 |
| TWIN FALLS | 2022 | ROR | 9.3 | 9.1 | 6.1 | 4.0 | 11.8 | 12.0 | 5.1 | 5.6 | 0.0 | 5.5 | 7.1 | 8.9 | 7.0 |
| UPPER MALAD | 2022 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2022 | ROR | 13.1 | 13.7 | 12.3 | 12.2 | 15.7 | 15.0 | 11.2 | 12.1 | 13.3 | 14.5 | 13.4 | 13.4 | 13.3 |
| UPPER SALMON 3&4 | 2022 | ROR | 12.4 | 12.9 | 11.8 | 11.7 | 14.6 | 14.0 | 10.8 | 11.6 | 12.6 | 13.6 | 12.6 | 12.7 | 12.6 |
| **HCC TOTAL** | | | **579.5** | **452.9** | **455.0** | **482.2** | **591.4** | **464.1** | **431.0** | **331.5** | **375.5** | **331.7** | **366.2** | **429.3** | **441.0** |
| **ROR TOTAL** | | | **196.5** | **198.8** | **189.1** | **209.5** | **281.6** | **279.5** | **217.2** | **218.2** | **203.6** | **204.5** | **192.6** | **197.8** | **215.8** |
| **TOTAL** | | | **776.0** | **651.7** | **644.1** | **691.7** | **873.0** | **743.6** | **648.2** | **549.7** | **579.0** | **536.2** | **558.8** | **627.1** | **656.8** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2023 | HCC | 254.0 | 193.7 | 196.9 | 209.0 | 260.7 | 206.6 | 191.1 | 140.7 | 157.6 | 139.8 | 159.0 | 191.2 | 191.8 |
| OXBOW | 2023 | HCC | 109.3 | 86.4 | 85.9 | 87.9 | 107.9 | 85.1 | 80.4 | 63.9 | 73.3 | 63.5 | 69.7 | 79.6 | 82.7 |
| HELLS CANYON | 2023 | HCC | 215.2 | 171.7 | 174.9 | 179.7 | 221.8 | 171.4 | 158.3 | 125.7 | 143.5 | 125.8 | 138.1 | 157.4 | 165.3 |
| 1000 SPRINGS | 2023 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2023 | ROR | 0.0 | 0.0 | 5.1 | 36.5 | 69.6 | 74.3 | 54.2 | 44.0 | 23.3 | 9.6 | 0.0 | 0.0 | 26.5 |
| BLISS | 2023 | ROR | 34.4 | 34.8 | 33.3 | 32.9 | 37.2 | 35.5 | 30.7 | 32.3 | 34.9 | 37.0 | 35.2 | 35.1 | 34.4 |
| C.J. STRIKE | 2023 | ROR | 43.6 | 43.7 | 43.5 | 40.9 | 43.6 | 38.3 | 29.9 | 33.9 | 40.8 | 46.3 | 44.9 | 44.2 | 41.1 |
| CASCADE | 2023 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2023 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2023 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2023 | ROR | 21.8 | 22.4 | 20.5 | 20.3 | 24.8 | 24.1 | 19.2 | 20.2 | 22.0 | 23.8 | 22.3 | 22.3 | 22.0 |
| MILNER | 2023 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 8.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.1 |
| SHOSHONE FALLS | 2023 | ROR | 12.0 | 12.0 | 9.8 | 7.5 | 12.0 | 12.0 | 8.7 | 9.3 | 6.9 | 9.0 | 11.0 | 12.0 | 10.2 |
| SWAN FALLS | 2023 | ROR | 14.9 | 14.9 | 15.0 | 14.1 | 14.8 | 13.7 | 10.6 | 11.5 | 13.6 | 15.2 | 15.0 | 15.1 | 14.0 |
| TWIN FALLS | 2023 | ROR | 9.2 | 9.1 | 6.0 | 4.0 | 11.8 | 12.0 | 5.1 | 5.6 | 0.0 | 5.4 | 7.1 | 8.9 | 7.0 |
| UPPER MALAD | 2023 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2023 | ROR | 13.1 | 13.6 | 12.3 | 12.1 | 15.6 | 14.9 | 11.1 | 12.0 | 13.2 | 14.5 | 13.3 | 13.3 | 13.2 |
| UPPER SALMON 3&4 | 2023 | ROR | 12.4 | 12.8 | 11.7 | 11.6 | 14.5 | 13.9 | 10.7 | 11.5 | 12.5 | 13.6 | 12.6 | 12.6 | 12.5 |
| **HCC TOTAL** | | | **578.5** | **451.8** | **457.7** | **476.6** | **590.3** | **463.1** | **429.8** | **330.3** | **374.4** | **329.1** | **366.8** | **428.2** | **439.8** |
| **ROR TOTAL** | | | **195.9** | **198.3** | **188.3** | **209.0** | **281.2** | **277.3** | **213.9** | **217.5** | **202.9** | **204.1** | **192.0** | **197.2** | **214.9** |
| **TOTAL** | | | **774.4** | **650.1** | **646.0** | **685.6** | **871.5** | **740.4** | **643.7** | **547.8** | **577.2** | **533.2** | **558.8** | **625.4** | **654.7** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2024 | HCC | 253.5 | 193.2 | 193.8 | 211.8 | 260.2 | 206.0 | 190.6 | 140.2 | 157.2 | 139.0 | 158.9 | 190.6 | 191.3 |
| OXBOW | 2024 | HCC | 109.0 | 86.2 | 84.4 | 88.9 | 107.6 | 84.9 | 80.2 | 63.7 | 73.1 | 63.1 | 69.7 | 79.4 | 82.5 |
| HELLS CANYON | 2024 | HCC | 214.8 | 171.2 | 172.1 | 181.7 | 221.4 | 171.0 | 157.8 | 125.3 | 143.1 | 125.1 | 138.0 | 157.0 | 164.9 |
| 1000 SPRINGS | 2024 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2024 | ROR | 0.0 | 0.0 | 5.1 | 36.8 | 69.8 | 73.0 | 53.1 | 43.9 | 23.3 | 9.7 | 0.0 | 0.0 | 26.3 |
| BLISS | 2024 | ROR | 34.3 | 34.7 | 33.2 | 32.8 | 37.2 | 35.4 | 30.5 | 32.1 | 34.8 | 36.8 | 35.1 | 35.0 | 34.3 |
| C.J. STRIKE | 2024 | ROR | 43.4 | 43.5 | 43.3 | 40.7 | 43.4 | 38.3 | 29.9 | 33.7 | 40.7 | 46.2 | 44.7 | 44.0 | 41.0 |
| CASCADE | 2024 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2024 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2024 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2024 | ROR | 21.7 | 22.3 | 20.4 | 20.2 | 24.7 | 24.0 | 19.1 | 20.1 | 21.9 | 23.7 | 22.2 | 22.2 | 21.9 |
| MILNER | 2024 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 7.7 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.1 |
| SHOSHONE FALLS | 2024 | ROR | 12.0 | 12.0 | 9.7 | 7.5 | 12.0 | 12.0 | 8.7 | 9.2 | 6.8 | 9.0 | 11.0 | 12.0 | 10.2 |
| SWAN FALLS | 2024 | ROR | 14.8 | 14.9 | 15.0 | 14.1 | 14.7 | 13.7 | 10.5 | 11.4 | 13.5 | 15.2 | 15.0 | 15.0 | 14.0 |
| TWIN FALLS | 2024 | ROR | 9.2 | 9.1 | 6.0 | 3.9 | 11.8 | 11.9 | 5.1 | 5.5 | 0.0 | 5.4 | 7.1 | 8.9 | 7.0 |
| UPPER MALAD | 2024 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2024 | ROR | 13.0 | 13.5 | 12.2 | 12.1 | 15.5 | 14.7 | 11.0 | 12.0 | 13.1 | 14.4 | 13.2 | 13.3 | 13.2 |
| UPPER SALMON 3&4 | 2024 | ROR | 12.3 | 12.8 | 11.6 | 11.5 | 14.5 | 13.8 | 10.6 | 11.4 | 12.4 | 13.5 | 12.5 | 12.5 | 12.4 |
| **HCC TOTAL** | | | **577.3** | **450.6** | **450.3** | **482.4** | **589.2** | **461.9** | **428.6** | **329.2** | **373.3** | **327.2** | **366.6** | **427.0** | **438.8** |
| **ROR TOTAL** | | | **195.2** | **197.8** | **187.6** | **208.7** | **280.8** | **274.6** | **212.2** | **216.5** | **202.2** | **203.6** | **191.4** | **196.6** | **214.0** |
| **TOTAL** | | | **772.5** | **648.4** | **637.9** | **691.1** | **870.0** | **736.5** | **640.8** | **545.7** | **575.5** | **530.8** | **558.0** | **623.6** | **652.7** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2025 | HCC | 253.0 | 192.7 | 195.7 | 208.2 | 259.6 | 205.5 | 190.1 | 139.8 | 156.7 | 137.9 | 159.1 | 190.1 | 190.8 |
| OXBOW | 2025 | HCC | 108.8 | 86.0 | 85.4 | 87.5 | 107.4 | 84.7 | 80.0 | 63.4 | 72.9 | 62.6 | 69.8 | 79.1 | 82.3 |
| HELLS CANYON | 2025 | HCC | 214.4 | 170.8 | 174.0 | 179.0 | 221.0 | 170.6 | 157.4 | 124.9 | 142.7 | 124.1 | 138.2 | 156.5 | 164.5 |
| 1000 SPRINGS | 2025 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2025 | ROR | 0.0 | 0.0 | 5.1 | 36.9 | 69.8 | 69.4 | 51.8 | 43.6 | 23.1 | 9.8 | 0.0 | 0.0 | 25.9 |
| BLISS | 2025 | ROR | 34.2 | 34.5 | 33.1 | 32.6 | 37.2 | 34.0 | 30.4 | 32.0 | 34.6 | 36.7 | 35.0 | 34.8 | 34.1 |
| C.J. STRIKE | 2025 | ROR | 43.3 | 43.3 | 43.2 | 40.6 | 43.3 | 38.3 | 29.8 | 33.5 | 40.6 | 46.0 | 44.5 | 43.8 | 40.8 |
| CASCADE | 2025 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2025 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2025 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2025 | ROR | 21.6 | 22.2 | 20.3 | 20.1 | 24.6 | 22.9 | 19.0 | 20.0 | 21.8 | 23.6 | 22.1 | 22.1 | 21.7 |
| MILNER | 2025 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 7.7 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 3.1 |
| SHOSHONE FALLS | 2025 | ROR | 12.0 | 12.0 | 9.7 | 7.5 | 12.0 | 12.0 | 8.7 | 9.2 | 6.8 | 9.0 | 10.9 | 12.0 | 10.1 |
| SWAN FALLS | 2025 | ROR | 14.8 | 14.9 | 15.0 | 14.0 | 14.7 | 13.2 | 10.5 | 11.4 | 13.5 | 15.1 | 14.9 | 14.9 | 13.9 |
| TWIN FALLS | 2025 | ROR | 9.2 | 9.1 | 6.0 | 3.9 | 11.8 | 11.9 | 5.1 | 5.5 | 0.0 | 5.3 | 7.0 | 8.8 | 7.0 |
| UPPER MALAD | 2025 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2025 | ROR | 12.9 | 13.5 | 12.1 | 12.0 | 15.4 | 13.9 | 11.0 | 11.9 | 13.0 | 14.3 | 13.1 | 13.2 | 13.0 |
| UPPER SALMON 3&4 | 2025 | ROR | 12.2 | 12.7 | 11.6 | 11.5 | 14.4 | 13.1 | 10.6 | 11.4 | 12.4 | 13.4 | 12.4 | 12.5 | 12.3 |
| **HCC TOTAL** | | | **576.2** | **449.5** | **455.1** | **474.7** | **587.9** | **460.8** | **427.5** | **328.1** | **372.2** | **324.6** | **367.1** | **425.7** | **437.6** |
| **ROR TOTAL** | | | **194.7** | **197.2** | **187.2** | **208.2** | **280.4** | **266.5** | **210.6** | **215.7** | **201.5** | **202.9** | **190.5** | **195.8** | **212.7** |
| **TOTAL** | | | **770.9** | **646.7** | **642.3** | **682.9** | **868.3** | **727.3** | **638.1** | **543.8** | **573.6** | **527.5** | **557.6** | **621.5** | **650.2** |

**2009 Integrated Resource Plan**

**Average Megawatt Hydro Output from PDR580**

**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2026 | HCC | 252.5 | 192.2 | 196.4 | 206.2 | 259.1 | 205.0 | 189.6 | 139.3 | 156.3 | 136.8 | 159.1 | 190.0 | 190.3 |
| OXBOW | 2026 | HCC | 108.6 | 85.8 | 85.7 | 86.7 | 107.2 | 84.5 | 79.8 | 63.2 | 72.7 | 62.1 | 69.7 | 79.1 | 82.1 |
| HELLS CANYON | 2026 | HCC | 214.0 | 170.4 | 174.6 | 177.5 | 220.6 | 170.1 | 157.0 | 124.4 | 142.3 | 123.0 | 138.0 | 156.4 | 164.0 |
| 1000 SPRINGS | 2026 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2026 | ROR | 0.0 | 0.0 | 5.0 | 37.1 | 69.8 | 69.3 | 50.5 | 43.3 | 23.1 | 9.9 | 0.0 | 0.0 | 25.8 |
| BLISS | 2026 | ROR | 34.0 | 34.4 | 32.9 | 32.5 | 37.2 | 33.8 | 30.2 | 31.8 | 34.5 | 36.6 | 34.9 | 34.7 | 34.0 |
| C.J. STRIKE | 2026 | ROR | 43.1 | 43.2 | 43.0 | 40.5 | 43.1 | 38.3 | 29.6 | 33.3 | 40.4 | 45.9 | 44.3 | 43.7 | 40.7 |
| CASCADE | 2026 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2026 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2026 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2026 | ROR | 21.5 | 22.0 | 20.2 | 20.0 | 24.5 | 22.7 | 18.9 | 19.8 | 21.7 | 23.5 | 22.0 | 21.9 | 21.6 |
| MILNER | 2026 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 5.4 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 2.9 |
| SHOSHONE FALLS | 2026 | ROR | 12.0 | 12.0 | 9.7 | 7.4 | 12.0 | 12.0 | 8.7 | 9.1 | 6.7 | 8.9 | 10.9 | 12.0 | 10.1 |
| SWAN FALLS | 2026 | ROR | 14.8 | 14.8 | 15.0 | 14.0 | 14.6 | 13.1 | 10.4 | 11.3 | 13.4 | 15.1 | 14.9 | 14.9 | 13.9 |
| TWIN FALLS | 2026 | ROR | 9.2 | 9.0 | 5.9 | 3.9 | 11.8 | 9.9 | 5.1 | 5.5 | 0.0 | 5.3 | 7.0 | 8.8 | 6.8 |
| UPPER MALAD | 2026 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2026 | ROR | 12.8 | 13.4 | 12.0 | 11.9 | 15.4 | 13.8 | 10.9 | 11.8 | 13.0 | 14.2 | 13.1 | 13.1 | 12.9 |
| UPPER SALMON 3&4 | 2026 | ROR | 12.2 | 12.6 | 11.5 | 11.4 | 14.3 | 13.0 | 10.5 | 11.3 | 12.3 | 13.4 | 12.4 | 12.4 | 12.3 |
| **HCC TOTAL** | | | **575.1** | **448.4** | **456.7** | **470.4** | **586.8** | **459.6** | **426.4** | **326.9** | **371.2** | **321.9** | **366.8** | **425.5** | **436.4** |
| **ROR TOTAL** | | | **194.1** | **196.4** | **186.3** | **207.8** | **279.9** | **261.4** | **208.5** | **214.4** | **200.8** | **202.5** | **190.1** | **195.2** | **211.5** |
| **TOTAL** | | | **769.2** | **644.8** | **643.0** | **678.2** | **866.7** | **721.0** | **634.9** | **541.3** | **571.9** | **524.4** | **556.9** | **620.7** | **648.0** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2027 | HCC | 252.0 | 191.7 | 197.0 | 204.1 | 258.6 | 204.4 | 189.1 | 138.8 | 155.8 | 136.1 | 159.0 | 189.5 | 189.8 |
| OXBOW | 2027 | HCC | 108.4 | 85.5 | 86.1 | 85.9 | 107.0 | 84.2 | 79.6 | 63.0 | 72.4 | 61.7 | 69.7 | 78.9 | 81.9 |
| HELLS CANYON | 2027 | HCC | 213.5 | 170.0 | 175.3 | 175.9 | 220.1 | 169.7 | 156.6 | 124.0 | 141.9 | 122.3 | 138.0 | 156.0 | 163.6 |
| 1000 SPRINGS | 2027 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2027 | ROR | 0.0 | 0.0 | 5.0 | 37.4 | 69.9 | 67.6 | 50.4 | 42.7 | 23.1 | 10.0 | 0.0 | 0.0 | 25.6 |
| BLISS | 2027 | ROR | 33.9 | 34.3 | 32.8 | 32.4 | 37.2 | 32.4 | 30.1 | 31.7 | 34.4 | 36.4 | 34.7 | 34.6 | 33.7 |
| C.J. STRIKE | 2027 | ROR | 42.9 | 43.0 | 42.8 | 40.5 | 42.9 | 38.1 | 29.4 | 33.1 | 40.4 | 45.7 | 44.2 | 43.5 | 40.5 |
| CASCADE | 2027 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2027 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2027 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2027 | ROR | 21.4 | 22.0 | 20.1 | 19.9 | 24.4 | 20.8 | 18.8 | 19.7 | 21.6 | 23.4 | 21.9 | 21.9 | 21.3 |
| MILNER | 2027 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 2.4 |
| SHOSHONE FALLS | 2027 | ROR | 12.0 | 12.0 | 9.6 | 7.4 | 12.0 | 9.3 | 8.7 | 9.1 | 6.7 | 8.9 | 10.8 | 12.0 | 9.9 |
| SWAN FALLS | 2027 | ROR | 14.7 | 14.8 | 15.0 | 14.0 | 14.6 | 13.1 | 10.4 | 11.2 | 13.4 | 15.0 | 14.8 | 14.8 | 13.8 |
| TWIN FALLS | 2027 | ROR | 9.2 | 9.0 | 5.9 | 3.8 | 11.8 | 5.6 | 5.1 | 5.4 | 0.0 | 5.3 | 6.9 | 8.8 | 6.4 |
| UPPER MALAD | 2027 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2027 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 15.3 | 12.3 | 10.8 | 11.7 | 12.9 | 14.1 | 13.0 | 13.0 | 12.7 |
| UPPER SALMON 3&4 | 2027 | ROR | 12.1 | 12.6 | 11.4 | 11.3 | 14.3 | 11.7 | 10.4 | 11.2 | 12.2 | 13.3 | 12.3 | 12.3 | 12.1 |
| **HCC TOTAL** | | | **573.9** | **447.2** | **458.4** | **465.9** | **585.6** | **458.3** | **425.3** | **325.8** | **370.1** | **320.1** | **366.7** | **424.4** | **435.3** |
| **ROR TOTAL** | | | **193.4** | **196.0** | **185.6** | **207.6** | **279.7** | **241.0** | **207.8** | **213.0** | **200.4** | **201.8** | **189.2** | **194.6** | **209.3** |
| **TOTAL** | | | **767.3** | **643.2** | **644.0** | **673.5** | **865.3** | **699.3** | **633.1** | **538.8** | **570.4** | **521.9** | **555.9** | **619.0** | **644.5** |

**2009 Integrated Resource Plan**
**Average Megawatt Hydro Output from PDR580**
**90th Percentile Water, 70th Percentile Load**

**Abbreviations:**
HCC - Hells Canyon Complex
ROR - Run of River

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2028 | HCC | 251.5 | 191.2 | 197.7 | 202.1 | 258.1 | 203.9 | 188.6 | 138.3 | 155.4 | 134.9 | 159.3 | 189.0 | 189.2 |
| OXBOW | 2028 | HCC | 108.2 | 85.3 | 86.4 | 85.1 | 106.8 | 84.0 | 79.3 | 62.8 | 72.2 | 61.1 | 69.8 | 78.7 | 81.7 |
| HELLS CANYON | 2028 | HCC | 213.1 | 169.5 | 176.0 | 174.4 | 219.7 | 169.3 | 156.1 | 123.5 | 141.5 | 121.3 | 138.2 | 155.6 | 163.2 |
| 1000 SPRINGS | 2028 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2028 | ROR | 0.0 | 0.0 | 5.0 | 37.6 | 70.0 | 66.4 | 49.6 | 41.6 | 23.0 | 10.0 | 0.0 | 0.0 | 25.3 |
| BLISS | 2028 | ROR | 33.8 | 34.1 | 32.7 | 32.2 | 37.2 | 32.3 | 30.0 | 31.6 | 34.2 | 36.3 | 34.6 | 34.4 | 33.6 |
| C.J. STRIKE | 2028 | ROR | 42.7 | 42.8 | 42.6 | 40.5 | 42.7 | 37.8 | 29.2 | 33.0 | 40.4 | 45.5 | 44.0 | 43.4 | 40.4 |
| CASCADE | 2028 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2028 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2028 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2028 | ROR | 21.3 | 21.8 | 20.0 | 19.8 | 24.3 | 20.6 | 18.6 | 19.5 | 21.5 | 23.3 | 21.8 | 21.7 | 21.2 |
| MILNER | 2028 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 2.5 |
| SHOSHONE FALLS | 2028 | ROR | 12.0 | 12.0 | 9.6 | 7.3 | 12.0 | 9.3 | 8.7 | 9.0 | 6.7 | 8.8 | 10.8 | 12.0 | 9.9 |
| SWAN FALLS | 2028 | ROR | 14.7 | 14.7 | 15.0 | 14.0 | 14.6 | 13.0 | 10.3 | 11.1 | 13.3 | 14.9 | 14.8 | 14.8 | 13.8 |
| TWIN FALLS | 2028 | ROR | 9.2 | 9.0 | 5.9 | 3.8 | 11.8 | 5.6 | 5.1 | 5.4 | 0.0 | 5.2 | 6.9 | 8.8 | 6.4 |
| UPPER MALAD | 2028 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2028 | ROR | 12.7 | 13.2 | 11.9 | 11.7 | 15.2 | 12.2 | 10.7 | 11.5 | 12.8 | 14.1 | 12.9 | 12.9 | 12.6 |
| UPPER SALMON 3&4 | 2028 | ROR | 12.0 | 12.5 | 11.4 | 11.2 | 14.2 | 11.6 | 10.3 | 11.1 | 12.1 | 13.2 | 12.2 | 12.3 | 12.0 |
| **HCC TOTAL** | | | **572.8** | **446.0** | **460.1** | **461.6** | **584.5** | **457.2** | **424.0** | **324.6** | **369.0** | **317.3** | **367.3** | **423.3** | **434.1** |
| **ROR TOTAL** | | | **192.9** | **195.1** | **185.2** | **207.2** | **279.3** | **238.9** | **206.2** | **211.0** | **199.7** | **201.0** | **188.6** | **194.0** | **208.3** |
| **TOTAL** | | | **765.7** | **641.1** | **645.3** | **668.8** | **863.8** | **696.1** | **630.2** | **535.6** | **568.7** | **518.3** | **555.9** | **617.3** | **642.5** |

| Resource | YEAR | TYPE | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | AVE. MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BROWNLEE | 2029 | HCC | 251.0 | 190.8 | 197.1 | 201.6 | 257.5 | 203.4 | 188.1 | 137.8 | 154.9 | 133.9 | 159.2 | 188.5 | 188.7 |
| OXBOW | 2029 | HCC | 108.0 | 85.1 | 86.2 | 84.9 | 106.6 | 83.8 | 79.1 | 62.5 | 72.0 | 60.6 | 69.7 | 78.4 | 81.4 |
| HELLS CANYON | 2029 | HCC | 212.7 | 169.1 | 175.5 | 174.0 | 219.3 | 168.9 | 155.7 | 123.1 | 141.0 | 120.3 | 138.0 | 155.2 | 162.8 |
| 1000 SPRINGS | 2029 | ROR | 6.5 | 6.5 | 6.1 | 6.1 | 5.4 | 5.8 | 6.0 | 6.3 | 6.5 | 6.6 | 6.6 | 6.6 | 6.2 |
| AMERICAN FALLS | 2029 | ROR | 4.3 | 4.1 | 4.9 | 37.9 | 70.2 | 65.4 | 49.6 | 41.1 | 23.0 | 10.1 | 0.0 | 0.0 | 26.0 |
| BLISS | 2029 | ROR | 33.6 | 34.0 | 32.5 | 32.1 | 37.1 | 32.2 | 29.8 | 31.4 | 34.1 | 36.2 | 34.5 | 34.3 | 33.5 |
| C.J. STRIKE | 2029 | ROR | 42.6 | 42.7 | 42.5 | 40.4 | 42.6 | 37.6 | 29.1 | 32.8 | 40.2 | 45.5 | 43.9 | 43.3 | 40.2 |
| CASCADE | 2029 | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| CLEAR LAKE | 2029 | ROR | 1.9 | 1.8 | 1.7 | 1.6 | 1.5 | 1.4 | 1.5 | 1.6 | 1.6 | 1.8 | 1.8 | 1.8 | 1.7 |
| LOWER MALAD | 2029 | ROR | 12.1 | 12.5 | 12.8 | 13.0 | 12.6 | 11.6 | 12.2 | 12.6 | 13.1 | 13.2 | 12.2 | 12.1 | 12.5 |
| LOWER SALMON | 2029 | ROR | 21.2 | 21.7 | 19.9 | 19.7 | 24.2 | 20.5 | 18.5 | 19.4 | 21.4 | 23.2 | 21.7 | 21.6 | 21.1 |
| MILNER | 2029 | ROR | 5.9 | 5.9 | 2.0 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 2.4 |
| SHOSHONE FALLS | 2029 | ROR | 12.0 | 12.0 | 9.5 | 7.3 | 12.0 | 9.2 | 8.7 | 9.0 | 6.6 | 8.8 | 10.8 | 12.0 | 9.8 |
| SWAN FALLS | 2029 | ROR | 14.6 | 14.7 | 14.9 | 14.0 | 14.6 | 13.0 | 10.3 | 11.1 | 13.2 | 14.9 | 14.7 | 14.7 | 13.7 |
| TWIN FALLS | 2029 | ROR | 9.2 | 9.0 | 5.8 | 3.8 | 11.8 | 5.5 | 5.1 | 5.3 | 0.0 | 5.2 | 6.9 | 8.7 | 6.4 |
| UPPER MALAD | 2029 | ROR | 6.8 | 7.0 | 7.1 | 7.2 | 7.5 | 7.1 | 7.0 | 7.0 | 7.2 | 6.7 | 6.8 | 6.8 | 7.0 |
| UPPER SALMON 1&2 | 2029 | ROR | 12.6 | 13.1 | 11.8 | 11.7 | 15.1 | 12.1 | 10.6 | 11.5 | 12.7 | 14.0 | 12.8 | 12.9 | 12.6 |
| UPPER SALMON 3&4 | 2029 | ROR | 12.0 | 12.4 | 11.3 | 11.2 | 14.1 | 11.6 | 10.2 | 11.0 | 12.1 | 13.2 | 12.2 | 12.2 | 12.0 |
| **HCC TOTAL** | | | **571.7** | **445.0** | **458.8** | **460.5** | **583.3** | **456.1** | **422.9** | **323.4** | **367.8** | **314.8** | **366.9** | **422.1** | **432.9** |
| **ROR TOTAL** | | | **196.6** | **198.7** | **184.2** | **207.2** | **279.0** | **237.2** | **205.6** | **209.8** | **199.0** | **200.8** | **188.1** | **193.4** | **208.4** |
| **TOTAL** | | | **768.3** | **643.7** | **643.0** | **667.7** | **862.3** | **693.3** | **628.5** | **533.2** | **566.8** | **515.6** | **555.0** | **615.5** | **641.3** |

# OREGON ORDER UM 1056 PLANNING CRITERIA

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| PUBLIC UTILITY COMMISSION OF OREGON | ) | ERRATA ORDER |
| | ) | |
| | ) | |
| Investigation Into Integrated Resource Planning. | ) | |
| | ) | |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 0 9 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# SUMMARY OF NORTHWEST UTILITY PLANNING CRITERIA

| Utility | Planning Criteria |
|---|---|
| **Avista Corporation** | *Peak Load*—The maximum one-hour obligation, including operating reserves, on the expected average coldest day in January and the average hottest day in August.[1]<br><br>*Peak Resource Capability*—The maximum one-hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak, and excluding resources that are on maintenance during peak load periods.[1]<br><br>*Planning Reserve*—Set at a level equal to 15 percent planning reserve margin during the company's peak load hour.[1]<br><br>*Confidence Interval*—Ninety percent confidence interval based on the monthly variability of load and the 10th percentile of monthly historical hydro energy. This results in a 10 percent chance of load exceeding the planning criteria for each month. In other words, there is a 10 percent chance that the company would need to purchase energy from the market in any given month.[1] |
| **Bonneville Power Administration** | *Load Forecast*—Based upon normal weather conditions.[2]<br><br>*Hydro Conditions*—Firm hydro energy and capacity estimates based on 1937 critical water conditions.[2]<br><br>*Hydro Energy*—Based on current generation capability under average monthly river discharge. Uses operating year (OY) 1937 water conditions (the 12-month period from August 1936 through July 1937) to estimate the firm hydro energy capability in low water conditions.[2]<br><br>*Federal Firm Energy Surplus Analysis*—Defined as the amount of generation that can be produced in excess of firm loads using 1937 critical water conditions.[2]<br><br>*Hydroelectric Capacity*—The monthly instantaneous capacity of hydroelectric projects is defined as the full-gate-flow maximum generation at mid-month reservoir elevation using 1929 through 1998 historical water conditions.[2] |
| **Idaho Power Company** | *Hydro Conditions*—70th percentile hydro conditions based upon historical data from 1928 through 2005.[3]<br><br>*Load Forecast*—Based upon 50th percentile weather conditions. [3]<br><br>*Monthly Average Energy*—Based on 70th percentile water and 70th percentile average load conditions.[3]<br><br>*Capacity*—Based on monthly peak-hour Northwest transmission deficit assuming 90$^{th}$ percentile water, 70th percentile average load and 95th percentile peak-hour load conditions.[3] |
| **Northwest Power and Conservation Council** | *Utilizes a fully probabilistic model*—Prospective plans are tested against 20 years of future conditions. The test process uses random simulations of the principal sources of uncertainty, including hydro conditions, regional electric loads, fuel prices, $CO_2$ control requirements, import and export markets, resource availability, and other factors. The Council's analytical process creates a two-dimensional mathematical surface defined by portfolio cost and portfolio risk. A subset of resource portfolios along the mathematical cost–risk frontier are selected for further consideration. The preferred portfolio is selected from the set of finalist portfolios using qualitative criteria.[4] |

[1] 2009 Integrated Resource Plan, Avista Utilities, August 2009, Chapter 2.

[2] 2009 Pacific Northwest Loads and Resources Study, Bonneville Power Administration, July 2009, Sections 2 & 4.

[3] 2009 Integrated Resource Plan, Idaho Power Company, December 2009.

[4] Draft Sixth Northwest Power Plan, Northwest Power and Conservation Council, September 2009.

| Utility | Planning Criteria |
|---|---|
| **PacifiCorp** | *Thermal*—Maximum dependable capacity for peak-hour assessment. Energy assessments used maximum dependable capacity de-rated for forced outages and maintenance.[5] |
| | *Hydro Conditions*—Critical water conditions. For peak hour assessment, decision support software is used to shape critical hydro energy to estimate maximum capability sustainable for one hour.[5] |
| | *Loads*—Average energy requirements based upon normal weather conditions.[5] |
| | *Planning Reserve*—Planning reserve margin of 12 percent assumed for energy and peak-hour assessments.[5] |
| **Portland General Electric Company (PGE)** | *Hydro Conditions*—Normal hydro conditions.[6] |
| | *Loads*—PGE identifies annual energy needs under a reference case (i.e., expected or most likely) and high-load and low-load forecasts, assuming normal weather conditions.[6] |
| | *Capacity*—PGE evaluates peaking needs by comparing the annual one-hour maximum load inclusive of 12 percent reserves (6 percent operating margin, 6 percent planning margin), calculated on a 1-in-2 or average basis, to the capability of energy-producing resources. Reports both the winter and the summer peak loads.[6] |
| **Puget Sound Energy** | *Loads*—For capacity, power demand was estimated at normal winter minimum temperature (23° F) plus a 15 percent planning margin. Five different economic growth scenarios were modeled in the resource plan.[7] |
| | *Hydro*—For capacity resource need, hydro projects assumed at full capacity output.[7] |
| | *Thermal*—For capacity resource need, thermal projects assumed at full capacity output.[7] |

[5] 2008 Integrated Resource Plan, PacifiCorp, May 28, 2009, Chapter 5.

[6] PGE 2009 Integrated Resource Plan, Portland General Electric, November 2009, Chapter 3.

[7] Integrated Resource Plan, Puget Sound Energy, July 2009, Chapters 5 & 8.

# IRP ADVISORY COUNCIL ROSTER

## Customer Representatives

| | |
|---|---|
| AARP | Maribeth Connell |
| Agricultural Representative | Sid Erwin |
| Boise State University | John Gardner/Todd Haynes |
| Heinz Frozen Foods | Steve Munn |
| Idaho Retailers | Pam Eaton |
| Industrial Customers of Idaho Power | David Hawk |
| INL | Tom Moriarty |
| Micron | John Velikoff |
| Simplot | Don Sturtevant |

## Public Interest Representatives

| | |
|---|---|
| Idaho Conservation League | Betsy Bridge |
| Idaho Department of Commerce | Don Dietrich/Lane Packwood |
| Idaho Office of Energy Resources | Paul Kjellander |
| Idaho State House of Representatives | Representative Fred Wood |
| Idaho State Senate | Senator Russ Fulcher |
| Northwest Power and Conservation Council | Jim Yost/Shirley Lindstrom |
| Snake River Alliance | Ken Miller |
| Twin Falls Canal Company | Vince Alberdi, Retired General Manager |

## Regulatory Commission Representatives

| | |
|---|---|
| Idaho PUC | Rick Sterling |
| Oregon PUC | Kelcey Brown |

## Consultant/Facilitator

| | |
|---|---|
| The Cadmus Group, Inc. | Brian Hedman |

# ATTACHMENT N-2
# IDAHO POWER COMPANY'S 2011 INTEGRATED RESOURCE PLAN (DOCKET LC 53)



# 2011 Integrated Resource Plan

June 2011

IDAHO POWER®
An IDACORP Company

Printed on recycled paper

# 2011 Integrated Resource Plan

**June 2011**



IDAHO POWER®
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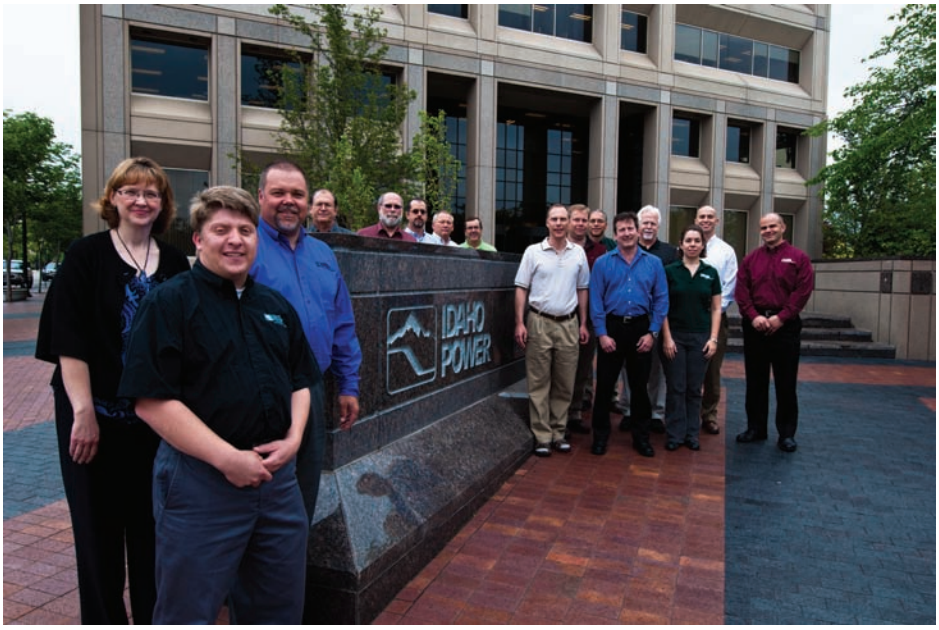
## Acknowledgement

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power prepares and publishes an Integrated Resource Plan (IRP) every two years and expects the experience gained over the next few years will lead to modifications in the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2011 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the IRP Advisory Council, and the comments provided by other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The IRP team is comprised of individuals that represent many different departments within the company. IRP team members are responsible for preparing forecasts, working with the IRP Advisory Council (IRPAC) and the public, and performing all the analyses necessary to prepare the resource plan.




Idaho Power looks forward to continuing the resource planning process with its customers and other interested parties. You can learn more about Idaho Power's resource planning process at www.idahopower.com.

**Safe Harbor Statement**

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

# TABLE OF CONTENTS

1. Summary ..... 1
Introduction ..... 1
Public Advisory Process ..... 2
IRP Methodology ..... 3
Demand-Side Management ..... 3
Supply-Side Resource Costs ..... 4
Greenhouse Gas Emissions ..... 5
Preferred Resource Portfolio ..... 6
Near-Term Action Plan ..... 7
Public Policy Issues ..... 8
2. Political, Regulatory, and Operational Issues ..... 13
Idaho Energy Plan ..... 13
Idaho Strategic Energy Alliance ..... 13
FERC Relicensing ..... 14
Idaho Water Issues ..... 15
Wind Integration Study ..... 16
Fixed Cost Adjustment ..... 17
Renewable Energy Certificates ..... 18
Federal Energy Legislation ..... 19
3. Idaho Power Today ..... 23
Customer Load and Growth ..... 23
2010 Energy Sources ..... 25
Existing Supply-Side Resources ..... 27
Committed Supply-Side Resources ..... 35
4. Demand-Side Resources ..... 37
Energy Efficiency Program Portfolio Analysis ..... 38
New Energy Efficiency Resources ..... 39
Demand Response Resources ..... 41
5. Supply-Side Resources ..... 43
Renewable Resources ..... 43
Natural Gas-Fired Resources ..... 46
Distributed Generation ..... 48

Conventional Coal Resources ..... 49
Integrated Gasification Combined Cycle and Carbon Sequestration ..... 49
Advanced Nuclear ..... 50
Transmission ..... 50
6. Planning Period Forecasts ..... 57
Load Forecast ..... 57
Planning Scenarios ..... 64
Existing Resources ..... 65
Natural Gas Price Forecast ..... 69
Resource Cost Analysis ..... 72
7. Transmission Planning ..... 79
Past and Present Transmission ..... 79
Transmission Planning Process ..... 79
Existing Transmission System ..... 81
Transmission Assumptions in the IRP Portfolios ..... 83
8. Planning Criteria and Portfolio Selection ..... 85
Planning Scenarios and Criteria ..... 85
Load and Resource Balance ..... 85
Portfolio Design and Selection ..... 89
9. Modeling Analysis and Results ..... 93
Economic Evaluation Components and Assumptions ..... 93
Risk Analysis and Results ..... 98
Stochastic Analysis ..... 107
Capacity Planning Margin ..... 115
Loss of Load Expectation ..... 119
10. Action Plans ..... 121
Near-Term Action Plan (2011–2020) ..... 121
Long-Term Action Plan (2021–2030) ..... 122
Conclusion ..... 124
List of Tables ..... 125
List of Figures ..... 125
List of Appendices ..... 127
Glossary of Abbreviations ..... 129

# 1. SUMMARY

## Introduction




Idaho Power's IRP is updated every two years.

The *2011 Integrated Resource Plan* (IRP) is Idaho Power's 10th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2011 IRP assumes that during the planning period (2011–2030), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and that the company will continue to operate as a vertically integrated electric utility. In developing this plan, Idaho Power has worked with the IRP Advisory Council (IRPAC), which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. There are four primary goals of Idaho Power's planning process.

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period
2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns
3. Give equal and balanced treatment to both supply-side resources and demand-side measures
4. Involve the public in the planning process in a meaningful way

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver resources to network

### Highlights

- The 2011 IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent) and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year planning period.
- In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.

customers[1] and the company's retail customers.[2] The 2011 IRP evaluates only the need for additional transmission capacity necessary to serve retail customers. The total capacity of proposed transmission line projects may be larger than identified in the IRP in order to accommodate third-party requests and network customer obligations for capacity on the same transmission path.

The number of customers in Idaho Power's service area is expected to increase from approximately 492,000 in 2010 to over 650,000 by the end of the planning period in 2030. Even with the recent recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base.

With hydroelectric generation as the foundation of its energy production, Idaho Power has an obligation to serve customer loads regardless of the water conditions that may occur. In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, Idaho Power will continue to emphasize a resource plan based on worse-than-median stream flows. The IRP uses more conservative planning criteria than median water planning, but the criteria are less conservative than critical water planning. Further discussion of Idaho Power's planning criteria can be found in Chapter 8.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Prior Idaho Power IRPs used a 10-year planning horizon, but with the increased need for resources with long construction lead times, the need for a 20-year resource plan to support *Public Utility Regulatory Policies Act of 1978* (PURPA) contract negotiations, and support from the IRPAC, Idaho Power decided to extend the planning horizon of the 2006 and future resource plans to 20 years.

Planning for the future is necessary to meet the needs of Idaho Power's customers today and tomorrow. While the 2011 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term in accordance with the *Energy Risk Management Policy and Standards* that were collaboratively developed in 2002 between Idaho Power, the IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). While the IRP has a planning horizon of 20 years and is updated every two years, the *Energy Risk Management Policy and Standards* focuses on an 18-month period and is updated every month.

## Public Advisory Process

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRPAC. The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2011 IRP, Idaho Power hosted a field trip covering wind, hydroelectric, and natural gas resources, two portfolio-design workshops, and nine monthly IRPAC meetings. The IRPAC meetings served as an open forum for discussions related to the development of the IRP. The IRPAC members and the public have made significant contributions to this plan. A list of the 2011 IRPAC members can be found in *Appendix C—Technical Appendix*.

Idaho Power believes working with members of the IRPAC and the public is a rewarding process, and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC Tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2011 IRP and the planning process in general.

Following the filing of the final plan, Idaho Power presents the IRP at public meetings in various cities around the company's service area. In addition, Idaho Power staff presents the plan and discusses the planning process with various civic groups and at educational seminars as requested.

## IRP Methodology

The preparation of Idaho Power's 2011 IRP begins with updating the forecast of future customer demand. Existing resources, the ability to import electricity, and the performance of existing demand-side management (DSM) programs are then accounted for in the load and resource balance. The next step involves evaluating new DSM programs and the expansion of existing programs. Finally, Idaho Power evaluates portfolios of supply-side resources designed to eliminate any remaining deficits.

Idaho Power primarily uses a financial analysis to compare various resource portfolios to determine the preferred portfolio. Idaho Power attempts to financially value the costs and benefits of each resource type. Traditional resources have fixed and variable costs and a market value for the delivered energy, and Idaho Power includes both the costs and the value when evaluating resources. The cost of any necessary transmission upgrades and the value of renewable energy certificates (REC) are also accounted for in the analysis.

Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP—1) the 300-megawatt (MW) Langley Gulch combined-cycle combustion turbine (CCCT) that is expected to be available in the summer of 2012, and 2) a 49-MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

For the 2011 IRP, the 20-year planning period was divided into two, 10-year segments. Dividing the planning period into these two segments prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years.

In the first 10-year period (2011–2020), nine resource portfolios were examined. Each resource portfolio was designed to substantially meet the energy and capacity deficits identified in the load and resource balance.

For the second 10-year period (2021–2030), the preferred resource portfolio from the first 10-year period was coupled with each of the 10 portfolios analyzed for the second period. Using the preferred portfolio from the first 10-year period ensures all the portfolios in the second 10-year period are analyzed consistently.

## Demand-Side Management

Energy efficiency programs from both the existing portfolio and new program opportunities included in the 2011 IRP are forecast to reduce average load by 233 average megawatts (aMW) by 2030. New energy efficiency opportunities come from a combination of new measures and program expansions. The cost to acquire energy efficiency will vary between an average of 3.6 cents per kilowatt hour (kWh) for existing programs to 5.1 cents per kWh for new program activities and measures for the 2011 IRP.

Demand response programs for the 2011 IRP are targeted to reduce peak summer load by 351 MW by summer 2016. Demand response resources have an average levelized cost of $48 per kilowatt (kW) over the IRP planning period. Demand response programs as peaking resources have grown dramatically in the past few years. The large increase comes from the introduction of the FlexPeak Management

program, which targets commercial and industrial customers, and the transition of the Irrigation Peak Rewards program into a dispatchable, direct load-control program as part of the 2011 IRP.

Details on Idaho Power's existing and proposed DSM programs can be found in Chapter 4 and in *Appendix B–2010 Demand-Side Management Annual Report*. An explanation of the methodologies used to incorporate prior and forecast energy efficiency impacts into the load forecast can be found in *Appendix A–Sales and Load Forecast.*

## Supply-Side Resource Costs

The 2011 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future needs of customers. Recent cost increases have significantly impacted the cost of new supply-side resources, especially when compared to the cost of the existing resources in Idaho Power's generation portfolio. Figure 1.1 shows the 2010 costs in dollars per megawatt hour (MWh) for Idaho Power's existing hydroelectric resources, coal generation facilities, and power purchased from the Elkhorn Valley Wind Project. In addition, Figure 1.1 shows the estimated cost of energy from new resources considered in the 2011 IRP. Existing resource costs are based on 2010 actual costs of capital, fuel, and non-fuel operating and maintenance (O&M). New resource costs are 30-year levelized estimates (based on expected annual generation), which include capital, fuel, non-fuel O&M, and the expected-case carbon adder.

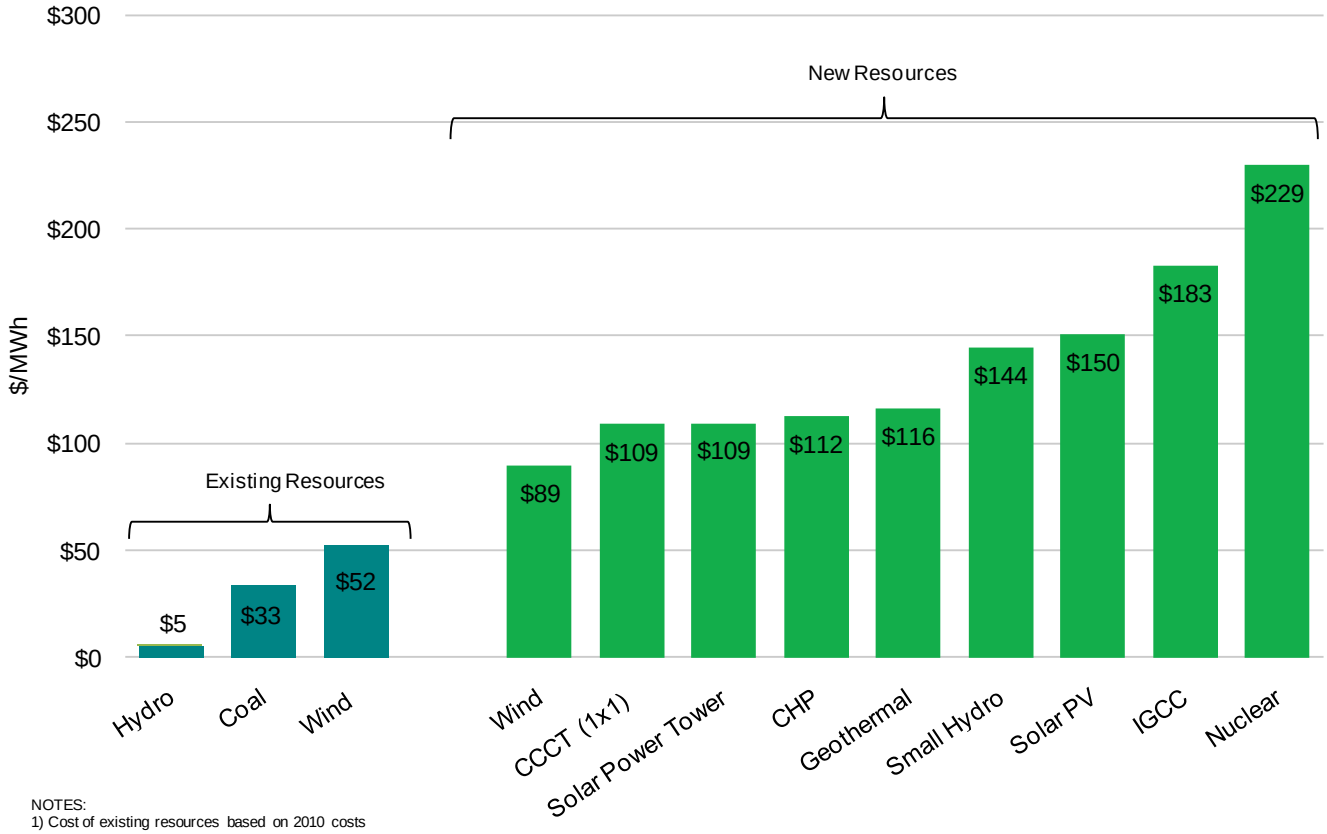



**Figure 1.1 Cost of existing and new supply-side resources**

While it is important to evaluate the costs presented in Figure 1.1, these figures represent only a part of the total resource cost. In preparing the IRP, Idaho Power must also consider the value that each type of resource provides in conjunction with the other resources in the company's generation portfolio. Supply-side resources have different operating characteristics, making some better suited for meeting

capacity needs while others are better for providing energy. The low capital cost and dispatch capability of a simple-cycle combustion turbine (SCCT) resource makes it a good choice for meeting capacity needs, as long as it is needed for only short durations to meet peak-hour load. A geothermal resource typically provides maximum generation during peak load periods, but because it is non-dispatchable and generally provides constant generation year round (baseload), it is considered a better energy resource. Wind is also a good source of energy; however, it provides almost no peak-hour capacity due to the variable and intermittent nature of the generation.

Figure 1.2 shows the 30-year levelized capital cost in dollars per MW of peak-hour capacity for many of the supply-side resources evaluated in the 2011 IRP. This metric provides useful information on the value of each resource type in terms of providing peak-hour capacity. Idaho Power's peak loads typically occur between 3:00 p.m. and 7:00 p.m. on hot summer days; the expected capacity factor for each resource type during this time period is also shown in Figure 1.2.

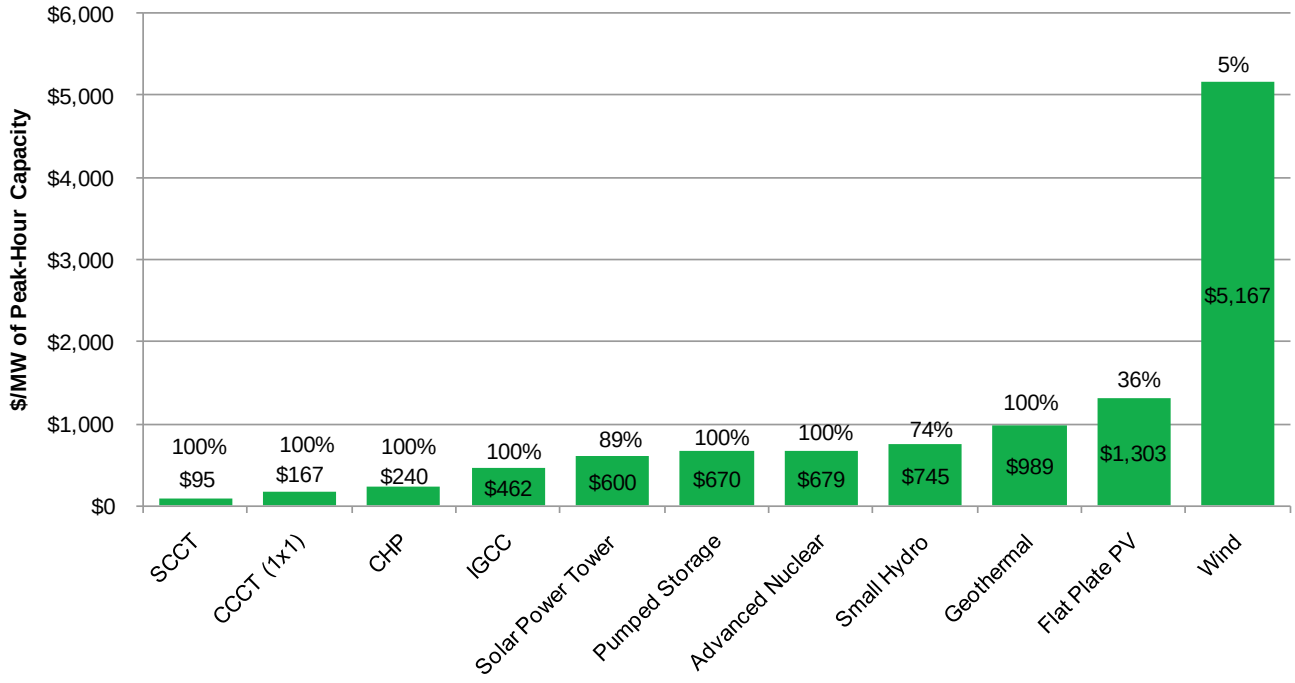



**Figure 1.2 30-year levelized capital cost of peak-hour capacity**

Resources capable of providing 100 percent of nameplate capacity during peak load periods have an obvious cost advantage when compared to resources with lower peak-hour capacity factors, such as wind. Because wind can be counted only to provide 5 percent of nameplate capacity during the peak-hour, 20 MW of nameplate wind would need to be built to get one MW of peak-hour capacity. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2011 IRP is presented in Chapter 6, and details of the calculations used to prepare Figure 1.2 are presented in *Appendix C–Technical Appendix*.

## Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 2 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide ($CO_2$) emissions levels have historically been well below the national average for the 100 largest electric utilities in the United States, both in terms of total $CO_2$ emissions (tons) and $CO_2$ emissions intensity (pounds [lbs] per MWh), based on the report of 2008 $CO_2$ emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States,*

released in June 2010 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and Portland Gas & Electric (PG&E) Corporation.

In September 2009, Idaho Power's Board of Directors approved guidelines to establish a goal to reduce the $CO_2$ emissions intensity of the company's utility operations. The guidelines are intended to prepare the company for potential legislative and or regulatory restrictions on greenhouse gas (GHG) emissions, while minimizing the cost of complying with such reductions on Idaho Power's customers.

The guidelines establish a goal to reduce Idaho Power's resource portfolio's average $CO_2$ emissions intensity for the 2010 through 2013 time period to a level of 10–15 percent below the company's 2005 $CO_2$ emissions intensity of 1,194 lbs per MWh. Since Idaho Power's $CO_2$ emissions intensity fluctuates with stream flows and the production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

At present, generation and emissions from company-owned resources are included in the $CO_2$ intensity calculation. The company's progress toward achieving this intensity reduction goal, as well as additional information on Idaho Power's $CO_2$ emissions, is currently reported on the company's website at www.idahopower.com/NewsCommunity/OurEnvironment/co2Intensity.cfm. Information related to Idaho Power's $CO_2$ emissions is also available through the Carbon Disclosure Project at www.cdproject.net.

Idaho Power's annual $CO_2$ emissions intensity for 2009 and 2010 were 1,003 lbs per MWh and 1,065 lbs per MWh respectively, both below the 2005 $CO_2$ emissions intensity level. Idaho Power's average $CO_2$ intensity for the goal period-to-date, January 2010–April 2011, is 949 lbs of $CO_2$ per MWh. This reduction in intensity relative to the 2010 level reflects an increase in hydroelectric generation, as a result of the current water conditions, and reduced coal-fired generation. For the 2010–2013 time period, Idaho Power fully expects to achieve its goal of reducing its $CO_2$ emissions intensity from company-owned resources (relative to the 2005 level of 1,194 lbs $CO_2$ per MWh) by more than 15 percent.

The guidelines are intended to reduce Idaho Power's near-term $CO_2$ emissions intensity levels in a manner that minimizes the cost of the reductions on the company's customers. The 2011 IRP attempts to quantify the cost and longer term impacts of carbon regulations by including a carbon adder that is applied to all resources that emit $CO_2$. Additional details regarding the assumptions and analysis are presented in Chapter 6 and Chapter 9 of the 2011 IRP.

## Preferred Resource Portfolio

The preferred portfolio for the 2011 IRP presented in Table 1.1 was constructed by combining the preferred portfolio for the first 10 years of the planning horizon (2011–2020) with the preferred portfolio for the second 10-year period (2021–2030). In addition to the committed resources (Langley Gulch and the Shoshone Falls upgrade) the preferred resource portfolio includes 450 MW of market purchases beginning in 2016 with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW.

The preferred portfolio for the second 10-year period (2021–2030) represents a balanced strategy of adding a mixture of renewable resources along with natural gas-fired baseload and peaking resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

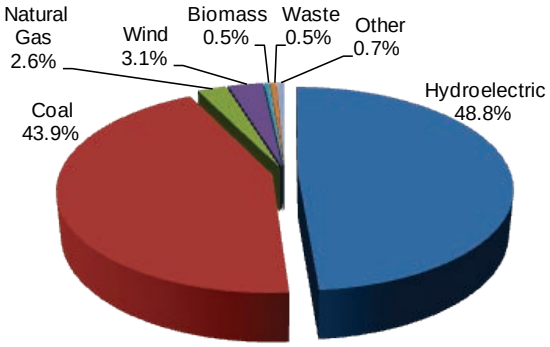
**Table 1.1 Preferred portfolios**

| 1–3 Boardman to Hemingway (2011–2020) | | | 2–6 Balanced 1 (2021–2030) | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2011 | | | 2021 | Geothermal | 52 |
| 2012 | CCCT (Langley Gulch)* | 300 | 2022 | SCCT | 170 |
| 2013 | Solar Demonstration Project | | 2023 | | |
| 2014 | | | 2024 | Solar Power Tower | 50 |
| 2015 | Shoshone Falls Upgrade* | 49 | 2025 | CCCT | 300 |
| 2016 | Boardman to Hemingway | 450 | 2026 | | |
| 2017 | | | 2027 | | |
| 2018 | | | 2028 | Small Hydro | 60 |
| 2019 | | | 2029 | SCCT | 170 |
| 2020 | | | 2030 | | |

*Committed resource

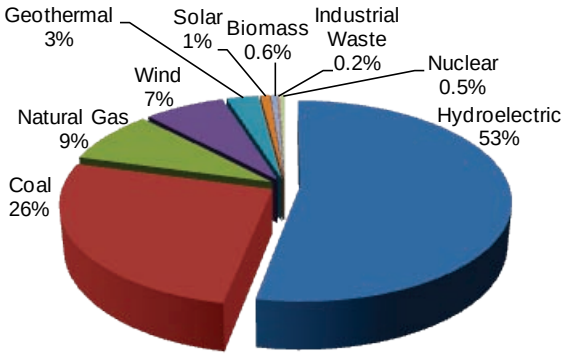
Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities along with purchased power to supply the energy needed to serve customers. Because Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River, the percentage of each energy source also changes year-to-year.

Figure 1.3 shows Idaho Power's "fuel mix" by resource type for 2010, and Figure 1.4 estimates the company's fuel mix in 2030 based on the implementation of the preferred portfolio. In 2030, Idaho Power's hydroelectric resources are the predominate resource and provide over 50 percent of the mix. Generation from coal-fired resources becomes a smaller part of the mix, being replaced by natural gas and a mixture of renewable resources. In preparing Figures 1.3 and 1.4, market purchases were assumed to be comprised of the estimated Pacific Northwest energy market fuel mix for 2010 and 2030.




**NOTE:** 2010 Market Purchases are 6% of Idaho Power's energy sources, and the fuel mix is modeled in this graph using the Northwest Power Pool (NWPP) system mix for 2010.

**Figure 1.3 2010 fuel mix**




**NOTE:** 2030 Market Purchases are 13% of Idaho Power's energy sources, and the fuel mix is modeled in this chart using the AURORA Washington system mix for 2030.

**Figure 1.4 2030 fuel mix**

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2013 IRP and subsequent plans as more certainty regarding carbon regulations and a federal renewable electricity standard (RES) become available. Future uncertainty requires alternate portfolios be considered in the resource planning process. Further details regarding the preferred portfolio and the alternate portfolios can be found in Chapter 10.

## Near-Term Action Plan

The Langley Gulch CCCT is currently under construction and is expected to be completed by summer 2012. Idaho Power also anticipates beginning preliminary design work for the Shoshone Falls Upgrade

Project in 2012, which is expected to be completed in 2015. Idaho Power is also continuing to work with federal and state agencies, FERC, other transmission providers, and the public on the Boardman to Hemingway and Gateway West transmission projects. Major milestones associated with these resources and programs are presented in Table 1.2.

**Table 1.2 Near-term action plan milestones**

| Year | Action |
|---|---|
| 2011 | Langley Gulch CCCT construction continues |
| | File 2011 IRP with regulatory commissions |
| | Demand response programs expected to provide 330 MW of load reduction |
| | Continue the Boardman to Hemingway permitting process |
| | Continue the Gateway West NEPA permitting process |
| | Prepare and issue an RFP for the Solar Demonstration Project |
| 2012 | Langley Gulch CCCT on line (300 MW) |
| | Evaluate responses to the Solar Demonstration Project and file a Certificate of Public Convenience and Necessity (CPCN) |
| | Complete design work on the Shoshone Falls Upgrade Project and issue RFP |
| | Continue Boardman to Hemingway permitting process |
| | Continue the Gateway West NEPA permitting process |
| | Solar Demonstration Project on line in late 2012/early 2013 |
| 2013 | Issue RFP for Boardman to Hemingway construction |
| | Shoshone Falls Upgrade Project construction begins |
| | File 2013 IRP with regulatory commissions |
| | Continue the Gateway West NEPA permitting process |
| 2014 | Shoshone Falls Upgrade Project construction continues |
| | Boardman to Hemingway construction begins |
| | Secure 83 MW PPA for summer 2015 from the east side |
| 2015 | Shoshone Falls Upgrade Project on line (49 MW) |
| | File 2015 IRP with regulatory commissions |
| 2016 | Boardman to Hemingway construction completed (450 MW) |
| 2017 | File 2017 IRP with regulatory commissions |
| 2018 | |
| 2019 | File 2019 IRP with regulatory commissions |
| 2020 | |

# Public Policy Issues

The 2011 IRP was completed using computer modeling and other analytical methods. However, certain public policy questions exist that cannot be directly examined through analytical methods. Idaho Power has presented these issues to the IRPAC for discussion, but the nature of issues typically precludes a strong majority opinion from IRPAC members. The public policy issues presented to the IRPAC are discussed in the following sections.

## *New Large Loads*

Locally, Idaho Power and its customers face internal conflicts created by traditional rate determination and the cost difference between existing resources and future resources. New customers that connect to Idaho Power's system benefit from energy rates based on the low-cost of existing resources that are embedded in current rates. However, Idaho Power's existing resources and transmission system are fully used, and new customers require the addition of generation, transmission, and distribution resources. Because new resources are more expensive than Idaho Power's existing portfolio, each new customer

dilutes the existing resource base and increases the cost to all customers. Accordingly, for a number of years, Idaho Power has attempted to balance the impact on both the new customer and existing customers through an intermediate period by using blocked contracts that provide for an element of marginal-cost pricing.

In addition, Idaho Power's ability to serve new large loads is limited as growth in summertime peak demand continues to drive the need for additional resources. New businesses are attracted to southern Idaho due in part to Idaho Power's low rates, which have consistently been some of the lowest in the nation. When a new large customer makes a request for service, Idaho Power must include restrictions in the contract limiting the customer's usage during peak summer months. These restrictions typically last for several years until new resources can be planned for and built, and many new large customers are unable or unwilling to accept these terms.

For the 2011 IRP, an analysis was performed to determine the cost of building additional natural gas-fired peaking capacity that could be used to serve new large loads. The analysis assumes 80 MW of capacity from a SCCT is added to Idaho Power's resource portfolio in 2014. The analysis also assumes the additional capacity is built and no new large load materializes.

The results show the net present value of the revenue requirement associated with the fixed and variable cost of adding the additional 80 MW of capacity would be $60 million. In addition to positioning the company to serve new large loads, which will promote local economic development and create jobs, this additional capacity will be able to assist with integrating wind generation and, when opportunities exist, make profitable surplus sales to help offset the fixed costs of ownership. *Appendix C–Technical Appendix* contains additional details regarding the analysis.

Idaho Power recognizes the ability to serve new large loads has an impact on Idaho's economy. Because of this, and the results of the analysis mentioned above, Idaho Power is proposing an additional 80 MW of peak-hour load be added to Idaho Power's load and resource balance beginning with the 2013 IRP. By adding this additional peak-hour load to the load and resource balance, the additional capacity will come from a diverse set of resources identified in the IRP process, perhaps at a lower cost, and not specifically from the construction of a single new resource.

## Asset Ownership

Idaho Power can develop and own generation assets, rely on power purchase agreements (PPA) and market purchases to supply the electricity needs of its customers, or use a combination of the two ownership strategies. Idaho Power expects to continue participating in the regional power market and enter into mid-term and long-term PPAs. However, when pursuing PPAs, Idaho Power must be mindful of imputed debt and its potential impact on Idaho Power's credit rating. In the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate of return advantages inherent in a regulated electric utility.

## Emissions Offsets

Depending on market conditions and future regulations, it may be possible to purchase emissions or carbon offsets for less than the cost of a carbon allowance. Some members of the IRPAC have suggested it would be prudent for Idaho Power to hedge carbon emissions risk by purchasing emissions offsets prior to the formal passage of carbon legislation. However, there are differing opinions among IRPAC members. The principal reason cited for not purchasing offsets today is the uncertainty associated with whether carbon offsets purchased today will meet future carbon control requirements and regulations. In addition, recent draft federal legislation has limited the amount of offsets that may be used to meet reduction targets.

Uncertainty in the future regulation of carbon is evidenced in the recent collapse of the Chicago Climate Exchange (CCX). CCX was established in 2003 as the sole voluntary GHG reduction and offset trading platform for North America and Brazil. In December 2010, CCX ceased trading due to the complete market free-fall of their carbon emissions product. However, CCX continues generation of their carbon financial instrument (CFI) product as a strictly voluntary GHG emissions offset system.

Idaho Power plans to continue to follow developments related to carbon offsets and options in the event either becomes a viable alternative. The company could potentially reduce the large financial exposure of possible carbon regulation for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emissions offset options as well as the cost of any emissions offsets purchased.

## Technology Risk and Joint Development

In the 2011 IRP, several resource options dependent on developing technology have been evaluated in various portfolios. Carbon capture and sequestration, integrated gasification combined-cycle (IGCC), advanced nuclear, and numerous storage technologies are not yet commercially available; however, the technology may become available during the 20-year planning horizon evaluated in the IRP. This raises the question of whether Idaho Power should participate in development efforts related to any of these technologies prior to them becoming commercially available.

Idaho Power believes that, as a medium-sized utility, it would be impractical to lead the development work on any particular technology. However, as certain technologies are identified that show promise as being beneficial to Idaho Power and its customers, the company may choose to participate in development efforts. Idaho Power's participation would most likely be part of a larger group-effort to develop a technology jointly with other utilities with similar needs.

Similarly, certain existing and emerging resource technologies are available only in large sizes—larger than what Idaho Power could or would consider developing alone. If opportunities become available to jointly develop large resources, Idaho Power plans to evaluate them on a case-by-case basis. A similar strategy has been used in the past and resulted in Idaho Power's joint ownership of three coal-fired resources.

## Solar Demonstration Project

While solar technology continues to be more expensive than other alternatives, the cost of solar resources continues to decrease while the cost of most other resource options has increased. In addition to providing RECs, solar resources typically deliver energy during the time of day when Idaho Power's customer demand is high.

Idaho Power's 2009 IRP discussed the advantages and disadvantages of several solar demonstration project options, including a utility-scale project located near an existing substation and a distributed rooftop program. During the preparation of the 2009 IRP, a substantial amount of support was expressed by IRPAC members and the public for some type of a local project.

Idaho Power has continued to evaluate the benefits of developing a solar photovoltaic (PV) demonstration project and the topic was again discussed with the IRPAC as part of preparing the 2011 IRP. Several IRPAC members expressed support for the project to include a research and development component as well as continued support for developing a solar rooftop program.

As the cost continues to decline, Idaho Power believes solar PV resources will become more prevalent in the future, and it will be important for the company to have operating experience and be able to determine what specific type of PV technology provides the most value for Idaho Power customers.

With that in mind, Idaho Power intends to make a more detailed proposal that would allow the company to invest in a small-scale solar PV resource.

Idaho Power anticipates issuing a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. A portion of the facility would be devoted to testing new PV panel technologies, inverters, and other mounting and tracking systems. Idaho Power would also offer to collaborate with the Center for Advanced Energy Studies (CAES) on relevant research into solar technologies.

Proposals would be evaluated by mid-2012, and if a successful bidder is identified, the company would then file a request with the IPUC for a CPCN. If approved, it is anticipated the facility could be on line as early as the end of 2012.

Based on the 2011 IRP cost estimate for a solar PV resource of $3,750 per kW, the expected cost of the project could be $2–$4 million and would require approximately 5–10 acres of land. While the proposed size of this project is small relative to what might be considered a utility-scale project, Idaho Power believes it will provide useful data and give the company experience owning and operating this type of resource. It will also allow the company to better evaluate the advantages and disadvantages of utility-scale solar PV projects and distributed rooftop programs.

Idaho Power views this proposal as a demonstration project because of its small size and its primary purpose being to collect information on how solar PV resources integrate with the company's other system resources. In addition to providing valuable information on solar integration, the demonstration project will provide an opportunity for Idaho Power to expand green power program options for customers.

Idaho Power's REC Management Plan details the company's intent to continue selling RECs in the near term until they are needed to meet a federal RES. In general, a majority of Idaho Power's customers support this policy, as 95 percent of the revenue from the sale of RECs is returned to customers to keep rates low. However, there is a growing segment of customers who desire, and are willing, to pay a premium for, green energy. Idaho Power believes it is important to provide additional options for these customers, and the solar demonstration project presents an opportunity to expand the available offerings.

In addition to the benefits already identified, Idaho Power is required to build a 500-kilovolt (kV) solar PV project within the next several years under the State of Oregon's Solar PV Pilot Program. The company is currently working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP. Additional details on the Oregon Solar PV Pilot Program can be found in Chapter 3.

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# 2. Political, Regulatory, and Operational Issues

Idaho Power is a regulated utility. On the federal level, Idaho Power is subject to the rules and regulation of FERC. On the state level Idaho Power is subject to the IPUC and OPUC because the company has customers in both Idaho and Oregon, with approximately 95 percent of Idaho Power's customers located in the state of Idaho. The following sections describe some of the federal and state regulatory issues facing Idaho Power.




The IPUC regulates Idaho Power in Idaho.

## Idaho Energy Plan

In 2006, the Idaho State Legislature directed the Interim Committee on Energy, Environment, and Technology to develop a state energy plan that provides for the state's power generation needs and protects the health and safety of Idaho citizens. In January 2007, the committee completed the *2007 Idaho Energy Plan* and concluded that all Idaho energy systems have performed very well, with retail electric and natural gas prices remaining some of the lowest in the country.

The committee also recognized that Idaho's reliance on low-cost coal plants may become a source of risk in the future due to the economic impact of potential federal regulation of carbon and mercury (Hg) emissions. To address these concerns, the committee recommended increasing investments in energy conservation and in-state renewable resources. In a resource priority policy statement, the committee stated, "When acquiring resources, Idaho and Idaho utilities should give priority to: 1) conservation, energy efficiency, and demand response; and 2) renewable resources; recognizing that these alone may not fulfill Idaho's growing energy requirements." The committee further stated, "…energy suppliers must continue to have access to conventional energy resources to keep Idaho's energy costs as low as possible."

## Idaho Strategic Energy Alliance

In 2007, Governor C.L. "Butch" Otter established the Idaho Office of Energy Resources (IOER) to oversee energy planning, policy, and coordination in Idaho. Under the umbrella of this office, the Idaho Strategic Energy Alliance was established to respond to rising energy costs and other energy challenges facing the state. The governor's philosophy is that there should be a joint effort between all stakeholders in developing options and solutions for Idaho's energy future.

**Highlights**

- Idaho Power continues to operate the Hells Canyon Complex under annual licenses issued by FERC until a new license is issued.
- The 2011 IRP assumes a federal RES will be enacted in the future.
- Idaho Power is preparing an updated wind integration study in association with the 2011 IRP.

The alliance promotes the development of a sound energy portfolio for Idaho that diversifies energy resources and provides stewardship of the environment. The alliance consists of a board of directors and 13 volunteer task forces working in the following areas:

- Conservation and energy efficiency
- Wind
- Geothermal
- Hydroelectric power
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

Idaho Power representatives serve on many of these task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council, a group of the governor's cabinet members.

## FERC Relicensing

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years, depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex and the Swan Falls hydroelectric project.

Idaho Power's most significant ongoing relicensing effort is the Hells Canyon Complex. The Hells Canyon Complex provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 40 percent of the company's total generating capacity. The current license for the Hells Canyon Complex expired at the end of July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The Hells Canyon Complex license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1978* (ESA); and other applicable federal laws.

The license for the Swan Falls project expired in June 2010. In March 2005, Idaho Power issued a Formal Consultation Package (FCP) to the public relating to environmental studies designed to determine project effects for the relicensing of the project. In September 2007, Idaho Power submitted a draft license application to FERC for public review and comment. The draft application was based on the results of environmental studies along with agency and public consultation. Idaho Power filed a final license application for the Swan Falls hydroelectric project with FERC in June 2008, and FERC issued its Final Environmental Impact Statement (FEIS) in August 2010.

Relicensing costs of $134 million and $5 million for the Hells Canyon Complex and Swan Falls projects, respectively, were recorded by Idaho Power as of March 2011. Administrative work on relicensing is expected to continue until new licenses are issued in 2012 for Swan Falls and 2014 for the Hells Canyon Complex. Once new licenses are issued, further costs will be incurred to comply with the terms of the new licenses. Given the new licenses for Swan Falls and the Hells Canyon Complex have not been issued, and discussions on the PM&E packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include: 1) coordination of the relicensing process; 2) consulting with regulatory agencies, tribes, and interested parties; 3) preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites; 4) preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, reservoir contours and volumes; 5) study and data analysis; 6) preparing all necessary reports, exhibits, and filings; 7) responding to requests for additional information from FERC; and 8) legal consultation. This estimate includes costs for all areas of Idaho Power related to the relicensing effort.

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) measures imposed as a condition for relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed was assumed as part of the 2011 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

## Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin stream flows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to be able to maintain generation from these projects, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues are expected to impact Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984.

In 1984, the Swan Falls Agreement resolved a struggle between the state of Idaho and Idaho Power over the company's water rights at the Swan Falls hydroelectric facility. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet-per-second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The agreement placed the portion of the company's water rights beyond those minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked that the court resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. It also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the state are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board.

Idaho Power actively participates in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between ESPA and the Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River.

The company hopes implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. It is assumed in the 2011 IRP that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations, to be implemented over a 5–10-year period, consist of a combination of ground-water to surface-water conversions, managed aquifer recharge, demand reduction programs, and weather-modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre feet. Additional funding mechanisms are being explored to implement measures outlined in the ESPA CAMP.

Further discussion of the ESPA CAMP is included in *Appendix C—Technical Appendix*. The Phase I measures with associated target water volumes are shown in Table 2.1.

**Table 2.1 Phase I measures**

| Measure | Target (acre-feet) |
|---|---|
| Ground water to surface water conversions | 100,000 |
| Managed aquifer recharge | 100,000 |
| Demand reduction | 0 |
| Surface-water conservation | 50,000 |
| Crop mix modification | 5,000 |
| Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP) | 40,000 |
| Weather modifications | 50,000 |

## Wind Integration Study

Total installed wind-generation capacity continues to expand in Idaho and the Pacific Northwest. A recent surge in wind development in southern Idaho by independent power producers has heightened concerns over Idaho Power's ability to integrate additional wind resources beyond the 395 MW currently online. The cost of integrating additional intermittent wind resources and the potential impact on system reliability is of primary concern. As a result of these concerns, Idaho Power is updating its study in association with the 2011 IRP.

The objective of the updated study is to assess the costs incurred in modifying operations of dispatchable generating resources in order to allow them to respond to the variable and intermittent nature of wind resources such that the reliable delivery of electrical power to customers is unaffected. Idaho Power considers the assessment of these costs an important part of efforts to ensure the price paid to acquire wind energy is fair to independent developers and Idaho Power customers. Although the purpose of the study is to estimate the cost of integrating wind, the actual impact of integrating large amounts of wind generation on a day-to-day basis will create ongoing operational and reliability issues for Idaho Power's system dispatchers.

Idaho Power has been concerned about wind integration issues since late 2010 when 771 MW of requests for PPAs by wind developers were made under PURPA. Initial efforts were focused on determining the value of the energy from these PURPA contracts, and in early 2011, Idaho Power entered into a contract with PLEXOS Solutions, LLC, for technical support in determining the cost of integrating wind and the impact on system reliability.

The study is designed to investigate the impact and cost of integrating wind on Idaho Power's system by modeling a range of wind build-out cases (600 MW, 800 MW, 1,200 MW, and 1,600 MW) and comparing the system operation and cost of these cases against a base case. The concept behind this approach is that a set of dispatchable generating resources is operated differently in the wind build-out cases to provide balancing reserves necessary for responding to the intermittency and variability associated with wind generation. These reserves, necessary to maintain system reliability, are provided at a cost.

An important consideration for the study, as well as wind integration in practice, is the designation of the set of resources responsible for integrating wind. For the updated study, Idaho Power's existing resources capable of providing balancing reserves includes the hydroelectric units of the Hells Canyon Complex, the coal-fired units at the Jim Bridger and North Valmy power plants, the company's fleet of SCCTs located in Mountain Home, Idaho, and the Langley Gulch CCCT expected to be commercially available in July 2012. In addition, the study will evaluate the benefits of the proposed Boardman to Hemingway transmission line project (planned for 2016) on the cost of integrating wind generation.

In March 2011, Idaho Power held a public workshop for interested stakeholders where the proposed study methodology was explained and input on the design of the study was solicited. The company anticipates holding a second public workshop in conjunction with the completion of the study in July 2011, and a final study report is expected to be released shortly thereafter.

## Fixed Cost Adjustment

Under the fixed cost adjustment (FCA), rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs that Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in DSM resources. The FCA Pilot is currently limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through energy charges.

On October 1, 2009, the company filed an application with the IPUC to convert the FCA to an ongoing and permanent rate schedule. On April 29, 2010, the IPUC issued Order No. 31063 extending the original 3-year FCA Pilot for an additional two years, effective January 1, 2010.

During the 4-year period that the FCA (Schedule 54) has been in effect, Idaho Power has made progress in promoting energy efficiency and DSM activities. During the term of the FCA Pilot, the company has increased the number of DSM programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained via DSM. Results from the first four years of the pilot indicate

the true-up mechanism is working as intended and operating to mitigate the unintended adverse effects of DSM by ensuring that the fixed costs the IPUC authorized the company to recover are being recovered via the FCA mechanism.

As part of a general rate case filed with the IPUC on June 1, 2011, the company has again requested to convert the FCA to an ongoing and permanent rate schedule. The company believes the FCA has proved to be an effective rate mechanism for removing the financial disincentives that exist when Idaho Power invests in DSM resources and if made permanent will continue to serve in the best interests of its customers.

## Renewable Energy Certificates

To promote the construction of renewable resources, a system was created that separates renewable generation into two parts, 1) the electrical energy produced by a renewable resource, and 2) the renewable attributes of that generation. These renewable attributes are referred to as RECs or green tags. The entity that holds a REC has the right to make claims about the environmental benefits associated with the renewable energy from the project. One REC is issued for each MWh of electricity generated by a qualified resource. Electricity that is split from the REC is no longer considered renewable and cannot be marketed as renewable by the entity that purchases the electricity.

A REC must be retired once it has been used for either regulatory compliance or to substantiate a claim regarding renewable energy. Once a REC is retired, it cannot be sold or transferred to another party. The same REC may not be claimed by more than one entity, including any environmental claims made pursuant to electricity coming from renewable energy resources, environmental labeling, or disclosure requirements. State renewable portfolio standards (RPS) also typically specify a "shelf life" for RECs so they cannot be banked indefinitely.

### *Renewable Portfolio Standards*

Under the state of Oregon's RPS, Idaho Power is classified as a "smaller utility" because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 10 percent RPS requirement beginning in 2025.

While the state of Idaho does not have an RPS, Idaho Power believes a federal RES, requiring Idaho Power to retire RECs for compliance, will be passed by Congress in the future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

### *REC Management Plan*

Idaho Power's acquisition of RECs has created an issue regarding the disposition of the RECs until either a state RPS or federal RES requirement exists. Two options exist: 1) retire RECs, which would allow Idaho Power to represent to customers that renewable energy is being delivered to them, or 2) sell RECs and use the proceeds to reduce customer rates.

This issue was debated by the IRPAC during the preparation of both the 2009 IRP and the 2011 IRP. In general, environmental representatives felt future RECs should be retired while customer representatives felt they should be sold so that the value could be returned to customers.

In December 2009, Idaho Power filed with the IPUC a REC Management Plan that detailed the company's plans to continue to acquire long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near term and return to customers their share of the proceeds through the power cost adjustment (PCA) mechanism. Public comments regarding the plan mirrored the positions expressed by IRPAC members, many of whom filed comments with the IPUC. In June 2010, the IPUC accepted Idaho Power's REC Management Plan.

## Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment, including air, water, and solid waste. Current and pending legislation relates to, among other items, climate change, GHG emissions and air quality, RES, Hg and other emissions, hazardous wastes, and polychlorinated biphenyls (PCB). Environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power discontinue operating certain power generation plants.

### *Federal Climate Change Legislation*



Future federal climate-change legislation could affect regulated utilities, such as Idaho Power.

For the past several years, Congress has considered comprehensive federal energy legislation requiring reductions in GHG emissions. Proposed GHG regulations target the reduction of carbon and other GHG emissions nationwide. The most recent and prominent bills that have been proposed are 1) the *American Clean Energy and Security Act of 2009* (Waxman–Markey), sponsored by Representatives Henry A. Waxman and Edward J. Markey; 2) the *Clean Energy Jobs and American Power Act of 2009* (Boxer–Kerry), sponsored by Senators Barbara Boxer and John Kerry in the Senate; and 3) the *American Power Act of 2010* (Kerry–Lieberman), sponsored by Senators John Kerry and Joe Lieberman.

In June 2009, the US House of Representatives narrowly passed the Waxman–Markey bill. The draft bill included a GHG emissions reduction goal of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and more than 80 percent by 2050. The Waxman–Markey bill proposed to accomplish the reductions under a cap-and-trade system that would establish a limit or cap on the total amount of GHG emissions. Although the Waxman–Markey bill passed in the House of Representatives, it did not pass in the Senate.

Under a cap-and-trade system, utilities would be allocated emissions allowances that would be decreased over time to achieve a total emissions reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society.

In September 2009, the Boxer–Kerry bill was introduced in the Senate. The draft bill included a GHG emissions reduction goal of 20 percent below 2005 levels by 2020. The Boxer–Kerry bill did not include a federal RES provision.

In May 2010, the Kerry–Lieberman bill was introduced in the Senate. The proposed legislation included a cap-and-trade system for reducing GHG emissions by 17 percent in 2020 and by over 80 percent in 2050. None of the proposed federal climate change legislation has been able to gain enough support to be passed by both the House of Representatives and the Senate.

In the summer of 2011, the Environmental Protection Agency (EPA) plans to begin regulating GHG emissions. However, some members of Congress are currently working to remove EPA's authority to regulate GHGs through legislative action and budget cuts.

## Environmental Protection Agency

Idaho Power co-owns three coal-fired power plants and owns two natural gas-fired combustion turbine power plants that are subject to air-quality regulation. The coal-fired plants are Jim Bridger (one-third interest) located in Wyoming; Boardman (10 percent interest) located in Oregon; and Valmy (50 percent interest) located in Nevada. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. In addition, Idaho Power is currently in the process of constructing the Langley Gulch power plant, a natural gas-fired CCCT generating plant with a nameplate capacity of approximately 300 MW.

The *Clean Air Act* (CAA) establishes controls on the emissions from stationary sources like those owned by Idaho Power. The EPA adopts many of the standards and regulations under the CAA, while states have the primary responsibility for implementation and administration of these air-quality programs. Idaho Power continues to actively monitor, evaluate, and work on air-quality issues pertaining to federal and state Hg emissions rules, possible legislative amendment of the CAA, Regional Haze–Best Available Retrofit Technology (RH BART), National Ambient Air Quality Standards (NAAQS), and New Source Review (NSR) permitting.

### Regional Haze–Best Retrofit Technology

In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. The Wyoming Department of Environmental Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) have conducted assessments of the Jim Bridger and Boardman plants pursuant to the RH BART process. These states have also evaluated the need for additional controls at Jim Bridger and Boardman to achieve reasonable progress toward a long-term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

On November 3, 2010, PacifiCorp, the majority owner and operator of the Jim Bridger plant, and the WDEQ signed a settlement agreement under which PacifiCorp agreed to install selective catalytic reduction (SCR) technology, alternative add-on nitrogen oxide ($NO_x$) controls, or otherwise achieve a 0.07 pounds-per-million British thermal units (MMBtu) 30-day rolling average $NO_x$ emissions rate by December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. In addition, PacifiCorp has agreed to install SCR technology, alternative add-on $NO_x$ controls, or otherwise achieve a 0.07 pounds-per-MMBtu 30-day rolling average $NO_x$ emissions rate by December 31, 2021, for Unit 2 and December 31, 2022, for Unit 1. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan that are consistent with the terms of the settlement agreement. In light of the settlement agreement, WDEQ issued a revised RH BART permit for Jim Bridger on November 24, 2010.

In August 2010, Portland General Electric (PGE), the majority owner and operator of the Boardman plant, submitted a new plan to the ODEQ that would cease coal-fired operations at the Boardman plant in 2020, but contemplated additional emissions reductions relative to PGE's previous 2020 closure plan.

Following an extensive public process, in December 2010, the Oregon Environmental Quality Commission approved PGE's August and October 2010 plan to cease coal-fired operations at the Boardman plant no later than December 31, 2020. The new rules implementing the plan are expected to contain the following measures:

- Install new low-$NO_x$ burners and modified overfire air ports by July 2011 to comply with BART standards for $NO_x$
- Conduct pilot studies for the dry sorbent-injection system to verify that set sulfur dioxide ($SO_2$) limits for 2014 and 2018, are achievable
- Install a dry sorbent-injection system by July 2014, to comply with BART standards for $SO_2$
- Repeal the ODEQ's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more expensive suite of emissions controls
- Permanent cessation of coal-fired operation no later than December 31, 2020

### National Ambient Air Quality Standards

In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). In December 2006, the EPA revised the NAAQS for PM2.5. This new standard is the subject of a legal challenge by a number of groups. However, all counties in Idaho, Nevada, Oregon, and Wyoming—where Idaho Power's power plants operate currently—were designated as meeting attainment with the revised PM2.5 NAAQS.

In January 2010, the EPA adopted a new NAAQS for $NO_2$ at a level of 100 parts-per-billion averaged over a 1-hour period. In addition, in June 2010, the EPA adopted a new NAAQS for $SO_2$ at a level of 75 parts-per-billion averaged over a 1-hour period. The EPA has not yet designated areas as attaining or not attaining these new standards. Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations.

### Hazardous Air Pollutants–Maximum Achievable Control Standard

On March 16, 2011, EPA issued proposed rules to reduce emissions of Hazardous Air Pollutants (HAP) from coal- and oil-fired electric utility steam-generating units. These rules target certain heavy metals, acid gases, organics, dioxins, and furans. EPA grouped these HAPs into the following categories; Hg, non-Hg HAP metals, acid gases, organics, and dioxins/furans. Of these groups, all but organics and dioxin/furan have numerical limits that must be met. Two of the groups (non-Hg HAP metals and acid gases) allow for "surrogate" pollutants to be used to demonstrate compliance with the limits. To demonstrate compliance with organic HAPs and dioxin/furans, the EPA has proposed Work Practice Standards.

Continuous emissions-monitoring systems of Hg have been installed on all the coal-fired units at the Jim Bridger, Boardman, and Valmy plants, and tests to confirm the accuracy of the data being collected are underway. In 2008, the state of Oregon adopted an Hg rule requiring the Boardman plant to reduce Hg emissions by 90 percent or meet an emissions rate of 0.6 pounds-per-trillion Btus by July 2012. Idaho Power continues to monitor Wyoming and Nevada actions related to Hg emissions. Idaho Power is unable to predict at this time what actions the EPA or the other states may take to reduce Hg emissions from their coal-fired power plants. In April 2010, the US District Court for the District of

Columbia approved, by consent decree, a timetable that would require the EPA to propose a standard to control Hg emissions from coal-fired power plants by May 2011 and to finalize it by November 2011.

### Clean Air Transport Rule

In July 2009, the EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in $SO_2$ and $NO_x$ emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule is intended to help states attain NAAQS set in 1997 for ozone and fine particulate-matter emissions. This rule replaces the Bush administration‘s Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS.

Idaho Power does not own generating units in states identified by the Transport Rule and thus will not be directly impacted; however, the company intends to monitor amendments to the Transport Rule closely, particularly since there is some indication that the 2014 revisions to the Transport Rule will extend the geographic scope of impacted states.

### Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs are currently considered exempt wastes under an amendment to the *Resource Conservation and Recovery Act of 1976* (RCRA); however, in 2010, the EPA proposed to regulate CCRs for the first time. The EPA is considering two possible options for the management of CCRs. Both options fall under the RCRA.

Under the first option, the EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition, including the closure of disposal units. Under the second option, the EPA would regulate CCRs as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. A final ruling is expected in 2012.

# 3. IDAHO POWER TODAY

## Customer Load and Growth




An Idaho Power employee installs a new Smart Meter.

In 1990, Idaho Power served approximately 292,000 general business customers. Today, Idaho Power serves more than 492,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW in 2006–2009. In June 2008, the peak-hour load reached 3,214 MW, which is the system peak-hour record. Idaho Power's successful demand reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand in both 2009 and 2010.

Average firm load (excluding Astaris/FMC) increased from nearly 1,200 aMW in 1990 to over 1,800 aMW in 2008. Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,276 MW. The 641-MW increase in capacity represents enough generation to serve approximately 100,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 300-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is being constructed in the western Treasure Valley in Payette County, Idaho. Construction began in August 2010, and the plant is expected to be operational in July 2012.

The data in Table 3.1 suggests each new customer adds approximately 6.5 kW to the peak-hour load and about 1.5 average kilowatts (akW) to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 200,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 200,000 customers require over 1,100 MW of additional peak-hour capacity and about 600 aMW of energy.

**Highlights**

- Idaho Power had over 492,000 retail customers at the end of 2010.
- The 300-MW Langley Gulch natural gas-fired CCCT is expected to begin operating in July 2012.
- Since 2003, Idaho Power has been operating a cloud-seeding program that increases snow accumulation and provides increased generation at the company's hydroelectric facilities.

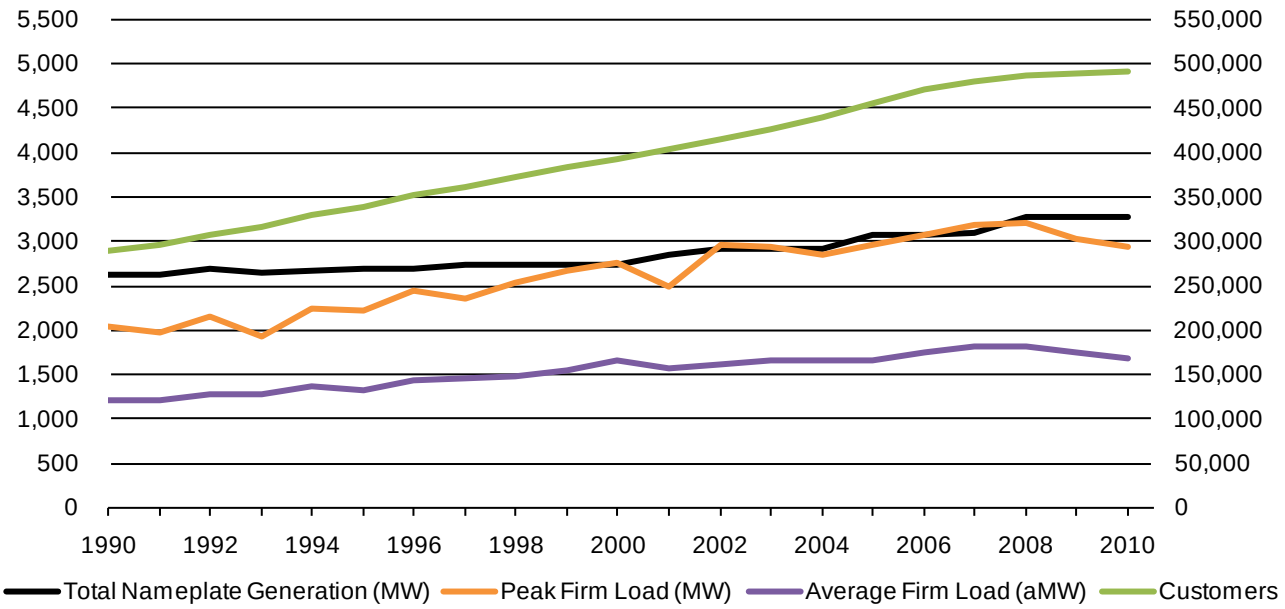


**Figure 3.1 Historical capacity, load, and customer data**

**Table 3.1 Historical capacity, load, and customer data**

| Year | Total Nameplate Generation (MW) | Peak Firm Load (MW) | Average Firm Load (aMW) | Customers |
|---|---|---|---|---|
| 1990 | 2,635 | 2,052 | 1,205 | 290,492 |
| 1991 | 2,635 | 1,972 | 1,206 | 296,584 |
| 1992 | 2,694 | 2,164 | 1,281 | 306,292 |
| 1993 | 2,644 | 1,935 | 1,274 | 316,564 |
| 1994 | 2,661 | 2,245 | 1,375 | 329,094 |
| 1995 | 2,703 | 2,224 | 1,324 | 339,450 |
| 1996 | 2,703 | 2,437 | 1,438 | 351,261 |
| 1997 | 2,728 | 2,352 | 1,457 | 361,838 |
| 1998 | 2,738 | 2,535 | 1,491 | 372,464 |
| 1999 | 2,738 | 2,675 | 1,552 | 383,354 |
| 2000 | 2,738 | 2,765 | 1,653 | 393,095 |
| 2001 | 2,851 | 2,500 | 1,576 | 403,061 |
| 2002 | 2,912 | 2,963 | 1,622 | 414,062 |
| 2003 | 2,912 | 2,944 | 1,657 | 425,599 |
| 2004 | 2,912 | 2,843 | 1,671 | 438,912 |
| 2005 | 3,085 | 2,961 | 1,660 | 456,104 |
| 2006 | 3,085 | 3,084 | 1,745 | 470,950 |
| 2007 | 3,093 | 3,193 | 1,808 | 480,523 |
| 2008 | 3,276 | 3,214 | 1,815 | 486,048 |
| 2009 | 3,276 | 3,031 | 1,744 | 489,927 |
| 2010 | 3,276 | 2,930 | 1,680 | 492,073 |

Idaho Power anticipates adding approximately 8,000 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 69 MW per year, and the average energy requirement is forecast to grow at 29 aMW

per year. More detailed customer and load forecast information is presented in Chapter 6 and in *Appendix A–Sales and Load Forecast*.

The simple peak-hour load growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 173-MW Bennett Mountain plant every 3 years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 10.

The generation costs per kW included in Chapter 6 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5.0–5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5.0–5.5 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,000 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

## 2010 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities and long-term PPAs to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year. The next sections provide specific details on Idaho Power's sources of energy in 2010 followed by a description of Idaho Power's existing and committed resources.

In 2010, 86 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.2 shows Idaho Power's electricity sources for 2010, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

Long-term power purchases are electric power contracts with independent power producers and firm PPAs with other utilities and can typically be identified by resource type. In 2010, Idaho Power purchased 1,399,661 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.3. Long-term power purchases that cannot be identified by resource type are shown as "other" in the chart.

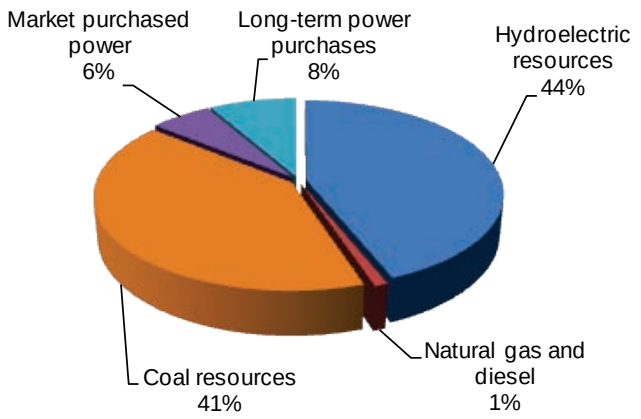


**Figure 3.2 2010 energy sources**

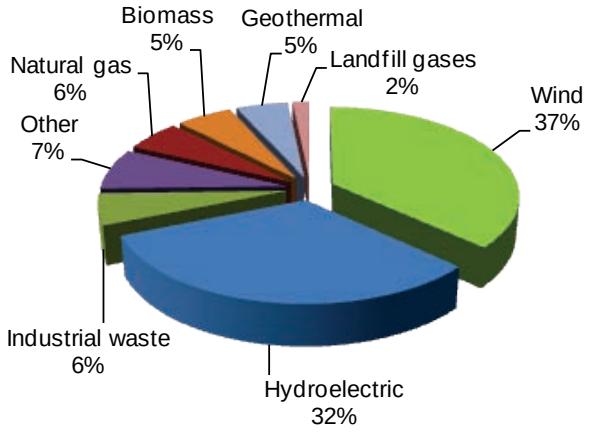


**Figure 3.3 2010 long-term power purchases by resource type**

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. Electricity produced by resources typically considered to be renewable, such as wind, biomass, geothermal, etc., is not counted as renewable energy delivered to retail customers in a given year, unless Idaho Power retires an equivalent number of RECs in that year.

In December 2009, Idaho Power filed with the IPUC a REC Management Plan that detailed Idaho Power's plans to continue to acquire long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near-term and return the customers' share of the proceeds through the PCA mechanism.

Table 3.2 shows Idaho Powers' energy sources and the subsequent electricity delivered to retail customers in 2010. Because Idaho Power sells electricity to other utilities and to retail customers, not all electricity purchased or generated by Idaho Power is delivered to its retail customers. Table 3.2 shows that no wind or geothermal generation was delivered to retail customers in 2010, the RECs associated with this generation were sold to others who have purchased the right to claim the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with this generation, the company would have been able to claim the renewable energy had been delivered to customers. Idaho Power also has several small hydroelectric projects that qualify under the state of Nevada's RPS, and RECs from these projects were sold to NV Energy in 2010. Idaho Power's Green Power Program retired 23,056 RECs in 2010, this energy can be reported as renewable energy delivered to customers.

**Table 3.2 Electricity delivered to customers (2010)**

| Resource by Type (MWh) | Generation | RECs Sold[1] | RECs Purchased and Retired[2] | Delivered to Customers |
|---|---|---|---|---|
| Hydroelectric | 7,344,433 | -188,336 | | 7,156,097 |
| Coal | 6,863,870 | | | 6,863,870 |
| Natural Gas & Diesel | 159,586 | | | 159,586 |
| Purchased Power | 1,992,584 | 573,438 | -23,056 | 2,542,966 |
| Wind | 313,256 | -313,256 | | 0 |
| Geothermal | 71,846 | -71,846 | | 0 |
| Renewable (Green Power Program) | 0 | | 23,056 | 23,056 |
| **Total** | **16,745,575** | **0** | **0** | **16,745,575** |

[1] When RECs are sold, Idaho Power can no longer claim the environmental attributes associated with the renewable resource. Therefore, the energy from REC sales is reclassified as Purchased Power.

[2] Idaho Power's Green Power Program retired 23,056 RECs in 2010; this energy is reported as renewable energy delivered to customers enrolled in the Green Power Program.

# Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are presented in *Appendix C–Technical Appendix*. Table 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

**Table 3.3 Existing Resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydro | 92.3 | Upper Snake |
| Bliss | Hydro | 75.0 | Mid-Snake |
| Brownlee | Hydro | 585.4 | Hells Canyon |
| C.J. Strike | Hydro | 82.8 | Mid-Snake |
| Cascade | Hydro | 12.4 | North Fork Payette |
| Clear Lake | Hydro | 2.5 | South Central Idaho |
| Hells Canyon | Hydro | 391.5 | Hells Canyon |
| Lower Malad | Hydro | 13.5 | South Central Idaho |
| Lower Salmon | Hydro | 60.0 | Mid-Snake |
| Milner | Hydro | 59.4 | Upper Snake |
| Oxbow | Hydro | 190.0 | Hells Canyon |
| Shoshone Falls | Hydro | 12.5 | Upper Snake |
| Swan Falls | Hydro | 27.2 | Mid-Snake |
| Thousand Springs | Hydro | 8.8 | South Central Idaho |
| Twin Falls | Hydro | 52.9 | Mid-Snake |
| Upper Malad | Hydro | 8.3 | South Central Idaho |
| Upper Salmon A | Hydro | 18.0 | Mid-Snake |
| Upper Salmon B | Hydro | 17.0 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| Valmy | Coal | 283.5 | North Central Nevada |
| Bennett Mountain | Natural Gas | 172.8 | Southwest Idaho |
| Danskin | Natural Gas | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | Eastern Idaho |
| **Total Existing Nameplate Capacity** | | **3,276.4** | |

The following sections describe Idaho Power's existing supply-side generation resources and long-term PPAs.

## *Hydroelectric Facilities*

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 970 aMW, or 8.5 million MWh under median water conditions.

### Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the Hells Canyon Complex in the Hells Canyon reach of the Snake River. The Hells Canyon Complex consists of Brownlee, Oxbow, and Hells Canyon

dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation and approximately 35 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the Hells Canyon Complex projects to provide the major portion of Idaho Power's peaking and load-following capability.

Idaho Power operates the Hells Canyon Complex to comply with the existing FERC license as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall Chinook plan, voluntarily adopted by Idaho Power in 1991 to protect spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the ESA.

Brownlee Reservoir is the only Hells Canyon Complex reservoir—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used for flood control, recreation, and for the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams that are coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood control directions received from the US Army Corps of Engineers (ACOE) as outlined in Article 42 of the existing FERC license.

After flood-control requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The US Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The periodic releases are part of the flow augmentation implemented by the 2000 FCRPS biological opinion. The flow augmentation water travels through Idaho Power's Mid-Snake projects and eventually through the Hells Canyon Complex before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the fall Chinook plan adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook plan operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

Maintaining constant flows to protect the fall Chinook spawning contributes to the need for additional generation resources during the fall months. The fall Chinook operations result in lower reservoir elevations in Brownlee Reservoir, which reduce the power production capability of the project. The reduced power production may necessitate Idaho Power's acquisition of power from other sources to meet customer load.

## Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the Hells Canyon Complex include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls, and Cascade projects. Although the Mid-Snake projects of Upper and Lower Salmon, Bliss, and C.J. Strike typically follow run-of-river operations, the Lower Salmon, Bliss, and C.J. Strike plants provide a limited amount of peaking and load-following capability. When possible, the projects are operated within FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants are operated as run-of-river projects.

Idaho Power has completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail, a species listed as threatened under the ESA.

The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to license the Upper Salmon, Lower Salmon, Bliss, and C.J. Strike hydroelectric projects. During the study, Idaho Power operated the Bliss and Lower Salmon facilities under both run-of-river and load-following operations. Study results indicated that while load following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A Bliss Rapids Snail Protection Plan developed in consultation with FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company will be able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has filed license amendment applications with FERC for both projects that would allow load-following operations to resume.

## Water Lease Agreements

Idaho Power views the lease of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. This approach is particularly attractive for water-lease agreements that allow the company to request delivery as needed. Acquiring water through leases also helps the company to improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex.

The company signed rental agreements in 2009 and 2010 with Water District 63 in the Boise River system to lease 13,500 and 15,400 acre feet of storage water released in December 2009 and January 2011, respectively.

In 2011, Idaho Power signed a lease agreement with Water District 1 (WD 1) in the upper Snake River system for 25,000 acre feet of storage water for release during summer 2011. The company is participating in development discussions with the WD 1 Rental Pool Committee and the upper Snake advisory committee, the Committee of Nine, regarding a supplemental rental pool for use by the company for releases below Milner Dam.

In August 2009, Idaho Power also entered into a five-year (2009–2013) water-lease agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre feet of American Falls storage water. Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of main stem Snake River hydroelectric projects.

In 2011, the company is pursuing an extension of the Shoshone–Bannock lease for two additional years, 2014 and 2015. The company plans to schedule delivery of the water between July and October of each

year during the term of the lease. The Shoshone–Bannock agreement was executed in part to offset the impact of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Idaho Power intends to continue to pursue water-lease opportunities as part of its regular operations.

### Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snow accumulation in the south fork of the Payette River watershed. In 2008, Idaho Power expanded its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River system above Milner Dam.

Idaho Power seeds clouds by introducing silver iodide into winter storms. This process increases precipitation from passing winter storm systems. If a storm has a combination of an abundance of super-cooled liquid water vapor and appropriate temperatures, the conditions are optimal for cloud seeding to increase precipitation.

Idaho Power uses two methods to seed clouds: 1) install ground generators at high elevations, or 2) attach special flares to modified airplanes. Either method successfully releases silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide particles and eventually grow and fall to the ground as snow.

Silver iodide has been used as a seeding agent in numerous western states for decades without any known harmful effects. Analyses conducted by Idaho Power since 2003, indicate the annual snowpack in the Payette River basin increased between 5 and 15 percent (depending on the year). Idaho Power estimates cloud seeding will provide an additional 120,000 to 180,000 acre-feet of water for the Hells Canyon Complex. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.



Cloud seeding station in the Payette basin.

For the 2010–2011 winter season, the program included 10, remote-controlled, ground-based generators and one airplane for operations in the Payette Basin. The program in the Upper Snake River Basin included 15, remote-controlled, ground-based generators operated by Idaho Power and 25, manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

## *Thermal Facilities*

### Jim Bridger

Idaho Power owns one-third, or 706 MW (net dependable capacity), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The plant consists of four generating units. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

### North Valmy

Idaho Power owns 50 percent, or 260.5 MW (net dependable capacity) of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The plant consists of two generating units. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

### Boardman

Idaho Power owns 10 percent, or 58.5 MW (net dependable capacity), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. PGE has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative (PRC) has 10 percent ownership. As the majority partner of the plant, PGE is the operator of the Boardman facility.

The 2011 IRP assumes Idaho Power's share of Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, $SO_2$, and $NO_x$ emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

At the end of 2010, the net-book value of Idaho Power's share of the Boardman facility was approximately $19.3 million. In order to continue operating the plant until 2020, the addition of new emissions controls will likely be required. Idaho Power's share of the additional capital cost for the new equipment is estimated to range from $1 million to $37 million depending on the final ruling from the EPA. Until the EPA formally approves the agreement, it would be difficult to estimate the net book value of Idaho Power's share of the plant in 2020.

## *Peaking Facilities*

### Danskin

Idaho Power owns and operates the Danskin plant, a 271-MW natural gas-fired project. The plant consists of one, 179-MW Siemens 501F SCCT and two, 46-MW Siemens–Westinghouse W251B12A combustion turbines. The 12-acre facility was initially constructed in 2001, and is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin plant operates as needed to support system load.

### Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173-MW Siemens–Westinghouse 501F natural gas-fired SCCT located near the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant also operates as needed to support system load.

### Salmon Diesel

Idaho Power owns and operates two diesel generation units located in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are operated primarily during emergency conditions.

## Solar Facilities

In 1994, a 25-kW solar PV array with 90 individual panels was installed on the rooftop of Idaho Power's corporate headquarters in Boise, Idaho. The company also maintains a remote, off-grid, 80-kW solar PV array for the US Air Force near Grasmere, Idaho.

Idaho Power uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring stream flows, and operating-cloud seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program; owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events; and has a 200-watt (W) solar water pump used for demonstrations and the promotion of solar PV technology.

### Net Metering Program

Idaho Power's net metering program allows customers to install small-scale, renewable generation projects on their property and connect to Idaho Power's system. Under the program, net energy generated beyond what the customer uses is sold back to Idaho Power. A majority of the program's participants are solar projects. Currently, there are 130 solar PV installations under this program with a total capacity of 607 kW.

### Oregon Solar Photovoltaic Pilot Program

In 2009, the Oregon Legislature passed ORS 757.365 as amended by House Bill 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to its customers in Oregon. Under the pilot program, Idaho Power will acquire up to 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW was allocated, and the remaining 200 kW will be offered during the next enrollment period in October 2011.

In addition to the smaller facilities under the pilot program, Idaho Power is required to either own or purchase the generation from a 500-kW, utility-scale solar PV facility by 2020. Under the rules, if the utility-scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the state of Oregon RPS.

## Power Purchase Agreements

### Elkhorn Valley Wind Project

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn wind project was constructed during 2007 and began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project.

### Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly.

For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the total RECs generated by the project.

### Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project is under development and is expected to begin commercial operations in 2012. Under the PPA, Idaho Power receives all the RECs from the project.

### Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the newly constructed 18-MW power plant at Arrowrock Dam on the Boise River; and in exchange, Idaho Power provides Clatskanie PUD energy of equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

## *Public Utility Regulatory Policies Act*

In 1978, Congress passed PURPA requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Individual states were tasked with establishing the PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in both Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in the state of Idaho, and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar, but not identical, for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The forecast used in the 2011 IRP was completed in September 2010 and did not include approximately 500 MW of wind contracts that were signed in late 2010. Because Idaho Power's future resource needs are driven by capacity requirements and not energy, the exclusion of these new contracts does not have a material impact on the 2011 IRP. At the 5-percent peak-hour capacity factor used for wind resources for planning purposes, the 500 MW of PURPA wind contracts represent only 25 MW of capacity for peak-hour planning.

As of March 31, 2011, Idaho Power had 127 PURPA contracts with independent developers for approximately 1,190 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, solar projects, and various other small, renewable-power projects. Of the 127 contracts, 91 were on line as of March 31, 2011, with a cumulative nameplate rating of approximately 491 MW. Figure 3.4 shows the total nameplate capacity of each resource type under contract. Figure 3.4 includes 294 MW from 13 PURPA wind contracts that were recently disapproved by the IPUC. Additional details on these contracts are presented in the next section.

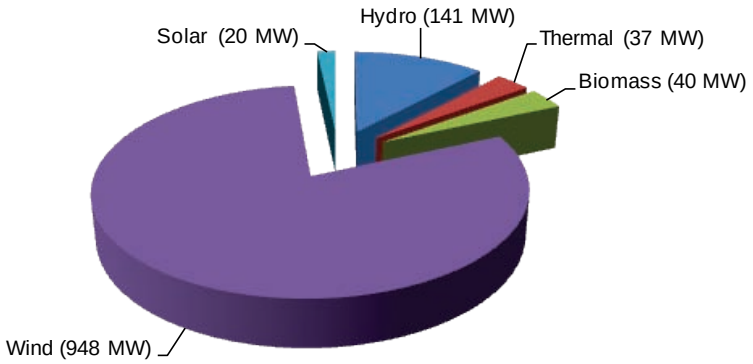


**Figure 3.4 PURPA contracts by resource type**

### Published Avoided Cost Rates

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided cost. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost rate that Idaho Power is required to include in PURPA contracts.

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04 and GNR-E-11-01). These issues include the disaggregation of larger, utility-scale projects in order to qualify for the published avoided cost rate and the methods used to calculate the published rate. As of June 2011, this case was not resolved, and the outcome may impact some of the existing PURPA contracts for projects not yet constructed as well as future PURPA project development.

On June 8, 2011, the IPUC issued Order 32262 in this case. The order recognized that the disaggregation issue could not be solved without simultaneously addressing pricing and other issues related to PURPA. In addition, the order established that the published avoided cost rate is available for only wind and solar projects with a nameplate rating of less than 100 kW. For all other resource types, the eligibility cap will remain at 10 aMW. The order goes on to state that the next phase of the case will be a thorough review of the energy pricing methods to be used for PURPA. The order requests the parties in the case meet no later than July 8, 2011, to establish a schedule to process the next phase of the case.

In addition to Order 32262, on June 8, 2011, the IPUC issued separate orders disapproving 13 PURPA wind contracts that Idaho Power had filed requesting IPUC approval. Idaho Power expects some of the counterparties to these contracts to request the IPUC reconsider these orders. The parties have 21 days from the date of the order to file the request for reconsideration, at which time the IPUC will take requests under consideration and issue additional rulings. Rulings on the reconsideration process and other orders in the case will not be complete by the June 30, 2011, IRP filing deadline.

## *Wholesale Contracts*

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. The agreement was established as a full-requirements contract after being approved by FERC and the Public Utilities Commission of Nevada. This contract has been renewed annually for several years; however, it is expected to expire at the end of September 2011.

Idaho Power continues to use its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during summertime heavy-load hours from PPL EnergyPlus, LLC. Although the purchase agreement expires in 2012,

Idaho Power plans to continue to use the available transmission capacity during the summer months as needed until the Boardman to Hemingway transmission line is completed.

### Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power is especially dependent on the regional markets during peak-load periods, and the existing transmission system is used to import these purchases. Reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the PCA.

## Committed Supply-Side Resources

Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility and are treated like existing resources in the IRP analysis.

### Langley Gulch

The need for a new baseload power plant was identified in Idaho Power's 2004 and 2006 IRPs. The initial decision was to construct a coal-fired baseload resource, but regulatory, price, and environmental issues led Idaho Power to reconsider the coal resource and instead select a natural gas-fired CCCT. Idaho Power completed the competitive bidding process in early 2009 and selected a 300 MW CCCT project near New Plymouth, Idaho to meet the resource need.

The Langley Gulch project is expected to begin delivering energy in time to meet summer peaking needs in July 2012. The Langley Gulch project will require the construction of short segments of 138-kV and 230-kV transmission lines to connect to the existing system in order to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon.

### Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric Project from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single, 50-MW unit that will result in a net upgrade of 49 MW.

In July 2010, FERC issued a license amendment for the project. This amendment allows two years to begin construction and five years to complete the project. For the 2011 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in October 2015. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median water conditions, some uncertainty exists regarding future Snake River streamflows that would not only impact the Shoshone Falls project, but all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls Upgrade Project, it is included in the 2011 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the state of Idaho. Prior to filing for a CPCN with the IPUC, Idaho Power plans to update the economic analysis of the project, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

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# 4. DEMAND-SIDE RESOURCES



Idaho Power's Long Valley Operations Center in Lake Fork was granted LEED gold status due in part to its energy-efficient design.

DSM customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with customers to promote energy efficiency and produce the same output or provide the same level of service with lower energy consumption. Through demand response programs, Idaho Power provides incentives to customers to identify applications where a short-term load reduction can be timed to coincide with peak energy consumption when all other resources, including transmission capacity to purchase energy, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side base load resources. Energy efficiency and demand response programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities since 2001. Due to the indirect nature of savings from market transformation, NEEA impacts are not accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of avoided power generation costs exceed the costs of offering an energy efficiency or demand response program, are published annually, and the most recent analysis can be found in the *Demand-Side Management 2010 Annual Report Supplement 1: Cost Effectiveness*. Each program in the existing portfolio of demand-side resources are reviewed as part of the IRP process for their potential impact over the 20-year IRP planning horizon. The resulting forecast of energy savings and demand-reduction potential, along with prior program performance, is then incorporated into the load forecast process. For a description of this process, see *Appendix A–Sales and Load Forecast.*

In addition to reviewing the existing portfolio of DSM resources, new opportunities for demand-side resources are evaluated for inclusion into the existing portfolio of programs and their impacts are

**Highlights**

- Energy Efficiency efforts from both the existing portfolio and program expansion will provide 233 aMW of system reduction over the 20-year planning period avoiding over $1.1 billion in power supply costs in 2011 dollars.
- Total peak summer capacity of the demand response program portfolio is targeted at 330 MW in 2011 and increases to 351 MW by 2016.
- Demand response programs will cost $48 per kW, and new energy efficiency will cost 5.1 cents per kWh over the IRP planning period.

forecasted. Idaho Power adopts all new demand-side resources when they are determined to be cost-effective. Energy efficiency resources are consistently one of the least-cost resources available for Idaho Power's resource stack.

All cost-effectiveness analyses for DSM forecasts for both the existing portfolio and new acquisition accounted for in the 2011 IRP are either presented as a summary in the IRP or in more detail in *Appendix C–Technical Appendix*. *Appendix B–Demand-Side Management 2010 Annual Report* contains a detailed description of Idaho Power's 2010 energy efficiency program portfolio along with historical program performance.

## Energy Efficiency Program Portfolio Analysis

Each energy efficiency program currently offered to customers as part of the existing portfolio is reviewed to forecast average demand reduction. The forecast of potential programs over the IRP planning horizon considers where the program is in its life cycle (i.e., ramping up or ramping down). Also, recent program participation trends, future changes in codes and standards that will affect program measures, along with program design changes are taken into consideration.

Idaho Power placed primary emphasis on the first five years (2011–2015) when reviewing program potential; then future program performance was assumed to be held constant at 2015 levels unless known codes and standards or other mitigating circumstances justified ramping the program down early. Many unknown factors may affect program participation for the second 10 years, including multiple changes in codes and standards or technology. Therefore, programs included in the 2020 portfolio are ramped down by the end of the 20-year IRP planning period.

Historical demand-side reductions are assumed to influence customer energy-usage behavior and are accounted for in the 2011 IRP load forecast methodologies. Therefore, the current portfolio is analyzed starting in 2011 and looks at 2011–2030 impacts only. The program performance forecast assumes customers will not replace existing efficiency measures with less-efficient measures once useful life expires, and the forecasted impact of energy efficiency programs accumulates from year-to-year. For example, in 2015, Idaho Power assumes all efficient measures installed during 2011–2014 are still in place, along with incremental 2015 energy savings.

Annual savings are measured in MWh; for the IRP analysis they are divided by 8,760 hours (hours in a year), or corresponding monthly hours, to convert to average annual or monthly demand reduction (aMW) to compare with supply-side resources. All forecasts are prepared in terms of generation equivalency and include line losses of 10.9 percent, which accounts for energy lost as a result of transmitting energy between the generation source and the customer.

Table 4.1 shows the forecast impact of the current portfolio of energy efficiency programs for 2011, 2015, 2020, and 2030, in terms of average demand reduction (aMW) by customer class. In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C–Technical Appendix*.

**Table 4.1 Energy efficiency current portfolio forecasted impacts (2011–2030)**

| | 2015 (aMW) | 2020 (aMW) | 2025 (aMW) | 2030 (aMW) |
|---|---|---|---|---|
| Industrial | 23 | 46 | 61 | 66 |
| Irrigation | 5 | 8 | 11 | 11 |
| Commercial | 30 | 60 | 80 | 86 |
| Residential | 11 | 20 | 26 | 28 |
| **Total** | **69** | **133** | **178** | **191** |

Table 4.2 shows the forecast cost-effectiveness of the current portfolio of energy efficiency programs. The table shows the net-present-value analysis of the 20-year forecast of utility costs, resource costs, and avoided energy. Utility costs are the costs to administer the energy efficiency programs, while total resource costs account for both the utility costs and the customer investment in efficiency technologies and measures offered through the programs. Utility costs and total resource costs were estimated based on 2010 program performance for industrial, commercial, and residential classes and a three-year average performance for irrigation to allow for annual fluctuations between custom- and menu-driven irrigation efficiency. Avoided energy is the benefit of the programs calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing portfolio of generation resources.

**Table 4.2 Existing energy efficiency portfolio cost-effectiveness summary**

| | 2030 Load Impact (aMW) | Utility Costs (20-Year NPV*) | Resource Costs (20-Year NPV) | Avoided Energy Costs (20-Year NPV) | Utility Cost: Benefit/Cost Ratio | Utility Levelized Costs ($/kWh) | Total Resource Cost: Benefit/Cost Ratio | Total Resource Cost Levelized Costs ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| Industrial | 66 | $49,398,586 | $96,635,806 | $257,704,824 | 5.2 | $0.015 | 2.7 | $0.028 |
| Irrigation | 11 | $14,229,458 | $38,651,984 | $43,667,373 | 3.1 | $0.023 | 1.1 | $0.061 |
| Commercial | 86 | $60,885,631 | $119,966,128 | $335,208,357 | 5.5 | $0.014 | 2.8 | $0.027 |
| Residential | 28 | $60,023,978 | $103,519,281 | $181,086,911 | 3.0 | $0.040 | 1.7 | $0.069 |
| **Total** | **191** | **$184,537,652** | **$358,773,200** | **$817,667,465** | **4.4** | **$0.019** | **2.3** | **$0.036** |

*Net present value (NPV)

The value of avoided energy over the 20-year investment in the energy efficiency measures was more than twice the total resource cost when comparing benefits and costs. This resulted in an overall benefit cost ratio of 2.3. The levelized cost to reduce energy demand by 191 aMW is 3.6 cents per kWh from a total resource cost perspective. Figure 6.9 in Chapter 6 compares energy efficiency program costs with Idaho Power's other supply-side resource options from an energy perspective.

## New Energy Efficiency Resources

During each IRP planning period, Idaho Power uses various resources, including existing portfolio program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill future resource needs.
New energy efficiency opportunities are evaluated through a cost-effectiveness analysis similar to the existing programs. Forecasting assumptions for new residential efficiency for the 2011 IRP were aided by the planning model that was developed by Nexant Inc., from the *2009 Demand Side Management Potential Study*.

Along with identifying new opportunities for energy efficiency it is also important to identify the barriers that may face new program measures and expansions. One challenge the company will continue

to face going forward is to increase the understanding of behaviors and decisions that residential customers make in regards to energy efficiency investments and providing the correct level of incentive to motivate them while maintaining cost-effectiveness. Much of the expansion to residential programs analyzed for the 2011 IRP include measures requiring increased customer investments, such as improved weatherization in electric home and multi-family housing. It will become increasingly important to understand the purchasing decisions of prior participants and continue forward with Idaho Power's efforts of targeted marketing and demographic analysis to work to overcome customers' investment barriers. Ongoing process evaluations of energy efficiency programs will also continue to be an important source of information for understanding customer participation in programs and for developing strategies to increase participation and program delivery. Examples of past process evaluations for energy efficiency programs can be found in the *Demand-Side Management 2010 Annual Report Supplement 2: Evaluation*.

## Industrial Efficiency

Efficiency projects, through the Custom Efficiency program, which provides efficiency projects to large commercial and industrial customers continues to exceed expectations and has performed well since the program began providing incentives in 2004. Projects can include any combination of approved custom measures and process improvements that show energy efficiency enhancements. Some of the most common projects include measures, such as higher-efficiency lighting, fans, compressed air, and pumps.

Program changes, including moving some smaller lighting projects of less than 100,000 annual kWh of savings to other programs, will allow increased capacity for more custom projects over the next few years. This will lead to an increased expansion of 13 aMW over the 20-year IRP planning horizon. The increased efficiency will cost approximately 2.6 cents per kWh.

## Commercial Efficiency

Program changes in the commercial and industrial efficiency programs in 2011 will shift some lighting projects into the Easy Upgrades prescriptive program that previously would have paid through the Custom Efficiency program. These potential savings were not accounted for in the original commercial program portfolio forecast and will result in an additional 6.6 aMW of average demand reduction potential over the IRP planning horizon.

## Residential Efficiency

New residential efficiency includes expanded weatherization measures identified in the *Idaho Power Demand-Side Management Potential Study*, published in 2009, along with growth in incentives for heat pumps for electrically heated homes, and expansion of existing programs into the multi-family sector. During 2011 and 2012, plans are being made to add additional weatherization measures to Idaho Power's Home Improvement Program, which currently provides incentives for increasing levels of attic insulation. The additional measures are also expected to be made available to multi-family housing and will focus on windows, infiltration, and HVAC duct sealing. These program additions for electrically heated homes are forecasted to add 20.1 aMW of savings to the program over the IRP planning horizon.

Increased incentives for air-source heat pumps in 2011 will encourage customers to transition from electric, forced-air furnaces and will add 0.3 aMW of average demand reduction to the program. Weatherization Solutions for Eligible Customers, a weatherization program for income-qualified customers, will be expanded to eastern Idaho in 2011. Idaho Power forecasts the new targeted area will provide 2 aMW of increased program reduction over the IRP planning horizon.

Table 4.3 shows the forecast combined contribution in reduced average consumption over the IRP planning horizon. In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

**Table 4.3 New energy efficiency portfolio forecasted impacts (2011–2030)**

| | 2015 (aMW) | 2020 (aMW) | 2025 (aMW) | 2030 (aMW) |
|---|---|---|---|---|
| Industrial | 7 | 10 | 12 | 13 |
| Commercial | 2 | 5 | 6 | 7 |
| Residential | 4 | 10 | 16 | 23 |
| **Total** | **13** | **25** | **35** | **42** |

Table 4.4 presents a summary of the cost and cost-effectiveness of new energy efficiency efforts. The overall benefit/cost ratio for all new energy efficiency measures is 3.2 at a levelized total resource cost of 5.1 cents per kWh. Additional details on annual costs and benefits can be found in *Appendix C–Technical Appendix*.

**Table 4.4 New energy efficiency portfolio cost-effectiveness summary**

| | 2030 Load Impact (aMW) | Utility Costs (20-Year NPV) | Resource Costs (20-Year NPV) | Avoided Energy Costs (20-Year NPV) | Utility Cost: Benefit/Cost Ratio | Utility Levelized Costs ($/kWh) | Total Resource Cost: Benefit/Cost Ratio | Total Resource Cost: Levelized Costs ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| Industrial | 13 | $10,293,124 | $20,135,886 | $56,034,905 | 5.4 | $0.013 | 2.8 | $0.026 |
| Commercial | 7 | $4,468,872 | $8,607,815 | $25,770,482 | 5.8 | $0.013 | 3.0 | $0.025 |
| Residential | 23 | $35,582,870 | $69,027,549 | $228,851,046 | 6.4 | $0.045 | 3.3 | $0.086 |
| **Total** | **42** | **$50,344,865** | **$97,771,250** | **$310,656,434** | **6.2** | **$0.026** | **3.2** | **$0.051** |

## Demand Response Resources

The goal of demand response programs at Idaho Power is to reduce summer peak load during periods of extremely high demand and minimize or delay the need to build new supply-side resources. Demand response programs were first implemented in summer 2004 when a 6.1-MW peak-hour load reduction was measured. Idaho Power's demand response portfolio has grown since that time, and 330 MW of peak-hour load reduction has been targeted for summer 2011. Three programs 1) A/C Cool Credit, 2) Irrigation Peak Rewards, and 3) FlexPeak Management allow residential, irrigation, commercial, and industrial customers to participate in potential peak-hour load reduction efforts. A complete description of the demand response programs can be found in *Appendix B–Demand-Side Management 2010 Annual Report*.



An Idaho Power customer representative discusses the Irrigation Peak Rewards program with a farmer.

An analysis that focused on the optimal level of demand response resources along with the costs and the most effective method of utilization was conducted as part of the 2011 IRP. The conclusions drawn from this analysis were that 1) there is a defined optimal amount of demand response for Idaho Power's

system; 2) in conjunction with each IRP, Idaho Power will update the targets for demand response; 3) the program managers will work to align program design with system needs; 4) stakeholders will be involved in this process; and 5) program designs and pricing options will be reassessed. In this analysis, the costs from an energy perspective for demand response was compared to the energy costs of owning and operating an SCCT. The results of this analysis indicated actual program energy costs were inherently more because of the limitations on the number of hours the programs could be operated (60 hours) and the limited time of the year when the programs were available. The program continues to be less expensive than an SCCT from a capacity perspective, which is how the program cost-effectiveness is determined. However, from an energy perspective, it is among the most expensive resources evaluated in the IRP.

Because of the results of the analysis, Idaho Power filed with the IPUC Case No. IPC-E-10-46 asking for significant changes to the Irrigation Peak Rewards program, including a method of paying participants with a variable component based on the level of use. The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period. Demand response, because of its limited availability, cannot continually satisfy all of the load and resource balance deficits throughout the IRP planning period; rather, the goal of setting the appropriate levels of demand response is to delay the addition of new supply-side resources.

Table 4.5 presents a summary of the cost-effectiveness of the demand response programs. The Irrigation Peak Rewards program is forecast to provide 260 MW of peak-hour load reduction. The A/C Cool Credit program is expected to have 40,000 residential customer participants and is expected to provide a peak-hour load reduction of 51 MW. The FlexPeak Management program is forecast to provide 40 MW of reduction and is controlled by EnerNoc, Inc., a third-party program administrator.

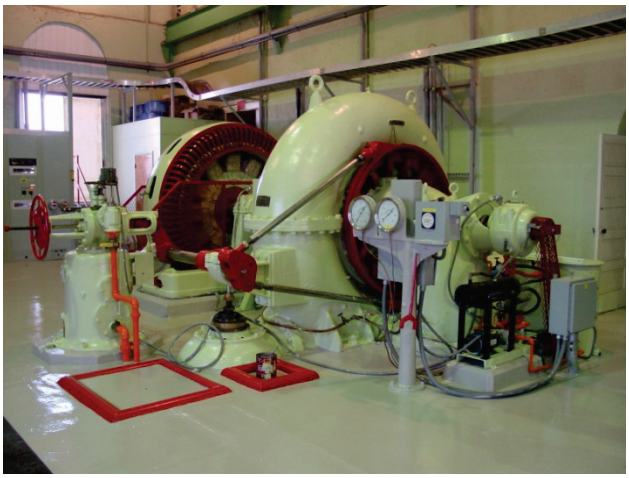
**Table 4.5 Demand response cost-effectiveness summary**

| | 2030 Load Impact (MW) | Resource Costs (20-Year NPV) | Avoided Energy Costs (20-Year NPV) | Total Resource Cost: Benefit/Cost Ratio | Total Resource Cost: Levelized Costs ($/kW) |
|---|---|---|---|---|---|
| Commercial/Industrial | 40 | $29,797,258 | $46,640,850 | 1.6 | $65 |
| Irrigation | 260 | $122,250,426 | $238,224,468 | 2.0 | $45 |
| Residential | 51 | $25,242,292 | $52,905,340 | 2.1 | $46 |
| **Total/Summary** | **351** | **$177,289,977** | **$337,770,659** | **1.9** | **$48** |

Across the demand response portfolio, the value of reduced demand compared with building a supply-side capacity resource is nearly twice the value of the cost to run the programs. The benefit/cost ratio is 1.9 with a levelized cost of $48 per kW. Detailed annual forecast costs and benefits of demand response resources are presented in *Appendix C–Technical Appendix*.

# 5. SUPPLY-SIDE RESOURCES

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. The company has done that; today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources considered when Idaho Power developed the resource portfolios for the 2011 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.



A vintage generator still in operation at Idaho Power's Thousand Springs power plant.

## Renewable Resources

Renewable resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. In the 2011 IRP, renewable resources were included in all portfolios analyzed to meet proposed federal RES legislation. Renewable resources are discussed in general terms in the following sections.

### *Geothermal*

Potential commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary-cycle technologies. Based on exploration to date in southern Idaho, binary-cycle geothermal development is more likely than flashed steam within Idaho Power's service area. Most optimal locations for potential geothermal development are believed to be in the southeastern part of the state. However, the potential for geothermal generation in southern Idaho is somewhat uncertain. The time required to discover and prove geothermal resource sites is highly variable and can take years, or even decades.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300ºFahrenheit (F) or greater. Binary-cycle technology is used for lower-temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid

**Highlights**

- The cost of solar PV technology has continued to decline as technology improvements have improved efficiency and the supply of PV panels has increased. The 2011 IRP cost estimate for solar PV is $3,750 per kW.
- Idaho Power continues the permitting process for the Boardman to Hemingway and Gateway West transmission projects that will provide additional access to the regional electricity market.
- The 2011 IRP assumes advanced nuclear, IGCC, and carbon capture and sequestration technologies will not be available until the 2020s.

(the secondary fluid). The secondary fluid is vaporized and used to drive a turbine/generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters used for binary-cycle geothermal generation in the IRP are based on data from independent geothermal developers and cost information from a PPA Idaho Power has with U.S. Geothermal, Inc., for the generation from the Neal Hot Springs geothermal project located in eastern Oregon. The capital cost estimate used in the IRP for geothermal resources is $6,250 per kW, and the 30-year levelized cost of production is $117 per MWh.

## Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 MW each. The majority of potential wind sites in southern Idaho lie between the south central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles-per-hour are prime locations for wind development.

The Pacific Northwest and Intermountain regions are good areas for the development of wind resources, as evidenced by the number of existing and planned projects. However, wind resources present challenges for utilities due to the variable and intermittent nature of the generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2011 IRP, Idaho Power used an annual average capacity factor of 32 percent and a capacity factor of 5 percent for peak-hour planning.

Cost estimates and operating parameters used for wind generation in the IRP are based on data from independent developers and cost information obtained from the 2012 Wind RFP issued by Idaho Power. The 2012 Wind RFP did not ultimately result in the identification of a successful bidder due in large part to a recent surge in PURPA wind development in southern Idaho. The capital cost estimate used in the IRP for wind resources is $1,450 per kW, and the 30-year levelized cost of production is $89 per MWh, which includes a cost for wind integration. In 2008, the IPUC approved a settlement stipulation establishing a wind integration cost of $6.50 per MWh, which was less than Idaho Power's estimated cost to integrate wind.

## Hydroelectric

Hydroelectric power is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. Idaho Power believes the development of new large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydroelectric sites have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PURPA contracts with Idaho Power.

### Small Hydroelectric

Because small hydroelectric, such as run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydroelectric, the IRPAC expressed an interest in evaluating small hydroelectric in the 2011 IRP. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in the state of Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow

opportunities. The capital cost estimate used in the IRP for small hydroelectric resources is $4,000 per kW and the 30-year levelized cost of production is $144 per MWh.

### Pumped Storage

Pumped storage is a type of hydroelectric power generation used to change the "shape" or timing when electricity is produced. The technology stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times in order to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change. The capital cost estimate used in the IRP for pumped storage is $5,000 per kW, and the 30-year levelized cost of production is $155 per MWh.

## *Solar*

The primary types of solar technology are solar thermal and PV. Solar thermal technologies use mirrors to focus the sun's rays onto a central receiver or a "collector" to collect thermal energy that can be used to make steam and power a turbine that creates electricity. PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons and creates an electric current.

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods, generally for 3–7 hours. PV technology uses panels that convert the sun's rays directly to electricity. Even on cloudy days, a PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per $m^2$ per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the Desert Southwest has the highest solar potential in the United States.

There are several types of solar thermal technologies, including power tower, parabolic dish engine, and parabolic trough. In designing initial portfolios that included solar resources, Idaho Power chose the power tower technology because of its lower overall cost. The company also selected the solar PV technology because of the increased availability of PV panels and the recent declining cost trend.

### Power Tower

Power tower technology uses thousands of small, flat, two-axis mirrors, called heliostats, to reflect the sun's rays onto a boiler at the top of a central tower. The concentrated sunlight strikes the boiler's pipes, heating the water inside to 1,000°F. The high-temperature steam is then piped from the boiler to a turbine where electricity is generated. The power tower technology can use molten salt as a storage medium to store energy. It has a storage time of 6.9 hours that has been used to evaluate this resource

in the IRP. The capital cost estimate used in the IRP for the power tower technology with storage is $3,220 per kW, and the 30-year levelized cost of production is $109 per MWh.

### Photovoltaic

Solar PV panels absorb solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons, creating an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy is passed through an inverter, converting it to alternating current (AC) that can then be used on-site or sent to the grid.

Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPS requirements, have made PV resources more cost competitive with other renewable and conventional generating technologies. The capital cost estimate used in the IRP for PV resources is $3,750 per kW, and the 30-year levelized cost of production, based on a 17-percent annual capacity factor, is $150 per MWh. Idaho Power will continue to closely follow the decreasing price trend of solar PV as this technology continues to become more cost competitive with more traditional resource alternatives.

## Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine to generate electricity. CCCTs are typically used for baseload energy, while less-efficient SCCTs are used to generate electricity during peak load periods. Additional details on the characteristics of both types of natural gas resources are presented in the following sections.

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2011 IRP assumes new natural gas resources would require building additional pipeline capacity. This additional cost is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

### *Combined-Cycle Combustion Turbines*

CCCT plants have been the preferred choice for new commercial power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits fewer emissions when compared to coal, thus requiring fewer pollution controls.

A traditional CCCT plant consists of a gas turbine/generator equipped with a heat recovery steam generator (HRSG) to capture waste heat from the turbine exhaust. The HRSG uses waste heat from the combustion turbine to drive a steam-turbine generator to produce additional electricity. In a CCCT plant, heat that would otherwise be wasted is used to produce additional power beyond that typically produced by an SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined-cycle units by adding an HRSG.

Several CCCT plants, including Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

The capital cost estimate used in the IRP for CCCT resources is $1,120 per kW, and the 30-year levelized cost of production at a 65-percent annual capacity factor is $108 per MWh with the carbon adder and $98 per MWh without the adder. If a CCCT were run at a 90-percent annual capacity factor, the 30-year levelized cost would be $100 per MWh with the carbon adder and $90 per MWh without the adder.

## Simple-Cycle Combustion Turbines

Simple-cycle, natural gas-turbine technology involves pressurizing air that then heats by burning gas in fuel combustors. The hot, pressurized air expands through the blades of the turbine that connects by a shaft to the electric generator. Designs range from larger, industrial machines at 80–200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are not typically economical to operate other than to meet peak-hour load requirements.

Several natural gas-fired SCCTs have been brought on line in the region in recent years, primarily in response to the regional energy crisis of 2000–2001. High electricity prices combined with persistent drought conditions during 2000–2001, as well as continued summertime peak load growth created interest in generation resources with low capital costs and relatively short construction lead times.

Idaho Power currently has approximately 430 MW of SCCT capacity. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been built to meet peak load during critical high-demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest.

The 2011 IRP evaluated two different SCCT technologies, 1) a 47-MW small, aeroderivative unit and 2) a 170-MW industrial-frame unit. The capital cost estimate used in the IRP for the small, aeroderivative unit is $1,050 per kW, and an industrial-frame unit is $610 per kW. Because of the higher efficiency of the aeroderivative unit, it is assumed to have an annual capacity factor of 8 percent, while the industrial-frame unit is expected to have an annual capacity factor of only 6 percent.

Based on these annual capacity factors, the 30-year levelized cost of production (including the estimated cost of carbon emissions) is $319 per MWh for the small, aeroderivative unit and $316 per MWh for the industrial-frame unit. These levelized costs are nearly identical as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If an SCCT resource is identified in the IRP preferred portfolio, Idaho Power would evaluate these two technologies in greater detail prior to issuing an RFP in order to determine which technology provided the greatest benefit.

## Combined Heat and Power

Combined Heat and Power (CHP), or cogeneration, typically refers to simultaneous production of both electricity and useful heat from a single plant. CHP plants are typically located at, or near, commercial or industrial facilities capable of using the heat generated in the process. These facilities are sometimes referred to as a steam host. Generation technologies frequently used in CHP projects are gas turbines or engines with a heat-recovery unit.

The main advantage of CHP is that higher overall efficiencies can be obtained because the steam host is able to use a large portion of the heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, building additional transmission capacity can also often be avoided. In addition, reduced costs for the steam host provides a competitive advantage that will ultimately help the local economy.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the

project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different.

Although a CHP resource was not identified in the 2011 IRP preferred portfolio, Idaho Power is committed to continuing its investigation into CHP opportunities on a case-by-case basis. While the actual cost of a CHP resource may be less as previous discussed, the capital-cost estimate used in the IRP for CHP is $1,860 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 93 percent, is $111 per MWh, which also accounts for the assumed cost of carbon emissions.

Several IRPAC members noted that, when considering the total societal benefit of a project, using CHP projects to produce both electrical energy and useful heat results in an overall reduction of $CO_2$ and other emissions. The 2011 IRP assumes emissions costs are associated with a new facility because it would be owned and operated by Idaho Power. For the next IRP, Idaho Power plans to raise this issue with the IRPAC early in the process to determine if it would be appropriate to remove some or all of the emissions cost adders from CHP resources.

Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in October 2009 with the IOER and the Amalgamated Sugar Company (TASCO), one of Idaho Power's large industrial customers. The agreement establishes the framework for a feasibility study for a CHP resource as large as 100 MW to be performed at TASCO's Nampa, Idaho facility. The TASCO facility currently uses coal to produce steam, and switching to natural gas as a fuel source would result in reduced $CO_2$ emissions and improve air quality in the Treasure Valley. The results of the first phase of the study looks promising, and a second, more detailed study is expected to be completed by June 2011.

## Distributed Generation

In September 2010, Idaho Power received a proposal to implement and manage a distributed generation program that would use existing emergency generators owned by some of Idaho Power's largest customers. The proposal included a load-shed option and a grid-synchronized option. Both options were analyzed as part of the 2011 IRP.

In the resource stack cost analysis, the load-shed option had a cost of almost $8,500 per MWh, and the grid-synchronized option was over $10,000 per MWh. These costs are high due to the limited amount of generation these programs are expected to produce and, therefore, must also be analyzed to determine the value they provide when included with Idaho Power's other generation resources.

The load-shed option was evaluated for the first 10-year period in the IRP (2011–2020). In portfolio 1-9, this program was assumed to be available beginning in 2012. To ascertain the marginal value of the program, the other resources in portfolio 1-9 were identical to portfolio 1-4 which contained simple-cycle peaking resources. It was not necessary to evaluate the grid synchronization option because of the higher costs associated with the program.

The results of the analysis of the load-shed option showed that the distributed generation portfolio (portfolio 1-9) had a higher NPV cost of $5.6 million for the 10-year period compared to the simple-cycle portfolio under the base case assumptions used in the IRP. Idaho Power will continue to evaluate distributed generation programs in the future; however, at this time the company does not intend to pursue the implementation of a distributed generation program.

## Conventional Coal Resources

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. Traditional pulverized-coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,100 MW of coal resources that are jointly owned with other utility partners who operate the facilities. Idaho Power's coal resources are located in the neighboring states of Wyoming (Jim Bridger), Nevada (Valmy), and Oregon (Boardman).

A pulverized-coal facility uses coal ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine and generator. Emissions controls at coal plants have become increasingly important in recent years, and many units in the region have been upgraded to include the latest scrubber and low-$NO_x$ burner technology to help reduce harmful emissions and particulates. Coal has the highest ratio of carbon-to-hydrogen of all fossil fuels, and significant research is being done to develop carbon capture and sequestration technology that can be economically added to existing coal facilities.

Though coal-fired power plants require significant capital commitments to develop, coal resources take advantage of a low-cost fuel and provide reliable and dispatchable energy. Coal supplies are abundant in the Intermountain Region and are sufficient to fuel Idaho Power's existing plants for many years to come.

In 2007, Idaho Power decided not to pursue the development of a coal-fired resource identified in the 2006 IRP. In addition to considering the cost of a coal-based resource, the company considered the uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly owned facilities as well as monitoring the development of clean coal technologies. However, due to the uncertainty regarding future carbon regulations, conventional coal resources were not included in any of the portfolios analyzed in the 2011 IRP.

## Integrated Gasification Combined-Cycle and Carbon Sequestration

IGCC is an evolving coal-based technology designed to substantially reduce $CO_2$ emissions. If the cost of $CO_2$ emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of the country's coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow $CO_2$ to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or "syngas" that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

The addition of $CO_2$-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. $CO_2$ has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of $CO_2$ produced would require the development of underground sequestration methods.

Carbon sequestration involves taking captured $CO_2$ and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent.

Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. For the 2011 IRP, Idaho Power is assuming this technology will not be available until the year 2024. The capital cost estimate used in the IRP for IGCC with carbon sequestration is $3,776 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $191 per MWh.

## Advanced Nuclear

The nuclear power industry has been working to develop and improve reactor technology for some time. In Idaho Power's 2006 IRP, an advanced nuclear resource was included in the preferred portfolio in the year 2023, based on the assumption that an advanced-design reactor would be built on the Idaho National Laboratory (INL) site in eastern Idaho. Updated information from INL suggests the plant, if built, would be located near an industrial manufacturing hub with a high baseload energy need, most likely outside of Idaho. High capital cost coupled with a great amount of uncertainty in the actual cost of building an advanced reactor prevented a nuclear resource from being included in the preferred portfolio in Idaho Power's 2011 IRP.

The recent earthquake and tsunami in Japan, and the impact on the nuclear reactors located there, have created a global concern over the safety of nuclear power generation. While there will undoubtedly be new design and safety measures implemented, it is difficult to know the impact this disaster will have on the future of nuclear power generation.

For the 2011 IRP, an advanced nuclear resource was assumed to not be commercially available until 2023. Additionally, if the IRP identified a nuclear resource in the preferred portfolio, Idaho Power would plan to partner with other utilities in a plant built around a smaller modular design with Idaho Power's share being approximately 250 MW. Similar to the 2009 IRP, the capital cost of an advanced nuclear reactor is considerable, and the IRP risk analysis continues to account for a great amount of uncertainty in the actual cost. The capital cost estimate used in the IRP for an advanced nuclear resource is $3,820 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $229 per MWh.

## Transmission

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of FERC, and under its Open Access Transmission Tariff (OATT), is required to expand its transmission system to provide requested firm transmission service and to construct and place in service sufficient capacity to reliably deliver electrical resources to customers.



The Hemingway Substation is located in southwestern Idaho.

Idaho Power's transmission system is currently limited in its ability to transmit energy from markets or new resources to load centers in Idaho and eastern Oregon. Because of the need to access markets, improve reliability, integrate new resources, and facilitate renewable resource development in the region, Idaho Power has considered two major transmission projects for a number of years ; they are both included in the 2011 IRP—Boardman to Hemingway and Gateway West. These two projects were

also evaluated in Idaho Power's 2009 IRP and sub-regional and regional transmission planning processes.

For the 2011 IRP, one portfolio requiring Boardman to Hemingway capacity was analyzed for the first 10 years of the planning horizon (2011–2020). In the second 10 years (2021–2030), one portfolio included additional capacity to the Pacific Northwest and another included additional capacity to the east side of Idaho Power's system. These two portfolios were designed to evaluate the cost of market purchases on either side of Idaho Power's system. The Gateway West project was included in portfolios for the second 10-year period when current constraints required the addition of new transmission capacity for resources to be added in southern Idaho, east of the Treasure Valley load center. However, the amount of Gateway West capacity is different in each portfolio, depending on other included resources.

Idaho Power faces increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including Bonneville Power Administration's (BPA) southern Idaho contracts. The development of wind and other renewable resources in response to state RPS requirements is anticipated to further increase the demand for transmission capacity between the Intermountain Region and the Pacific Northwest.

The concept of "right sizing" a transmission project, or building the project to an appropriate potential, has been carefully considered. There are many factors involved in the decision process prior to proposing a solution to the identified requirements, including planning horizon perspectives. The Boardman to Hemingway and Gateway West projects have been designed to appropriately size the transmission line and allow phased construction to meet Idaho Power's needs as well as satisfy requests from third parties for capacity on the same path. A more detailed description of each project is presented in the following sections.

## Boardman to Hemingway

The proposed Boardman to Hemingway project involves constructing, operating, and maintaining a new, single-circuit, 500-kV transmission line approximately 300 miles in length. The proposed route is between northeast Oregon and southwest Idaho. The new line will provide many benefits, including 1) greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area; 2) improved system reliability and reduced capacity limitations on the Pacific Northwest's transmission system as demand for energy continues to grow; and 3) assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon.

The project is expected to be completed and in service in 2016. The overhead, 500-kV, high-voltage transmission line will connect a future substation near Boardman, Oregon, to the Hemingway Substation, located near Melba, Idaho. The proposed transmission line will connect with other transmission lines on either end of the project to convey electricity on a regional scale. Figure 5.1 shows a map of the region with the proposed route of the new line.

In the 2006 IRP, Idaho Power anticipated the new line would interconnect at the McNary substation; however, there is insufficient room at the existing McNary substation for major transmission expansion options. A number of utilities are also considering a northeast Oregon (NEO) substation to provide future interconnectivity of regional projects. The exact location and in-service date for the NEO substation is unknown at this time. The proposed Boardman to Hemingway project is not dependent on completion of the NEO substation project or any of the other transmission proposals to satisfy Idaho Power's load-serving need or other existing service requests.

The Boardman to Hemingway project will use a bundled-conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the Western Electricity

Coordinating Council's (WECC) rating process, the initial implementation of the Boardman to Hemingway project is likely to result in an Idaho to Northwest path increase of 1,300 MW from east-to-west (exports into the Pacific Northwest), on completion of the Gateway West Project and about 850 MW from west-to-east (imports into Idaho Power's balancing authority area). The ratings are subject to technical peer review and will be revisited as other regional projects continue to develop. As additional projects reinforce the transmission network, additional capacity rating increases of the Boardman to Hemingway project may occur.

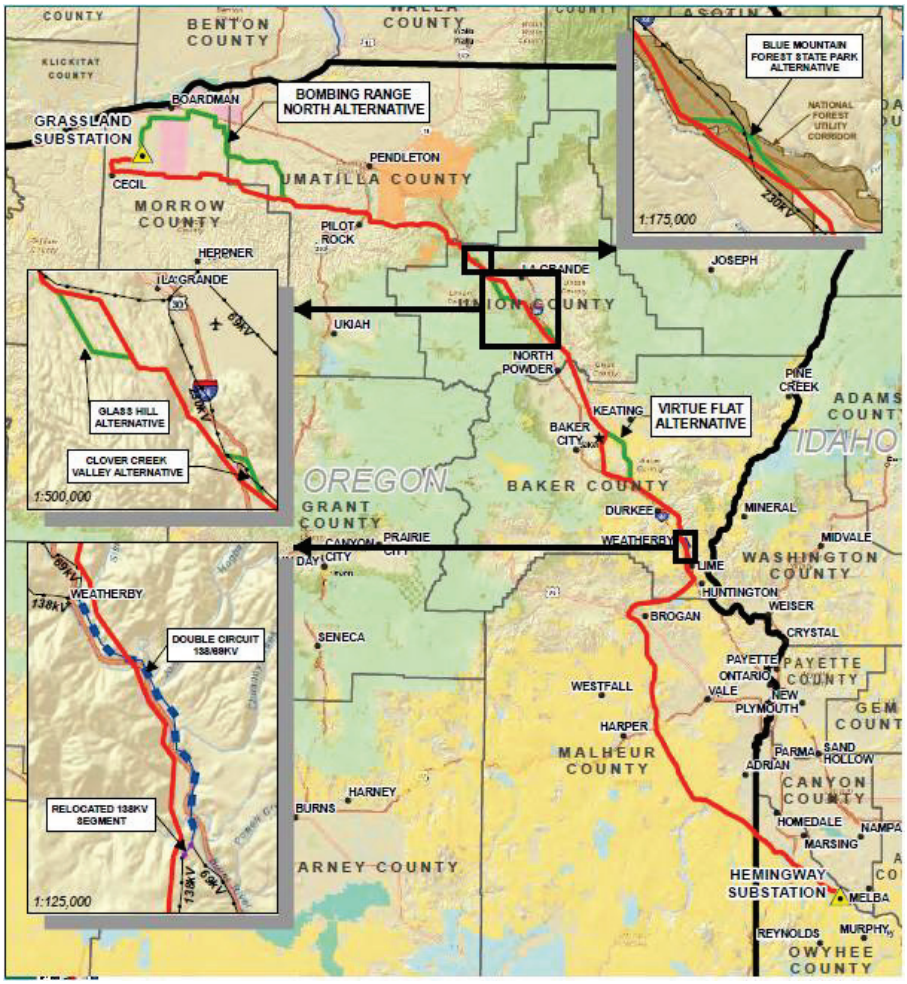



**Figure 5.1 Boardman to Hemingway line project map**

The Boardman to Hemingway project capacity or sizing considerations and termination locations were developed in the public review process conducted by the Northern Tier Transmission Group (NTTG) and the regional planning phase of the project's WECC rating process. During the review process, it was determined a 230-kV project was too small to meet Idaho Power's overall resource planning needs and would underuse a substantial and valuable transmission corridor. A project operating voltage of 500 kV was selected to match the existing Pacific Northwest transmission grid. A 765-kV line designed with a thermal capacity of approximately 7,000 MW would not achieve a greater rating than the proposed 500-kV project, but would be nearly twice the cost. Because of the higher cost, no further consideration was given to a 765-kV transmission line.

Idaho Power received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho–Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. In the 2006 IRP, Idaho Power identified a need for 225 MW of energy imports from the

Pacific Northwest to Idaho Power's system. The 2009 IRP analyzed various levels of imports, and the final preferred portfolio included 425 MW of capacity on Boardman to Hemingway. The updated analysis in the 2011 IRP indicates 450 MW of capacity is needed on the line to meet Idaho Power's needs.

The Boardman to Hemingway project is important for the development of renewable resources as northeast Oregon has the potential for both wind and geothermal resource development. In 2007, Idaho Power and Horizon Wind Energy developed the first phase of the 101-MW Elkhorn Valley Wind Project in Union County, Oregon, and Idaho Power purchases the output from the facility under a long-term PPA. Firm transmission capacity existed for the first 66 MW of the wind project. The remaining 34 MW of output from the Elkhorn project may face curtailment during times of transmission congestion. Further renewable resource development in northeast Oregon will require additional transmission resources.

Idaho Power is committed to working with communities to identify proposed and alternate routes for the Boardman to Hemingway project. The initial process of identifying a route began in late 2007 when Idaho Power submitted documents to the Bureau of Land Management (BLM), the US Forest Service (USFS), and the Oregon Department of Energy (ODOE).

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power conduct more extensive outreach as part of identifying a route for the new transmission line. In response, Idaho Power initiated the Community Advisory Process (CAP) to engage communities from Boardman, Oregon to Melba, Idaho in siting the Boardman to Hemingway project. The CAP enlisted project advisory team members in five geographic regions within the project area. The members were familiar with the local areas and issues and understand the topography, recreation, wildlife, and view-shed issues; they collaboratively worked with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009. The CAP process was completed in July 2010; however, Idaho Power continues to meet with landowners and work with local communities as the project moves forward through the local-, state-, and federal-review processes.

Additional information about the Boardman to Hemingway project can be found at http://www.boardmantohemingway.com.

### Updated Cost Estimate

The 2011 IRP contains an updated cost estimate for the Boardman to Hemingway line. Idaho Power worked with two primary contractors, Pike Energy Solutions and Tetra Tech EC, Inc., to prepare the updated estimate. The new estimate also updates Idaho Power's internal costs in addition to the estimates provided by Pike Energy Solutions and Tetra Tech EC, Inc. As a result of the analysis, the updated cost estimate increased from the 2009 IRP estimate of $634 million to $820 million.

Pike Energy Solutions provided the line and stations engineering and construction costs for the project and Tetra Tech EC, Inc. provided the environmental permitting and mitigation cost estimates for the project. In addition, Idaho Power included estimated costs for internal labor hours, right-of-way overheads, property taxes, allowance for funds used during construction (AFUDC), and contingency estimates in support of the entire project. The detailed estimate included in *Appendix C–Technical Appendix* shows the combination of third-party cost estimates provided by Pike Engineering Solutions, Tetra Tech EC, Inc., and estimates for Idaho Power's internal costs.

The updated costs show significant increases in material prices and construction costs, primarily due to increased material and labor prices and line-route modifications to move the routing away from agricultural land. The AFUDC estimate has also increased due to a projected rate increase of 5 percent

to 7.5 percent. Property taxes were not included in the 2009 IRP estimate and have now been included in the updated estimate.

For the 2011 IRP, the contingency estimate has been reduced from 30 percent to 20 percent because of the higher level of project definition and detail and increased level of confidence in the line location and the engineering and design aspects of the project. The contingency estimate is consistent with Idaho Power's estimating practices and industry standards for contingency estimating. The updated cost estimate does not include any estimated impacts of future inflation that may occur following the date of the estimate; however, the IRP analysis assumes a general inflation rate of 3 percent, which is applied consistently to all resources.

The results of the 2011 IRP analysis indicate the Boardman to Hemingway transmission line will be a well-used resource that benefits Idaho Power's retail and transmission customers, as well as consumers and generators in both the Pacific Northwest and the Intermountain Region. The capital cost of the Boardman to Hemingway project, as measured on a dollars-per-kW-of-capacity basis, has the lowest capital cost of any supply-side resource alternative.

## Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,150 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming to the Hemingway substation near Melba, Idaho. The project is being designed so multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service in the 2015–2017 timeframe. Numerous routes under consideration are shown in Figure 5.2.

The two transmission projects, Boardman to Hemingway and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah through Rocky Mountain Power's Gateway South project.

Significant renewable resource development potential exists in Wyoming and southern and eastern Idaho. Idaho Power's transmission system is currently limited in its ability to transmit energy from new resources from the east to the major load centers in Idaho. Gateway West will provide new transmission capacity to integrate and deliver any such selected resources in addition to meeting third-party transmission service requests under Idaho Power's OATT.

The Gateway West project is currently undergoing an extensive and ongoing public involvement process to identify proposed and alternate routes. The outreach work is being done in conjunction with the NEPA process related to environmental studies, as well as local jurisdictions for permitting. The project as proposed in Idaho includes two separate 500-kV lines between the Populus substation in southeast Idaho, and the Hemingway Substation in southwestern Idaho, with connection in central Idaho between the Midpoint Substation and the proposed Cedar Hill substation.

Phase 1 is expected to provide between 700 MW and 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Similarly, the project extending east from the Populus substation into eastern Wyoming is expected to provide Phase 1 capacity improvements of approximately 700 to 1,500 MW, with the full build-out capacity increase being greater than 2,000 MW east of Jim Bridger and 3,000 MW between the Populus substation and Jim Bridger.

The project cost and capacity is expected to be shared between Idaho Power and Rocky Mountain Power based on load service requirements and third-party transmission service request obligations. Additional information about the Gateway West project can be found at www.gatewaywestproject.com.

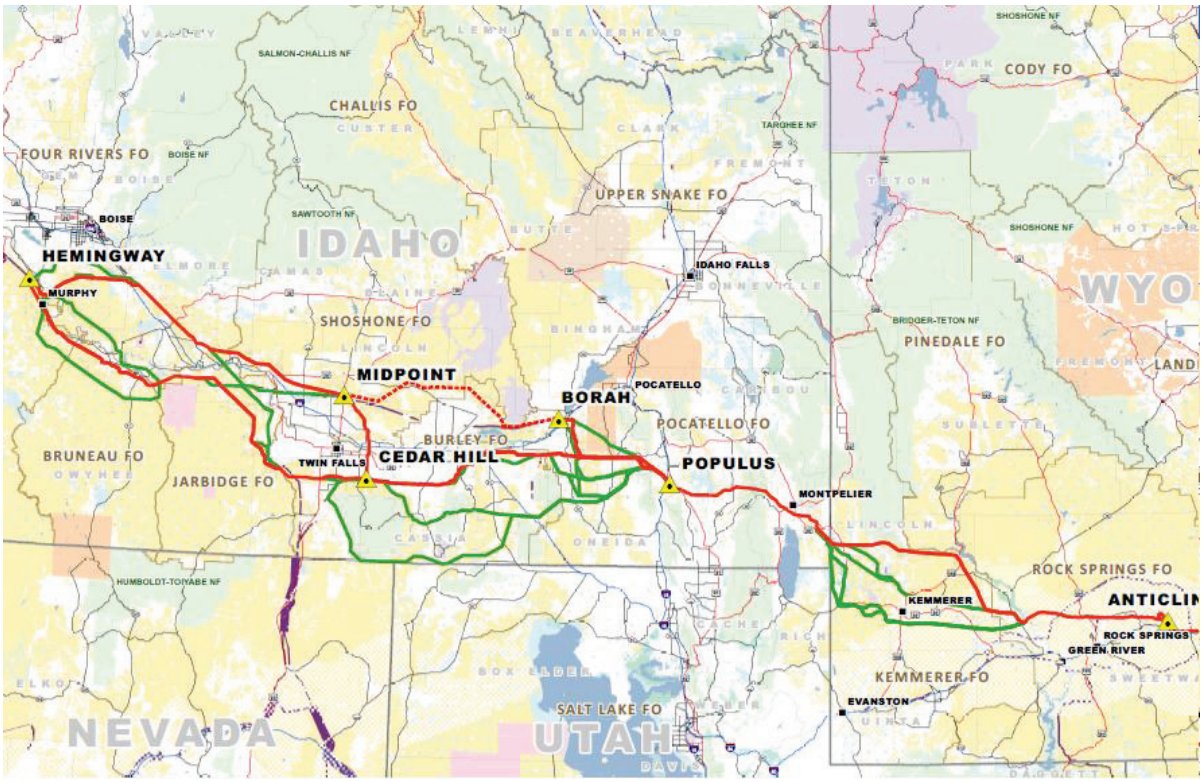



**Figure 5.2 Gateway West line project map**

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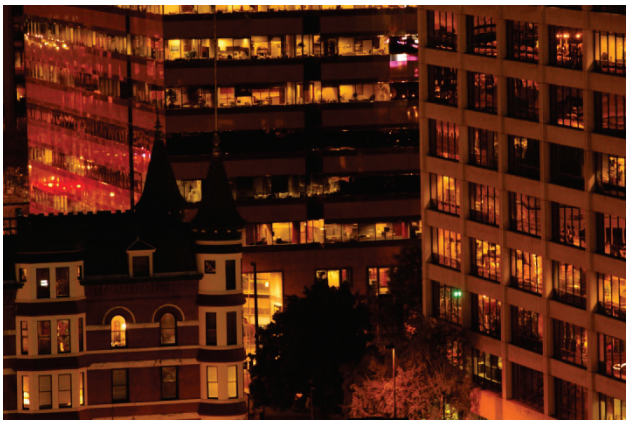
# 6. Planning Period Forecasts

The IRP process requires Idaho Power prepare numerous forecasts that can be grouped into four main categories, 1) load forecasts, 2) a generation forecast, 3) fuel price forecasts, and 4) financial assumptions. The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2011 IRP.



Forecasting load growth is essential for Idaho Power to meet the future needs of customers.

## Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning in the months of June, July, and August. For a number of years, the growth rate of peak-hour load has exceeded the growth of average monthly load. However, both measures are important in planning for future resources and are part of the load forecast prepared for the 2011 IRP.

The expected-case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not precisely follow the path suggested by the expected-case forecast. Therefore, Idaho Power prepared four additional load forecasts, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather.

The high-growth and low-growth scenarios provide boundaries on each side of the expected-case forecast and historical load variability potential on future load due to demographic, economic, and other non-weather-related influences. The 70$^{th}$ percentile and 90$^{th}$ percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics,

**Highlights**

- Idaho Power's summer peak load record of 3,214 MW was set in June 2008.
- Idaho Power's customers set a new winter system peak record of 2,528 MW on December 10, 2009, during several days of below-normal temperatures.
- The 2011 IRP assumes an expected-case carbon adder of $20 per ton starting in 2015.
- For the first time, the IRP load forecast includes the expected impact of electric vehicles.
- The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period.

Inc.'s July 2010 macroeconomic forecast strongly influenced the 2011 IRP load forecast. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., are also used in developing the 2011 IRP load forecast. The forecast of the number of households, employment projections, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

## Weather Impacts

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50 percent chance that loads will be higher or lower than the expected-case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios are analyzed to address load variability due to weather. Idaho Power has generated load forecasts for 70$^{th}$ percentile and 90$^{th}$ percentile weather. Seventieth percentile weather means that, in 7 out of 10 years, load is expected to be less than forecast and, in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1 in 10 likelihood that the load will be greater than the forecast.

Idaho Power's system load is highly dependent on weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand how the probabilities associated with the load forecasts apply to any given month. For example, an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast over the long-term time horizon.

## Economic Impacts

The national recession that began in 2008 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the recession resulted in a collapse in new residential customer growth from the addition of 15,000 new residential customers each year prior to the recession, to approximately 2,000 new customers added each year at the present. Commercial and industrial customer energy use contracted and overall system energy use declined by 3.5 percent in 2009, followed by a 1.2 percent decline in 2010—the first time overall energy use has declined since the energy crisis of 2001.

Increased population in Idaho Power's service area—due to migration to Idaho from other states—is expected to continue throughout the planning period and has been included in the load forecast model. Idaho Power also continues to receive requests from prospective new large-load customers attracted to southern Idaho due to the relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual, county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with estimated consumption per household and considerations made for DSM measures, results in a 1.5-percent residential load growth rate.

The number of residential customers in Idaho Power's service area is expected to increase 1.4 percent annually from approximately 409,000 at the end of 2010 to nearly 536,000 by the end of the planning period in 2030.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A–Sales and Load Forecast*. For example, the expected annual average system load growth of 1.4 percent (over the period 2011 through 2030) is comprised of residential load growth of 1.5 percent, commercial load growth of 1.3 percent, irrigation load growth of 0.3 percent, industrial load growth of 1.7 percent, and additional firm load growth of 2.0 percent.

The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow significantly. In addition, the significant increase in assumed DSM combined with retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified in the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP) and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario in the 2009 IRP, Idaho Power curtailed coal resources to comply with target emissions levels.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service-area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power customers. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to slowly recover; by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004). The cost of carbon impact on the 2011 IRP load forecast was not material because of the cap-and-trade assumption used in the 2009 IRP, which was the basis for carbon costs in the 2011 IRP load forecast.
- In this year's forecast, an additional customer referred to as "Special" was included in the additional firm load category even though a long-term contract had not yet been fully executed.

At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough for it to be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

- There continues to be significant uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contact Idaho Power and express interest in locating production operations within Idaho Power's service area and the unknown magnitude of the energy and peak demand requirements. The current sales and load forecast reflects only those customers that have a high probability of locating in the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron, Inc.'s residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron, Inc.'s SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast compared to earlier forecasts (prior to 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand-lines to electrically operated pivots may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand-lines has triggered the substitution of labor with electrically operated pivots.

## Peak-Hour Load Forecast

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris historically) and the Raft River Rural Electric Cooperative wholesale agreement. Idaho Power uses the 95$^{th}$ percentile forecast as the basis for peak-hour planning in the IRP. The 95$^{th}$ percentile forecast is based on 95$^{th}$ percentile average peak-day temperatures to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record, 3,214 MW, was recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as air conditioning became standard in nearly all new residential home construction and new commercial buildings. The growth in peak demand slowed considerably in 2008 and 2009 due to a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also served to reduce peak demand. The 2011 IRP load forecast projects peak-hour load to grow by approximately 69 MW per year throughout the planning period.

The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance.

Figure 6.1 and Table 6.1 summarize three forecast outcomes of Idaho Power's estimate of annual system peak load considering median, 90th percentile, and 95th percentile weather impacts on the expected (median) peak forecast. The 95th percentile forecast uses the 95th percentile peak-day average temperature to determine monthly peak-hour demand. The planning criteria for determining the need for peak-hour capacity assumes the 95th percentile peak-day temperature conditions.

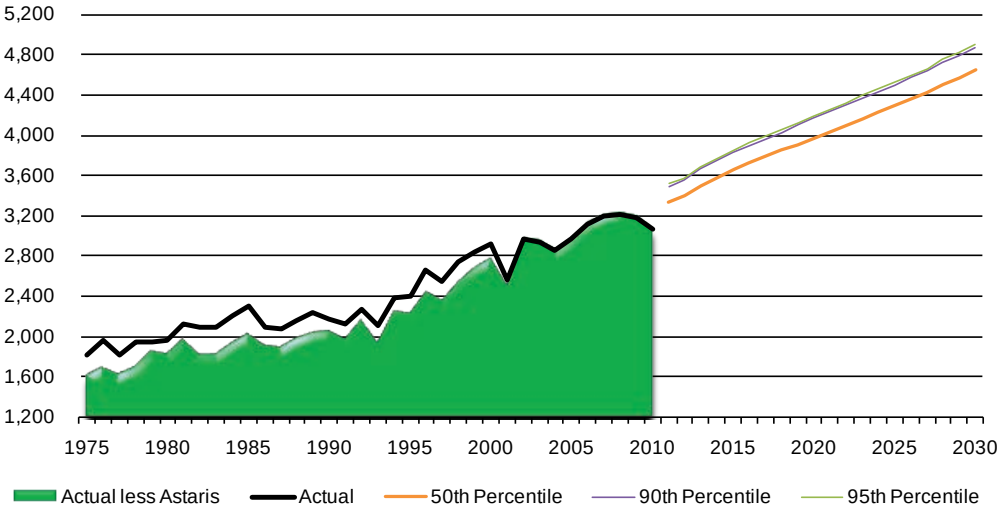



**Figure 6.1 Peak-hour load growth forecast (MW)**

**Table 6.1 Load forecast—peak-hour (MW)**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2010 (Actual) | 2,930 | 2,930 | 2,930 |
| 2011 | 3,334 | 3,494 | 3,515 |
| 2012 | 3,392 | 3,555 | 3,577 |
| 2013 | 3,496 | 3,662 | 3,684 |
| 2014 | 3,577 | 3,747 | 3,770 |
| 2015 | 3,657 | 3,831 | 3,854 |
| 2016 | 3,725 | 3,902 | 3,925 |
| 2017 | 3,787 | 3,967 | 3,991 |
| 2018 | 3,847 | 4,031 | 4,056 |
| 2019 | 3,911 | 4,098 | 4,123 |
| 2020 | 3,973 | 4,164 | 4,190 |
| 2021 | 4,034 | 4,229 | 4,254 |
| 2022 | 4,098 | 4,296 | 4,323 |
| 2023 | 4,165 | 4,367 | 4,394 |
| 2024 | 4,229 | 4,435 | 4,462 |
| 2025 | 4,291 | 4,501 | 4,529 |
| 2026 | 4,358 | 4,571 | 4,599 |
| 2027 | 4,419 | 4,635 | 4,664 |
| 2028 | 4,498 | 4,718 | 4,747 |
| 2029 | 4,569 | 4,792 | 4,822 |
| 2030 | 4,643 | 4,870 | 4,901 |
| **Growth Rate (2011–2030)** | **1.8%** | **1.8%** | **1.8%** |

The median or expected-case peak-hour load forecast predicts peak-hour load will grow from 3,334 MW in 2011 to 4,643 MW in 2030, an average annual compound growth rate of 1.8 percent. The projected average annual compound growth rate of the 95th percentile peak forecast is 1.8 percent. In the 95th percentile forecast, summer peak-hour load is expected to increase from 3,515 MW in 2011 to 4,901 MW in 2030. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on Thursday, December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to the variability of peak day temperatures in winter months, which is far greater than the variability of peak-day temperatures in summer months.

## Average-Energy Load Forecast

Potential monthly average energy use by customers in Idaho Power's service area is defined by a series of four load forecasts that reflect a range of load uncertainty resulting from differing economic growth and weather-related assumptions. Figure 6.2 and Table 6.2 show the results of the four forecasts used in the 2011 IRP to estimate the boundaries of annual system load growth over the planning period. There is approximately a 90-percent probability that Idaho Power's load growth will exceed the low-load growth forecast, a 50-percent probability of load growth exceeding the expected-case forecast, a 30-percent probability of load growth exceeding the 70th percentile forecast, and approximately a 10-percent probability that load growth will exceed the high-growth forecast. The projected 20-year average annual compound growth rate in the expected-load forecast is 1.4 percent.

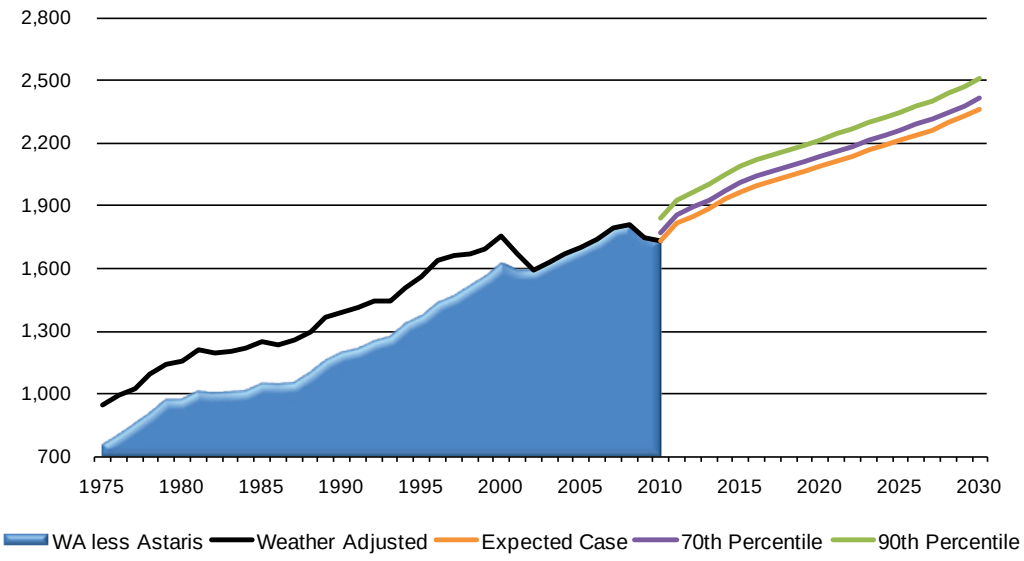



**Figure 6.2 Average monthly load growth forecast (aMW)**

**Table 6.2 Load forecast—average monthly energy (aMW)**

| Year | Median | 70th Percentile | Low | High |
|---|---|---|---|---|
| 2011 | 1,819 | 1,860 | 1,793 | 1,878 |
| 2012 | 1,852 | 1,893 | 1,814 | 1,936 |
| 2013 | 1,890 | 1,931 | 1,836 | 1,987 |
| 2014 | 1,932 | 1,974 | 1,866 | 2,043 |
| 2015 | 1,970 | 2,013 | 1,894 | 2,094 |
| 2016 | 1,998 | 2,042 | 1,913 | 2,135 |
| 2017 | 2,023 | 2,067 | 1,927 | 2,170 |
| 2018 | 2,045 | 2,090 | 1,940 | 2,203 |
| 2019 | 2,070 | 2,115 | 1,956 | 2,238 |
| 2020 | 2,090 | 2,136 | 1,970 | 2,271 |
| 2021 | 2,114 | 2,160 | 1,983 | 2,303 |
| 2022 | 2,139 | 2,186 | 2,000 | 2,338 |
| 2023 | 2,166 | 2,214 | 2,019 | 2,375 |
| 2024 | 2,189 | 2,237 | 2,036 | 2,410 |
| 2025 | 2,214 | 2,263 | 2,051 | 2,443 |
| 2026 | 2,241 | 2,290 | 2,070 | 2,480 |
| 2027 | 2,263 | 2,313 | 2,084 | 2,511 |
| 2028 | 2,298 | 2,349 | 2,113 | 2,560 |
| 2029 | 2,329 | 2,380 | 2,133 | 2,598 |
| 2030 | 2,362 | 2,414 | 2,158 | 2,642 |
| **Growth Rate (2011–2030)** | **1.4%** | **1.4%** | **1.0%** | **1.8%** |

Idaho Power uses the 70th percentile forecast as the basis for monthly average energy planning in the IRP. The 70th percentile forecast is based on 70th percentile weather to forecast average monthly load, 70th percentile water to forecast hydroelectric generation, and 95th percentile average peak-day temperature to forecast monthly peak-hour load.

## Additional Firm Load

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each individual, large-power customer. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement.

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River Rural Electric Cooperative. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special-contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered imminent. In this year's forecast, the company has included the anticipated load of an additional special-contract customer referred to as "Special" in the additional firm load category even though a long-term special contract had

not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special-contract customers and the new "Special" contract together make up the additional firm-load category.

### Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on the market demand for their products.

### Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

### Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010) Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013. In the time since the IRP load forecast was prepared, Hoku Materials has delayed the ramp up of its operations; however, this delay is not expected to impact the results of the 2011 IRP.

### "Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm-load category even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within the Idaho Power service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact.

## Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficits for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison.

Table 6.3 provides a summary of the six planning scenarios analyzed for the 2011 IRP, and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2011 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2011 IRP are consistent with the criteria used in the 2009 IRP.

**Table 6.3 Planning criteria for average monthly and peak-hour load**

| | |
|---|---|
| Average monthly load/energy (aMW) | 50th Percentile Water, 50th Percentile Average Load<br>**70th Percentile Water, 70th Percentile Average Load**<br>90th Percentile Water, 70th Percentile Average Load |
| Peak-hour load (MW) | 50th Percentile Water, 90th Percentile Peak-Hour Load<br>70th Percentile Water, 95th Percentile Peak-Hour Load<br>**90th Percentile Water, 95th Percentile Peak-Hour Load** |

The planning criteria used for energy or average load are 70th percentile water and 70th percentile average load. In addition, 50th percentile water and 50th percentile average load conditions are analyzed to represent a median condition, and 90th percentile water and 70th percentile average load are analyzed to examine the effects of low water conditions.

Peak-hour load planning criteria consist of 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system. A median condition of 50th percentile water and 50th percentile peak-hour load are also analyzed, as well as 70th percentile water and 95th percentile peak-hour load. Peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods. Surpluses and deficits for the average and peak-hour load scenarios can be found in *Appendix C–Technical Appendix*.

## Existing Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are shown in *Appendix C–Technical Appendix*. The following sections describe recent events or changes accounted for in the load and resource balance regarding Idaho Power's hydroelectric, thermal, and transmission resources.



Brownlee Dam is part of the Hells Canyon Complex.

### *Hydroelectric Resources*

For the 2011 IRP, Idaho Power continues the practice of using 70th percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means that basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90$^{th}$ percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ percentile means that streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse than median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50$^{th}$ percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

The 50$^{th}$, 70$^{th}$, and 90$^{th}$ percentile streamflow forecasts used in the IRP are derived from a streamflow planning model developed by the Idaho Department of Water Resources (IDWR). The IDWR streamflow planning model is used by Idaho Power to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The normalized model accounts for current hydroelectric conditions and historical hydroelectric development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70$^{th}$ percentile year in 2010 is identical to a 70$^{th}$ percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface water outflow from the river basin. The ESPA CAMP includes demand reduction and weather modification measures that will add new water to the basin water budget. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years is expected to resume and result in a return to declining basin outflows that is assumed to persist through at least the first 10 years of the 2011 IRP planning horizon. The declining basin outflows for this IRP are assumed to continue through 2023, with no further decline assumed for the remainder of the planning period through 2030. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on the projected date at which basin hydrologic conditions equilibrate as a standard part of forecasting hydroelectric generation for future IRPs.

River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies continue to support efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of the naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years.

Because worse-than-median water is assumed in the IRP, and the importance of July as a resource-constrained month, Idaho Power incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP and continues to incorporate the modified flow augmentation for the 2011 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on resource planning analyses, monthly average hydroelectric generation for July under the 70$^{th}$ percentile streamflow condition is projected to decline by approximately 115 aMW as a result of the water being shifted out of the month of July.

Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the Hells Canyon Complex as run-of-river plants. The generation model mathematically manages reservoir storage in the Hells Canyon Complex to meet the remaining system load, while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April–July runoff period. Figure 6.3 shows historical April–July Brownlee inflow as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability, but do include reductions related to declining base flows in the Snake River. As noted previously in this section of the report, these declines are assumed to equilibrate beyond 2023.

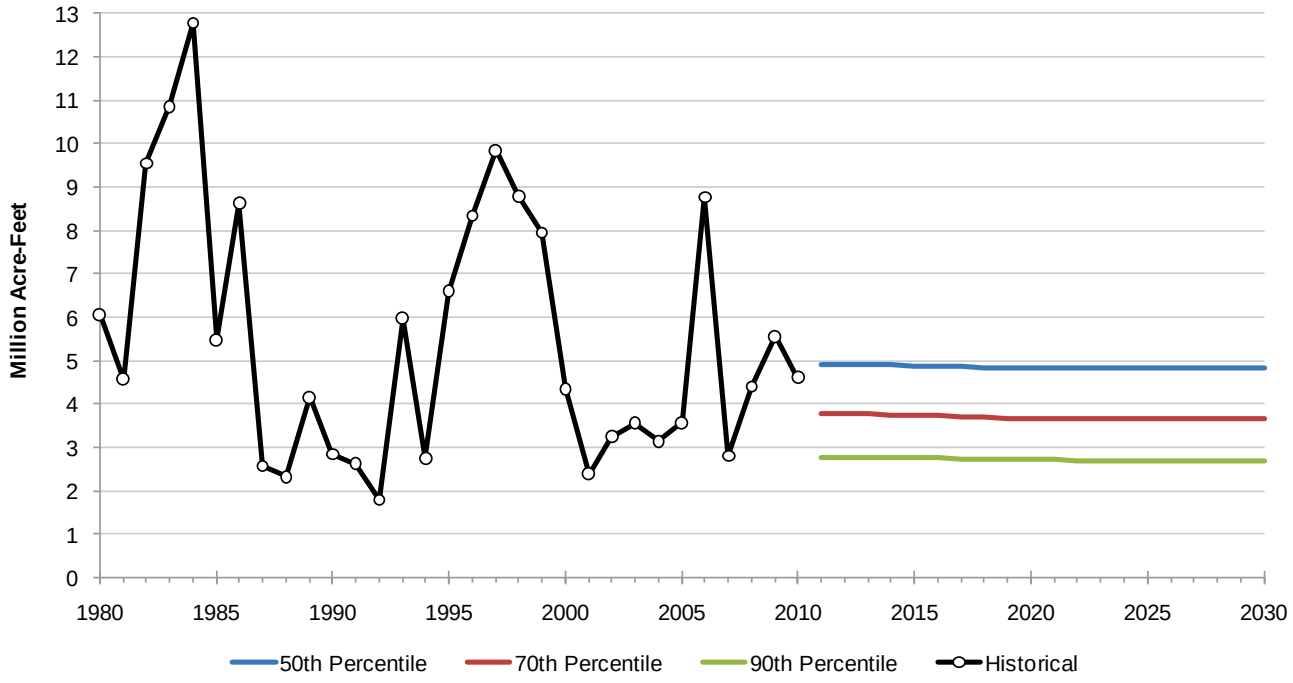



**Figure 6.3 Brownlee historical and forecast inflows**

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2011 IRP.

## Coal Resources

Idaho Power's coal-fired generating facilities have operated typically as fully dispatched baseload resources. Monthly average-energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low-market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the full-rated, maximum dependable

capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C–Technical Appendix*.

Plant modifications required to maintain compliance with air-quality standards are projected for the Boardman plant in 2011, 2014, and 2018, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The total effect of the air-quality modifications is a reduction in coal-fired generation of less than 1 percent.

The 2011 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, $SO_2$, and $NO_x$ emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

### Planned Upgrades at Jim Bridger

Turbine upgrades are continuing at the Jim Bridger plant with the replacement of the high-pressure/intermediate-pressure turbine on unit 2 planned for 2013. The high-pressure/intermediate-pressure turbine on unit 1 was upgraded in 2010. Upgrades of the high-pressure/intermediate-pressure turbines on units 3 and 4 and upgrades to the low-pressure turbines on all four units are currently being evaluated.

## Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs. These resources are typically operated during high-load occurrences in summer and winter months. The monthly average energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during the months of January, June, July, August, and December, producing on average approximately 230 aMW of gas-fired generation for the selected months. With respect to peak-hour output, the SCCTs are assumed capable of producing on-demand peak capacity of 416 MW. While this dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power is currently constructing the Langley Gulch CCCT, which is expected to be commercially available in July 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. For the 2011 IRP, Langley Gulch is forecast to contribute 251 aMW of energy per month, with on-demand peaking capacity of 300 MW.

## Transmission Resources

Transmission capacity limitations are an important factor in Idaho Power's ability to reliably serve peak-hour load. Idaho Power uses spot-market purchases when the company's generating resources and firm purchases are inadequate to meet peak-hour load requirements, and transmission capacity limitations restrict Idaho Power's ability to import additional energy.

From the load and generation forecasts, a determination can be made regarding the need for, and the magnitude of, the off-system market purchases needed to serve system load. The projected off-system market purchases are added to all other committed transmission obligations to determine if the additional imported energy will exceed the operational limits of the transmission system. The analysis assumes that all off-system market purchases will come from the Pacific Northwest.

During Idaho Power's peak-hour load periods, off-system market purchases from the east and south have historically proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power also experience a summer peak, and the weather conditions that drive Idaho Power's summer peak-hour load are often similar across the Intermountain Region. Therefore, Idaho Power does not typically rely on imports from the Intermountain Region for planning purposes.

For the 2011 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90th percentile streamflows, 70th percentile load, and 95th percentile peak-hour load. The 95th percentile peak-hour load planning criterion means that there is a 1-in-20 chance that Idaho Power will be required to initiate more drastic measures, such as curtailing load, if attempts to acquire energy and transmission access from the spot market are unsuccessful.

Idaho Power used the results of the transmission analysis to establish a capacity target for planning purposes. The capacity target identifies the amount of additional generation, demand response programs, or transmission resources that must be added to Idaho Power's system to avoid capacity deficits.

On a yearly basis, Idaho Power's transmission capacity is reserved for the company's retail customers based on annual load and resource forecasts. Although transmission resources are owned by Idaho Power, the unreserved transmission capacity may be purchased by other parties due to FERC's open access requirements. Idaho Power must reserve the use of its own transmission system under FERC's open access rules. Often, Snake River flow forecasts for the remainder of the year are not known with a high degree of accuracy until May or June, and late spring is often too late to acquire firm transmission capacity for the summer months.

## Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2011 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The forecast sources include the NPCC, the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Moody's Analytics, Inc.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness of the forecasts when compared with others, and the current forward price of actual contracts being executed on various exchanges. In the near-term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to longer-term forecasts that are weighted more heavily towards projected prices without underlying financial trades (EIA, Moody's, Inc.).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment (basis) based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate. Figure 6.5 shows the major natural gas pipeline transportation paths in the Pacific Northwest.

The Henry Hub price, including the Sumas Basis, is shaped monthly to reflect the normal seasonal supply and demand price variation. The gas price forecast in all future years receives the same monthly price shaping. Sumas gas prices can have high seasonal spot price variability, especially in the winter months, and the Sumas price volatility is not included in the regional adjustment. Idaho Power's geographic position between Sumas gas and Rockies gas allows Idaho Power to access two independent gas markets that may not have high-price correlation. Also, Idaho Power hedges a portion of its short- and mid-term gas planned for use in the resource portfolio. This hedging activity is intended to reduce the spot and seasonal-price volatility of natural gas costs incurred by customers.

The 2011 IRP analyzes three gas price scenarios as shown in Figure 6.4. The expected-case forecast has a 20-year levelized cost of $7.92 per MMBtu, while the high case is $9.82 per MMBtu and the low case is $6.01 per MMBtu. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

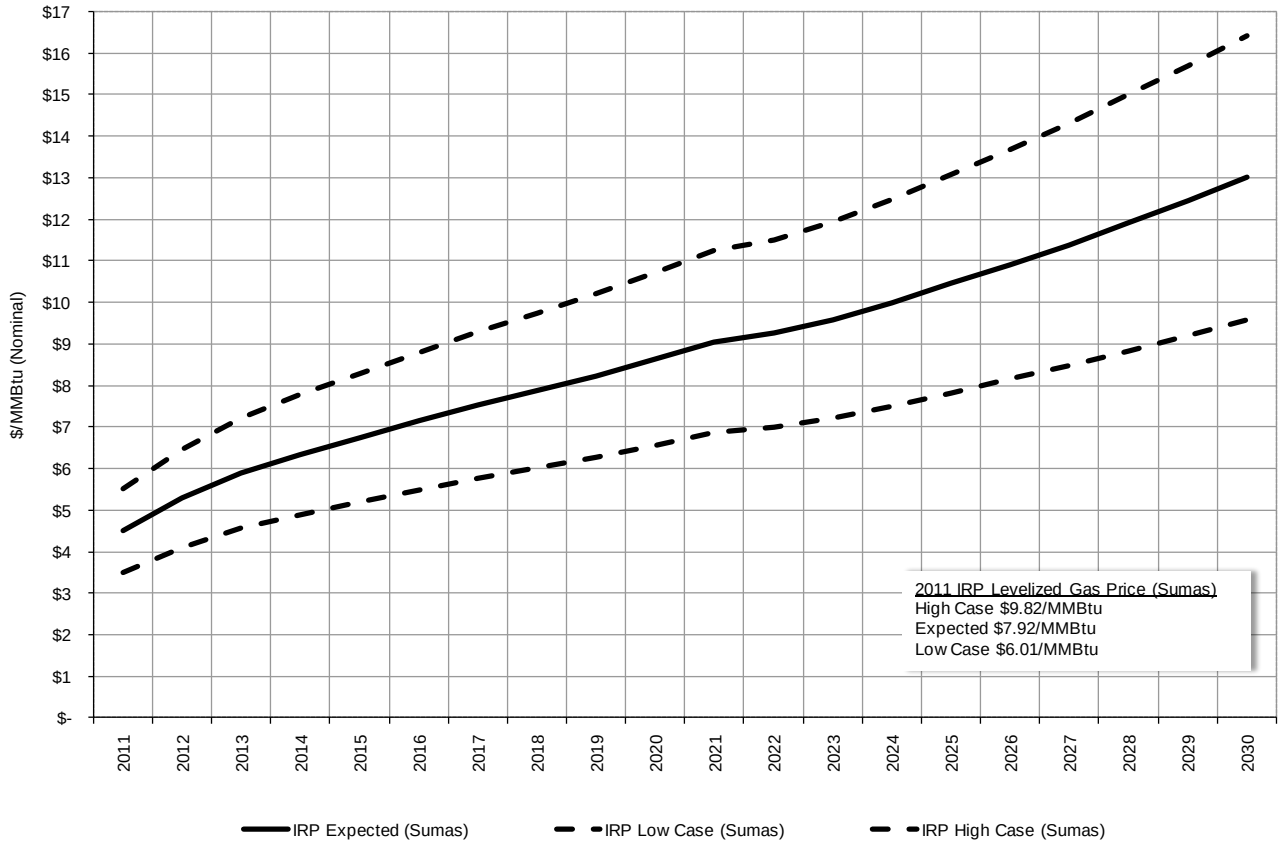



**Figure 6.4 Natural gas price forecast**

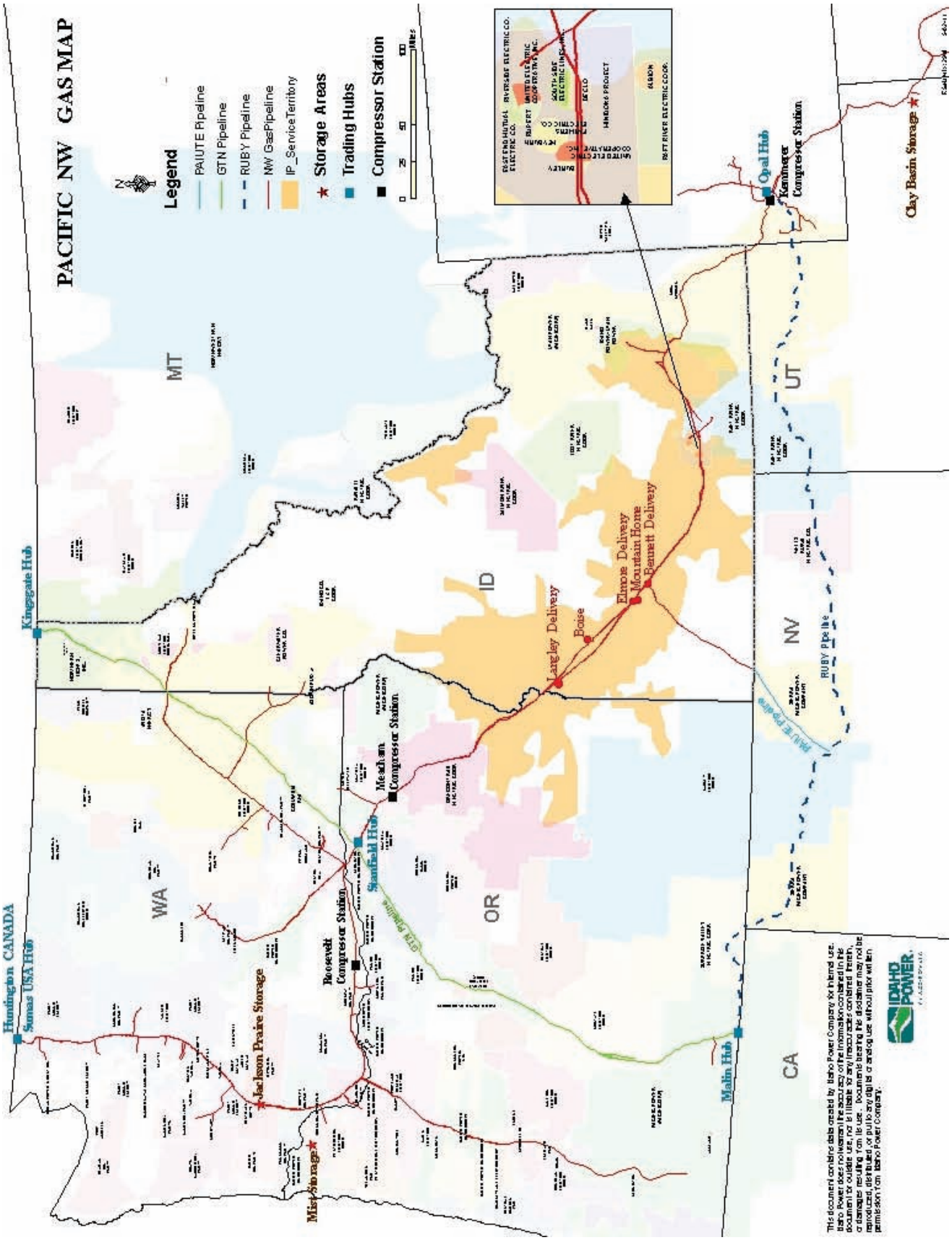



**Figure 6.5 Pacific Northwest natural gas transportation paths**

# Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2011 IRP. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources, including, but not limited to, the NPCC, the US Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as follows:

- Levelized fixed cost-per-kW of installed (nameplate) capacity per month
- Total levelized cost-per-MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine capital cost of the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system upgrade costs were estimated by Idaho Power's transmission planning group and were included in the total portfolio cost. The capital costs also includes AFUDC (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial impact to Idaho Power as a result of these load reduction programs.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are shown in *Appendix C–Technical Appendix.*

## *Emissions Adders for Fossil Fuel-Based Resources*

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of the environmental and social costs. It is likely that further emissions regulations will be implemented during the period covered in the 2011 IRP.

In the analysis, Idaho Power incorporated estimates for the future cost of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emissions adders for $CO_2$, $NO_x$, Hg, and $SO_2$. The additional costs are assumed to begin in 2015. Table 6.4 provides the emissions intensity rates assumed in the analysis and the emissions adder costs shown in Table 6.5 were used to calculate the total emissions costs of the various fossil fuel-based resources that were analyzed. Additional information regarding the cost of carbon emissions is provided in the next section.

In addition to including the emission adders in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for $CO_2$, $NO_x$, Hg, and $SO_2$ emissions for each portfolio in the first 10-year and second 10-year planning periods. The expected case regulatory environmental compliance costs for each planning period is shown in *Appendix C–Technical Appendix.* A sensitivity analysis (low-case and high-case) for these compliance costs can also be found in *Appendix C–Technical Appendix.*

**Table 6.4 Emissions intensity rates (lbs/MWh)**

| Adder | $CO_2$ | $NO_x$ | Hg | $SO_2$ |
|---|---|---|---|---|
| Pulverized Coal | 1,901 | 3.38 | 0.000050 | 8.5339 |
| IGCC | 2,279 | 0.21 | 0.000006 | 0.1490 |
| IGCC with Carbon Sequestration | 420 | 0.43 | 0.000006 | 0.1833 |
| Distributed Generation Natural Gas | 1,115 | 1.07 | N/A | 0.0096 |
| SCCT | 1,413 | 1.36 | N/A | 0.0122 |
| CCCT | 809 | 0.08 | N/A | 0.0070 |

**Table 6.5 Emissions adder cost assumptions**

| Adder | Emission Adder Cost | First Year Applied | Annual Escalation |
|---|---|---|---|
| GHG | $20 per ton | 2015 | 5.0% |
| $NO_x$ | $2,600 per ton[1] | 2015 | 2.5% |
| Hg | $1,443 per ounce[1] | 2015 | 2.5% |
| $SO_2$ | $1.75 per ton | 2011 | 2.5% |

[1] 2011 dollars

## *Cost of Carbon Emissions*

Although Idaho Power believes a cap-and-trade system is more likely than a carbon tax to be implemented in the future, regulatory requirements dictate the analysis be performed using a carbon adder or tax, which Idaho Power has done for the 2011 IRP. The purpose of a carbon adder is to account for all of the costs in the price of energy produced by carbon-emitting resources.

Four carbon-adder scenarios were analyzed as part of the 2011 IRP: 1) the expected case starting at $20 per ton in 2015 and escalating at 5 percent annually, 2) the high case starting at $25 per ton in 2015 and escalating at 7.5 percent annually, 3) the low case starting at $15 per ton and escalating at 2.5 percent annually, and 4) the zero-cost case where there is no future cost associated with carbon emissions. The carbon adder assumptions used in the 2011 IRP are shown in Figure 6.6. A discussion of the analysis results of the cost of carbon emissions is contained in Chapter 9.

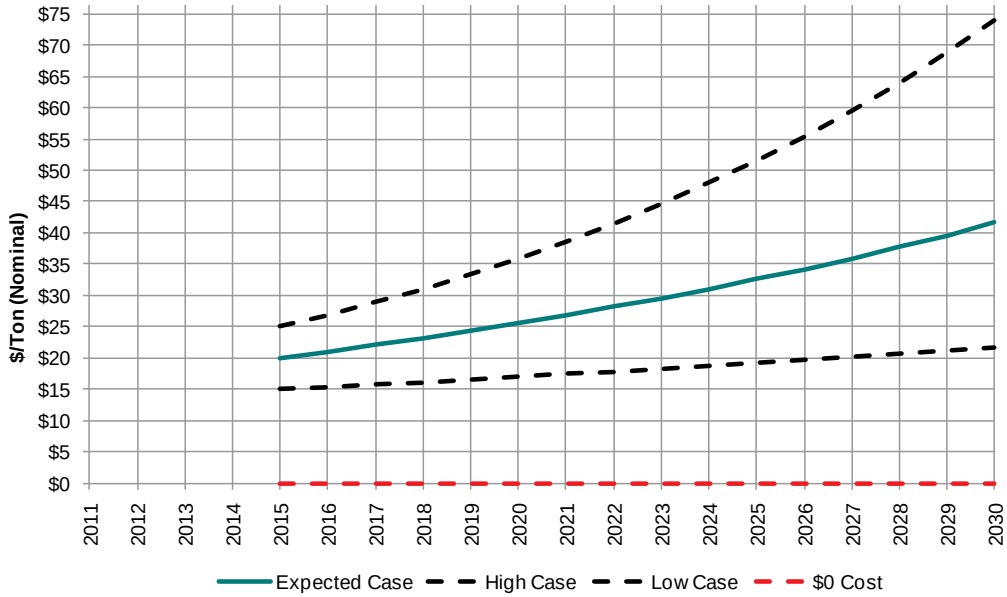



**Figure 6.6 Carbon-adder assumptions**

## Production Tax Credits for Renewable Generating Resources

Various federal tax incentives for renewable resources were extended and/or renewed within the *Emergency Economic Stabilization Act of 2008*. This legislation requires most projects be on line by December 31, 2016, to be eligible for the federal production tax credits (PTC) identified in Section 45 of the *Internal Revenue Code*. The credit is earned on power produced by the project during the first 10 years of operation. The credit, adjusted annually for inflation, is currently valued at $21 per MWh.

## Renewable Energy Credits

While the state of Idaho does not have an RPS requirement, Idaho Power believes a federal RES requiring Idaho Power to retire RECs for compliance will be passed by Congress in the near future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010 by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Three different scenarios for the future value of RECs were analyzed as part of the 2011 IRP: 1) the expected-case scenario where RECs are valued at $7 in 2013 and escalated at 3 percent annually, 2) a high-case scenario where RECs are valued at $21 in 2013 and escalated at 3 percent annually, and 3) a low-case scenario where RECs have no value beginning in 2013. The three REC price assumptions used in the 2011 IRP are presented in Figure 6.7. A discussion of the analysis of the value of RECs in each of the portfolios analyzed in the 2011 IRP is presented in Chapter 9.

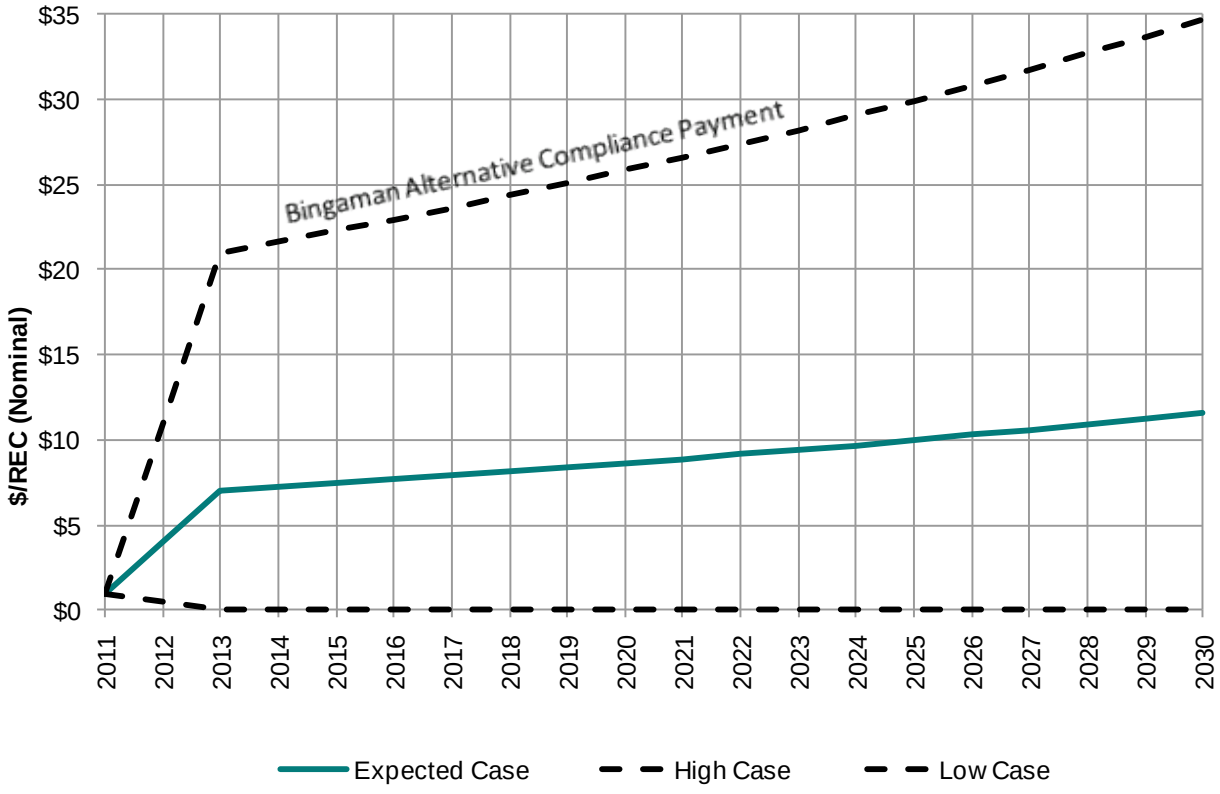



**Figure 6.7 REC price assumptions**

## Levelized Capacity (Fixed) Cost

The annual fixed revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars-per-kW of plant nameplate capacity per month. Included in these costs were the cost of capital and fixed O&M estimates. Figure 6.8 provides a combined ranking of all the various resource options, in order of lowest to highest levelized fixed cost-per-kW-per-month. The ranking shows distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours-per-year to meet peak-hour demand.

## Levelized Cost of Production

Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost of production measurement represents the estimated annual cost-per-MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource-type is shown in Figure 6.9. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost of production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost of production calculation for a generation resource is the assumed level of annual capacity utilization over the life of the resource, referred to as capacity factor. A capacity factor of 50 percent would suggest that a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost will be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity factor assumptions reduce the MWh and the levelized cost would be higher.

Resource capital costs are annualized over a 30-year period for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.

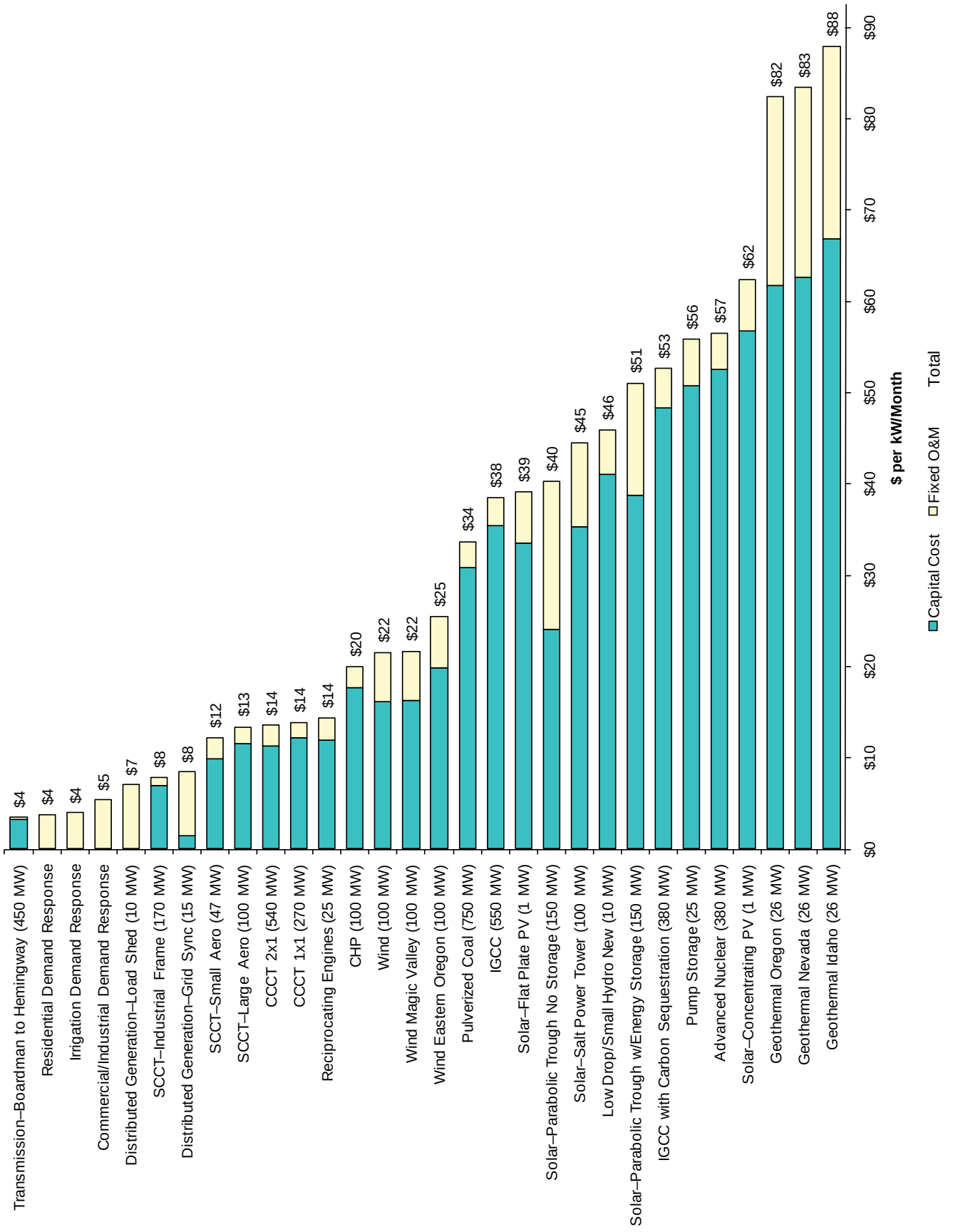



**Figure 6.8 30-year levelized capacity (fixed) costs**

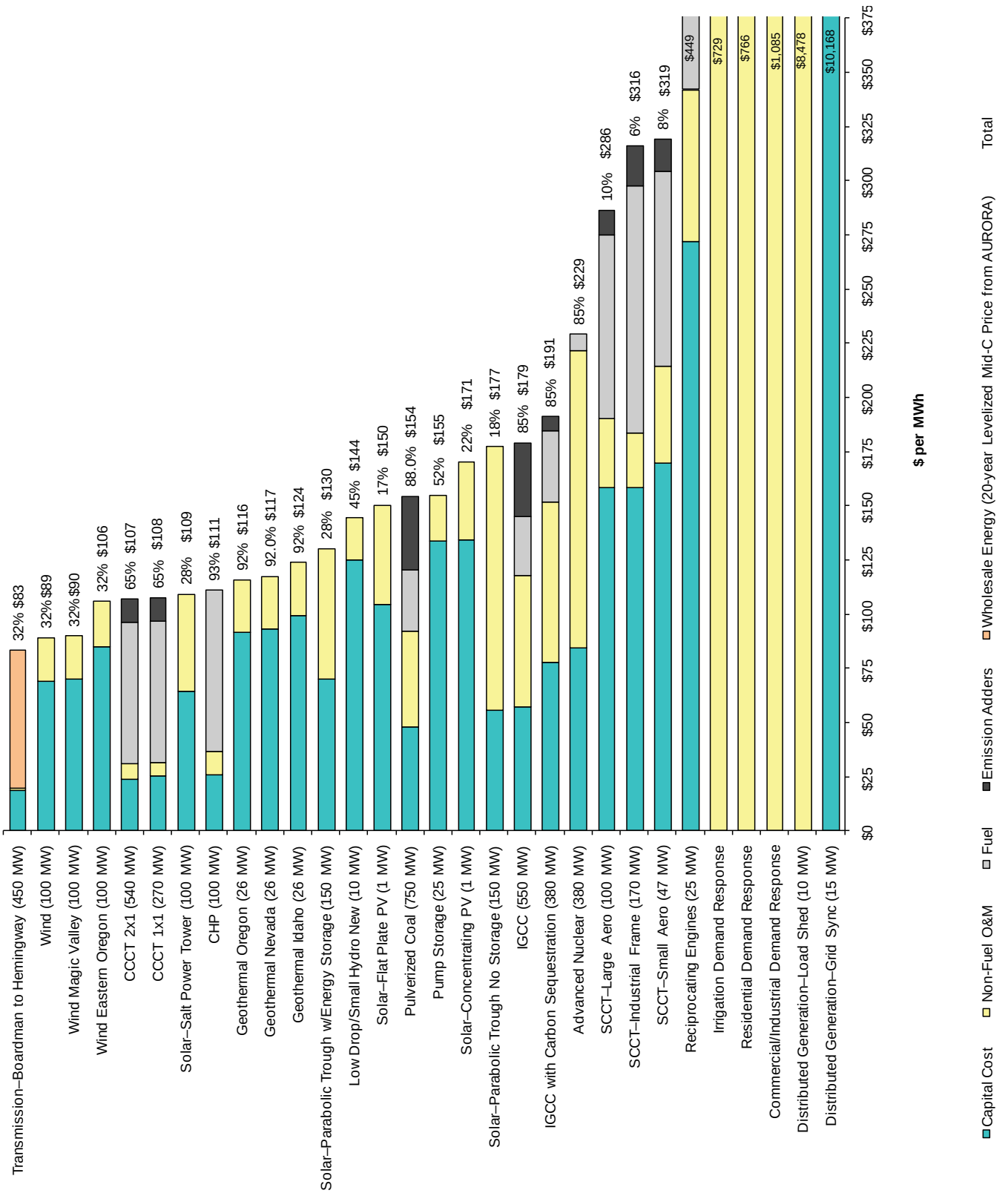



**Figure 6.9 30-year levelized cost of production (at stated capacity factors)**

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# 7. TRANSMISSION PLANNING

## Past and Present Transmission



High-voltage transmission lines are necessary to deliver electricity to load and connect with other regional utilities.

High-voltage transmission lines have been vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that have served the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the Hells Canyon Complex and on to the Treasure Valley were central to the development of the Hells Canyon Complex in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three, coal-fired power plants located in neighboring states, which supply approximately 40 percent of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric resources with access to wholesale energy markets.

The regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of this, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load and sells excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits the environment and Idaho Power's customers because the construction of additional peaking resources to serve summer peak load is delayed or avoided, revenue from off-system sales during the winter and spring is credited to customers through the PCA, and revenue from others' use of the transmission system is credited to customers in general rates.

## Transmission Planning Process

In recent years, FERC has mandated several aspects of the transmission planning process. One regulation requires Idaho Power to participate in transmission planning on a local, sub-regional, and regional basis, as described in Attachment K of the Idaho Power OATT and summarized in the following sections.

### Highlights

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Restrictions on the Brownlee East Total and Idaho–Northwest transmission paths limit the import of Hells Canyon Complex generation and off-system purchases from the Pacific Northwest.
- The 500-kV Boardman to Hemingway project, expected to be in service in 2016, will significantly increase the capacities of the Brownlee East Total and Idaho–Northwest paths.

## Local Transmission Planning Process

The expansion planning of Idaho Power's transmission network occurs through a local area transmission advisory process, and the biennial local transmission planning process.

### Local Area Transmission Advisory Process

Idaho Power develops long-term local area transmission plans with community advisory committees. These committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for full development of the area limited by the land-use plan and other resources of the local area. The plans identify the approximate year the project will be placed in service. Local area plans have been created for four load centers in southern Idaho, 1) eastern Idaho, 2) Magic Valley, 3) Wood River Valley, and 4) Treasure Valley. Development of a fifth plan for the western Treasure Valley and eastern Oregon is in progress.

### Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the transmission upgrades identified in the Local Area Transmission Advisory Process, the forecasted network customer load (e.g., BPA customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and point-to-point transmission customer requirements. By identifying potential resource areas and load-center growth, the required transmission capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the sub-regional transmission planning process.

## Sub-Regional Transmission Planning

Idaho Power is active in sub-regional transmission planning through the NTTG. NTTG was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). NTTG also relies on a biennial process to develop the sub-regional transmission plan and incorporates the member's biennial local transmission plans. A public stakeholder process evaluates transmission needs as determined by state-mandated IRPs and load forecasts, proposed resource development and generation interconnection queues, and forecast uses of the transmission system by wholesale transmission customers.

## Regional Transmission Planning

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the regional transmission planning facilitator in the western United States. Specifically, TEPPC has three distinct functions, 1) oversee data management for the western interconnection, 2) provide policy and management of the planning process, and 3) guide the analyses and modeling for Western Interconnection economic transmission expansion planning. In addition to providing the means to model the transmission implications of various load and resource scenarios at a regional level, these functions serve to fulfill the requirement to coordinate planning between transmission owners/operators and sub-regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. These activities include

regional resource adequacy analyses and corresponding North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission-line rating process.

## Existing Transmission System

Idaho Power's transmission system spans southern Idaho from eastern Oregon to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as "transmission paths." There are defined transmission paths to other states and between the southern Idaho load centers mentioned earlier in this chapter. Idaho Power's transmission system and paths are shown in Figure 7.1.

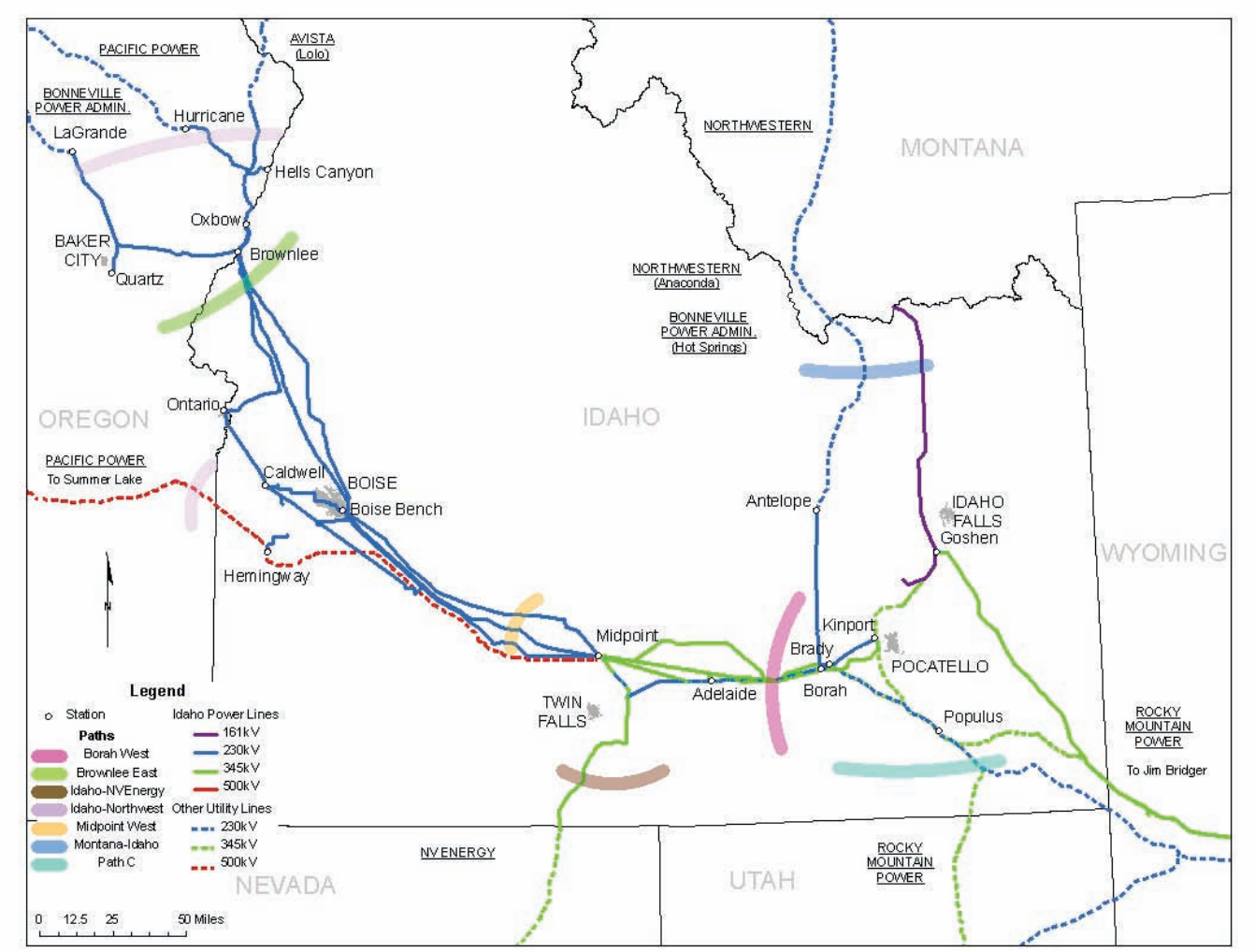



**Figure 7.1 Idaho Power transmission system map**

The transmission paths identified on the map are described in the following sections, along with descriptions of the conditions that result in capacity limitations.

### *Idaho–Northwest Path*

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three, 230-kV lines between the Hells Canyon Complex and the Pacific Northwest, and the 115-kV interconnection at Harney substation near Burns, Oregon. The Idaho–Northwest path is most likely to be capacity-limited during summer months in low-to-normal water years due to transmission-wheeling obligations for BPA's eastern Oregon and south Idaho loads and energy

imports from the Pacific Northwest to serve Idaho Power's retail load. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to eastern Oregon and southern Idaho.

## Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 7.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the Hells Canyon Complex, and Quartz substation, near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Brownlee East Total path. The capacity limitation on the Brownlee East transmission path is located between Brownlee and the Treasure Valley.

The Brownlee East transmission path has different capacity limitations than the Northwest path. The Brownlee East path is most likely to face capacity limitations in the summer during normal-to-high water years. The capacity limitations result from a combination of Hells Canyon Complex hydroelectric generation flowing east into the Treasure Valley, concurrent with transmission-wheeling obligations for BPA's eastern Oregon and southern Idaho loads and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the Hells Canyon Complex, as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

## Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Jefferson–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power and others move energy south from Montana into Idaho.

## Borah West Path

The Borah West transmission path is internal to the Idaho Power system. The path is comprised of 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation, located near American Falls, Idaho. Idaho Power's share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric and energy imports from Montana, Wyoming, and Utah. The Borah West path is capacity limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production moves east-to-west across the system. Additional transmission capacity will likely be required if new resources, including market purchases, are located east of the path to deliver the energy to the Treasure Valley load center.

## Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint substation, located near Jerome, Idaho. Capacity on the Midpoint West path is fully subscribed with east-side Idaho Power resources and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources (or market purchases), are located east of the path to deliver the energy to the Treasure Valley load center.

### Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the Valmy power plant was built in northern Nevada. Idaho Power is allocated 100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the Valmy generation plant.

### Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path operator and owner of all of the transmission lines; however, several of the lines terminate at Idaho Power-owned substations. The path effectively feeds into the Borah West path when power is moving from east-to-west and, consequently, the import capability of Path C is limited by Borah West path capacity limitations.

**Table 7.1 Available transmission import capacity**

| Transmission Path | Total Transmission Capacity* | | Available Transmission Capacity (MW) |
|---|---|---|---|
| | Import Direction | Capacity (MW) | |
| Idaho–Northwest | West-to-East | 1,200 | 0 |
| Idaho–Nevada | South-to-North | 262 | 0 |
| Idaho–Montana | North-to-South | 166 | 0 |
| Brownlee East | West-to-East | 1,915 | 0 |
| Midpoint West | East-to-West | 1,027 | 0 |
| Borah West | East-to-West | 2,557 | 0 |
| Idaho–Utah | South-to-North | 1,250 | 198** |

*Total transmission capacity and available transmission capacity as of May 1, 2011.
**Idaho Power estimated value, actual available transmission capacity managed by PacifiCorp.

## Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions in order to determine the transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements are dependent on the location and size of the resource. The transmission assumptions and transmission upgrade requirements are summarized in Table 7.2.



The Hemingway substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

**Table 7.2 Transmission assumptions**

| Resource Type | Geographic Area | Resource levels (per portfolio) | Additional Transmission Requirements |
|---|---|---|---|
| Gas Turbines* | Elmore County | 0 MW–150 MW | No upgrades required |
| | | 150 MW–325 MW | New 230-kV line into Treasure Valley |
| | | >325 MW | Additional 230-kV line into Treasure Valley |
| Solar* | Elmore County | 0 MW–150 MW | No upgrades required |
| | | 150 MW–325 MW | New 230-kV line into Treasure Valley |
| | | >325 MW | Additional 230-kV line into Treasure Valley |
| CHP | Treasure Valley | 0 MW–100 MW | No upgrades required |
| | Magic Valley | 100 MW–200 MW | No upgrades required |
| Geothermal | Northern Nevada | 0 MW–26 MW | No upgrades required |
| | Cassia County | 26 MW–52 MW | No upgrades required |
| Pumped Storage | Anderson Ranch Reservoir | 0 MW–80 MW | No upgrades required |
| | | 80 MW–240 MW | New 230-kV line into Treasure Valley |

* Because gas and solar resources are assumed to be in the same geographic area, the resource levels and corresponding transmission requirements are cumulative.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. For example, the location of a pumped storage resource listed in Table 7.2 will require a new 230-kV transmission line if sized greater than 80 MW, where other resources of that size may not require such improvements when located in another geographic area. An additional analysis of the transmission requirements was undertaken when these supply-side resources were arranged into portfolios. A transmission plan that provided the required transmission capacity from the new resources to the growing Treasure Valley load center was developed for each portfolio. This analysis of the first 10-year portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

# 8. Planning Criteria and Portfolio Selection

Many utilities plan to median, or expected, conditions and then include a reserve margin to cover the 50 percent of the time when conditions are less favorable than median. Idaho Power discussed planning criteria with IPUC and OPUC staff members and the public as part of the 2002 IRP. Out of these discussions came the company's practice of using more stringent planning criteria than median conditions. The planning criteria and planning scenarios are discussed in the following section.



Idaho Power relies on a collaborative process to develop the IRP.

## Planning Scenarios and Criteria

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficits for monthly average load and peak-hour load. The 20-year forecast is further divided into two, 10-year periods that coincide with the near-term action plan and the long-term action plan.

The planning criteria for monthly average load planning are 70$^{th}$ percentile water and 70$^{th}$ percentile average load conditions. For peak-hour load conditions, the planning criteria used are 90$^{th}$ percentile water and 95$^{th}$ percentile peak-hour load. The peak-hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system. Peak-hour load planning criteria are more stringent than average-load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods. The median forecast is no longer used for resource planning but it is used to set retail rates and avoided-cost rates during regulatory proceedings.

## Load and Resource Balance

Idaho Power has adopted the practice of assuming drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources, while using the conservative water and load conditions, is considered comparable to requiring capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having generating capacity in reserve for meeting day-to-day operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. The updated load and resource balance showing Idaho Power's existing and committed resources for

**Highlights**

- Idaho Power uses 70th percentile average load and 70th percentile water conditions for energy planning.
- For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour loads.
- Growth in summertime peak-hour demand continues to drive Idaho Power's needs for additional resources.

average energy and peak-hour load is shown in *Appendix C–Technical Appendix.*

## Average Monthly Energy Planning

Average energy surpluses and deficits are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 8.1 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available. Figure 8.1 illustrates that, starting in July 2018, monthly average energy deficit positions grow steadily in magnitude and number of months affected. By July 2030, these energy deficits exceed 600 aMW.

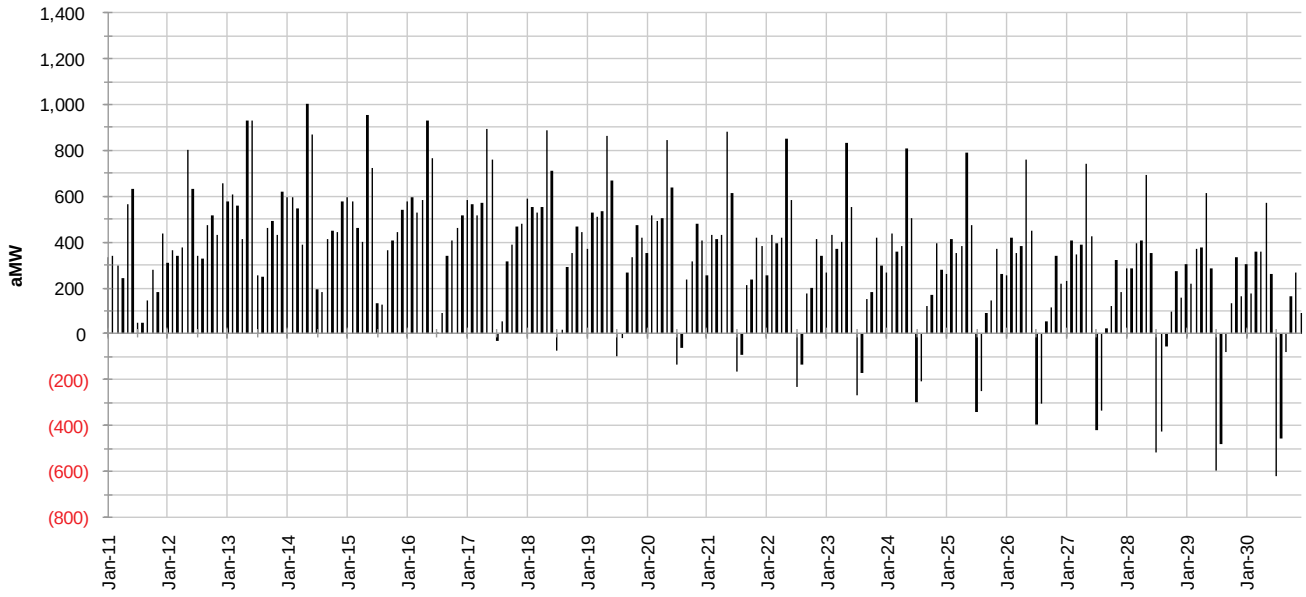



**Figure 8.1 Monthly average energy surpluses and deficits with existing and committed resources and existing DSM (70th percentile water and 70th percentile load)**

Idaho Power is committed to implementing all cost-effective energy efficiency programs in the IRP prior to evaluating supply-side resource options. Figure 8.2 shows the monthly average energy surplus and deficit data from Figure 8.1 with the addition of all new cost-effective energy efficiency. With the new energy efficiency programs accounted for, monthly average energy deficits in 2030 are reduced to approximately 550 aMW.

Energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy, as this is the case in the 2011 IRP.

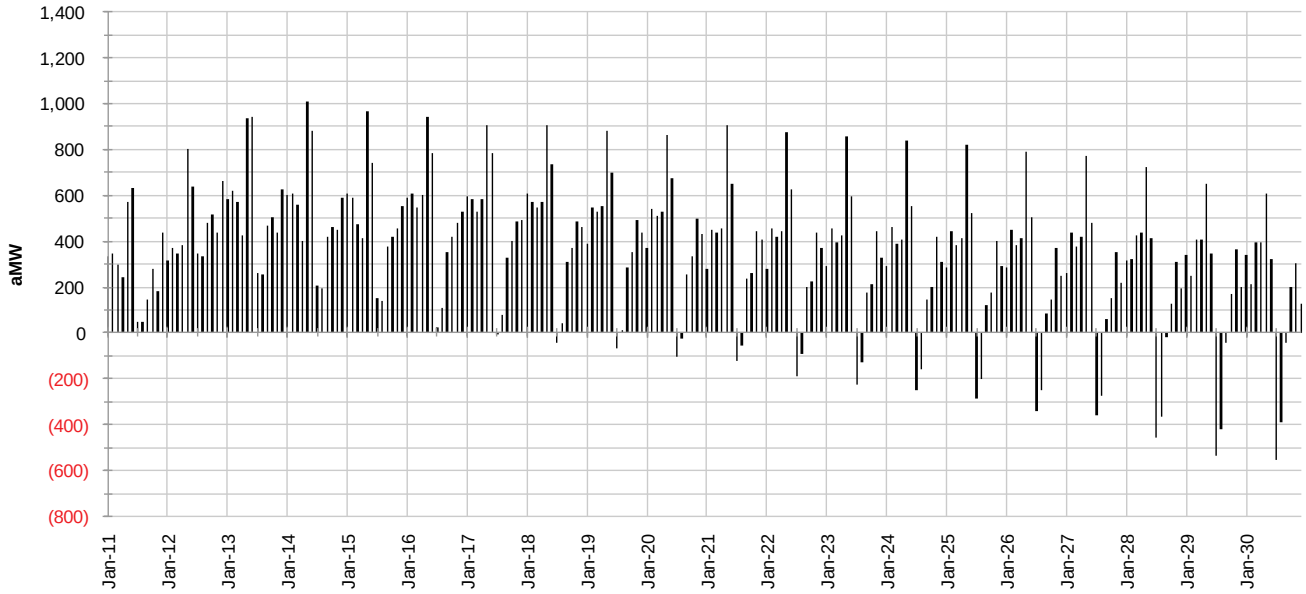



**Figure 8.2 Monthly average energy surpluses and deficits with new DSM (70th percentile water and 70th percentile load)**

## *Peak-Hour Planning*

Peak-hour load deficits are determined using 90th percentile water and 95th percentile peak-hour load conditions. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

Idaho Power's customers reach a maximum energy demand in the summer. Idaho Power's existing and committed resources are insufficient to meet the projected peak-hour growth, and the company's customers in Oregon and Idaho face significant capacity deficits in the summer months if additional resources are not added.

At times of peak summer load, Idaho Power is fully using all available transmission capacity from the Pacific Northwest. If Idaho Power were to face a significant outage at one of its main generation facilities, or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power is unable to meet reserve requirements, the company is then required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Figure 8.3 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 8.3 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available.

A deficit of approximately 100 MW in September 2011 highlights the need for the Langley Gulch CCCT plant as demand response programs are not available in the month of September. Idaho Power is actively managing this near-term deficit in accordance with its *Energy Risk Management Policy and*

*Standards*. Starting in July 2015, monthly peak-hour deficit positions grow steadily in magnitude and number of months affected. By July 2030, these capacity deficits are approximately 1,300 MW.

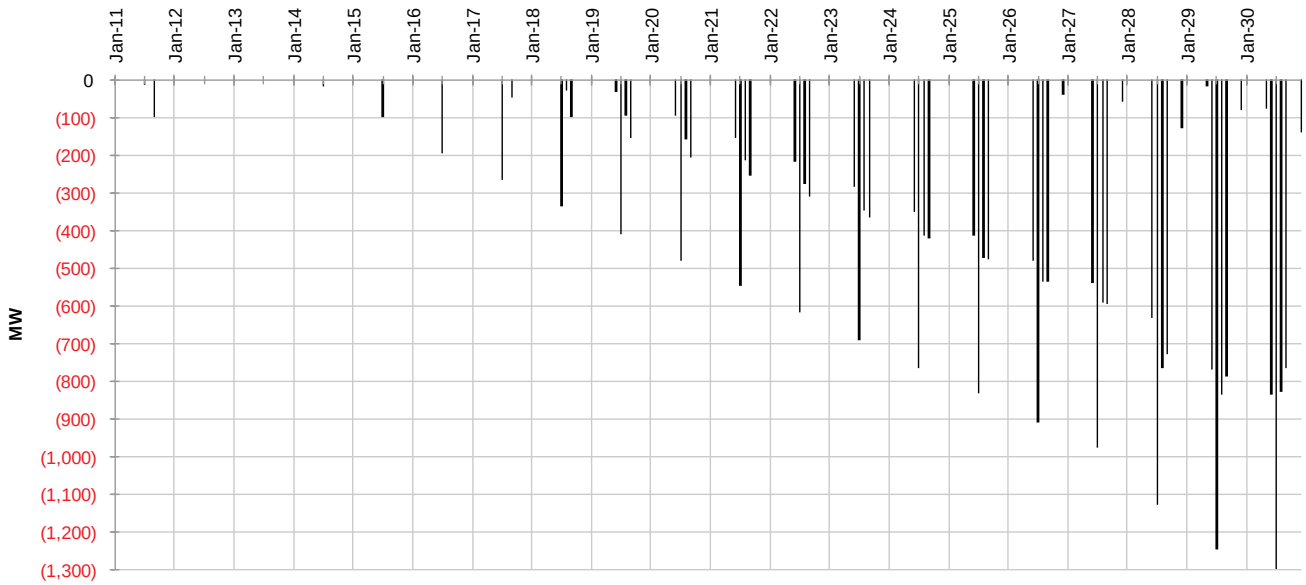



**Figure 8.3 Monthly peak-hour deficits with existing and committed resources and existing DSM (90th percentile water and 95th percentile load)**

As discussed in Chapter 4, the evaluation of demand response programs was switched from an "all cost-effective DSM" approach to a "needs-based" approach in the 2011 IRP. The new method was designed to identify annual levels of demand response needed to delay the addition of new supply-side peaking resources until the capacity of a SCCT would be greater than the seasonal limitations on demand response programs. Figure 8.4 shows the monthly peak-hour deficit data from Figure 8.3 with the addition of all new DSM under this methodology. With the new DSM accounted for, monthly peak-hour deficits in 2030 are reduced to approximately 1,230 MW.

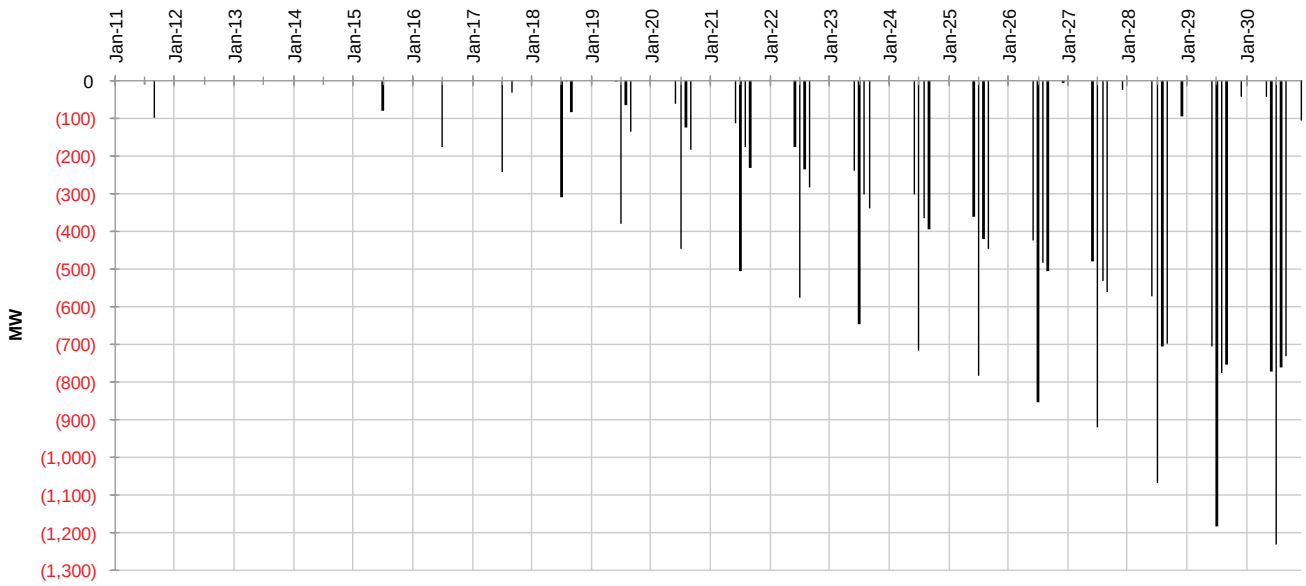



**Figure 8.4 Monthly peak-hour deficits with new DSM (90th percentile water and 95th percentile load)**

Capacity and energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional

summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 8.4 were used to design the portfolios analyzed in the 2011 IRP. In addition to eliminating the peak-hour deficits identified in Figure 8.4, the initial resource portfolios described in the next section also eliminated the energy deficits identified in Figure 8.2.

## Portfolio Design and Selection

The 2011 IRP portfolio development strategy divides the study period into two, 10-year periods, 2011–2020 and 2021–2030. Resource portfolios in each 10-year period are designed to satisfy the energy and peak-hour deficits shown in the load and resource balance.

Idaho Power also believes a federal RES will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

### *First 10 Years (2011–2020)*

The first 10-year planning period has significant committed resources, including the Langley Gulch CCCT and the Shoshone Falls upgrade. These committed resources are treated as existing resources for the purpose of analyzing each portfolio of new resources. The capital cost of these committed resources is not included in the comparison between portfolios.

For the first 10-year period, the 2011 IRP analyzed nine different resource portfolios. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the first 10 years of the planning horizon is shown in Figure 8.5, and a description of each portfolio follows.

| 1-1 Sun & Steam | | 1-2 Solar | | 1-3 B2H | | 1-4 SCCT | | 1-5 CCCT | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 2011 | | 2011 | | 2011 | | 2011 | |
| 2012 | Solar PV-1 | 2012 | | 2012 | | 2012 | | 2012 | |
| 2013 | Solar PV-5 | 2013 | | 2013 | | 2013 | | 2013 | |
| 2014 | CHP-75 | 2014 | Solar PV-5 | 2014 | | 2014 | | 2014 | |
| 2015 | Solar PV-30 | 2015 | Solar PT-100 | 2015 | Eastside Purchase | 2015 | SCCT Frame | 2015 | CCCT |
| 2016 | CHP-100 | 2016 | Solar PT-100 | 2016 | B2H-450 | 2016 | | 2016 | |
| 2017 | Geothermal-52 | 2017 | Solar PT-125 | 2017 | | 2017 | SCCT Frame | 2017 | |
| 2018 | Solar PT-125 | 2018 | Solar PV-50 | 2018 | | 2018 | | 2018 | |
| 2019 | Solar PV-30 | 2019 | Solar PT-100 | 2019 | | 2019 | SCCT S Aero-94 | 2019 | SCCT Frame |
| 2020 | Solar PT-75 | 2020 | Solar PV-50 | 2020 | | 2020 | | 2020 | |
| **MW** | **493** | **MW** | **530** | **MW** | **450** | **MW** | **434** | **MW** | **470** |

| 1-6 CHP | | 1-7 Balanced | | 1-8 Pumped Storage | | 1-9 Distributed Gen | |
|---|---|---|---|---|---|---|---|
| 2011 | | 2011 | | 2011 | | 2011 | |
| 2012 | | 2012 | | 2012 | | 2012 | Dist Gen-10 |
| 2013 | | 2013 | | 2013 | | 2013 | |
| 2014 | | 2014 | | 2014 | | 2014 | |
| 2015 | CHP-100 | 2015 | CHP-100 | 2015 | Pump St-80 | 2015 | SCCT Frame |
| 2016 | SCCT Frame | 2016 | SCCT Frame | 2016 | SCCT Frame | 2016 | |
| 2017 | | 2017 | Solar PV-10 | 2017 | | 2017 | SCCT Frame |
| 2018 | CHP-50 | 2018 | Solar PT-100 | 2018 | Pump St-80 | 2018 | |
| 2019 | CHP-50 | 2019 | Geothermal-26 | 2019 | SCCT S Aero-47 | 2019 | SCCT S Aero-94 |
| 2020 | SCCT S Aero-94 | 2020 | SCCT S Aero-47 | 2020 | Pump St-80 | 2020 | |
| **MW** | **464** | **MW** | **453** | **MW** | **457** | **MW** | **444** |

**Figure 8.5 Initial resource portfolios (2011–2020)**

- **1-1 Sun and Steam**—This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and

power tower resources with geothermal and CHP. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 493 MW.

- **1-2 Solar—**This resource portfolio includes a mixture of solar PV and power tower resources and is designed to test the performance of a portfolio consisting entirely of solar resources. The total nameplate capacity of this portfolio is 530 MW.
- **1-3 Boardman to Hemingway—**This resource portfolio includes the Boardman to Hemingway transmission line project is anticipated to be available in 2016. A more expensive market purchase on the east side of Idaho Power's system was needed to meet a peak-hour deficit in the summer of 2015 prior to the Boardman to Hemingway line becoming available. The total nameplate capacity of this portfolio is 450 MW.
- **1-4 SCCT**—This resource portfolio includes three SCCT's—two industrial-frame units and two small aeroderivative units (47 MW each). The purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building gas-peaking capacity near load. The total nameplate capacity of this portfolio is 434 MW.
- **1-5 CCCT—**This resource portfolio includes one CCCT and one SCCT. Like portfolio 1-4, the purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building baseload gas capacity near load. The total nameplate capacity of this portfolio is 470 MW.
- **1-6 CHP—**This resource portfolio includes a mixture of CHP resources with two SCCTs. The purpose of this portfolio is to compare the cost of CHP resources to the cost of CCCT and SCCT technologies. The total nameplate capacity of this portfolio is 464 MW.
- **1-7 Balanced**—This resource portfolio includes a mixture of CHP, SCCTs, geothermal, and solar resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 453 MW.
- **1-8 Pumped Storage—**This resource portfolio includes a mixture of pumped storage resources and SCCTs. The purpose of this portfolio is to compare the cost of pumped storage to other resource alternatives. The total nameplate capacity of this portfolio is 457 MW.
- **1-9 Distributed Generation—**This resource portfolio is identical to portfolio 1-4 SCCT with the exception that it includes a 10-MW distributed generation resource. The purpose of this portfolio is to evaluate the cost and value of the proposed distributed generation program. Additional details on the distributed generation program can be found in Chapter 5. The total nameplate capacity of this portfolio is 444 MW.

### *Second 10 Years (2021–2030)*

For the second 10-year period, the 2011 IRP analyzed 10 different resource portfolios. The second 10-year planning period is more of an academic exercise than the first 10-year period, where resources are identified that will require a financial commitment. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the second 10 years of the planning horizon is shown in Figure 8.6, and a description of each portfolio follows.

| 2-1 Nuclear | | 2-2 IGCC | | 2-3 SCCT/Wind | | 2-4 CCCT/Wind | | 2-5 Hydro/CHP | |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | Solar PT-100 | 2021 | Geothermal-52 | 2021 | SCCT S Aero-141 | 2021 | CCCT | 2021 | Hydro Sm-60 |
| 2022 | Pump St-50 | 2022 | SCCT Frame | 2022 | Wind-100 | 2022 | Wind-150 | 2022 | CHP-75 |
| 2023 | Solar PT-100 | 2023 | | 2023 | SCCT S Aero-141 | 2023 | | 2023 | Pump St-80 |
| 2024 | Nuclear | 2024 | CHP-50 | 2024 | Wind-100 | 2024 | | 2024 | CHP-100 |
| 2025 | | 2025 | Solar PT-75 | 2025 | SCCT S Aero-94 | 2025 | | 2025 | Hydro-40 |
| 2026 | | 2026 | IGCC w/CS | 2026 | Wind-100 | 2026 | CCCT | 2026 | Pump St-80 |
| 2027 | | 2027 | | 2027 | SCCT S Aero-141 | 2027 | | 2027 | Hydro Sm-100 |
| 2028 | Nuclear | 2028 | Solar PT-75 | 2028 | SCCT S Aero-141 | 2028 | Wind-150 | 2028 | SCCT S Aero-141 |
| 2029 | Pump St-50 | 2029 | | 2029 | SCCT S Aero-94 | 2029 | SCCT Frame | 2029 | Hydro Sm-80 |
| 2030 | | 2030 | | 2030 | | 2030 | | 2030 | Hydro Sm-60 |
| **MW** | **800** | **MW** | **802** | **MW** | **1,052** | **MW** | **1,070** | **MW** | **816** |

| 2-6 Balanced 1 | | 2-7 Balanced 2 | | 2-8 PNW Transmission | | 2-9 E/S Transmission | | 2-10 Renewable | |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | CHP-75 |
| 2022 | SCCT Frame | 2022 | CHP-75 | 2022 | PNW Purchase | 2022 | E/S Purchase | 2022 | Pump St-80 |
| 2023 | | 2023 | SCCT Frame | 2023 | | 2023 | | 2023 | Solar PT-150 |
| 2024 | Solar PT-50 | 2024 | | 2024 | | 2024 | | 2024 | |
| 2025 | CCCT | 2025 | Geothermal-52 | 2025 | | 2025 | | 2025 | CHP-75 |
| 2026 | | 2026 | CHP-75 | 2026 | | 2026 | | 2026 | Solar PT-150 |
| 2027 | | 2027 | Hydro Sm-60 | 2027 | Solar PV-20 | 2027 | Solar PV-20 | 2027 | Solar PV-150 |
| 2028 | Hydro Sm-60 | 2028 | CCCT | 2028 | Geothermal-52 | 2028 | Geothermal-52 | 2028 | Geothermal-52 |
| 2029 | SCCT Frame | 2029 | | 2029 | SCCT Frame | 2029 | SCCT Frame | 2029 | Hydro Sm-100 |
| 2030 | | 2030 | | 2030 | | 2030 | | 2030 | Solar PV-200 |
| **MW** | **802** | **MW** | **784** | **MW** | **794** | **MW** | **794** | **MW** | **1,032** |

**Figure 8.6 Initial resource portfolios (2021–2030)**

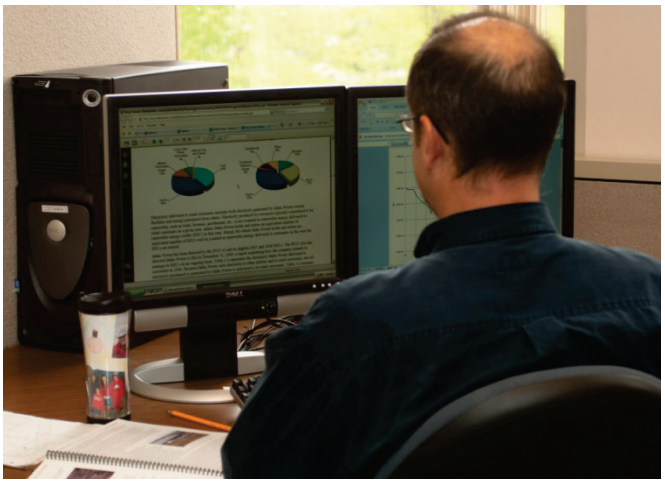
- **2-1 Nuclear—**This resource portfolio includes a mixture of pumped storage and solar resources combined with 500 MW of nuclear resources. The purpose of this portfolio is to evaluate the cost of the advanced nuclear technology against other resource alternatives. The total nameplate capacity of this portfolio is 800 MW.
- **2-2 IGCC**—This resource portfolio includes a mixture of geothermal, solar, CHP, and SCCT resources combined with a 380-MW IGCC resource. The purpose of this portfolio is to evaluate the cost of the IGCC technology against other resource alternatives. The total nameplate capacity of this portfolio is 802 MW.
- **2-3 SCCT/Wind—**This resource portfolio includes a combination of wind and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas peaking units that provide capacity. The total nameplate capacity of this portfolio is 1,052 MW.
- **2-4 CCCT/Wind**—This resource portfolio includes a combination of wind and CCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas baseload resources that provide capacity and energy. The total nameplate capacity of this portfolio is 1,070 MW.
- **2-5 Hydro/CHP—**This resource portfolio includes a combination of small hydroelectric, pumped storage, CHP and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains hydroelectric and CHP resources. The total nameplate capacity of this portfolio is 816 MW.
- **2-6 Balanced 1—**This resource portfolio includes a mixture of geothermal, solar, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 802 MW.

- **2-7 Balanced 2—**This resource portfolio includes a mixture of geothermal, CHP, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 784 MW.
- **2-8 PNW Transmission—**This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity to the Pacific Northwest. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on increased market purchases from the Pacific Northwest. The total nameplate capacity of this portfolio is 794 MW.
- **2-9 Eastside Transmission—**This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity across southern Idaho and into Wyoming. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on market purchases from the east side of Idaho Power's system. The total nameplate capacity of this portfolio is 794 MW.
- **2-10 Renewable—**This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and power tower resources, geothermal, CHP, small hydroelectric, and pumped-storage resources. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 1,032 MW.

Details on how the portfolios were modeled and the assumptions used in the analysis are provided in Chapter 9. Chapter 9 also presents the risk analysis and the process that lead to the selection of a preferred and alternate portfolio for each 10-year period.

# 9. Modeling Analysis and Results

Idaho Power uses the AURORAxmp® (AURORA) electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data.



Computer modeling is an essential part of preparing the IRP.

The AURORA software applies economic principles and dispatch simulation to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, and regional pool pricing logic. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS, Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results. Updates to the database generally add additional hourly operational detail and move away from flat generation output, de-rates, and fixed-capacity factors. The updates also incorporate detailed generating resource scheduling, which results in a model that is more deterministic in character and provides a more specific operational view of the WECC.

## Economic Evaluation Components and Assumptions

The total cost of each portfolio analyzed for the IRP is determined by four components: 1) variable operating costs (determined with AURORA), 2) the capital cost of new resources in each portfolio,

**Highlights**

- Idaho Power uses the AURORA Electric Market Model as the primary tool for determining future resource build out of operations and portfolio cost impacts for the 20-year IRP planning period.
- The 2011 IRP incorporates anticipated federal RES legislation and plans for the resources necessary to comply with the legislation.
- Quantitative risk factors analyzed in the 2011 IRP include the cost of carbon emissions, natural gas prices, capital cost, load growth, DSM program performance, REC prices, electric market prices, and third-party transmission subscription.

3) the cost of transmission upgrades necessary for each portfolio, and 4) the value of RECs generated by renewable resources in each portfolio. In addition, numerous financial assumptions are necessary to calculate the total portfolio cost. The financial assumptions used in the 2011 IRP are shown in Table 9.1.

**Table 9.1 Financial assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount rate (weighted average cost of capital) | 7.00% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 3.00% |
| Emissions adder escalation rate | 2.50% |
| Carbon adder escalation rate | 5.00% |
| Annual property tax escalation rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premium (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.00% |
| Production tax credit escalation rate | 3.00% |

## *AURORA Modeling*

Idaho Power uses the AURORA model to evaluate the variable cost of production for existing and committed resources along with the new resources proposed in the portfolios. Operational constraints are approximated along with energy purchases and sales in the regional market. While more extreme planning criteria are used to determine the average energy and peak-hour capacity of existing resources in the load and resource balance, median or 50th percentile conditions are used in AURORA for modeling load and hydroelectric generation. The following sections describe additional variable operating costs also included in the analysis.

### Carbon Cost

The potential cost of carbon emissions is accounted for in the IRP by applying a carbon adder or tax. The carbon adder is applied to all carbon-emitting resources within the WECC starting in 2015. Including the carbon adder cost for all carbon-emitting resources in the AURORA model results in market prices that reflect the anticipated future cost of carbon emissions. Therefore, the cost of carbon emissions is captured for specific resources and in the price of market purchases and sales.

The carbon adder increases the dispatch cost of each carbon-emitting resource in AURORA, which affects how the model economically dispatches resources. Once a unit is dispatched, the carbon adder can also affect how much generation is produced from each unit. Past experience shows the carbon adder has to be very large to completely curtail units; however, smaller carbon adders reduce generation compared to a similar unit with no carbon adder. Additional details on the carbon adder and the values used for the high, expected, low and no carbon scenarios can be found in Chapter 6.

### Transmission Modeling

The need for additional power from new resources or market purchases will require additional transmission. Idaho Power faces severe transmission capacity limitations when evaluating additional supply-side resources. These transmission limitations were a major factor in evaluating supply-side resources, such as Bennett Mountain, Danskin, the Elkhorn Valley Wind Project, and Langley Gulch in previous IRPs.

The 2011 IRP uses different transmission assumptions for each of the 10-year periods. For the first 10-year period, transmission capacity is increased only to the extent necessary to deliver the energy from the new resources to the Treasure Valley in southwest Idaho. Idaho Power has adopted a conservative approach for the first 10 years and includes additional transmission capacity for market purchases only when market-need is specifically identified in a resource portfolio.

For the second 10-year period, transmission capacity identified in the preferred portfolio from the first 10-year period is included, plus any additional transmission necessary for each resource portfolio in the second 10-year period.

### Natural Gas Transportation Cost

For the 2011 IRP analysis, the cost of gas transportation for existing resources, including the Langley Gulch project, is based on the cost of existing pipeline capacity. Because existing pipeline capacity is close to being fully utilized, the transportation cost for new gas resources reflects the cost of adding additional pipeline capacity for delivery to Idaho Power's service area.

The increased cost for new pipeline capacity is approximately twice the current tariff rate. For the IRP, the additional cost for new pipeline capacity was added to the cost of each new gas resource outside the AURORA model. Additional details on transportation costs can be found in *Appendix C–Technical Appendix.* The natural gas price forecast described in Chapter 6 is based on a Sumas hub price and does not include any transportation cost.

## Capital Cost

Idaho Power uses an internal financial analysis model to evaluate the capital cost of new resources and to estimate the associated revenue requirements. Estimated construction costs are escalated at the base inflation rate of 3 percent per year and included in the model.

Estimated capital costs are translated into an annual revenue requirement that corresponds to the size and timing of the investment required for each resource. The annual revenue requirement for each resource portfolio is then discounted and summed. The annual revenue requirement analysis has the benefit of matching the annual revenue requirements with the corresponding annual energy benefits. The annual revenue requirement analysis eliminates the need to estimate resource values beyond the study period because resource capital costs and resource benefits are matched annually within the study period.

## Transmission Cost

For the IRP, the total estimated transmission cost of each resource portfolio is used to determine the annual transmission revenue requirement, and the NPV of the cost is included in the portfolio evaluation. A more detailed presentation of the transmission assumptions for each portfolio can be found in *Appendix C–Technical Appendix.*

The degree of Idaho Power's investment participation differs between the portfolios, and the costs are included according to the transmission subscription in each resource portfolio. Each transmission subscription represents an Idaho Power equity investment in the project. Each equity investment translates into a revenue requirement, and the revenue requirements for the transmission investments are estimated and included in the portfolio total cost comparisons. Idaho Power's investment defines the revenue requirement, and the NPV of the revenue requirement is included as part of the expected-case cost of each resource portfolio. The NPV of any possible transmission capacity sales to third parties are included in the risk analysis as project benefits.

Two categories of transmission are accounted for in the IRP. The first is the transmission that integrates resources and allows energy to flow from a generation resource to Idaho Power's load centers.

An example of this type of transmission are the transmission lines that deliver generation from the Hells Canyon Complex to the load center in the Treasure Valley.

Interstate transmission is the second transmission type and is generally higher voltage and covers greater distances. Interstate transmission is planned on a regional basis to meet the needs of electric utilities and the needs of third parties requesting transmission service. Very little interstate transmission has been constructed in the last 30 years. Examples of interstate transmission include the proposed Gateway West and Boardman to Hemingway projects.

In the first 10-year portfolios (2011–2020), only portfolio 1-3 Boardman to Hemingway included a proposed interstate transmission project. This was the Boardman to Hemingway project with an on-line date of 2016 and Idaho Power's share of the line at 450 MW. For the second 10-year period (2021–2030), all the portfolios assume that the preferred portfolio 1-3 Boardman to Hemingway is built, and only portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission included additional interstate transmission projects. In portfolio 2-8 Pacific Northwest Transmission, Idaho Power adds 500 MW of additional capacity between Idaho and the Pacific Northwest in 2022. In portfolio 2-9 Eastside Transmission, the Gateway West project is built in 2022, allowing Idaho Power to have an additional 500 MW of transmission capacity for market purchases from the east side of Idaho Power's service area.

## Renewable Energy Certificates

For the 2011 IRP analysis, each portfolio is designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Because it is impossible to exactly match the number of RECs Idaho Power would need to meet this requirement with the amount of RECs created by individual resources, the value of additional RECs and the cost of purchasing RECs if short is captured in the total cost of each portfolio. With the exception of portfolio 2-4 CCCT & Wind, all the portfolios analyzed had a net benefit from the value of surplus RECs. This value is shown as a negative cost in Tables 9.2 and 9.3. The forward price curve for RECs used in the analysis is presented in Chapter 6.

## Expected-Case Portfolio Analysis Results

The NPV total portfolio cost is calculated by summing the variable operating costs calculated in AURORA, the capital and transmission costs, and the value of RECs from each portfolio. The expected-case NPV total portfolio cost of each of the portfolios analyzed for the first 10-year period are shown in Table 9.2.

Under expected case conditions, for the first 10-year period, portfolio 1-3 Boardman to Hemingway is the lowest cost portfolio at $3.18 billion, while portfolio 1-4 SCCT is the second lowest at $3.22 billion. These results are similar to the results of the 2009 IRP analysis where the Boardman to Hemingway project was evaluated against a portfolio of SCCT resources that could be built close to load centers.

**Table 9.2 Expected case total portfolio cost (2011–2020)**

| | NPV Portfolio Costs (2011 dollars, 000's) | | | | |
|---|---|---|---|---|---|
| **Base Case** | **Variable (AURORA)** | **Capital** | **Transmission** | **RECs** | **Total** |
| 1-1 Sun & Steam | $3,041,735 | $552,164 | $17,925 | ($24,396) | **$3,587,428** |
| 1-2 Solar | $2,924,308 | $683,497 | $20,865 | ($32,033) | **$3,596,637** |
| 1-3 Boardman to Hemingway | $3,088,318 | $0* | $98,929 | ($9,940) | **$3,177,308** |
| 1-4 SCCT | $3,099,029 | $108,835 | $22,748 | ($9,940) | **$3,220,672** |
| 1-5 CCCT | $3,115,384 | $188,415 | $19,546 | ($9,940) | **$3,313,406** |
| 1-6 CHP | $3,162,397 | $190,436 | $15,798 | ($9,940) | **$3,358,691** |
| 1-7 Balanced | $3,085,533 | $293,344 | $16,349 | ($15,384) | **$3,379,843** |
| 1-8 Pumped Storage | $3,093,051 | $416,887 | $23,099 | ($15,206) | **$3,517,831** |
| 1-9 Distributed Generation | $3,099,323 | $114,153 | $22,748 | ($9,940) | **$3,226,284** |

*Portfolio 1-3 Boardman to Hemingway capital cost is included in the transmission column.

Table 9.3 shows the NPV total cost of each portfolio analyzed for the second 10-year period. Under expected-case conditions, the NPV cost of portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission are close at $3.30 billion and $3.32 billion respectively. Portfolio 2-6 Balanced 1 is the next lowest-cost portfolio at $3.50 billion.

**Table 9.3 Expected case total portfolio cost (2021-2030)**

| | NPV Portfolio Costs (2011 dollars, 000's) | | | | |
|---|---|---|---|---|---|
| **Base Case** | **Variable (AURORA)** | **Capital** | **Transmission** | **RECs** | **Total** |
| 2-1 Nuclear | $2,548,176 | $1,806,082 | $25,300 | ($713) | $4,378,845 |
| 2-2 IGCC | $2,665,714 | $958,555 | $59,523 | ($2,908) | $3,680,885 |
| 2-3 SCCT & Wind | $3,079,453 | $515,846 | $27,147 | ($2,545) | $3,619,901 |
| 2-4 CCCT & Wind | $3,095,043 | $498,966 | $26,688 | $246 | $3,620,943 |
| 2-5 Hydro & CHP | $3,014,673 | $880,443 | $27,622 | ($6,669) | $3,916,069 |
| 2-6 Balanced 1 | $2,937,689 | $555,581 | $10,646 | ($2,646) | $3,501,270 |
| 2-7 Balanced 2 | $2,952,566 | $668,771 | $10,849 | ($8,840) | $3,623,346 |
| 2-8 Pacific Northwest Transmission* | $2,933,037 | $335,516 | $29,278 | ($1,773) | $3,296,059 |
| 2-9 Eastside Transmission* | $2,929,353 | $335,516 | $53,373 | ($1,773) | $3,316,469 |
| 2-10 Renewable | $2,910,691 | $1,112,624 | $10,504 | ($11,537) | $4,022,282 |

*2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission capital costs are included in the transmission column.

## Portfolio Carbon Emissions

Figure 9.1 shows the average $CO_2$ intensity for each portfolio analyzed for the first 10-year period. The average intensity for each portfolio includes emissions from new resources in addition to emissions from Idaho Power's existing and committed resources. The intensity rates range from approximately 775 lbs-per-MWh to 805 lbs-per-MWh and are all well below Idaho Power's 2005 intensity rate of 1,194 lbs-per-MWh.

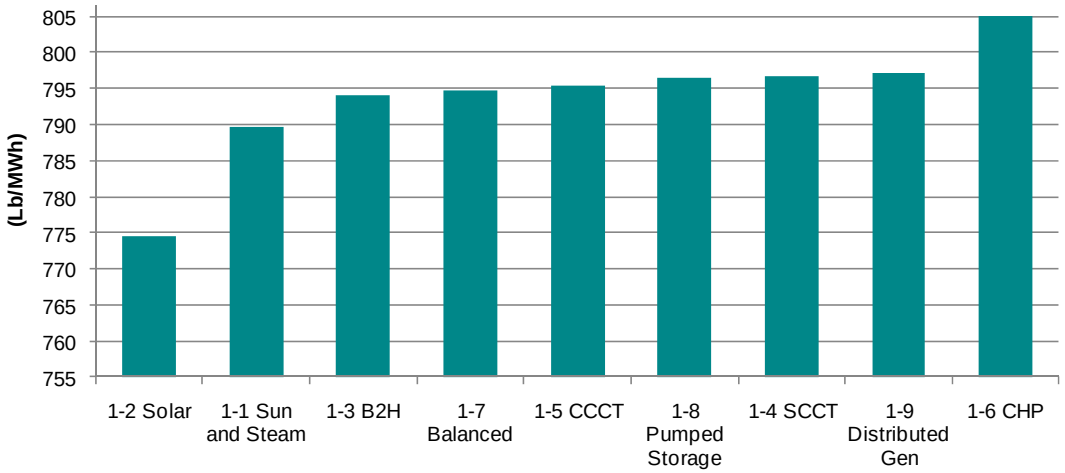



**Figure 9.1 Average $CO_2$ intensity by portfolio (2011–2020)**

Figure 9.2 shows similar information for the portfolios analyzed for the second 10-year period, which assumes portfolio 1-3 Boardman to Hemingway is built. The intensity rates range from approximately 660 lbs-per-MWh to 745 lbs-per-MWh, which shows a further reduction from the portfolios analyzed in the first 10-year period.

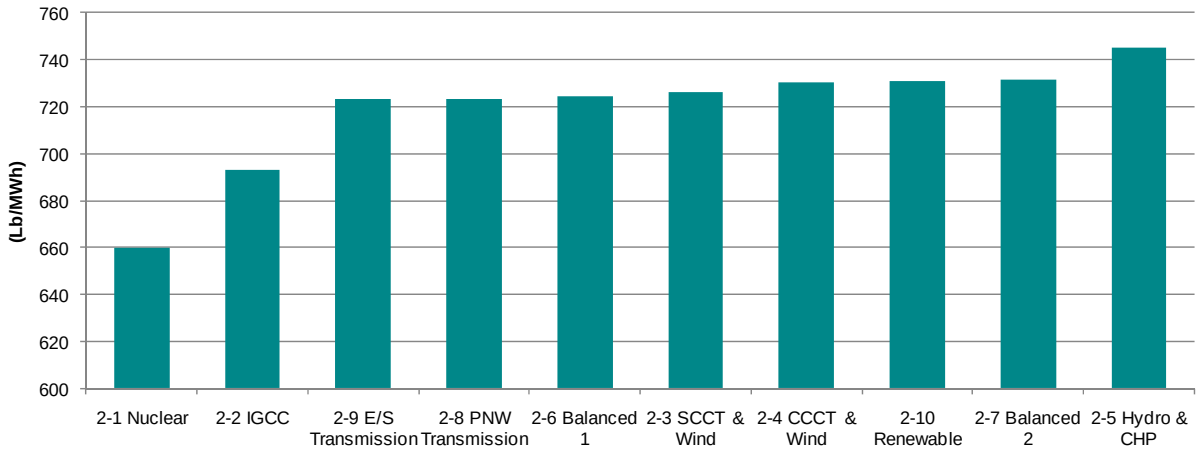



**Figure 9.2 Average $CO_2$ intensity by portfolio (2021–2030)**

The lower emissions intensity rates presented in Figures 9.1 and 9.2 are the result of the carbon adder used in the IRP analysis in addition to the reduced operation of Idaho Power's coal resources at times when market prices are lower than the dispatch cost of the coal resources. These results also indicate a majority of the risk associated with the future regulation of carbon is related to Idaho Power's existing resources.

## Risk Analysis and Results

Idaho Power evaluated all the resource portfolios identified in the 2011 IRP for both qualitative and quantitative risks. Risk analysis identifies resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

One of the major risks is load-growth uncertainty associated with the present economic conditions. Economic growth has slowed considerably in Idaho Power's service area, and there has been extensive speculation regarding the duration of the economic downturn. A quick return to the economic growth rates of the past 20 years will require additional generation resources to meet load.

The other factor affecting load growth is the effectiveness of Idaho Power's DSM programs. Idaho Power projects continued success with DSM programs, but the success is dependent on overall economic conditions as well as program funding and consumer preferences. A lower realization factor for DSM programs will increase load and require additional generation resources.

Electric vehicles are another factor having the potential to increase load. Study reports completed by the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory were used to estimate load impacts associated with electric-vehicle charging. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. Further discussion on electric vehicles is contained in *Appendix A–Sales and Load Forecast.*

Many of the other risk factors are regulatory in nature. Idaho Power faces regulatory uncertainty associated with carbon regulation and a federal RES. Idaho Power is planning for a resource future that restricts the quantity of carbon that can be released into the earth's atmosphere. The proposed carbon legislation is anticipated to restrict the quantity of carbon emissions and increase the price of RECs. Limited or ineffective carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional, fossil-fuel plants.

Natural gas prices are primarily affected by supply and demand; however, economic growth, load growth, carbon legislation, and transmission availability will also influence prices. Presently, natural gas prices are relatively low. However, Idaho Power analyzed the portfolio costs under a scenario where natural gas is considerably more expensive.

## Qualitative Risk Analysis

Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Idaho Power discussed the qualitative factors in public forums, including the IRPAC meetings, as well as in regulatory workshops and proceedings. Some of the qualitative risks, such as planning for new large loads, may be considered policy issues and are discussed in Chapter 1. The qualitative risk of schedule delays and siting issues associated with the Boardman to Hemingway transmission project are addressed by identifying both a preferred and alternate resource portfolios. Many of the qualitative risks, such as carbon policy, resource technology, and market price risk, are covered in the quantitative analysis through variations in carbon emissions prices, capital cost, and natural gas prices. In general, Idaho Power addresses the qualitative risks through policy discussions with the IRPAC and regulatory agencies or by associating the risk with proxy variables in the quantitative analysis.

## Quantitative Risk Analysis

For the 2011 IRP, Idaho Power analyzed high, low, and expected cases for the following risk factors: 1) carbon, 2) natural gas prices, 3) capital cost, 4) DSM variability, 5) load variability, and 6) REC prices. In addition to the high, low, and expected cases for carbon, a no-carbon cost case was also analyzed.

The results of the quantitative risk analysis show a change from the expected cost of each portfolio for each risk factor analyzed. The results of the quantitative risk analyses are presented in terms of NPV total portfolio cost resulting in a side-by-side comparison of the range of potential costs for each risk factor.

### Carbon Risk (2011–2020)

Four carbon adder scenarios, an expected case and three alternate cases, were analyzed as part of the 2011 IRP. A description of the four cases is contained in Chapter 6. With respect to the cost of carbon, the nine portfolios perform relatively similarly for the three alternate levels of carbon cost considered.

As expected—given their renewable focus, the 1-1 Sun and Steam and 1-2 Solar portfolios are not as adversely affected by high carbon costs (costs estimated to increase slightly less than costs for other portfolios), nor are they benefitted as much by lower or zero carbon costs. However, the modest differences between portfolios in comparing the estimated cost effects associated with the levels of carbon cost suggest that much of the cost of carbon is driven by the operation of Idaho Power's existing and committed resources. Thus, based on the varying levels of carbon cost risk considered, none of the portfolios are likely to lead to a catastrophic financial outcome occurring as a result of carbon costs deviating from expected costs.

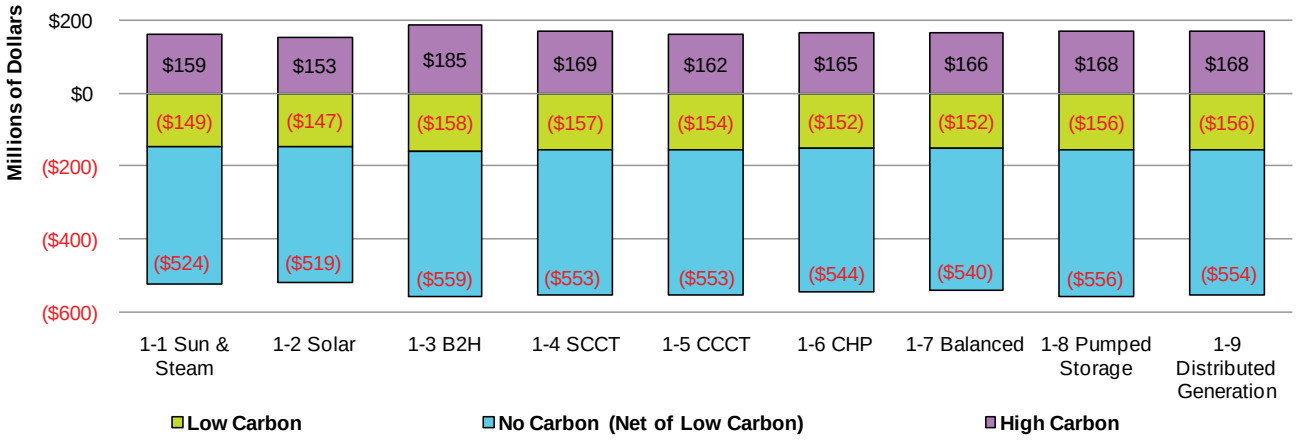



**Figure 9.3 Carbon risk analysis results (2011–2020)**

## Natural Gas Price Risk (2011–2020)

Three natural gas price scenarios were analyzed for the 2011 IRP—high, expected, and low. Additional details of the natural gas price scenarios are presented in Chapter 6, and the results are presented in Figure 9.4. As expected, portfolios having SCCT, CCCT, or CHP resources show a greater range of risk associated with natural gas prices. The portfolios having elevated risk related with higher-than-expected natural gas prices include 1-1 Sun and Steam, 1-6 CHP, and 1-7 Balanced. Conversely, these portfolios are likely to experience greater cost decreases in the event of lower-than-expected natural gas prices. The risk analysis also indicates that the 1-5 CCCT portfolio is projected to benefit disproportionately from lower-than-expected natural gas prices, because the CCCT is economically dispatched more frequently under the low natural gas price scenario.

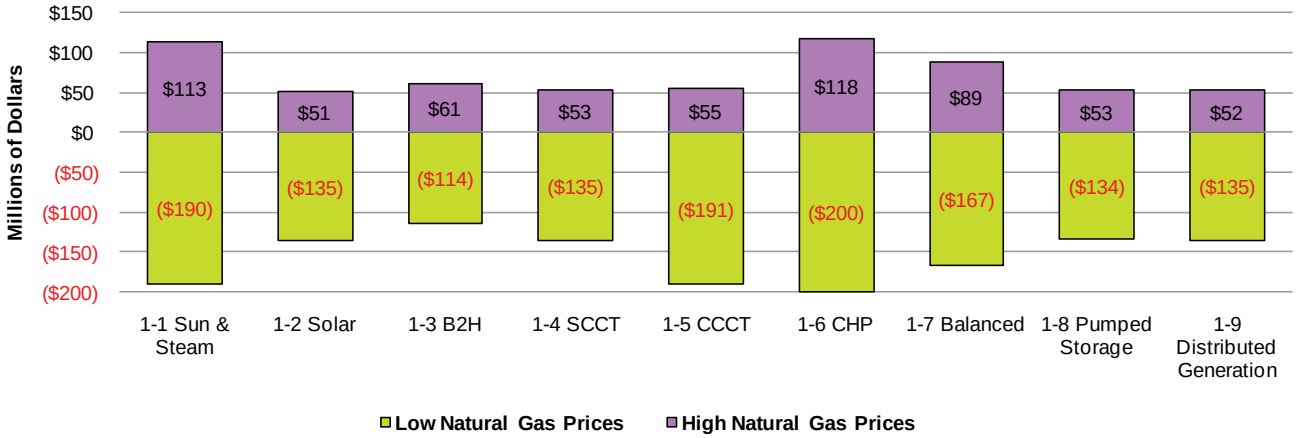



**Figure 9.4 Natural gas price risk analysis results (2011–2020)**

## Capital Cost Risk (2011–2020)

For the 2011 IRP, Idaho Power introduced asymmetry into the estimates of capital cost risk. The introduction of this bias is consistent with comments received from the IRPAC suggesting that development costs for particular resources do not have equal increase/decrease potential. Figure 9.5 illustrates the assumed range in capital costs for considered generating resources, where the horizontal dash for each resource is the expected-case cost in dollars per kW, and the vertical bar reflects the potential capital cost risk for each resource relative to its expected-case cost. Figure 9.5 includes resources used in portfolios for both the first and second 10-year periods of the analysis.

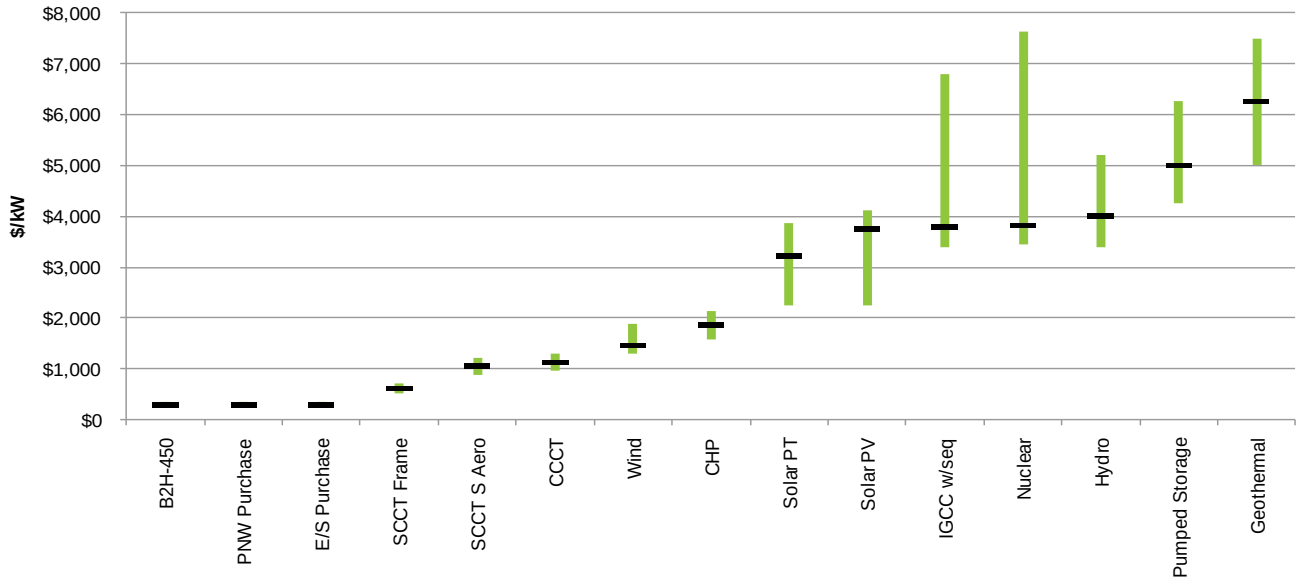



**Figure 9.5 Capital cost risk analysis**

The results of the capital cost risk analysis demonstrate that resource portfolios comprised of high-capital-cost resources have the greatest potential for deviating from expected-case portfolio cost estimates. The asymmetry in the capital-cost risk is particularly evident for portfolio 1-1 Sun and Steam, 1-2 Solar, and 1-8 Pumped Storage. Solar resources (thermal and PV) are expected to have a greater potential for capital cost decrease versus cost increase; consequently, the two, solar-based portfolios are likely to have the greatest cost-reduction potential. Solar-powered resources are also estimated to have substantial potential for increased capital costs. Consequently, the potential cost increase for portfolios containing solar resources either matches or exceeds that of other portfolios. The results of the capital-cost risk analysis are presented in Figure 9.6.

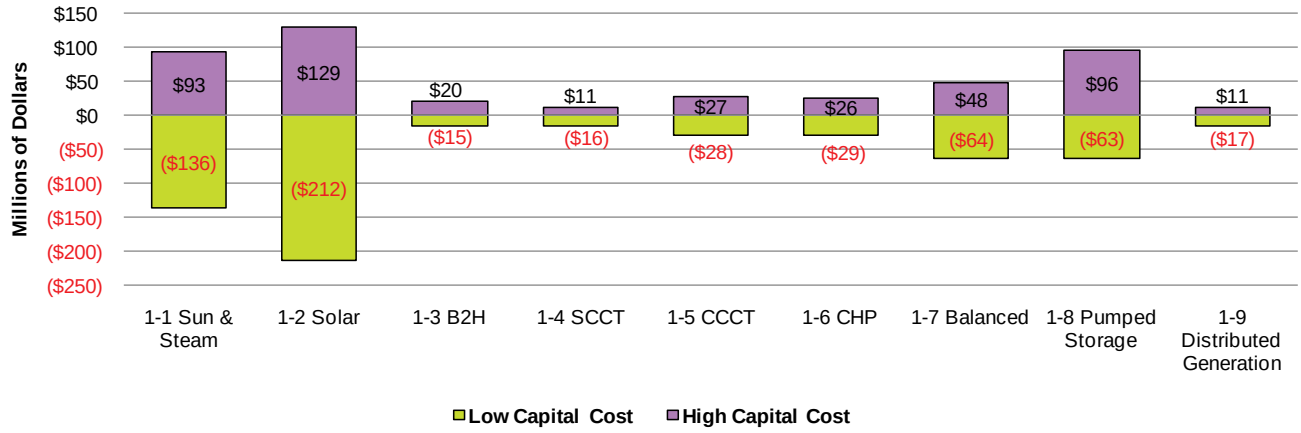



**Figure 9.6 Capital-cost risk analysis results (2011–2020)**

## Risk Due to DSM Variability (2011–2020)

The 2011 IRP risk analysis also evaluated the costs associated with higher-than-expected and lower-than-expected levels of DSM. For the high-DSM case, DSM levels resulting in load being 8 percent lower than expected are reached by the mid-2020s. For the low-DSM case, lower than expected DSM levels resulting in load being 4 percent higher-than-expected are reached by the mid-2020s. The DSM risk scenarios analyzed are shown in Figure 9.7.

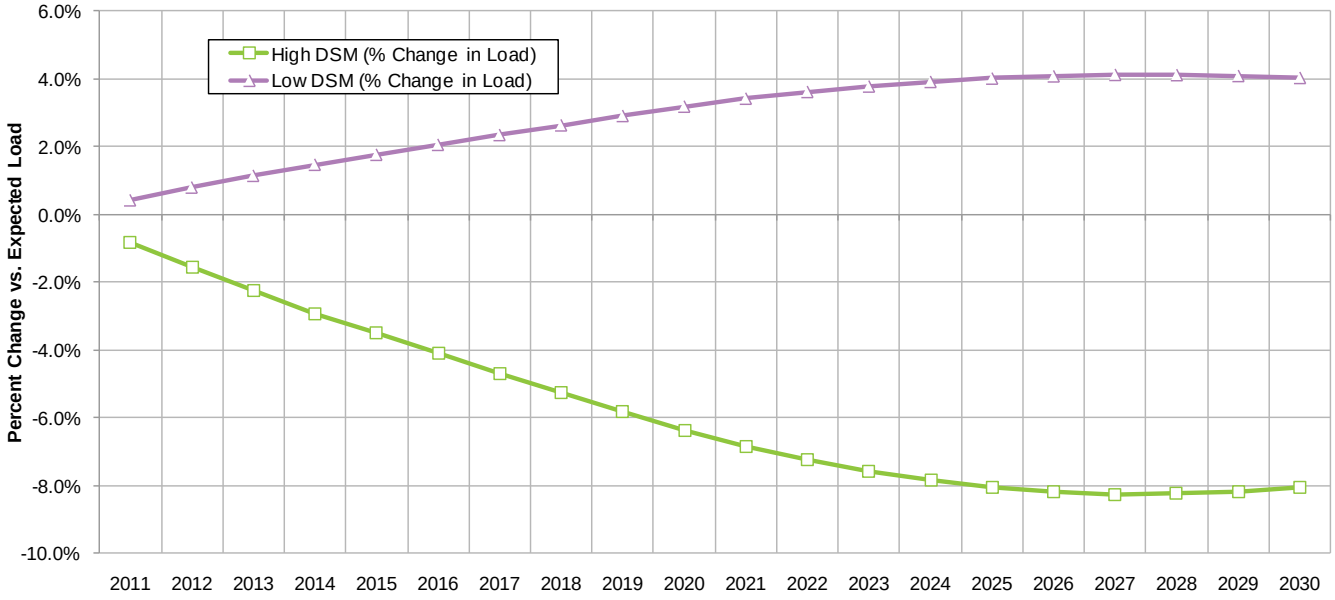



**Figure 9.7 DSM variability risk analysis**

Figure 9.8 indicates that deviations of DSM program performance from the expected-case forecast have a relatively small impact on total portfolio costs, and the estimated impacts are relatively uniform across portfolios.




**Figure 9.8 DSM variability risk analysis results (2011–2020)**

## Risk Due to Load Variability (2011–2020)

For the 2011 IRP, high- and low-load risk scenarios were derived to analyze the impact of deviations in the IRP load forecast. Figure 9.9 shows the range in load analyzed as a percentage of the expected-case load forecast. For the high-case, loads are approximately 10 percent higher than the expected-case forecast by the end of the planning period in 2030. For the low-case, loads are nearly 10 percent lower than the expected-case forecast in 2030.

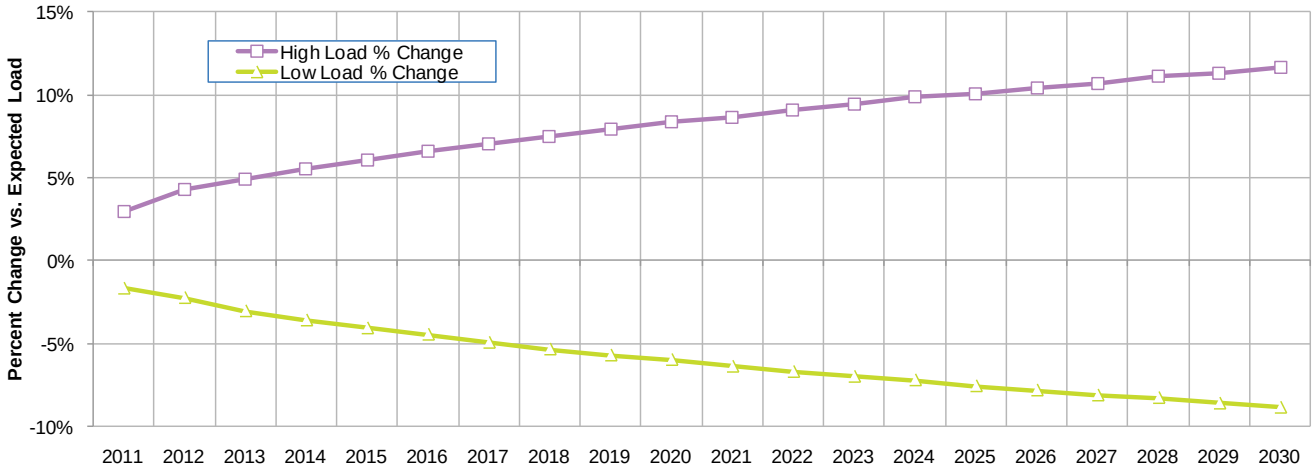



**Figure 9.9 Load variability risk analysis**

Figure 9.10 indicates that load deviations from the expected-case forecast have the potential to significantly impact portfolio costs. However, the estimated impacts are fairly uniform across portfolios, suggesting equal exposure with respect to load risk for the portfolios. Furthermore, the analysis accounts only for power supply costs and does not include revenues associated with retail sales being higher or lower than expected.

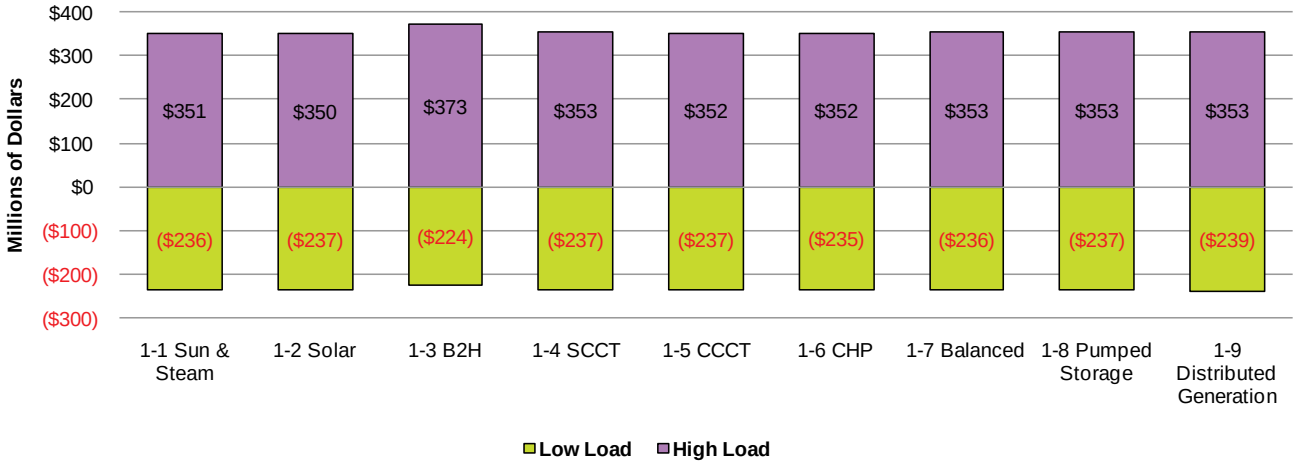



**Figure 9.10 Load risk analysis results (2011–2020)**

## REC Price Risk (2011–2020)

In addition to an expected case for REC prices, high- and low-price scenarios were also analyzed. Additional details on the REC price scenarios is presented in Chapter 6. The results of the analysis indicate none of the portfolios are exposed to severe risk potential with respect to REC price. This is expected because each portfolio was designed to have approximately the number of RECs needed to be compliant with a federal RES.

Because a majority of the portfolios have surplus RECs, high REC prices result in lower portfolio costs relative to the expected REC price case. Similarly, RECs having little or no value leads to higher portfolio costs. The small differences between portfolios follow expected trends. For example, portfolios that generate more RECs (1-1 Sun and Steam and 1-2 Solar) will see a greater cost decrease as a consequence of high REC prices. Conversely, the cost of these portfolios increases more under the low REC price scenario.




**Figure 9.11 REC price risk analysis results (2011–2020)**

## Quantitative Risk Analysis Summary (2011–2020)

Several conclusions can be drawn from the quantitative risk analysis performed for the first 10-year period. Those conclusions include the following:

- Portfolios with solar resources (1-1 Sun and Steam and 1-2 Solar) could have substantially lower-than-expected capital costs, and therefore lower total portfolio costs. However, this lower cost potential is insufficient to overcome the disparity between the expected costs of these portfolios and the expected cost of portfolio 1-3 Boardman to Hemingway.
- The portfolios are designed for REC compliance, and, consequently, carry minimal exposure to REC price risk.
- Portfolio 1-3 Boardman to Hemingway has minimal potential for cost increases or decreases associated with capital costs deviating from expected costs.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources.

The following sections present a similar analysis for the second 10 year period (2021–2030).

## Carbon Risk (2021–2030)

Portfolio 2-1 Nuclear, with no incremental carbon-producing resources, has the least potential for cost deviations as a result of the high, low, and no carbon cost scenarios. However, the differences between this portfolio and the other portfolios, with respect to the cost of carbon, are relatively modest. Again, this suggests that carbon risk is primarily due to Idaho Power's existing and committed resources. Figure 9.12 shows the results of the carbon risk analysis for the second 10-year period.

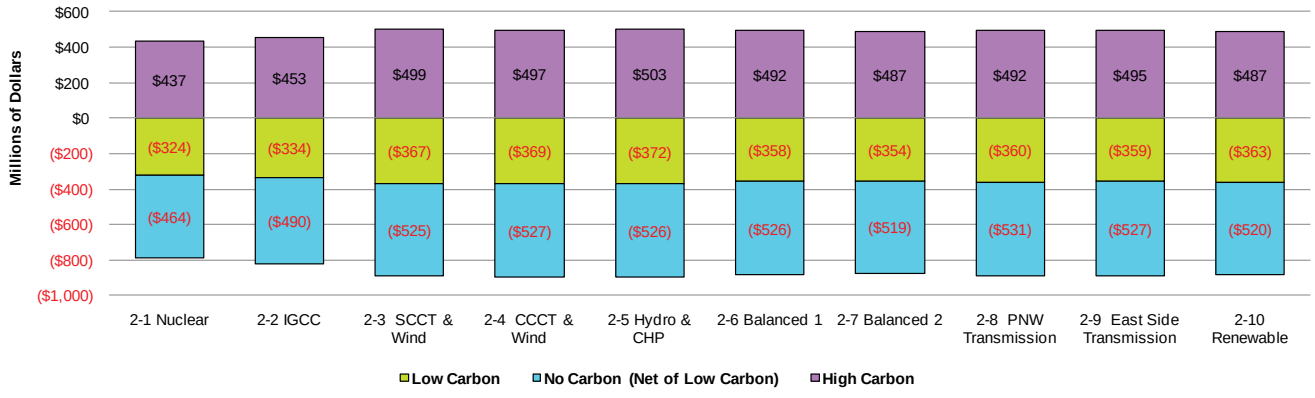
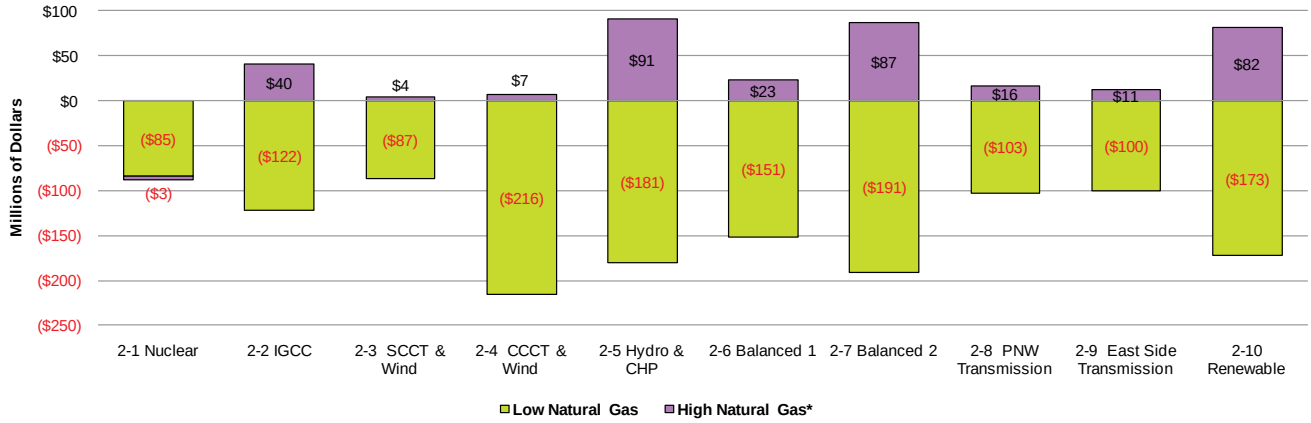



**Figure 9.12 Carbon risk analysis results (2021–2030)**

## Natural Gas Price Risk (2021–2030)

Lower-than-expected natural gas prices lead to portfolio costs that are lower than those occurring under expected natural gas price conditions. The portfolio cost reductions are greatest for the portfolios containing new gas resources. Under higher-than-expected natural gas prices, portfolio 2-5 Hydro and CHP and portfolio 2-7 Balanced 2 have the highest risk under a high-gas-price scenario. These portfolios contain CHP resources, which are typically operated at high-capacity factors to meet the needs of the steam host. Portfolio 2-6 Balanced 1 has a modest potential for cost deviations occurring in response to different-than-expected natural gas prices. Figure 9.13 shows the results of the natural gas price risk analysis for the second 10-year period.




*In portfolio 2-1 Nuclear, high natural gas prices results in a reduced portfolio cost of ($3).

**Figure 9.13 Natural Gas price risk analysis results (2021–2030)**

## Capital Cost Risk (2021–2030)

Figure 9.14 shows the range of costs for portfolios due to capital cost risk. The results of the analysis shows that nuclear generating facilities have considerably greater potential for capital-cost increases versus their potential for cost decrease. This is evident in the potential cost increase of portfolio 2-1 Nuclear, which could have an NPV cost of $1.3 million more than expected under the high capital-cost scenario. Portfolio 2-2 IGCC also has a substantially greater risk for cost increases relative to other portfolios. Portfolio 2-6 Balanced 1 is among the group of portfolios having the lowest exposure to capital cost risk.

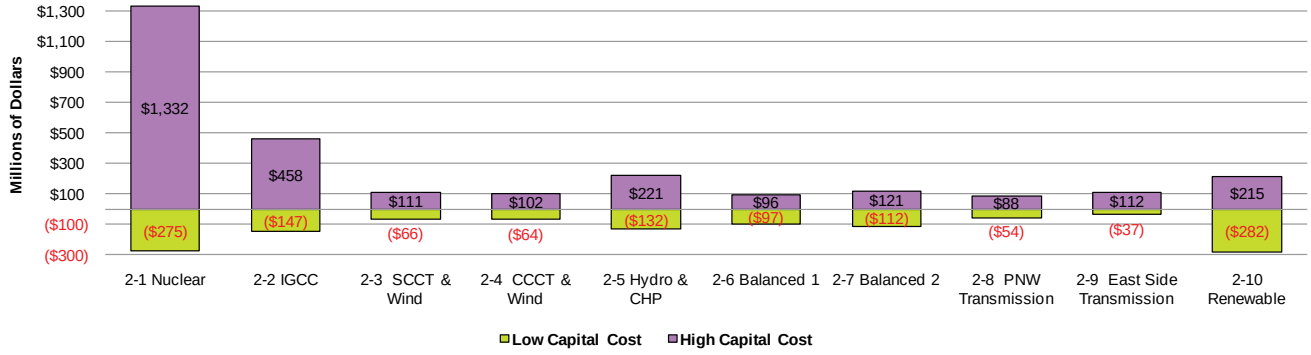



**Figure 9.14 Capital cost risk analysis results (2021–2030)**

## Risk Due to DSM Variability (2021–2030)

The 10 resource portfolios considered for the second 10 years contain the same energy efficiency and demand response programs. The potential for portfolio costs to deviate as a result of different-than-expected DSM program performance is very similar between the portfolios.

Thus, the DSM risk is not a characteristic that can be used to discriminate between the different resource portfolios.




**Figure 9.15 DSM risk analysis results (2021–2030)**

## Risk Due to Load Variability (2021–2030)

Different-than-expected load conditions also increase or decrease costs similarly between the portfolios considered for the second 10 years. This suggests that the portfolios have equal exposure to load variability risk.

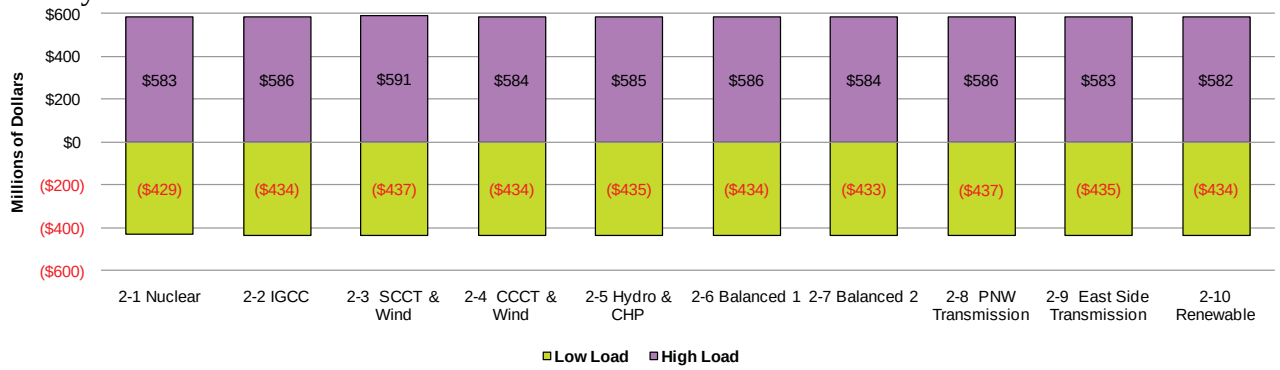
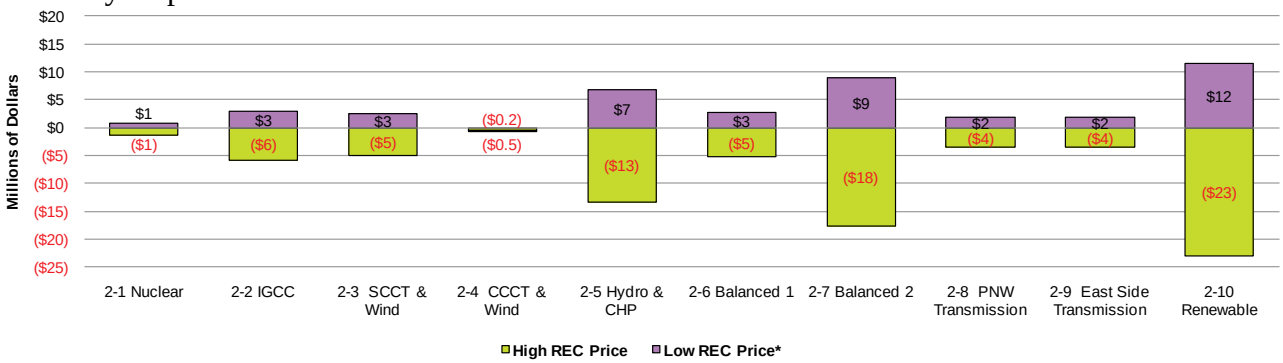



**Figure 9.16 Load variability risk analysis results (2021–2030)**

## REC Price Risk (2021–2030)

As seen in the analysis for the first 10-year period, REC prices have a minimal impact on total portfolio costs. Portfolio 2-10 Renewable produces the greatest amount of surplus RECs and, consequently, has the highest potential for a cost decrease as a result of higher-than-expected REC prices. Conversely, this portfolio has the greatest risk for increased costs due to lower-than-expected REC prices. However, the potential cost changes due to the high- and low-REC price scenarios are similar between portfolios and relatively small compared to other risk factors. This suggests the portfolios are similarly exposed to REC price risk, which is minimal. Figure 9.17 shows the results of the REC price risk analysis for the second 10-year period.




*In portfolio 2-4 CCCT & Wind, a low REC price results in a reduced portfolio cost of ($.02).

**Figure 9.17 REC price risk analysis results (2021–2030)**

### Quantitative Risk Analysis Summary (2021–2030)

Under higher-than-expected capital costs, portfolios 2-1 Nuclear and 2-2 IGCC have the greatest exposure to higher costs relative to the other portfolios. With this exception, the differences between the portfolios with respect to the risk factors considered are generally modest, suggesting that the portfolios contain a similar amount of risk exposure. Other conclusions from the 2021–2030 risk analysis include the following:

- All portfolios are designed to be compliant with a federal RES and, consequently, carry minimal exposure to REC price risk.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources. However, there is some incremental carbon risk associated with all the portfolios except portfolio 2-1 Nuclear. This incremental exposure is evidenced by the greater potential for cost increase/decrease of the other portfolios relative the nuclear portfolio.
- Portfolio 2-10 Renewable has the greatest potential for total cost decrease occurring as a result of lower-than-expected capital costs, reflecting the expectation that solar-powered resources have a greater potential for capital cost decreases than increases.
- The 2-6 Balanced 1, 2-8 PNW Transmission, and 2-9 Eastside Transmission portfolios are among the group of portfolios having the lowest exposure to capital cost risk.

## Stochastic Analysis

Stochastic analysis is a statistical technique often used in resource planning. The OPUC recognized the benefits of stochastic analysis and included stochastic analysis as part of its Resource Planning Guidelines (Oregon Docket UM 1056, Order 07-047, February 9, 2007, Appendix A, page 4, Guideline 4 b). The entire Oregon order listing the resource planning guidelines is included in *Appendix C–Technical Appendix*. Idaho Power has used a probabilistic analysis to model loss of load in the 2011 IRP as well as in previous resource plans. Idaho Power applied a stochastic analysis to the natural gas price forecast in the 2009 IRP, and the 2011 IRP is Idaho Power's first application of a stochastic analysis to the expected cost of the various resource portfolios.

Idaho Power modeled the combined effects of the risk variables on the resource portfolio costs for each of the 10-year periods. The results of the stochastic analysis were then used as the determining factor in identifying the preferred and alternate portfolios.

To complete the stochastic analysis, Idaho Power identified six risk variables, calculated the incremental resource portfolio cost at the extremes of the range for each risk variable, divided the cost range for each risk variable into five sections, and randomly sampled from the five sections to calculate a distribution of resource portfolio costs. The key points for the analysis of the first 10-year period include the following:

- Nine resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

## Risk Variables

Idaho Power identified six risk variables that are included in the stochastic analysis, 1) natural gas price, 2) REC price, 3) carbon cost, 4) load variation, 5) DSM variation, and 6) capital cost. Idaho Power and the IRPAC identified a range for each of the six variables, and Idaho Power applied the range to each risk variable and calculated the range of portfolio costs for the risk variable using the AURORA model. For example, in the year 2020 natural gas prices were expected to be within the approximate range of $6.50 to $10.50 per MMBtu. Idaho Power then used AURORA and the identified range to calculate the cost of each resource portfolio at the two natural gas price extremes. For portfolio 1-3 Boardman to Hemingway the values are—base cost: $86 million; high natural gas price: $96 million; and low natural gas price: $108 million.

Portfolio 1-3 Boardman to Hemingway shows an interesting result. Of the three possibilities analyzed, the base cost with intermediate natural gas prices had the lowest overall cost. Under high gas prices, Idaho Power paid more for energy, and the costs increase; under low gas costs, off-system energy sales were not as profitable for Idaho Power and its customers.

In the case of natural gas prices, the range used in the stochastic analysis was from the low value of $86 million to the high value of $108 million, or a range of $22 million. Similarly, a range was calculated for each of the six risk variables for all nine resource portfolios in the first 10 years. The low value for most of the risk variables in most of the resource portfolios was lower than the base portfolio cost.

After determining the high and low values for each risk variable, the portfolio cost range was divided into five equal segments. For the Boardman to Hemingway portfolio example, the range from $86 million to $108 million was divided into five segments with each segment equal to $4.4 million. Similarly, the range was divided into five equal segments for each of the six risk variables. The entire process was repeated for each of the nine resource portfolios. Five possible states for each of the six risk variables create over 15,000 possible combinations.

## Stochastic Modeling

The objective of the stochastic modeling was to estimate the distribution of the incremental portfolio costs. The distribution was calculated by randomly sampling from the range for each risk value, combining the effects of the six risk values, and calculating the resulting resource portfolio cost. The sampling process was repeated 100,000 times for each resource portfolio to estimate the distribution of the resource portfolio costs.

Each risk variable was assumed to be uniformly distributed over the range of values. The uniform distribution means that there is an equal chance of sampling from each of the five segments of the range. For natural gas prices and the 1-3 Boardman to Hemingway portfolio, the uniform distribution means that each $4.4-million segment was equally likely to be sampled. In 100,000 draws, each segment is expected to be sampled 20,000 times.

Three of the six risk variables were considered independent: load variation, DSM variation, and capital cost. For capital costs, independence means that the result of any other risk variable is presumed to have no, or only minor, influence on the capital cost.

The first three risk variables were assumed to show some level of coincidence: natural gas price, REC price, and carbon cost. Specifically, carbon cost was assumed to be the primary risk factor. REC prices were assumed to be 80-percent coincident with carbon cost, and natural gas price was assumed to be 60-percent coincident with carbon cost. The coincidence means that if the sample for carbon cost is from the highest segment in the risk range, there is an 80-percent chance that the sample

of the REC price will also be in the highest segment, with a 60 percent chance that the sample of the natural gas price will also be in the highest segment. Likewise for a sample from any of the other four segments in the carbon cost range. The coincidence was added to the model to reflect the thought that the three variables may be correlated. Even though each of the six risk variables was uniformly distributed, Idaho Power assumed that there is a coincidence factor between three of the six risk variables.

## Stochastic Analysis Results and Portfolio Selection (2011–2020)

The results of 100,000 samples for portfolio 1-3 Boardman to Hemingway are shown in the histogram in Figure 9.18.

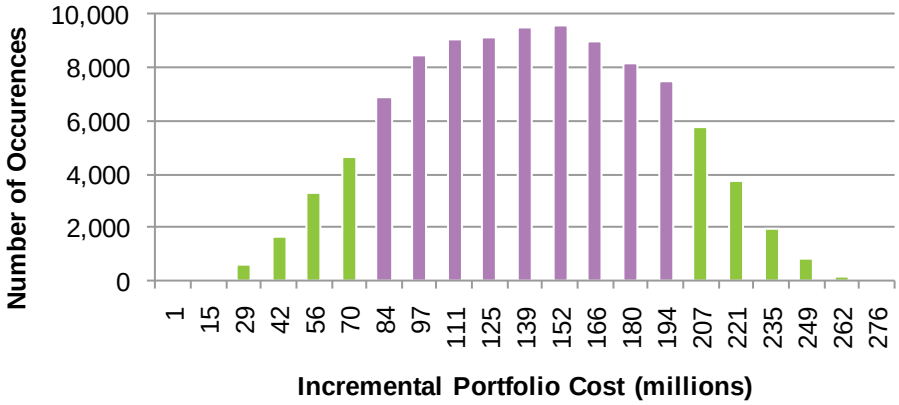



**Figure 9.18 Sampling results from portfolio 1-3 Boardman to Hemingway**

Based on the sampling of the stochastic analysis, the incremental cost of the Boardman to Hemingway portfolio is expected to range from approximately $1 million to $276 million, with a median value of $133 million. The green bars show the lowest 10 percent and the highest 10 percent of the distribution, and the purple bars represent the middle 80 percent of the distribution. The distribution for portfolio 1-3 Boardman to Hemingway appears to be a normal distribution; however, other resource portfolios had distributions that appear less like a normal distribution. The histogram for portfolio 1-4 SCCT is shown in Figure 9.19. The stochastic cost range for the SCCT portfolio does not appear to be normally distributed; the histogram is roughly flat from an incremental portfolio cost of $100 million up to $200 million and declines on either end. The summary data for all of the resource portfolios, including the distribution charts, is included in *Appendix C–Technical Appendix.*

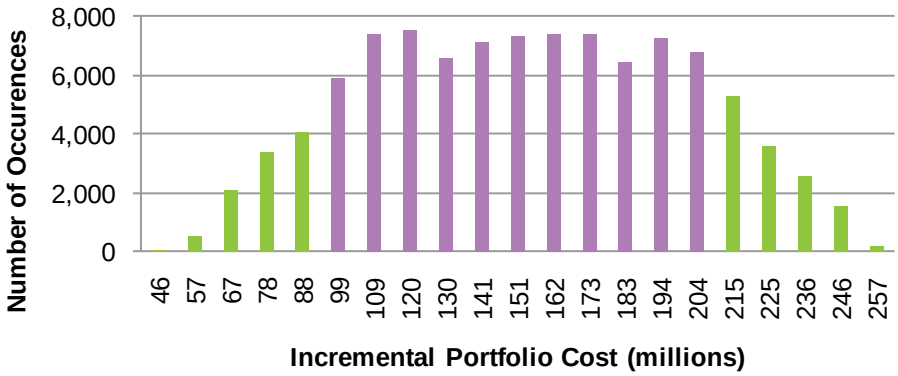



**Figure 9.19 Sampling results from portfolio 1-4 SCCT**

Table 9.4 compares the nine resource portfolios during the 2011–2020 time period. The table shows the base cost of each resource portfolio, the rank of the base cost in the stochastic analysis, the median of the stochastic analysis, some values defining the range of the stochastic analysis. The base rank is the percentile in the stochastic analysis representing the base cost of the resource portfolio. For example, the

base cost of 1-3 Boardman to Hemingway is approximately $86 million, and $86 million would fall at the 19th percentile in the stochastic distribution—19 percent of the draws have a cost less than the 1-3 Boardman to Hemingway base cost of $86 million, and 81 percent of the draws have a higher cost than the base cost of $86 million.

**Table 9.4 Stochastic analysis results (2011–2020)**

| | Portfolio Cost Calculations (000) | | | | Risk Analysis Range (000) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base | Base Rank | Stochastic Median | Difference | Lower | 10th | Median | 90th | Upper |
| 1-1 Sun & Steam | $496,198 | 54% | $488,367 | -$7,831 | $201,786 | $356,662 | $488,367 | $612,505 | $808,750 |
| 1-2 Solar | $505,407 | 58% | $478,897 | -$26,510 | $162,718 | $321,382 | $478,897 | $628,336 | $805,521 |
| 1-3 Boardman to Hemingway | $86,079 | 19% | $133,582 | $47,503 | $1,143 | $67,712 | $133,582 | $198,852 | $276,164 |
| 1-4 SCCT | $129,443 | 36% | $148,643 | $19,200 | $46,060 | $88,149 | $148,643 | $210,860 | $256,889 |
| 1-5 CCCT | $222,177 | 60% | $208,242 | -$13,935 | $66,345 | $138,884 | $208,242 | $277,954 | $368,603 |
| 1-6 CHP | $267,462 | 44% | $277,183 | $9,721 | $104,783 | $195,179 | $277,183 | $361,535 | $486,767 |
| 1-7 Balanced | $288,613 | 44% | $299,237 | $10,624 | $115,778 | $217,378 | $299,237 | $381,340 | $507,002 |
| 1-8 Pumped Storage | $426,601 | 31% | $462,254 | $35,653 | $287,183 | $376,777 | $462,254 | $550,862 | $645,560 |
| 1-9 Distributed Generation | $135,055 | 39% | $151,697 | $16,642 | $49,879 | $91,196 | $151,697 | $212,500 | $259,478 |

Figure 9.20 shows an overview of the stochastic analysis for all of the resource portfolios for the 2011–2020 time period.

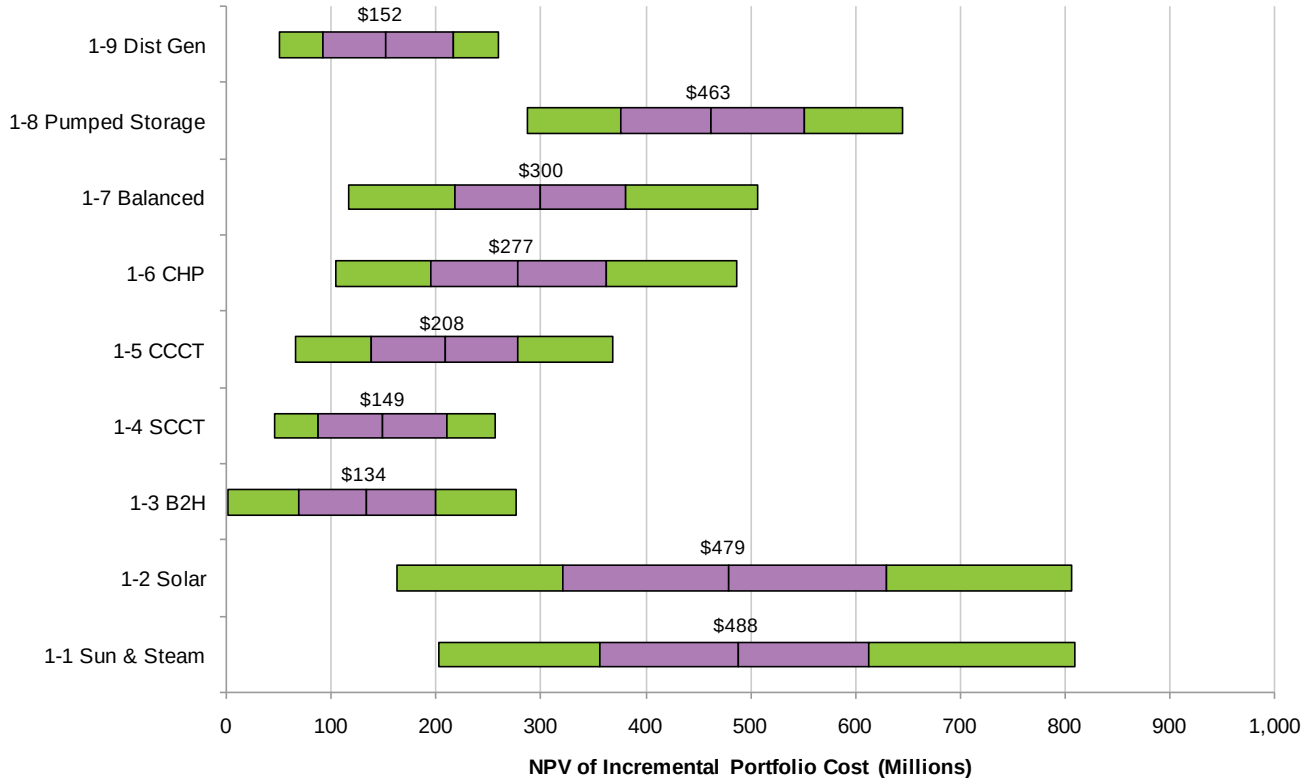



**Figure 9.20 Stochastic analysis results (2011–2020)**

The length of the bars in Figure 9.20 show the stochastic range of the incremental portfolio costs. The purple portion of the bar represents the middle 80 percent of the distribution, and the green bars at either end represent the 10-percent tails of the distribution similar to the colors in the histogram presented in Figure 9.19. The upper and lower limits, median, 10th, and 90th percentile values represented in Figure 9.20 are also shown in Table 9.4.

The capital cost risk variable seems to have the greatest effect on the stochastic range for a resource portfolio and the stochastic range of a resource portfolio increases as the capital cost of the portfolio cost increases. Portfolio 1-4 SCCT has the lowest capital cost, and 1-1 Sun and Solar and 1-2 Solar have the highest capital cost.

The link between the stochastic range and the capital cost is a direct result of Idaho Power's summer capacity deficit as described in Chapter 8 and Figure 8.1. The effect of the summer capacity deficits is that Idaho Power needs energy during a limited number of summer hours each year to meet customers' peak demand. Limited operation of a generation resource leads to low total operating costs, even if the hourly operating costs are high, because the resource operates only during a limited number of hours each year to meet peak demand.

Limited operation means that variations in the capital costs can overshadow any variations in operating costs when the corresponding capital costs are high, even for resources with extremely low operating costs. An example is a solar PV resource where the operating costs are very low, but the capital costs are high. What the range also indicates is if the capital costs of a resource, such as solar, decline sufficiently, both the overall portfolio cost and the stochastic range will be reduced.

The conclusion of the stochastic analysis indicates that the two resource portfolios with SCCT generation, 1-4 SCCT and 1-9 Distributed Generation have the smallest stochastic price risk range. Portfolio 1-3 Boardman to Hemingway has the lowest expected cost and a slightly larger risk range. Capital costs overshadow the operating costs for the other resource portfolios, especially for the resource portfolios with a large amount of solar generation, 1-1 Sun and Solar and 1-2 Solar. The resource portfolios with the lowest capital cost have the smallest stochastic price range.

The stochastic analysis is a key part of the portfolio selection process used by Idaho Power in the 2011 IRP. Based on the expected low cost, and the limited risk spread, Idaho Power selected two resource portfolios for the first 10 years of the planning period (2011–2020), 1-3 Boardman to Hemingway (preferred) and 1-4 SCCT (alternate).

## *Stochastic Analysis Results and Portfolio Selection (2021–2030)*

Idaho Power followed the same process to analyze the second 10 years of the planning period:

- Ten resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

The 2011 IRP also identifies a preferred portfolio and an alternate portfolio for the 2021–2030 time period. However, the selection of these two portfolios is not as straightforward as the selection for the first 10-year period. The preferred portfolio is 2-6 Balanced 1, which incorporates geothermal, solar, small hydroelectric, and natural gas resources. The alternate portfolio for the second 10-year period is 2-8 Pacific Northwest Transmission which substantially relies on additional market purchases from the Pacific Northwest. An explanation of the rationale for the selection of these portfolios follows.

Figure 9.21 shows the incremental cost distribution for portfolio 2-6 Balanced 1, and Figure 9.22 shows the same information for the 2-8 Pacific Northwest Transmission portfolio.

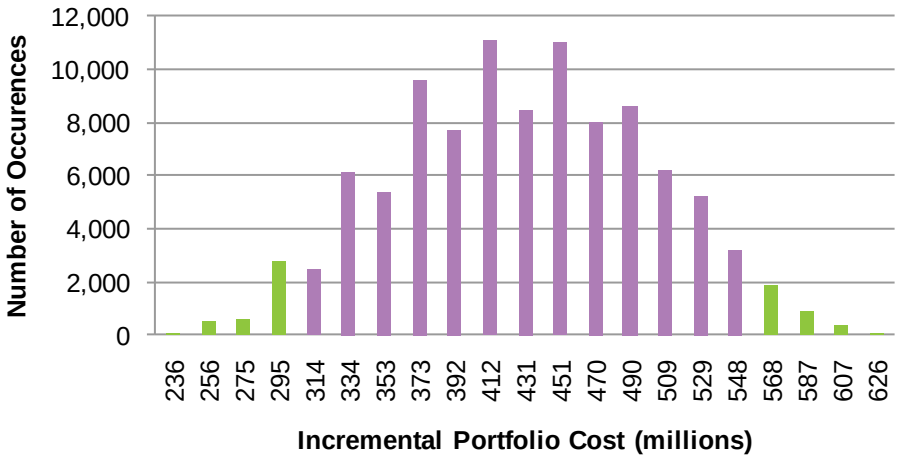



**Figure 9.21 Sampling results from portfolio 2-6 Balanced 1**

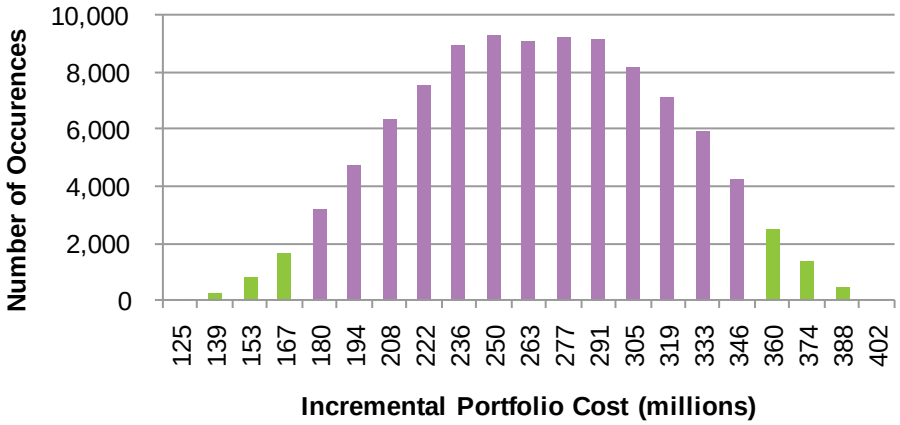



**Figure 9.22 Sampling results from portfolio 2-8 Pacific Northwest Transmission**

Like the first 10 years of the planning period, the distribution of the results from stochastic analysis of some resource portfolios more closely approximates a normal distribution than for other resource portfolios. Having a normal distribution is an interesting finding, but the normal distribution is not critical to the analysis or to the selection of a preferred portfolio. The main information resulting from the stochastic analysis is the cost range for the resource portfolio.

Table 9.5 shows the cost distribution for all 10 resource portfolios considered in the stochastic analysis of the second 10 years of the planning period, and Figure 9.23 shows the graphical results of the stochastic analysis for all of the resource portfolios for the 2021–2030 time period.

The nuclear resource portfolio has the highest expected cost and the broadest cost range. Like the analysis of the first 10 years, the cost distribution is driven by capital costs, and nuclear generation has a very high capital cost. The preferred and alternate portfolios, 2-6 Balanced 1 and 2-8 Pacific Northwest Transmission, both have relatively low-expected costs and a narrow range of possible costs.

Although the results of the stochastic analysis show portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission have a lower expected total portfolio cost, neither was selected as the preferred portfolio. Because of uncertainty regarding the ability to build new long-distance, high-voltage transmission projects in the second 10-year planning period, Idaho Power does not believe either portfolio presents the best option. In addition, the low cost of these portfolios is contingent on long-term, low market prices that are currently the result of a surplus of energy in the Pacific Northwest for portfolio 2-8, and the anticipation of low market prices on the east side of Idaho Power's system due to considerable amounts of wind generation being built in Wyoming.

**Table 9.5 Stochastic analysis results (2021–2030)**

| | Portfolio Cost Calculations (000) | | | | Risk Analysis Range (000) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base | Base Rank | Stochastic Median | Difference | Lower | 10th | Median | 90th | Upper |
| 2-1 Nuclear | $1,323,279 | 13% | $1,906,067 | $582,788 | $937,479 | $1,258,961 | $1,906,067 | $2,558,841 | $2,826,562 |
| 2-2 IGCC | $625,319 | 25% | $774,304 | $148,985 | $355,848 | $524,204 | $774,304 | $1,024,405 | $1,200,846 |
| 2-3 SCCT & Wind | $564,334 | 35% | $591,640 | $27,306 | $460,369 | $516,699 | $591,640 | $667,135 | $725,935 |
| 2-4 CCCT & Wind | $565,377 | 78% | $511,684 | -$53,693 | $332,030 | $421,411 | $511,684 | $599,584 | $722,088 |
| 2-5 Hydro & CHP | $860,503 | 44% | $879,828 | $19,325 | $586,902 | $720,494 | $879,828 | $1,042,838 | $1,221,484 |
| 2-6 Balanced 1 | $445,704 | 63% | $421,349 | -$24,355 | $236,458 | $326,718 | $421,349 | $513,673 | $626,463 |
| 2-7 Balanced 2 | $567,780 | 59% | $546,270 | -$21,510 | $283,996 | $412,351 | $546,270 | $674,989 | $855,880 |
| 2-8 Pacific Northwest Transmission | $240,492 | 53% | $234,915 | -$5,577 | $104,988 | $169,359 | $234,915 | $300,819 | $373,437 |
| 2-9 Eastside Transmission | $260,903 | 50% | $261,081 | $178 | $125,155 | $192,356 | $261,081 | $328,692 | $401,798 |
| 2-10 Renewable | $966,716 | 63% | $904,983 | -$61,733 | $523,823 | $692,378 | $904,983 | $1,121,324 | $1,333,728 |

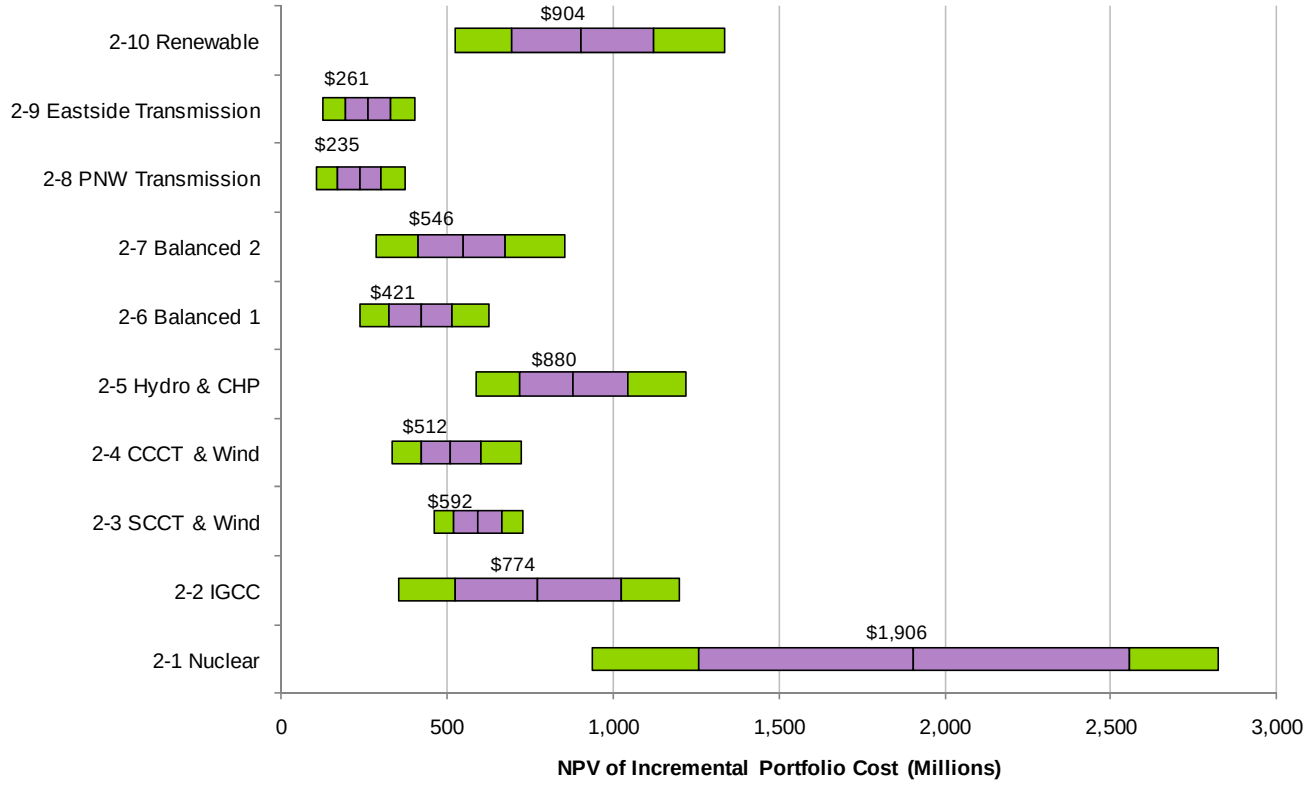



**Figure 9.23 Stochastic analysis results (2021–2030)**

Although it has a slightly higher expected cost, portfolio 2-6 Balanced 1 was selected as the preferred portfolio because it contains a diversified set of resources that are low risk, it does not rely on substantial technology improvements, and Idaho Power is confident it could be implemented.

## *Tipping Point Analysis—Market Risk*

Idaho Power examined the effect of wholesale market prices on the cost of portfolio 1-3 Boardman to Hemingway relative to the cost of the less-market-dependent 1-4 SCCT portfolio. While the cost of purchased power rises with increased market prices, the revenues associated with surplus power sales

also increase. Therefore, the Boardman to Hemingway portfolio remains the lower-cost portfolio under all elevated market price scenarios, and a tipping point does not exist.

However, further investigation into just the purchased power component of these two portfolios provides some useful information related to market price risk. The NPV total cost of the Boardman to Hemingway portfolio is approximately $43 million less than the cost of the SCCT portfolio. The Boardman to Hemingway portfolio also has an additional 62,000 MWh of market purchases when compared to the SCCT portfolio.

To make up the difference in total portfolio cost, average market prices for the additional 62,000 MWh of purchases in the Boardman to Hemingway portfolio would need to be more than $700 per MWh. While this analysis ignores the benefit of surplus sales at higher market prices, it offers insight on the level market prices would have to rise to in order to make the Boardman to Hemingway portfolio no longer the least-cost option.

## *Tipping Point Analysis—Boardman to Hemingway*

The 2011 IRP analysis assumes Idaho Power has 28-percent equity ownership in the Boardman to Hemingway project. If third-party equity interest in the project is less than expected, the company's share of the capital cost for the project will be higher, and the total cost of portfolio 1-3 Boardman to Hemingway will also be higher. Therefore, a tipping point analysis was performed to determine how great of an ownership share Idaho Power could take in the project in order for the total cost of portfolio 1-3 Boardman to Hemingway to be equivalent to the next best alternative, portfolio 1-4 SCCT.

The results of the analysis indicate Idaho Power's share of the project could go as high as 42 percent before the cost of the two portfolios were equal. This analysis assumes that Idaho Power's use of the Boardman to Hemingway line is the same as it was under the expected 28-percent ownership scenario, and the incremental capital cost associated with a greater equity share is not offset by economic utilization of the additional capacity. Figure 9.24 presents the graphical results of the analysis and additional details of the calculations can be found in *Appendix C–Technical Appendix*.

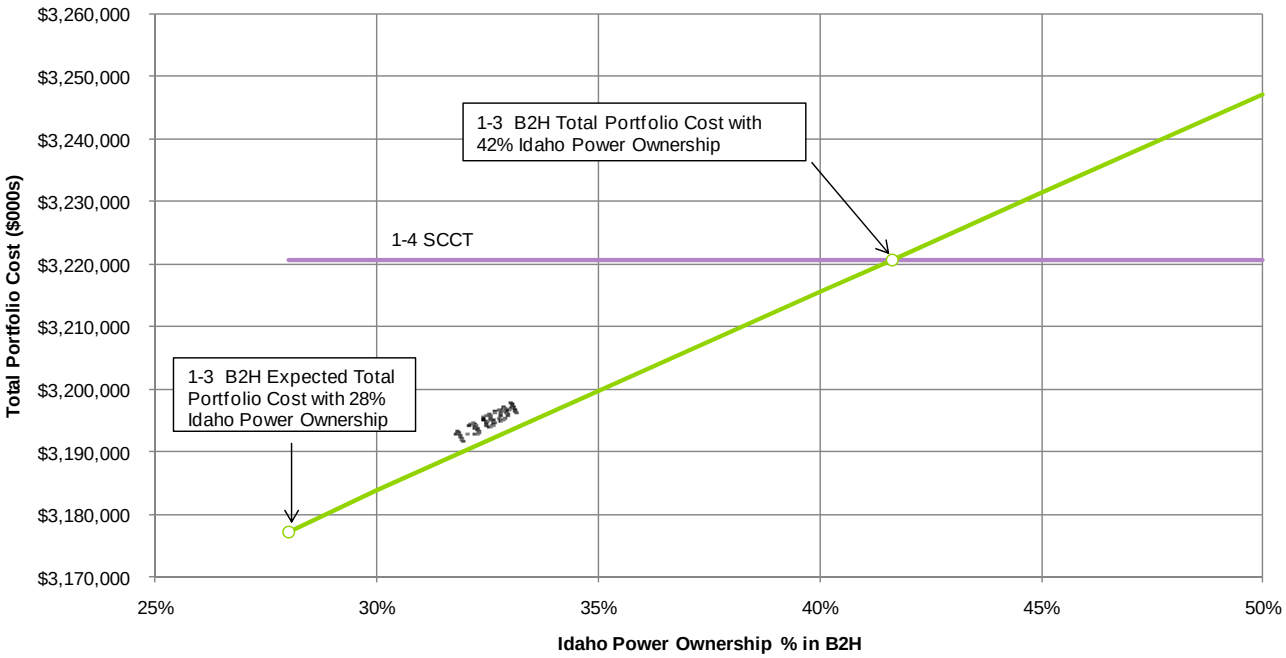



**Figure 9.24 Boardman to Hemingway ownership tipping point analysis**

### *Tipping Point Analysis—Cost of Solar Resources versus Market Purchases*

Recent trends in the decreasing cost of solar PV technology generated significant interest from members of the IRPAC. If this trend continues, solar PV will become more cost competitive with other available resource options. A tipping point analysis was performed to determine how low the cost of solar PV would have to be in order to be competitive with portfolio 1-3 Boardman to Hemingway, which relies on market purchases.

For the tipping point analysis, Idaho Power investigated the capital cost decrease necessary to make the total cost of portfolio 1-2 Solar equivalent to the total cost of portfolio 1-3 Boardman to Hemingway. Figure 9.25 shows the results of the tipping point analysis. The figure notes that average solar costs (average of solar thermal and PV) are expected to be $3,614 per kW and would need to decrease by 72 percent to $1,012 per kW to match the total cost of portfolio 1-3 Boardman to Hemingway. This analysis assumes that capital cost decreases affecting the solar resources are specific to these resources, and would not place downward pressure on the capital cost of the Boardman to Hemingway transmission project or on wholesale power market prices. If wholesale power market prices rise, a smaller reduction in solar capital costs is necessary for the portfolio costs to be equal. Current federal tax incentives available for solar technologies are included in this analysis.

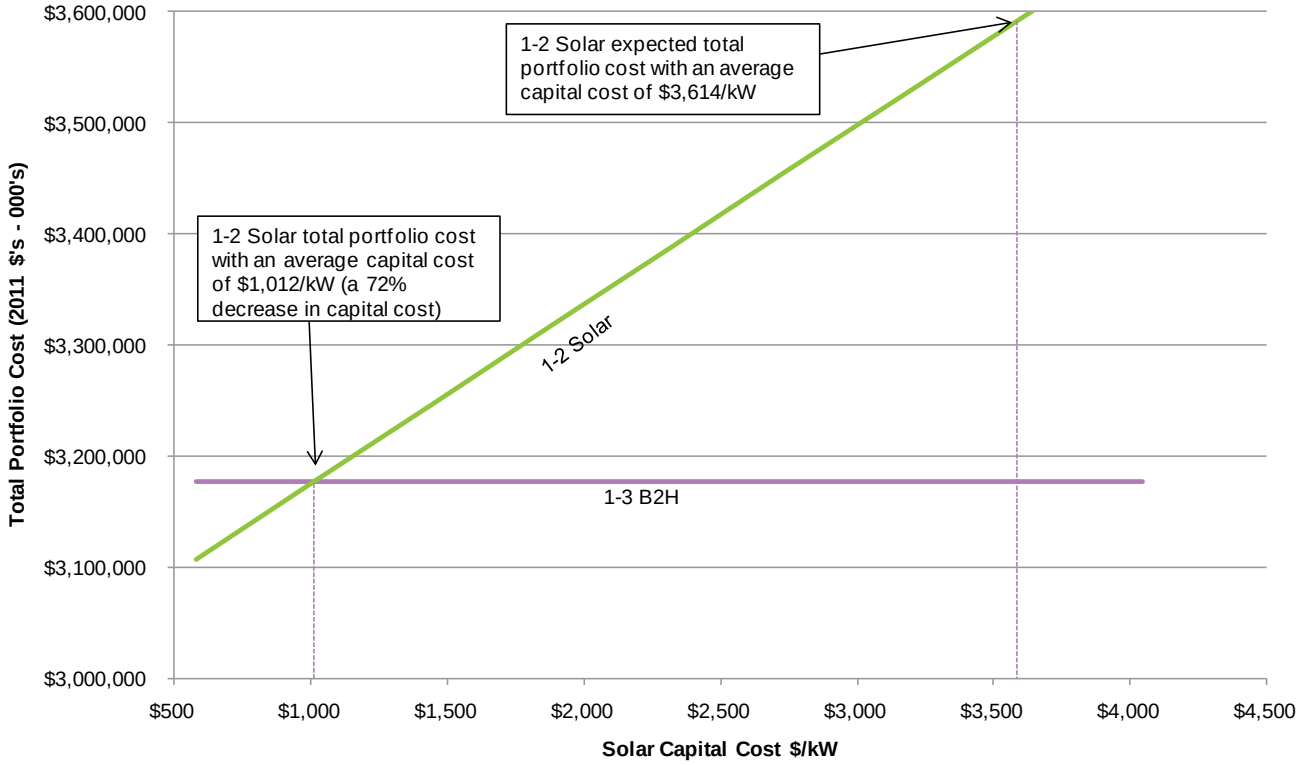



**Figure 9.25 Cost of solar tipping point analysis**

## Capacity Planning Margin

Idaho Power discussed planning criteria assumptions with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2011 IRP, Idaho Power has calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected-case ($50^{th}$ percentile) water and load conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with expected-case ($50^{th}$ percentile) peak-hour load, with the excess resource capacity designated as planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Tables 9.6 and 9.7.

## Table 9.6 Capacity planning margin (2011–2020)

| Capacity Planning Margin | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jul-11** | **Jul-12** | **Jul-13** | **Jul-14** | **Jul-15** | **Jul-16** | **Jul-17** | **Jul-18** | **Jul-19** | **Jul-20** |
| Load Forecast (50th%) - Aug 2010 w/No DSM | (3,367) | (3,440) | (3,560) | (3,656) | (3,750) | (3,832) | (3,908) | (3,982) | (4,060) | (4,136) |
| Existing DSM (Energy Efficiency) | 33 | 48 | 64 | 79 | 93 | 107 | 121 | 135 | 149 | 163 |
| **Load Forecast (50th% w/EE)** | (3,334) | (3,392) | (3,496) | (3,577) | (3,657) | (3,725) | (3,787) | (3,847) | (3,911) | (3,973) |
| Existing Demand Response | 330 | 310 | 315 | 315 | 321 | 351 | 351 | 351 | 351 | 351 |
| **Peak-Hour Forecast w/DR** | **(3,004)** | **(3,082)** | **(3,181)** | **(3,262)** | **(3,336)** | **(3,374)** | **(3,436)** | **(3,496)** | **(3,560)** | **(3,622)** |
| **Existing Resources** | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 0 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (50th%)—HCC | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 |
| Hydro (50th%)—Other | 286 | 286 | 286 | 285 | 284 | 283 | 282 | 281 | 281 | 280 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 | 4 |
| Sho-Ban Water Lease | 47 | 48 | 48 | 48 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (50th%)** | 1,453 | 1,454 | 1,454 | 1,453 | 1,452 | 1,407 | 1,406 | 1,405 | 1,405 | 1,404 |
| **CSPP (PURPA)** | 160 | 161 | 166 | 166 | 166 | 166 | 166 | 166 | 166 | 166 |
| **Power Purchase Agreements** | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange - Take | 12 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange - Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (83 MW) | 83 | 83 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 75 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 185 | 110 | 47 | 47 | 47 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 126 | 233 | 229 | 225 | 222 | 218 | 214 | 209 | 205 | 201 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | **3,302** | **3,637** | **3,574** | **3,569** | **3,565** | **3,504** | **3,499** | **3,494** | **3,489** | **3,484** |
| **Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(3)** | **(71)** | **(138)** |

| **2011 IRP DSM** | **Jul-11** | **Jul-12** | **Jul-13** | **Jul-14** | **Jul-15** | **Jul-16** | **Jul-17** | **Jul-18** | **Jul-19** | **Jul-20** |
|---|---|---|---|---|---|---|---|---|---|---|
| Industrial | 2 | 3 | 5 | 6 | 7 | 8 | 8 | 9 | 10 | 10 |
| Commercial | 0 | 1 | 1 | 2 | 2 | 3 | 3 | 3 | 4 | 4 |
| Residential | 1 | 2 | 4 | 6 | 8 | 10 | 12 | 15 | 17 | 20 |
| **Total New DSM Peak Reduction** | 3 | 6 | 10 | 14 | 17 | 20 | 24 | 27 | 31 | 34 |
| **Remaining Monthly Surplus/Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(40)** | **(103)** |

| **2009 IRP Resources** | **Jul-11** | **Jul-12** | **Jul-13** | **Jul-14** | **Jul-15** | **Jul-16** | **Jul-17** | **Jul-18** | **Jul-19** | **Jul-20** |
|---|---|---|---|---|---|---|---|---|---|---|
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 83 | 0 | 0 | 0 | 0 | 0 |
| 2016 B2H | 0 | 0 | 0 | 0 | 0 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 83 | 450 | 450 | 450 | 450 | 450 |
| **Remaining Monthly Surplus/Deficit** | 302 | 561 | 403 | 321 | 329 | 600 | 537 | 475 | 410 | 347 |
| **Planning Margin** | 10.0% | 18.2% | 12.7% | 9.8% | 9.9% | 17.8% | 15.6% | 13.6% | 11.5% | 9.6% |

## Table 9.7 Capacity planning margin (2021–2030)

| Capacity Planning Margin | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | **Jul-21** | **Jul-22** | **Jul-23** | **Jul-24** | **Jul-25** | **Jul-26** | **Jul-27** | **Jul-28** | **Jul-29** | **Jul-30** |
| Load Forecast (50th%) - Aug 2010 w/No DSM | (4,211) | (4,289) | (4,370) | (4,448) | (4,524) | (4,605) | (4,680) | (4,773) | (4,858) | (4,918) |
| Existing DSM (Energy Efficiency) | 177 | 191 | 205 | 219 | 233 | 247 | 261 | 275 | 289 | 275 |
| **Load Forecast (50th% w/EE)** | (4,034) | (4,098) | (4,165) | (4,229) | (4,291) | (4,358) | (4,419) | (4,498) | (4,569) | (4,643) |
| Existing Demand Response | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 351 | 351 |
| **Peak-Hour Forecast w/DR** | **(3,683)** | **(3,747)** | **(3,814)** | **(3,878)** | **(3,940)** | **(4,007)** | **(4,068)** | **(4,147)** | **(4,218)** | **(4,292)** |
| **Existing Resources** | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (50th%)—HCC | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 |
| Hydro (50th%)—Other | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 | 280 |
| Shoshone Falls Upgrade | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (50th%)** | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 | 1,404 |
| **CSPP (PURPA)** | 166 | 166 | 166 | 166 | 166 | 166 | 166 | 101 | 63 | 93 |
| **Power Purchase Agreements** | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange - Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange - Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Power Purchase Agreements** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 257 | 254 | 250 | 246 | 243 | 238 | 234 | 231 | 227 | 224 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | **3,485** | **3,482** | **3,478** | **3,474** | **3,471** | **3,466** | **3,462** | **3,394** | **3,352** | **3,379** |
| **Monthly Surplus/Deficit** | **(198)** | **(265)** | **(336)** | **(404)** | **(469)** | **(541)** | **(606)** | **(753)** | **(866)** | **(913)** |
| **2011 IRP DSM** | **Jul-21** | **Jul-22** | **Jul-23** | **Jul-24** | **Jul-25** | **Jul-26** | **Jul-27** | **Jul-28** | **Jul-29** | **Jul-30** |
| Industrial | 11 | 11 | 12 | 12 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 22 | 24 | 27 | 30 | 32 | 35 | 38 | 40 | 43 | 45 |
| **Total New DSM Peak Reduction** | 38 | 41 | 44 | 48 | 51 | 54 | 57 | 59 | 62 | 65 |
| **Remaining Monthly Surplus/Deficit** | **(160)** | **(224)** | **(292)** | **(357)** | **(419)** | **(487)** | **(550)** | **(694)** | **(804)** | **(848)** |
| **2009 IRP Resources** | **Jul-21** | **Jul-22** | **Jul-23** | **Jul-24** | **Jul-25** | **Jul-26** | **Jul-27** | **Jul-28** | **Jul-29** | **Jul-30** |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 B2H | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 170 | 170 | 170 | 170 | 170 | 170 | 170 | 170 | 170 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 52 | 52 | 52 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 170 | 170 |
| **New Resource Subtotal** | 502 | 672 | 672 | 716 | 1,016 | 1,016 | 1,016 | 1,068 | 1,238 | 1,238 |
| **Remaining Monthly Surplus/Deficit** | 342 | 448 | 380 | 360 | 598 | 529 | 467 | 374 | 434 | 390 |
| **Planning Margin** | 9.3% | 11.9% | 10.0% | 9.3% | 15.2% | 13.2% | 11.5% | 9.0% | 10.3% | 9.1% |

## Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2011 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred and alternate portfolios. As mentioned in previous chapters, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2011 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator/purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has chosen to calculate LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5–1.0 hours per year. The results of the loss of load probability analysis are shown in Figure 9.26, and additional data can be found in *Appendix C–Technical Appendix*.

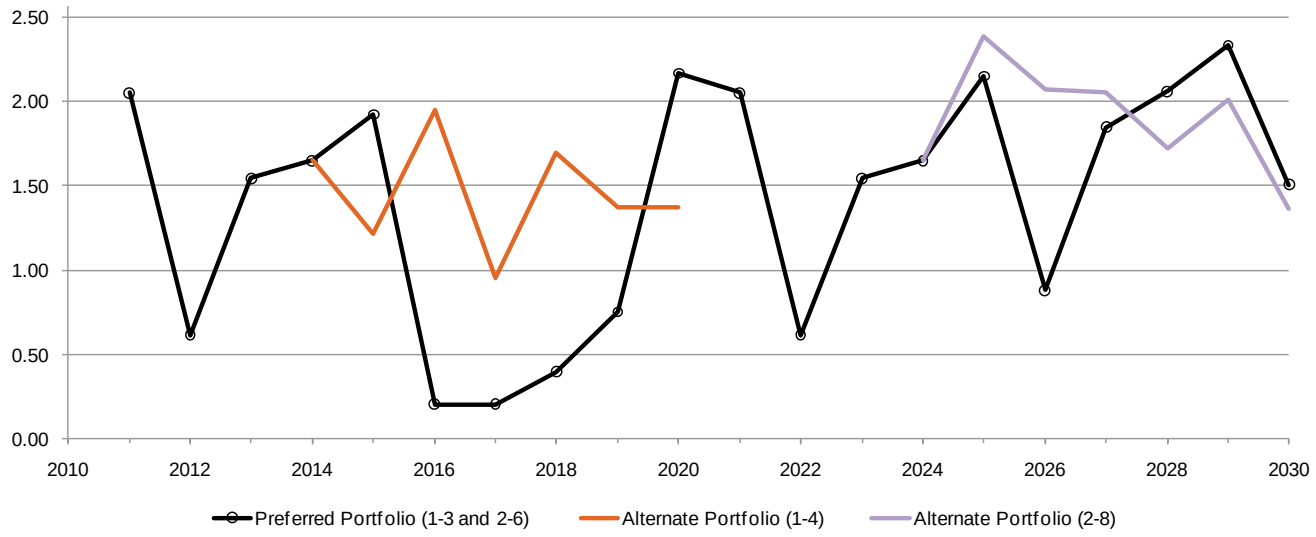



**Figure 9.26 Loss of load expectation**

In performing the analyses, there were several instances where extending purchases of east-side energy similar to the purchases contemplated in 2010–2012 were necessary to achieve the results shown in Figure 9.26.

[3] Based on Roy Billinton "Power System Reliability Evaluation" Chapter 2&3, Copyright 1970.

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# 10. Action Plans

Once the final preferred portfolio has been selected, an action plan is necessary to identify the steps that must be taken to implement the plan. Like the portfolio analysis, the action plan is split into two, 10-year periods. The near-term action plan addresses the years 2011–2020, and the long-term action plan covers the years 2021–2030. The two action plans represent the culmination of the IRP process.




Action plans describe how Idaho Power will implement the results of the IRP.

## Near-Term Action Plan (2011–2020)

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years to implement the preferred portfolio (2011–2020). No long-lead-time generation resources, such as advanced nuclear or IGCC are considered in the near-term plan. However, Idaho Power intends to continue its efforts to participate in regional utility planning forums and to explore regional alliances as generation resource, energy storage, energy efficiency, and transmission technologies develop.

Table 10.1 presents a list of the resources Idaho Power expects to add to its generation portfolio over the next 10 years for both the preferred portfolio and an alternate portfolio. An alternate portfolio is also identified in the IRP in the event substantial changes impact the assumptions used to select the preferred portfolio.

**Table 10.1 Near-term action plan (2011–2020)**

| Year | Preferred Resource Portfolio<br>1-3 Boardman to Hemmingway | Alternative Resource Portfolio<br>1-4 SSCT |
|---|---|---|
| 2011 | | |
| 2012 | | |
| 2013 | Solar Demonstration Project (500kW–1 MW) | Solar Demonstration Project (500kW–1 MW) |
| 2014 | | |
| 2015 | Eastside PPA (83 MW) | SCCT (170 MW) |
| 2016 | Boardman to Hemingway (450 MW) | |
| 2017 | | SCCT (170 MW) |
| 2018 | | |
| 2019 | | SCCT (94 MW) |
| 2020 | | |

### Highlights

- The Boardman to Hemingway transmission line is the primary resource in the near-term action plan, and the long-term action plan includes a diverse set of renewable and gas-fired resources.
- Idaho Power is proposing a solar demonstration project as part of the 2011 IRP.
- IRPAC members and members of the public made significant contributions through the nine public meetings conducted while preparing the 2011 IRP.

### Preferred Portfolio Near-Term Action Plan

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term action plan preferred portfolio. The new transmission line was first identified in Idaho Power's 2006 IRP, and the company continues working to acquire the necessary regulatory approvals and permits necessary to begin construction. Construction of the Boardman to Hemingway transmission line is expected to start in early 2014, after completing the permitting, regulatory, and engineering work. If the Boardman to Hemingway project is substantially delayed, Idaho Power will have to consider implementing the alternate portfolio.

The preferred portfolio also includes a market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016. Idaho Power has used the east side for market purchases in the past, but prices have historically been higher than the prices at the Mid-C hub in the Pacific Northwest. A purchase on the east side does not require substantial lead time, and Idaho Power will continue to monitor market prices, load growth, and the status of the Boardman to Hemingway project prior to committing to this purchase.

As part of the 2011 IRP, Idaho Power is proposing to construct a solar demonstration project. Details of this proposal are explained in Chapter 1 and the project could be on line as early as late 2012.

### Alternate Portfolio Near-Term Action Plan

The alternate portfolio presents the actions Idaho Power will take if the Boardman to Hemingway transmission line is significantly delayed or canceled. In the alternate resource portfolio, Idaho Power anticipates adding natural gas-fired SCCTs to meet capacity deficits. The company expects to acquire the generation resources identified in the alternate portfolio through a competitive RFP process meeting the requirements of Oregon Order 06-446 issued on August 10, 2006, as well as any revisions to the requirements resulting from Oregon Docket UM 1182.

Although the alternate portfolio identifies the first 170-MW SCCT in 2015, in the event the alternate portfolio is implemented, Idaho Power will continue to evaluate resource needs and may alter the size, timing, and technology of the combustion turbine depending on market conditions at the time an RFP is issued.

Should the permitting, regulatory, engineering work, or construction of the Boardman to Hemingway project be delayed, Idaho Power will face the decision to acquire the first resource identified in the alternate portfolio. To meet the competitive procurement guidelines, Idaho Power would need to initiate the resource procurement process by issuing an RFP as early as 2012. Beginning the procurement process in 2012 is necessary to achieve an on-line date in 2015. The resource procurement process would most likely begin prior to the completion of Idaho Power's 2013 IRP, which is scheduled to be filed in June 2013.

## Long-Term Action Plan (2021–2030)

The long-term action plan describes Idaho Power's planned resource acquisitions during the second 10 years of the planning period (2021–2030). The long-term action plan assumes that the near-term action plan is completed with only minor variations. If the Boardman to Hemingway project is significantly delayed or canceled and Idaho Power implements the alternate resource plan in the first 10 years of the planning period, Idaho Power may reconsider its concerns about over-reliance on market purchases and select the alternate resource portfolio relying on a regional transmission project for the second 10 years of the planning period.

It is important to note that the Gateway West project was included in each resource portfolio for only the second 10-year period when current transmission constraints required the addition of new transmission capacity for resources to be added in southern Idaho east of the Treasure Valley load center. The amount of Gateway West capacity is different in each portfolio, depending on other included resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

With the exception of the Gateway West transmission project, both the preferred and alternate resource portfolios for the second 10 years of the planning period include a combination of renewable and natural gas-fired resources. The long-term action plan for both the preferred and alternate portfolios is shown in Table 10.2.

**Table 10.2 Long-term action plan (2021–2030)**

| Year | Preferred Resource Portfolio<br>2-6 Balanced 1 | Alternative Resource Portfolio<br>2-7 PNW Transmission |
|---|---|---|
| 2021 | Geothermal (52 MW) | Geothermal (52 MW) |
| 2022 | SCCT (170 MW) | Pacific NW Purchase (500 MW) |
| 2023 | | |
| 2024 | Solar Power Tower (50 MW) | |
| 2025 | CCCT (300 MW) | |
| 2026 | | |
| 2027 | | Solar PV (20 MW) |
| 2028 | Small Hydro (60 MW) | Geothermal (52 MW) |
| 2029 | SCCT (170 MW) | SCCT (170 MW) |
| 2030 | | |

## Preferred Portfolio Long-Term Action Plan

The preferred portfolio selected for the second 10 years consists of a diverse mixture of renewable and natural gas resources. With the possible exception of the solar power tower technology, none of the identified resources present a technological challenge. The longest lead-time resource in the preferred portfolio is the CCCT identified to come on line in 2025, which would require approximately four years to design, permit, and construct. Therefore no significant actions are required in the next two years to pursue this portfolio.

After the 2011 IRP, Idaho Power's next IRP will be completed in June 2013. Idaho Power will continue to evaluate "balanced" portfolios, as they have historically performed well in the IRP analysis.

## Alternate Portfolio Long-Term Action Plan

The alternate portfolio for the second 10 years presents a dilemma. Although this portfolio performed well, as covered in Chapter 9, concerns regarding an over-reliance on market purchases and the future ability of utilities to permit and construct long-distance, high-voltage transmission raise questions regarding the viability of this portfolio.

Idaho Power will continue to monitor forward market prices and the progress that can be made on the Boardman to Hemingway and Gateway West projects between now and the completion of the 2013 IRP. Based on recent experience, new long-distance, high-voltage transmission projects require a lead time of 8–10 years. If additional transmission capacity to either the Pacific Northwest or to the east side of

Idaho Power's system continues to perform well in the IRP analysis, Idaho Power will need to begin work on permitting and initial designs for new transmission projects shortly after the completion of the 2013 IRP.

## Conclusion

Each Idaho Power IRP builds on the foundation of earlier resource plans, and each plan includes incremental changes due to forecasts of future events. The 2011 IRP is no exception.

Idaho Power and other utilities in the West face major regional transmission decisions. No significant interstate transmission has been built in the region for many years. Idaho Power's 2006 IRP was the first of the company's resource plans where Idaho Power made a significant commitment to new interstate transmission projects. Idaho Power continues its commitment to regional transmission with the 2011 IRP.

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term preferred resource portfolio, and Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction. As part of acknowledging the 2009 IRP, the OPUC requested Idaho Power treat the Boardman to Hemingway project as an uncommitted resource in the 2011 IRP. And, once again, the Boardman to Hemingway transmission project has outperformed other alternatives.

In the 2011 plan, Idaho Power conducted a thorough analysis of resource alternatives, including generation, transmission, demand-response, and energy efficiency. The only committed resources not yet constructed but included in the 2011 IRP are the Langley Gulch CCCT and an upgrade at the company's Shoshone Falls hydroelectric project. The Boardman to Hemingway transmission project was analyzed using the same methods as other uncommitted resources. After the analysis, the Boardman to Hemingway transmission line is again the preferred resource to meet customer needs in Idaho and Oregon.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2011 IRP. The IRPAC discussed many technical aspects of the 2011 resource plan along with a significant number of political/societal topics at nine meetings conducted during the second half of 2010 and the first half of 2011. Idaho Power's resource planning process is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP biennially. At the time of the next plan in 2013, Idaho Power will have additional information regarding supply-side resources, demand-side management programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the development of a federal RES, and the feasibility of advanced nuclear, IGCC, and other resource options that currently face technological challenges.

One of the key strengths of Idaho Power's planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the IRPAC, the IPUC, the OPUC, and concerned customers to revisit the IRP and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near-term action plan allows for discussion and adjustment of the IRP as warranted.

# LIST OF TABLES

Table 1.1 Preferred portfolios ....7
Table 1.2 Near-term action plan milestones ....8
Table 2.1 Phase I measures ....16
Table 3.1 Historical capacity, load, and customer data ....24
Table 3.2 Electricity delivered to customers (2010) ....26
Table 3.3 Existing Resources ....27
Table 4.1 Energy efficiency current portfolio forecasted impacts (2011–2030) ....39
Table 4.2 Existing energy efficiency portfolio cost-effectiveness summary ....39
Table 4.3 New energy efficiency portfolio forecasted impacts (2011–2030) ....41
Table 4.4 New energy efficiency portfolio cost-effectiveness summary ....41
Table 4.5 Demand response cost-effectiveness summary ....42
Table 6.1 Load forecast—peak-hour (MW) ....61
Table 6.2 Load forecast—average monthly energy (aMW) ....63
Table 6.3 Planning criteria for average monthly and peak-hour load ....65
Table 6.4 Emissions intensity rates (lbs/MWh) ....73
Table 6.5 Emissions adder cost assumptions ....73
Table 7.1 Available transmission import capacity ....83
Table 7.2 Transmission assumptions ....84
Table 9.1 Financial assumptions ....94
Table 9.2 Expected case total portfolio cost (2011–2020) ....97
Table 9.3 Expected case total portfolio cost (2021-2030) ....97
Table 9.4 Stochastic analysis results (2011–2020) ....110
Table 9.5 Stochastic analysis results (2021–2030) ....113
Table 9.6 Capacity planning margin (2011–2020) ....117
Table 9.7 Capacity planning margin (2021–2030) ....118
Table 10.1 Near-term action plan (2011–2020) ....121
Table 10.2 Long-term action plan (2021–2030) ....123

# LIST OF FIGURES

Figure 1.1 Cost of existing and new supply-side resources ....4
Figure 1.2 30-year levelized capital cost of peak-hour capacity ....5
Figure 1.3 2010 fuel mix ....7

Figure 1.4 2030 fuel mix ..... 7
Figure 3.1 Historical capacity, load, and customer data ..... 24
Figure 3.2 2010 energy sources ..... 26
Figure 3.3 2010 long-term power purchases by resource type ..... 26
Figure 3.4 PURPA contracts by resource type ..... 34
Figure 5.1 Boardman to Hemingway line project map ..... 52
Figure 5.2 Gateway West line project map ..... 55
Figure 6.1 Peak-hour load growth forecast (MW) ..... 61
Figure 6.2 Average monthly load growth forecast (aMW) ..... 62
Figure 6.3 Brownlee historical and forecast inflows ..... 67
Figure 6.4 Natural gas price forecast ..... 70
Figure 6.5 Pacific Northwest natural gas transportation paths ..... 71
Figure 6.6 Carbon-adder assumptions ..... 73
Figure 6.7 REC price assumptions ..... 74
Figure 6.8 30-year levelized capacity (fixed) costs ..... 76
Figure 6.9 30-year levelized cost of production (at stated capacity factors) ..... 77
Figure 7.1 Idaho Power transmission system map ..... 81
Figure 8.1 Monthly average energy surpluses and deficits with existing and committed resources and existing DSM ($70^{th}$ percentile water and $70^{th}$ percentile load) ..... 86
Figure 8.2 Monthly average energy surpluses and deficits with new DSM ($70^{th}$ percentile water and $70^{th}$ percentile load) ..... 87
Figure 8.3 Monthly peak-hour deficits with existing and committed resources and existing DSM ($90^{th}$ percentile water and $95^{th}$ percentile load) ..... 88
Figure 8.4 Monthly peak-hour deficits with new DSM ($90^{th}$ percentile water and $95^{th}$ percentile load) ..... 88
Figure 8.5 Initial resource portfolios (2011–2020) ..... 89
Figure 8.6 Initial resource portfolios (2021–2030) ..... 91
Figure 9.1 Average $CO_2$ intensity by portfolio (2011–2020) ..... 98
Figure 9.2 Average $CO_2$ intensity by portfolio (2021–2030) ..... 98
Figure 9.3 Carbon risk analysis results (2011–2020) ..... 100
Figure 9.4 Natural gas price risk analysis results (2011–2020) ..... 100
Figure 9.5 Capital cost risk analysis ..... 101
Figure 9.6 Capital-cost risk analysis results (2011–2020) ..... 101
Figure 9.7 DSM variability risk analysis ..... 102
Figure 9.8 DSM variability risk analysis results (2011–2020) ..... 102
Figure 9.9 Load variability risk analysis ..... 103

Figure 9.10 Load risk analysis results (2011–2020) ..... 103
Figure 9.11 REC price risk analysis results (2011–2020) ..... 104
Figure 9.12 Carbon risk analysis results (2021–2030) ..... 104
Figure 9.13 Natural Gas price risk analysis results (2021–2030) ..... 105
Figure 9.14 Capital cost risk analysis results (2021–2030) ..... 105
Figure 9.15 DSM risk analysis results (2021–2030) ..... 106
Figure 9.16 Load variability risk analysis results (2021–2030) ..... 106
Figure 9.17 REC price risk analysis results (2021–2030) ..... 106
Figure 9.18 Sampling results from portfolio 1-3 Boardman to Hemingway ..... 109
Figure 9.19 Sampling results from portfolio 1-4 SCCT ..... 109
Figure 9.20 Stochastic analysis results (2011–2020) ..... 110
Figure 9.21 Sampling results from portfolio 2-6 Balanced 1 ..... 112
Figure 9.22 Sampling results from portfolio 2-8 Pacific Northwest Transmission ..... 112
Figure 9.23 Stochastic analysis results (2021–2030) ..... 113
Figure 9.24 Boardman to Hemingway ownership tipping point analysis ..... 114
Figure 9.25 Cost of solar tipping point analysis ..... 115
Figure 9.26 Loss of load expectation ..... 119

## LIST OF APPENDICES

Appendix A–Sales and Load Forecast
Appendix B–Demand-Side Management 2010 Annual Report
Appendix C–Technical Appendix

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# GLOSSARY OF ABBREVIATIONS

AC–Alternating Current

A/C–Air Conditioning

ACOE–United States Army Corps of Engineers

AFUDC–Allowance for Funds Used During Construction

akW–Average kilowatt

aMW–Average Megawatt

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

CAA–Clean Air Act

CAES–Center for Advanced Energy Studies

CAIR–Clean Air Interstate Rule

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CCR–Coal Combustion Residuals

CCX–Chicago Climate Exchange

CFI–Carbon Financial Instrument

cfs–Cubic-Feet-per-Second

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

CPCN–Certificate of Public Convenience and Necessity

$CO_2$–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

EPA–Environmental Protection Agency

EPRI–Electric Power Research Institute

ESA–Endangered Species Act

ESPA–Eastern Snake River Plain Aquifer

F–Fahrenheit

FCA–Fixed-Cost Adjustment

FCP–Formal Consultation Package

FCRPS–Federal Columbia River Power System

FEIS–Final Environmental Impact Statement

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

FWS–US Fish and Wildlife Service

GHG–Greenhouse Gas

HAP–Hazardous Air Pollutants

Hg–Mercury

HRSG–Heat Recovery Steam Generator

IDWR–Idaho Department of Water Resources

IGCC–Integrated Gasification Combined Cycle

INL–Idaho National Laboratory

IOER–Idaho Office of Energy Resources

IPUC–Idaho Public Utilities Commission

IRP–Integrated Resource Plan

IRPAC–IRP Advisory Council

kV–Kilovolt

kW–Kilowatt

kWh–Kilowatt Hour

lbs–Pounds

LOLE–Loss of Load Expectation

LTP–Local Transmission Plan

$m^2$–square meters

mm–Millimeter

MMBtu–Million British Thermal Units

MSA–Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NAAQS–National Ambient Air Quality Standards

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NERC–North American Electric Reliability Corporation

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

$NO_x$–Nitrogen Oxide

NPV–Net Present Value

NWPP–Northwest Power Pool

NREL–National Renewable Energy Laboratory

NSR–New Source Review

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

ODEQ–Oregon Department of Environmental Quality

ODOE–Oregon Department of Energy

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCB–Polychlorinated Biphenyls

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PRC–Power Resources Cooperative

PTC–Production Tax Credit

PURPA–*Public Utility Regulatory Policies Act of 1978*

PV–Photovoltaic

QF–Qualifying Facility

RCRA–*Resource Conservation and Recovery Act of 1976*

REC–Renewable Energy Certificate

RES–Renewable Electricity Standard

RFP–Request for Proposal

RH BART–Regonal Haze Best Available Retrofit Technology

RPS–Renewable Portfolio Standard

SCCT–Simple-Cycle Combustion Turbine

SCR–Selective Catalytic Reduction

$SO_2$–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TASCO–The Amalgamated Sugar Company

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

USFS–United States Forest Service

WDEQ–Wyoming Department of Environmental Quality

WECC–Western Electricity Coordinating Council

W–Watt




# *Appendix A—Sales and Load Forecast*

For the 2011 Integrated Resource Plan

**June 2011**

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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... ii
List of Figures ..... ii
List of Appendices ..... iii
Introduction ..... 1
2011 IRP Sales and Load Forecast ..... 3
Average Load ..... 3
Peak-Hour Demands ..... 4
Overview of the Forecast ..... 7
Fuel Prices ..... 7
Electric Vehicles ..... 10
Forecast Probabilities ..... 11
Load Forecasts Based on Weather Variability ..... 11
Load Forecasts Based on Economic Uncertainty ..... 13
Residential ..... 17
Commercial ..... 19
Irrigation ..... 21
Industrial ..... 23
Additional Firm Load ..... 25
Micron Technology ..... 26
Simplot Fertilizer ..... 26
Idaho National Laboratory ..... 26
Hoku Materials ..... 27
"Special" Contract ..... 27
Raft River Rural Electric Cooperative ..... 27
Company System Peak ..... 29
Company System Load ..... 31
Contract Off-System Load ..... 33
Total Company Load ..... 35
Demand-Side Management ..... 37
Energy Efficiency Programs ..... 37
Demand Response Programs ..... 38

# LIST OF TABLES

Table 1. Residential fuel-price escalation (2011–2030) ....8
Table 2. Average load and peak-demand forecast scenarios ....12
Table 3. Forecast probabilities ....14
Table 4. System load growth ....14
Table 5. Residential load growth ....17
Table 6. Commercial load growth ....19
Table 7. Irrigation load growth ....21
Table 8. Industrial load growth ....23
Table 9. Additional firm load growth ....25
Table 10. System summer peak load growth ....29
Table 11. System winter peak load growth ....30
Table 12. System load growth ....31

# LIST OF FIGURES

Figure 1. Forecasted electricity prices ....9
Figure 2. Forecasted residential natural gas prices ....10
Figure 3. Electric vehicles ....11
Figure 4. Forecasted system load ....15
Figure 5. Forecasted residential load ....17
Figure 6. Forecasted residential-use-per-customer ....18
Figure 7. Forecasted commercial load ....19
Figure 8. Forecasted commercial-use-per-customer ....20
Figure 9. Forecasted irrigation load ....21
Figure 10. Forecasted industrial load ....23
Figure 11. Industrial electricity consumption by industry group ....24
Figure 12. Forecasted additional firm load ....26
Figure 13. Forecasted system summer peak ....29
Figure 14. Forecasted system winter peak ....30
Figure 15. Forecasted system load ....31
Figure 16. Composition of total company electricity sales ....35

# LIST OF APPENDICES

Appendix A1. Historical and Projected Sales and Load ..... 39
Residential Load ..... 39
Historical Residential Sales and Load, 1970–2010 ..... 39
Projected Residential Sales and Load, 2011–2030 ..... 40
Commercial Load ..... 41
Historical Commercial Sales and Load, 1970–2010 ..... 41
Projected Commercial Sales and Load, 2011–2030 ..... 42
Irrigation Load ..... 43
Historical Irrigation Sales and Load,1970–2010 ..... 43
Projected Irrigation Sales and Load, 2011–2030 ..... 44
Industrial Load ..... 45
Historical Industrial Sales and Load, 1970–2010 ..... 45
Projected Industrial Sales and Load, 2011–2030 ..... 46
Additional Firm Sales and Load* ..... 47
Historical Additional Firm Sales and Load, 1970–2010 ..... 47
Projected Additional Firm Sales and Load, 2011–2030 ..... 48
Company System Load (excluding Astaris) ..... 49
Historical Company System Sales and Load, 1970–2010 ..... 49
Company System Load (including Astaris) ..... 50
Historical Company System Sales and Load, 1970–2010 ..... 50
Astaris Sales and Load (1970–2002) ..... 50
Projected Company System Sales and Load, 2011–2030 ..... 51
Contract Off-System Load ..... 52
Historical Contract Off-System Sales and Load, 1970–2010 ..... 52
Projected Contract Off-System Sales and Load, 2011–2030 ..... 52
Total Company Load ..... 53
Historical Total Company Sales and Load, 1970–2010 ..... 53
Projected Total Company Sales and Load, 2011–2030 ..... 54

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# INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2011 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2011 through 2030.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70$^{th}$ percentile and 90$^{th}$ percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly, dependent on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70$^{th}$ percentile average load forecast and 90$^{th}$ percentile average load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70$^{th}$ percentile load forecast assumes monthly loads that can be exceeded in three-out-of-ten years (30 percent of the time). The 90$^{th}$ percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,362 average megawatts (aMW) in the year 2030 from the 2011 forecast load of 1,819 aMW. The expected-case forecast system load growth rate averages 1.4 percent per year over the 20 years of the planning period (2011–2030). In the more critical 70$^{th}$ percentile load forecast, used for resource planning, the system load is forcasted to read 2,414 aMW. Idaho Power system peak load (95$^{th}$ percentile) is forecast to grow to 4,901 megawatts (MW) in the year 2030 from the 2008 actual system summer peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.8 percent per year over the 20 years of the planning period (2011–2030). The number of Idaho Power active retail customers increased from the December 2010 level of 490,869 customers to over 653,000 customers at year-end 2030.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2010 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., were also used in development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during

the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated in the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2010 Annual Report*. This report is Appendix B to the 2011 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as the impact of a wide-range of possible carbon scenarios and the subsequent potential for much higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, might also impact the future demand for electricity. The high degree of uncertainty associated with such changes is assumed to be reflected in the economic high- and low-load growth scenarios previously described. However, due to the possibility of proposed carbon legislation becoming law, the impact of carbon legislation on the load forecast was reflected in the forecast of retail electricity prices, which is a driver in the major sector sales forecasting models. The alternative sales and load scenarios of *Appendix A–Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for the sales and load forecast is presented in Appendix A1 of this report.

# 2011 IRP SALES AND LOAD FORECAST

## Average Load

The 2011 IRP average system load forecast is lower initially than the 2009 IRP average system load forecast. However, after 2015, the 2011 IRP forecast is higher in all remaining years of the forecast period . The recovery in the national and service-area economy is expected to cause load growth to steadily revive. In addition, the lowered expectations in existing and committed energy efficiency measures, combined with retail electricity prices that incorporate much-reduced impact of carbon on Idaho Power's retail electricity prices, result in an increase of forecast average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The retail electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast* in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected cost of carbon emissions. When compared to the electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast*, the 2009 IRP price forecast yielded significantly higher future electricity prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions. The carbon assumptions from the 2006 IRP is the driver for the 2011 IRP's retail electricity price forecasts.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials planned to begin operation in January 2011 and will reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power retail customers. Both factors resulted in a higher long-term load forecast than was used in the 2009 IRP. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to recover; and by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).
- In this year's forecast, an additional customer referred to in this document as "Special" was included in the Additional Firm Load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this

forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the Additional Firm Load category.

- There continues to be significant uncertainty associated with the growth of new industrial and special contract customers and their potential impact on the load forecast. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area and the unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron's residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the IRP load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the IRP load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast is expected, compared to earlier forecasts (prior to the 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). Higher farm commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.

## Peak-Hour Demands

Peak day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- This year's peak forecast also reflects the increased expected peak demand of an additional "Special" contract customer. The anticipated peak load of the new contract has been included in this year's forecast based on discussions with the interested parties.
- The 2011 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs selected for implementation since 2001. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2011 IRP peak demand forecast model does not consider or adjust for the impact of demand response programs. The demand response programs are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model allows peaks to be calculated at the 50th, 90th, and 95th percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the 100th percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model regressions.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. The median peak day temperature has a 50-percent probability of being exceeded. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures. The weighted average peak day temperature drivers are calculated over the 1980–2009 time period (the most recent 30 years).

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# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special contract customers, including Micron Technology, Inc., (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, one additional high-probability special contract customer (referred to as "Special"), and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These six, special contract customers are combined into a single forecast category labeled Additional Firm Load. In the 2009 IRP sales and load forecast, the "Special" contract load was combined with the industrial sector (Schedule 19) load forecast. Given the magnitude of their expected future load, the "Special" contract has now been combined with the other larger special contract customers that have monthly metered demands greater than 20,000 kilowatts (kW). Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as they are billed, it is necessary to adjust these billed sales to the proper timeframe to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual-average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2011 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space heating demand that normally occurs in December, January, or February; and 2) a larger, summer-peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak day temperatures, historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River are forecast based on historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

## Fuel Prices

Fuel prices, in combination with service area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for

electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2011–2030)**
*(average annual percent change)*

| | Nominal | Real* |
|---|---|---|
| Electricity–2011 IRP–Carbon | 2.6% | 0.9% |
| Electricity–2009 IRP–Carbon | 5.1% | 3.2% |
| Natural Gas | 2.5% | 0.8% |

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2010 and over the forecast period 2011–2030. Both nominal and real prices are shown. In the 2011 IRP carbon scenario, nominal electricity prices are expected to slowly climb to nearly 13 cents per kilowatt-hour (kWh) by the end of the forecast period in 2030. Real electricity prices (inflation adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 0.9 percent each year. In the 2009 IRP electricity price carbon scenario, nominal electricity prices were assumed to climb to nearly 22 cents per kWh by 2030, and real electricity prices (inflation adjusted) were expected to increase over the forecast period at an average rate of 3.2 percent each year. The impact of the much higher electricity price forecast on the 2009 IRP load forecast was significant and served to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions.

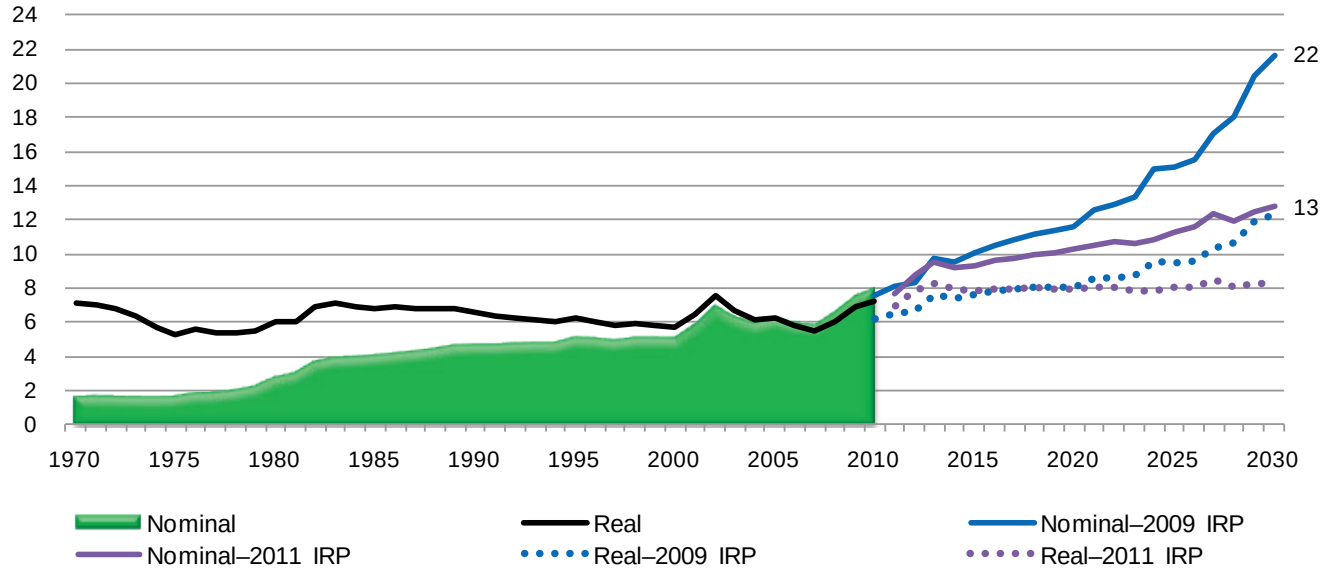


**Figure 1. Forecasted electricity prices**
*(cents per kWh)*

Electricity prices for Idaho Power customers moved significantly higher in 2001 and 2002 because of the Power Cost Adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2009, and forecast prices from 2010–2030. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before again moving sharply upward in 2004, 2005, and 2006. Natural gas prices moved downward in 2010, reflecting the collapse in natural gas prices that began in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise in 2011, plateau through 2014, and then slowly rise throughout the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2009, growing at an average rate of 2.5 percent per year over the forecast period (2011–2030). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.8 percent each year.

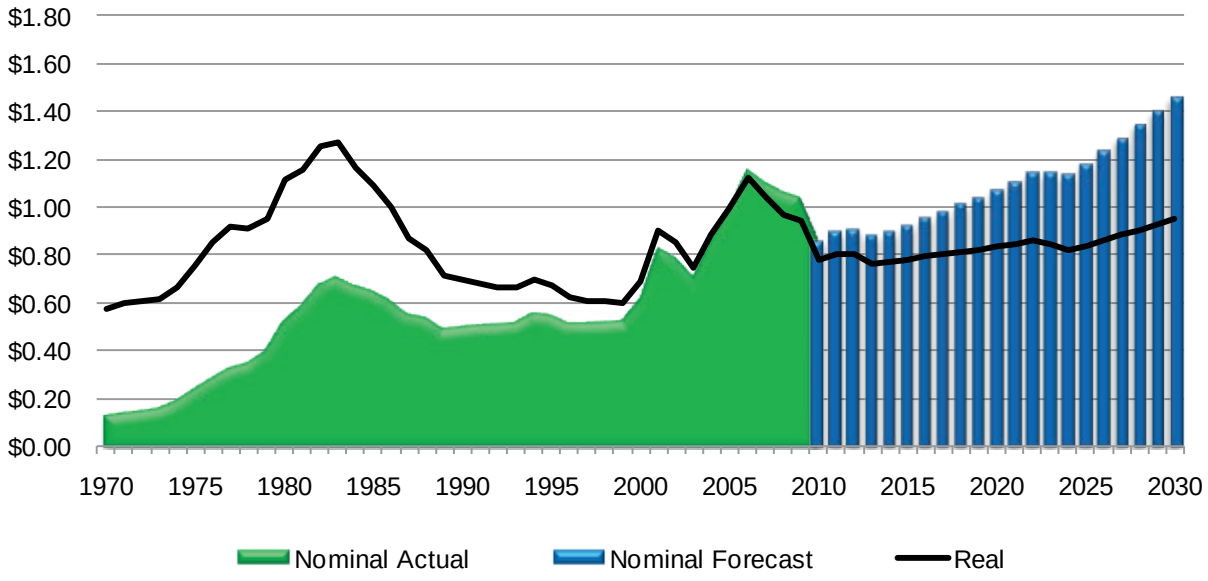


**Figure 2. Forecasted residential natural gas prices**
*(dollars per therm)*

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2011 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

With the anticipated introduction of electric vehicles in December 2010 from General Motors and Nissan, Idaho Power includes a forecast of the potential load impact associated with customer needs for battery recharging. Without the benefit of actual consumer adoption data and clarity on charging infrastructure composition, the forecast methodology relies on previous modeling efforts from EPRI[1] and Oak Ridge National Laboratory[2] drawing on their forecasts of the electric-vehicle market share and charging usage and loads. The assumptions of these and other early forecasts were made without benefit of empirical vehicle performance attributes, such as vehicle battery capacity, pricing, actual consumer adoption behavior, and other salient marketing variables. Since these variables represent primary economic determinants of electric-vehicle adoption, the early forecasts are subject to potentially high degrees of revision. Other determinant variables, such as gasoline price, exhibit high degrees of volatility that add to the wide range of potential adoption outcomes.

The Oak Ridge study assumed a 25 percent electric-vehicle share of new vehicle registrations by 2020 and thereafter held constant. The EPRI study relied on year 2050 share scenarios that ranged from 20 percent to 80 percent. Their medium range forecast for 2020 was approximately 35 percent. After evaluating historical rates of adoption of new transportation technology, particularly those associated with fuel-efficient diesel engine adoption in Europe, the Idaho Power model was based on a

[1] Environmental Assessment of Plug-In Hybrid Electric Vehicles, July, 2007.

[2] Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation, January, 2008.

40-percent share by 2050 with annual adoption growth rate associated with diesel-technology adoption. The resulting Idaho Power forecast share of electric vehicles of new, light-duty vehicles registered in Idaho Power's service area is approximately 12 percent in 2020 and 26 percent in 2030. These rates were applied to a forecast of new, light-duty vehicle registrations for Idaho Power's service area using base-case assumptions from Moody's Analytics, Inc.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption for the purposes of improving the forecasting model in future forecasts.

Figure 3 illustrates the increase in loads expected from the roll-out of electric vehicles over 2010–2030. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, the residential sector representing the greatest impact.




**Figure 3. Electric vehicles**
*(aMW)*

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation, i.e., there is a 50 percent chance that loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures, or wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December over the 1980–2009 time period (the most recent 30 years) was 1,036. The 70th percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90th percentile HDD is 1,291 and would be exceeded in one-out-of-ten years. The 100th percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70th percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile, reflecting drier-than-median weather. The 90th percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume that temperatures and precipitation would maintain a 70th percentile or 90th percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th percentile or 90th percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2011 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak day average temperatures. The probability associated with each individual peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

| Scenario | Weather Probability | Probability of Exceeding | Weather Driver |
|---|---|---|---|
| **Forecasts of Average Load** | | | |
| 90th Percentile | 90% | 1-in-10 years | HDD, CDD, GDD, Precipitation |
| 70th Percentile | 70% | 3-in-10 years | HDD, CDD, GDD, Precipitation |
| Expected Case | 50% | 1-in-2 years | HDD, CDD, GDD, Precipitation |
| **Forecasts of Peak Demand** | | | |
| 95th Percentile | 95% | 1-in-20 years | Peak Day Temperatures |
| 90th Percentile | 90% | 1-in-10 years | Peak Day Temperatures |
| 50th Percentile | 50% | 1-in-2 years | Peak Day Temperatures |

The analysis of resource requirements is based on the 70th percentile average load forecast coupled with the 95th percentile peak-demand forecast to provide a more adverse representation of average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average load forecast and the 90th percentile peak-demand forecast are typically used.

## Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also serve to impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2011–2030 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1985–2009).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted system sales (excluding Astaris) observed between 1985 and 2009. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50-percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50-percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1985–2009). The high- and low-case load forecasts also reflect the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, there is a 10-percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 20-year time period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability that the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, one-year, five-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

| Probability of Exceeding | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 90% | 90% | 90% | 90% |
| Expected Case | 50% | 50% | 50% | 50% |
| High Growth | 10% | 10% | 10% | 10% |

| Probability of Occurrence | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 26% | 26% | 26% | 26% |
| Expected Case | 48% | 48% | 48% | 48% |
| High Growth | 26% | 26% | 26% | 26% |

System load includes the sum of residential, commercial, industrial, irrigation, special contracts (including Astaris, historically), and Raft River. Idaho Power system load projections are reported in Table 4 and pictured in Figure 4. The expected-case system load forecast growth rate averages 1.4 percent per year over the 20 years of the planning period. The low scenario projects that system load will increase at an average rate of 1.0 percent per year throughout the forecast period. The high scenario projects load growth of 1.8 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth**
*(aMW)*

| | | | | | Annual Growth Rate |
|---|---|---|---|---|---|
| **Growth** | **2011** | **2015** | **2020** | **2030** | **2011–2030** |
| Low | 1,793 | 1,894 | 1,970 | 2,158 | 1.0% |
| Expected | 1,819 | 1,970 | 2,090 | 2,362 | 1.4% |
| High | 1,878 | 2,094 | 2,271 | 2,642 | 1.8% |

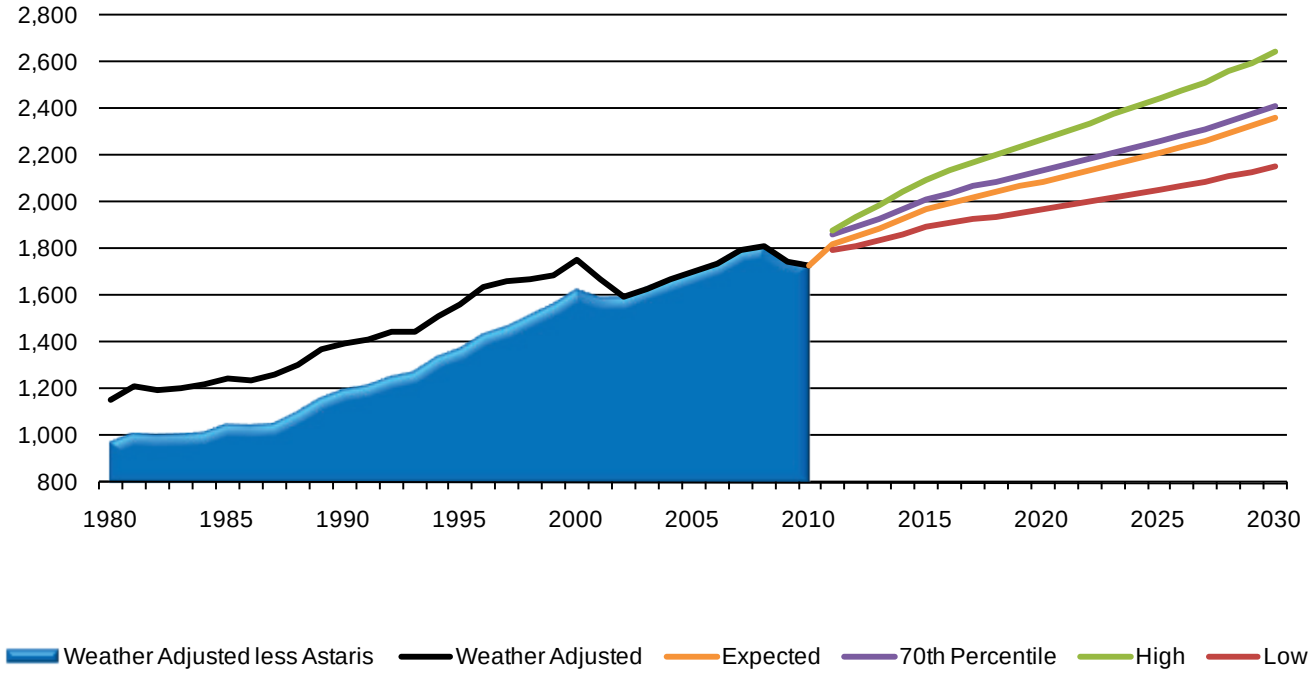


**Figure 4. Forecasted system load**
*(aMW)*

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# RESIDENTIAL

The expected-case residential load is forecast to increase from 595 aMW in 2011 to 786 aMW in 2030, an average annual compound growth rate of 1.5 percent. In the 70th percentile scenario, residential load is forecast to increase from 611 aMW in 2011 to 810 aMW in 2030, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 5.

**Table 5. Residential load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 646 | 681 | 744 | 860 | 1.5% |
| 70th Percentile | 611 | 644 | 702 | 810 | 1.5% |
| Expected Case | 595 | 626 | 682 | 786 | 1.5% |

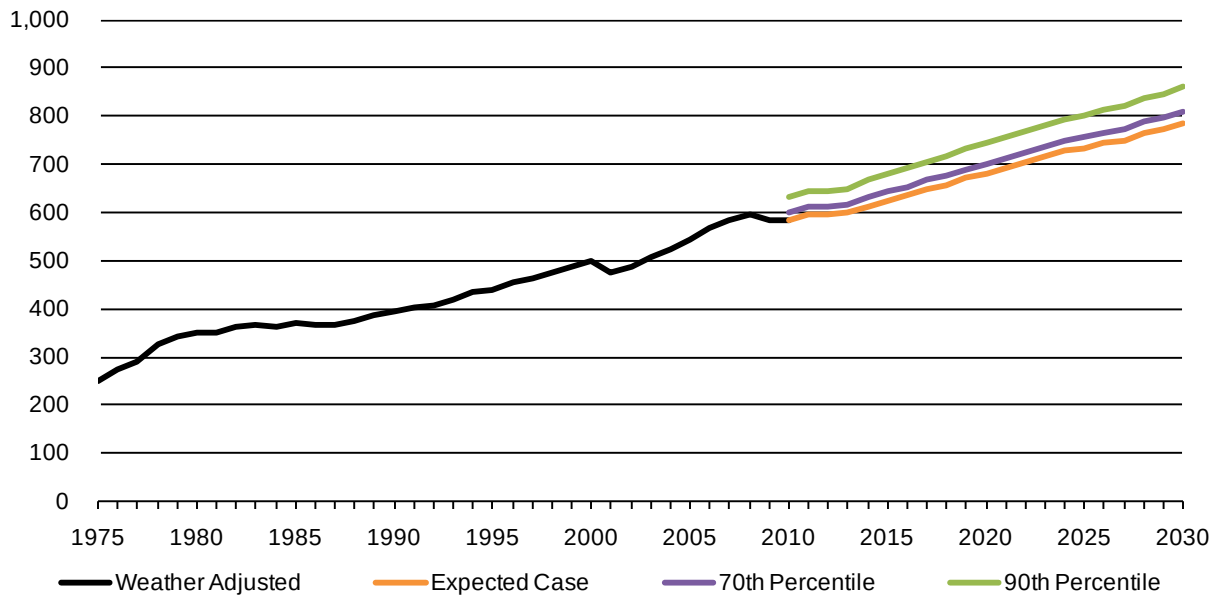


**Figure 5. Forecasted residential load**
*(aMW)*

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1980 and 37 percent of system sales in 2010. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2030. There were 408,754 residential customers as of December 2010. The number of residential customers is projected to increase to approximately 536,000 by December 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average sales per residential customer were nearly 13,000 kWh in 1975. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential-use-per-customer to stabilize and rise through 2007. However, the recession

in 2008 and 2009 combined with conservation programs designed to reduce electricity use served to slow the growth in residential-use-per-customer. The average sales per residential customer are expected to slowly rise to approximately 12,900 kWh per year in 2030. Average annual sales per residential customer are shown in Figure 6.

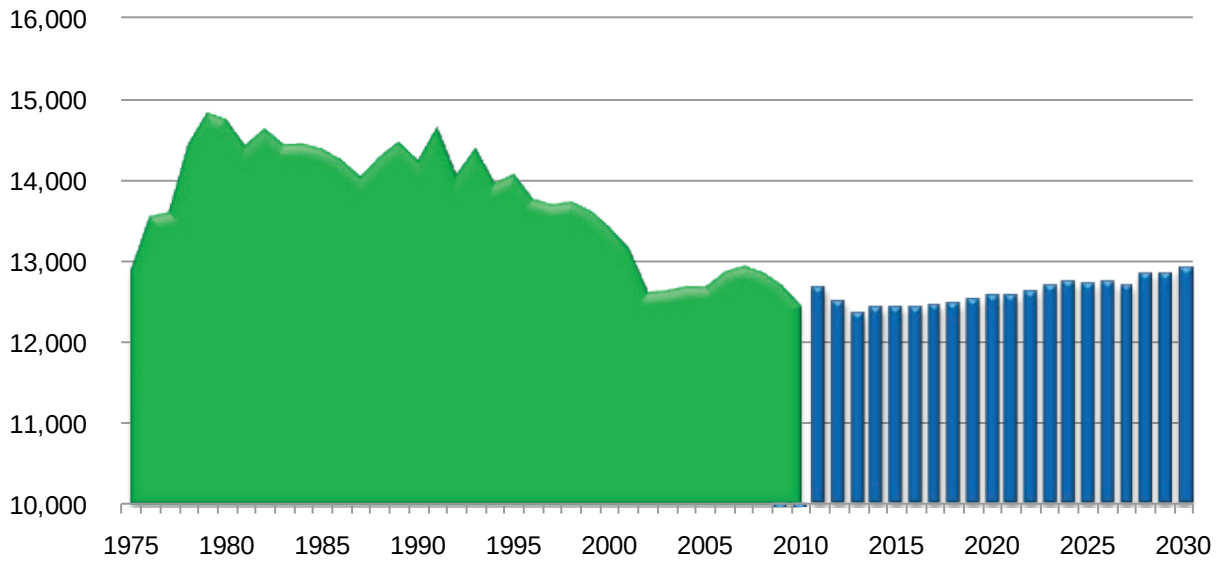


**Figure 6. Forecasted residential-use-per-customer**
*(weather-adjusted kWh)*

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 forecast of county housing stock and demographic data. The residential-customer forecast for 2011–2030 shows an average annual growth rate of 1.4 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics, Inc., forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential-use-per-customer is arrived at by dividing the residential sales forecast, which considers the impact of forecasted DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 439 aMW in 2011 to 561 aMW in 2030. The average annual compound-growth rate of commercial load is 1.3 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 443 aMW in 2011 to 568 aMW in 2030. The commercial load forecasts are illustrated in Figure 7.

**Table 6. Commercial load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 453 | 479 | 504 | 583 | 1.3% |
| 70th Percentile | 443 | 468 | 492 | 568 | 1.3% |
| Expected Case | 439 | 463 | 486 | 561 | 1.3% |

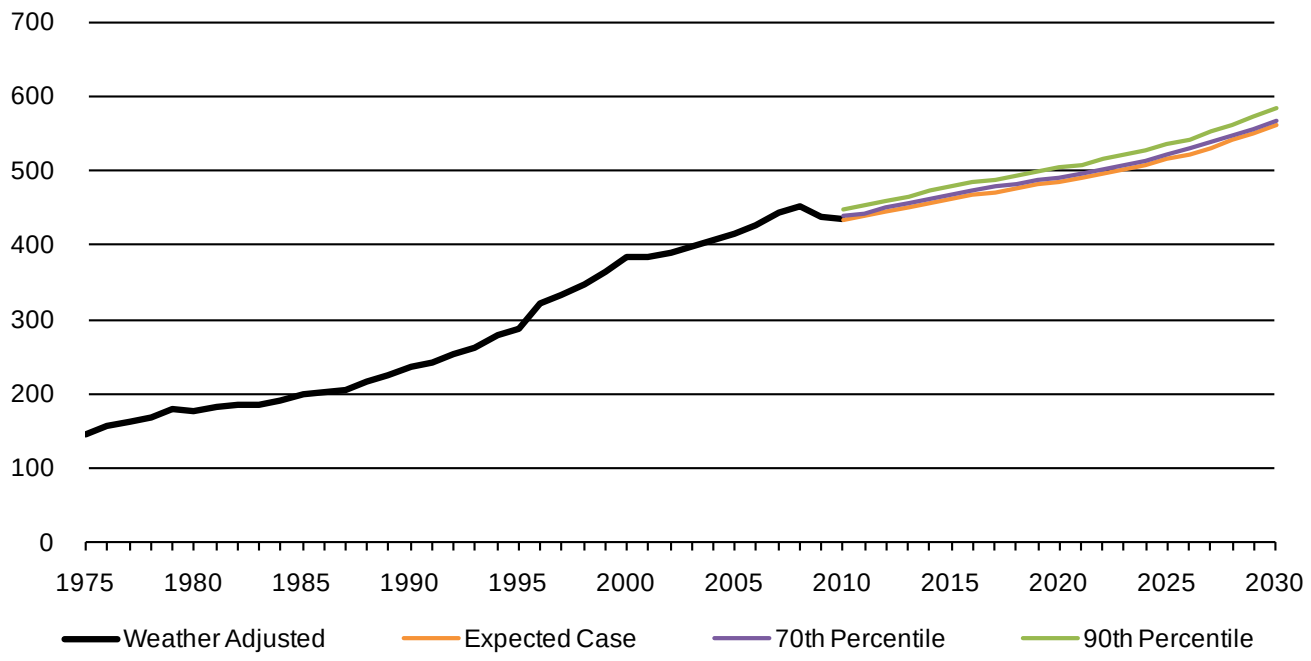


**Figure 7. Forecasted commercial load**
*(aMW)*

As of December 2010, Idaho Power had 64,647 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2 percent, reaching 94,600 customers by 2030. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1980 and nearly 28 percent of system sales in 2010. The commercial customer proportion of system sales is projected to decline to 26 percent of system sales by 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average consumption per commercial customer increased to a record 67,500 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening out over the time period 2010–2011, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 52,400 kWh per customer in 2030. Average annual use per commercial customer is shown in Figure 8.

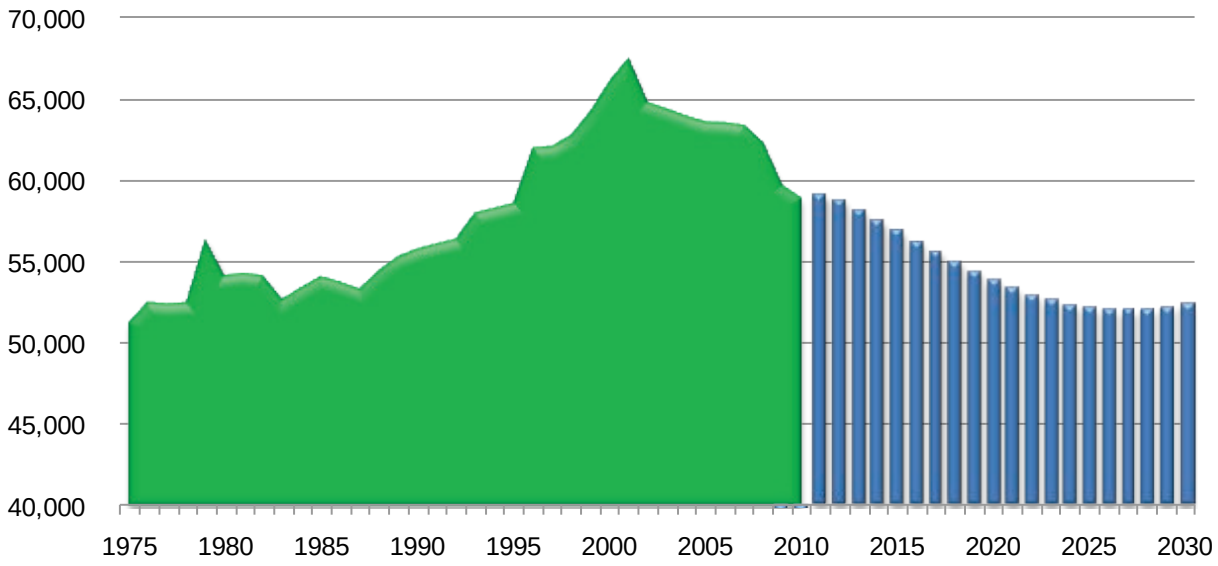


**Figure 8. Forecasted commercial-use-per-customer**
*(weather-adjusted kWh)*

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2011–2030 shows an average annual growth rate of 2 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics, Inc., forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecasted DSM, by the commercial-customer forecast.

# IRRIGATION

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly rise from 197 aMW in 2011 to 207 aMW in 2030, an average annual compound growth rate of 0.3 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast slow growth in irrigation load over the 2011–2030 time period. In the 70th percentile scenario, irrigation load is projected to be 213 aMW in 2011 and 223 aMW in 2030. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 9. The figure illustrates the poorer economic conditions and the dramatic reduction in land being put into production that was experienced by the agricultural economy in the mid-1980s.

**Table 7. Irrigation load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 232 | 234 | 237 | 242 | 0.2% |
| 70th Percentile | 213 | 215 | 217 | 223 | 0.2% |
| Expected Case | 197 | 199 | 202 | 207 | 0.3% |

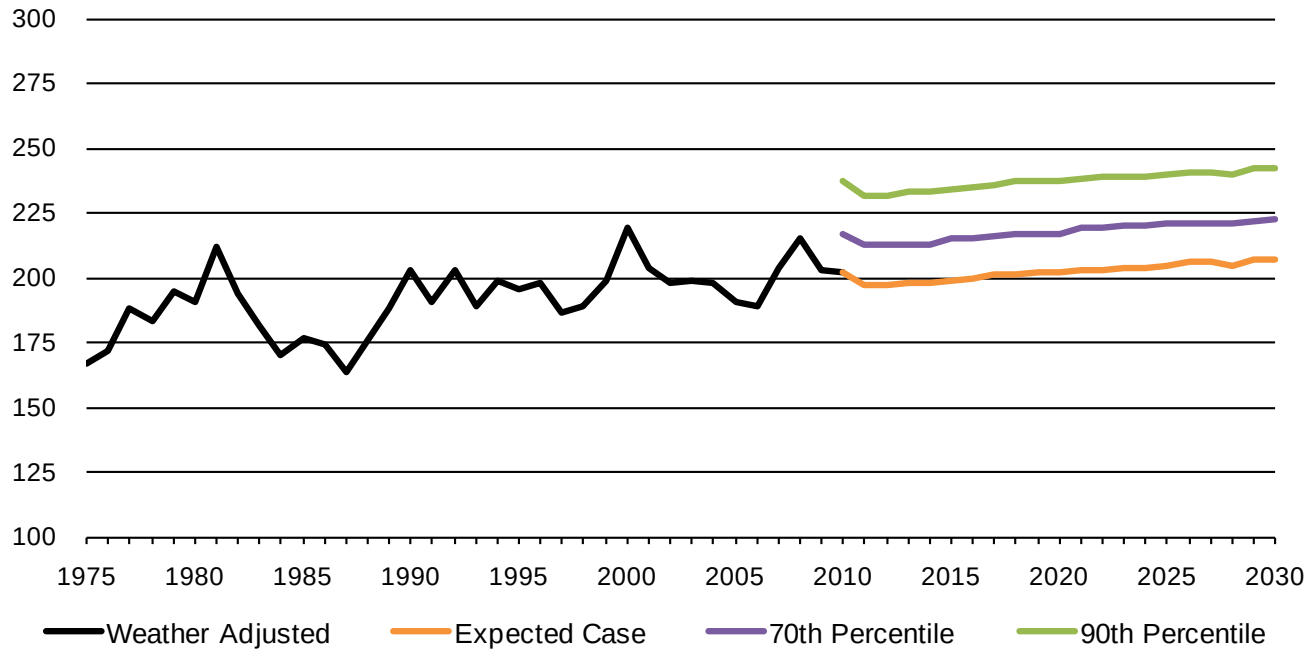


**Figure 9. Forecasted irrigation load**
*(aMW)*

It is important to understand the annual average-load figures reported in Table 7 and graphed in Figure 9 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half

of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

The 2011 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce consumption of electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hour (MWh) reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1980. Irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2010, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes. By 2030, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 16.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2010, the number of active irrigation accounts had increased to 17,846 and is projected to be about 23,500 irrigation accounts at the end of the planning period in 2030.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells. In 2007 and 2008, irrigation sales (weather-adjusted) increased by 8 percent and 6 percent, respectively, over each prior year. The increase can be explained, in part, by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh each year.

In the future, factors related to the conjunctive management of ground and surface water, and the possible litigation associated with the resolution, will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

# INDUSTRIAL

The industrial category is made up of Idaho Power's Large Power Service (Schedule 19) customers with monthly metered demands between 1,000 kW and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2010, the number of industrial customers had risen to 121, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 262 aMW in 2011 to 359 aMW in 2030, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70$^{th}$ and 90$^{th}$ percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 10.

**Table 8. Industrial load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| Expected Case | 262 | 283 | 302 | 359 | 1.7% |

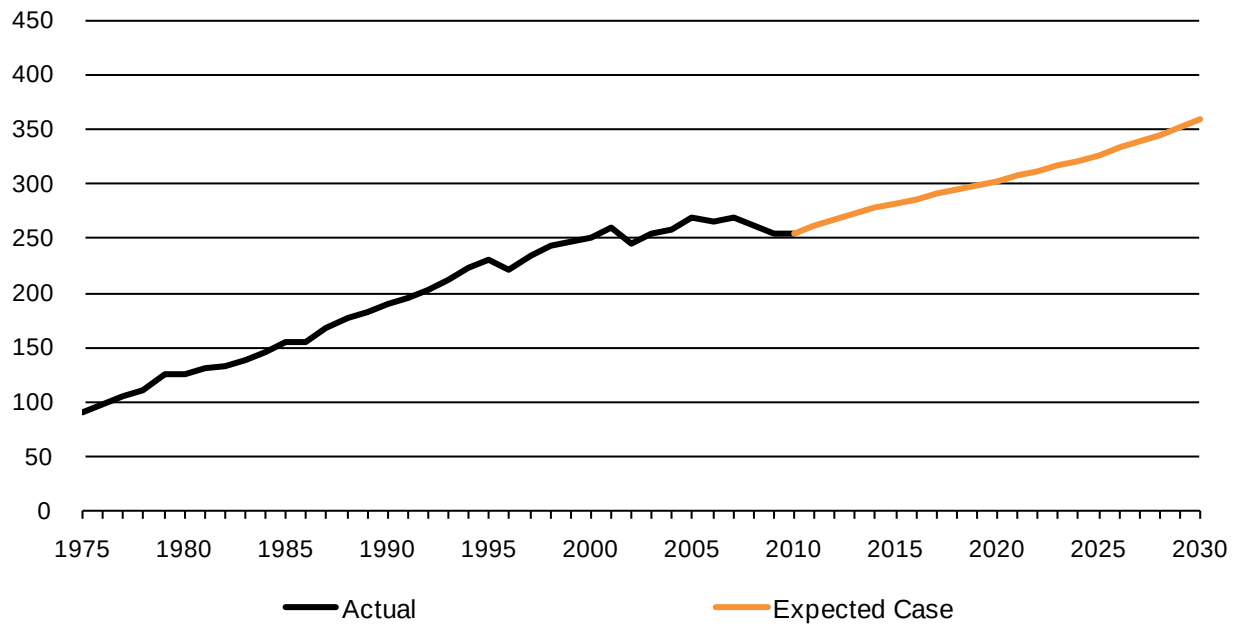


**Figure 10. Forecasted industrial load**
*(aMW)*

The industrial energy forecast is based on the most recent (July 2010) national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined

with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 11 illustrates the 2010 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (46 percent); followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (7 percent); Educational Services, Wholesale and Retail Trade, and Health Services (each representing 6 percent); and Other Manufacturing (5 percent). As Figure 11 shows, several other industry groups make up the remaining share of the 2010 industrial electricity consumption.

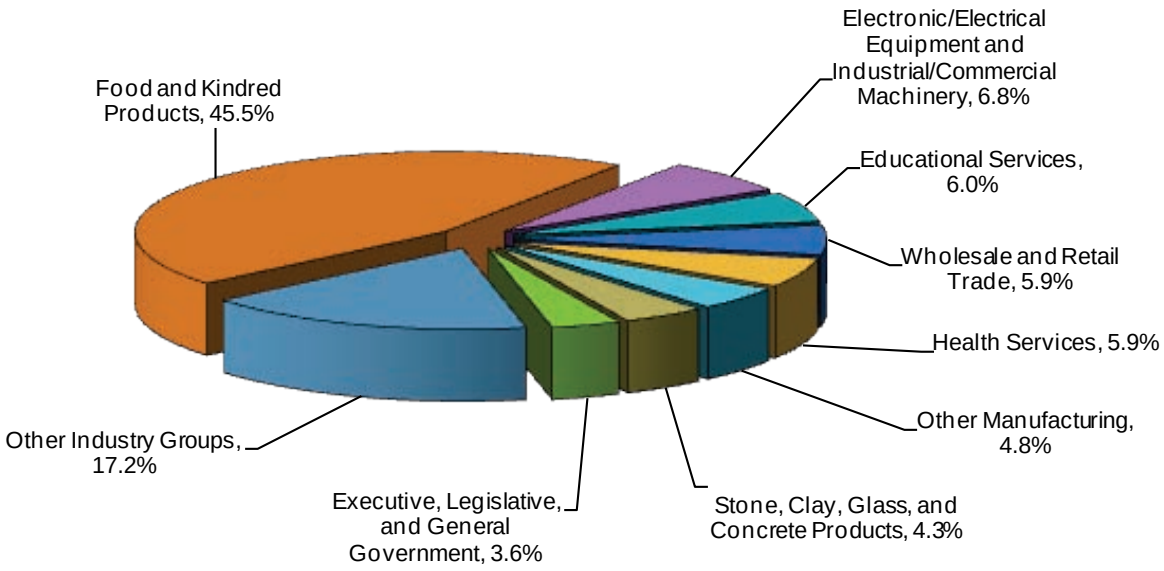


**Figure 11. Industrial electricity consumption by industry group**
*(based on 2010 figures)*

# ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a "special contract" schedule negotiated between Idaho Power and each of these individual large-power customers. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific, cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special contract customers recognized as firm load customers. These special contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered eminent. In this year's forecast, the company has included the anticipated load of an additional special contract customer referred to as "Special" in the additional firm load category, even though a long-term special contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contract customers and the new "Special" contract together make up the additional firm load category.

In the expected-case forecast, additional firm load is expected to increase from 165 aMW in 2011 to 243 aMW in 2030, an average growth rate of 2 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$ percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 12.

**Table 9. Additional firm load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| Expected Case | 165 | 229 | 236 | 243 | 2% |

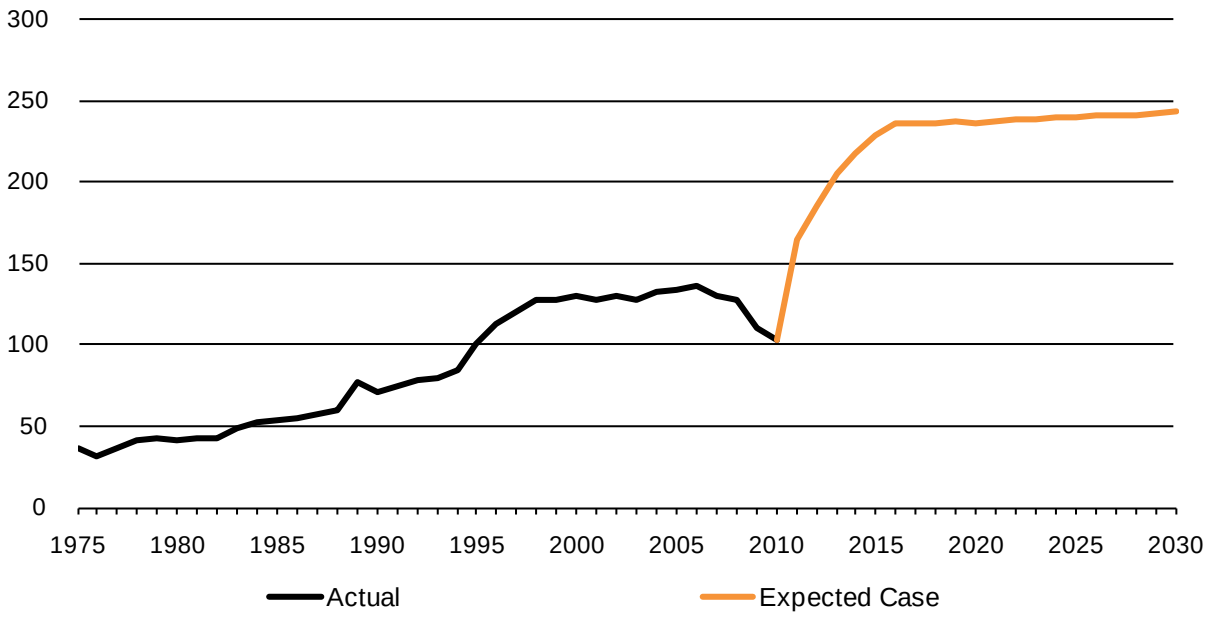


**Figure 12. Forecasted additional firm load**
*(aMW)*

## Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on the market demand for their products.

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing for the Pocatello MSA.

## Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2030 for the INL. The forecast calls for loads to increase considerably through 2014, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. As of October 1994, the INL nuclear reactor no longer generates electricity, consequently, the amount of electricity provided by Idaho Power increased considerably.

## Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2013.

## "Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

## Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. In April 2001, Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. Raft River is located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2010. However, Raft River renewed the agreement for an additional one-year term, which would extend service until September 30, 2011. The load forecasts in the 2011 IRP assume that Idaho Power will continue to provide service to the Raft River area through September 30, 2011.

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# COMPANY SYSTEM PEAK

System peak load includes the sum of individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically), and Raft River.

The all-time system summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer system peak load growth accelerated over the 10 years ending in 2008 as a record number of residential and commercial customers were added to the system and air conditioning became standard in nearly all new residential homes and new commercial buildings.

In the 90th percentile forecast, total system summer peak load is expected to increase from 3,494 MW in 2011 to 4,870 MW in the year 2030, an average growth rate of 1.8 percent per year over the planning period (Table 10). In the 95th percentile forecast, total system summer peak load is expected to increase from 3,515 MW in 2010 to 4,901 MW in the year 2030. The three scenarios of projected system summer peak load are illustrated in Figure 13. The 2001 summer peak was dampened by the nearly 30 percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth**
*(MW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 95th Percentile | 3,515 | 3,854 | 4,190 | 4,901 | 1.8% |
| 90th Percentile | 3,494 | 3,831 | 4,164 | 4,870 | 1.8% |
| 50th Percentile | 3,334 | 3,657 | 3,973 | 4,643 | 1.8% |

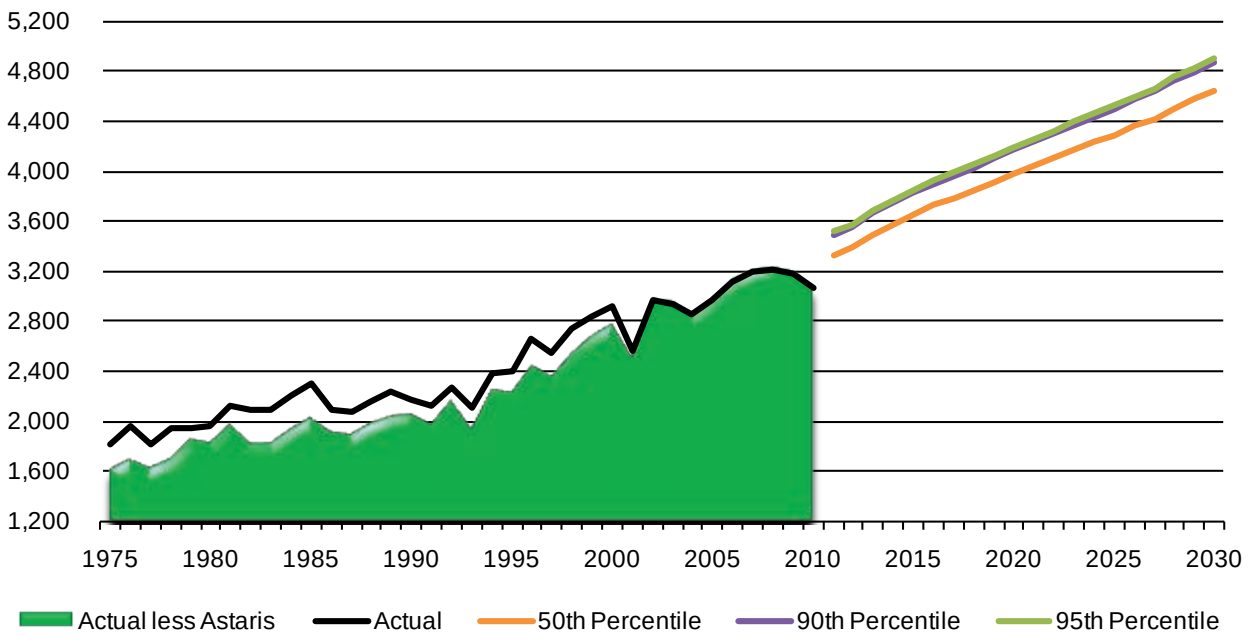


**Figure 13. Forecasted system summer peak**
*(MW)*

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical system winter peak load is much more variable than

summer system peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th percentile forecast, total system winter peak load is expected to increase from 2,693 MW in 2011 to 3,336 MW in 2030, an average growth rate of 1.1 percent per year over the planning period (Table 11). In the 95th percentile forecast, total system winter peak load is expected to increase from 2,815 MW in 2011 to 3,509 MW in 2030, an average growth rate of 1.2 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 14.

**Table 11. System winter peak load growth**
*(MW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 95th Percentile | 2,815 | 2,948 | 3,121 | 3,509 | 1.2% |
| 90th Percentile | 2,693 | 2,815 | 2,976 | 3,336 | 1.1% |
| 50th Percentile | 2,384 | 2,478 | 2,604 | 2,896 | 1.0% |

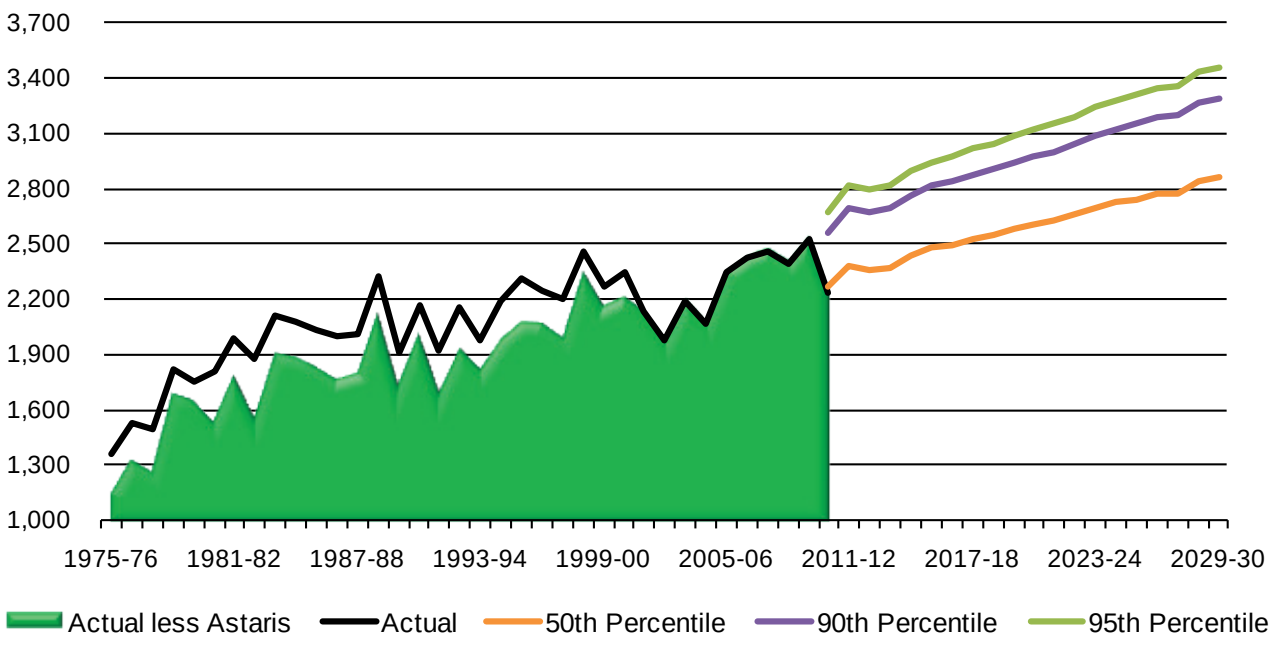


**Figure 14. Forecasted system winter peak**
*(MW)*

# COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and Raft River. System load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics, Inc., economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.4 percent per year over the 2011–2030 time period. Company system load projections are reported in Table 12 and shown in Figure 15.

In the expected-case forecast, company system load is expected to increase from 1,819 aMW in 2011 to 2,362 aMW in 2030. In the 70$^{th}$ percentile forecast, company system load is expected to increase from 1,860 aMW in 2011 to 2,414 aMW by 2030, an average growth rate of 1.4 percent per year over the planning period (Table 12).

**Table 12. System load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,931 | 2,088 | 2,218 | 2,508 | 1.4% |
| 70$^{th}$ Percentile | 1,860 | 2,013 | 2,136 | 2,414 | 1.4% |
| Expected Case | 1,819 | 1,970 | 2,090 | 2,362 | 1.4% |

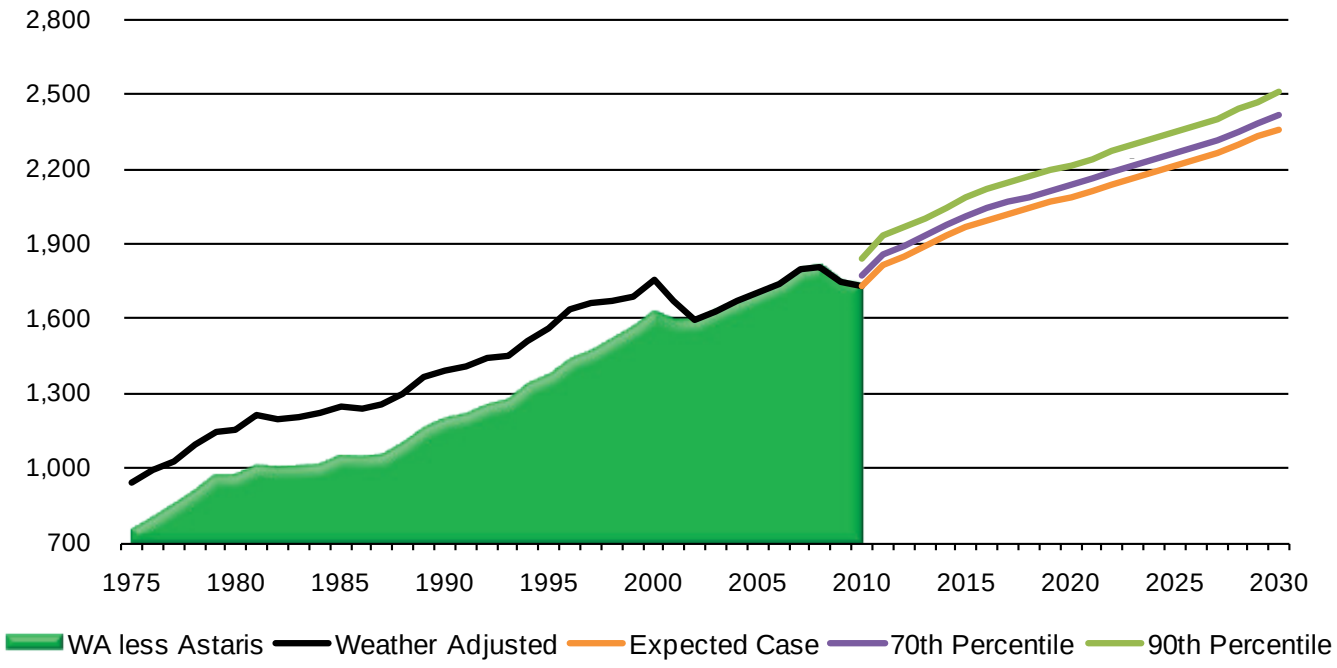


**Figure 15. Forecasted system load**
*(aMW)*

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest

individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load excluding Astaris more accurately portrays the underlying general business growth trend within the service area.

# CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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# TOTAL COMPANY LOAD

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

The composition of total company electricity sales by year is shown in Figure 16. Residential sales are forecast to be over 32 percent higher in 2030, gaining nearly 1.7 million MWh over 2011. Commercial sales are expected to be nearly 28 percent higher or nearly 1.1 million MWh above 2011 followed by industrial (37 percent higher or nearly 0.8 million additional MWh) and irrigation (only 5 percent higher in 2030 than 2011). Electricity sales to Astaris ended in April 2002.

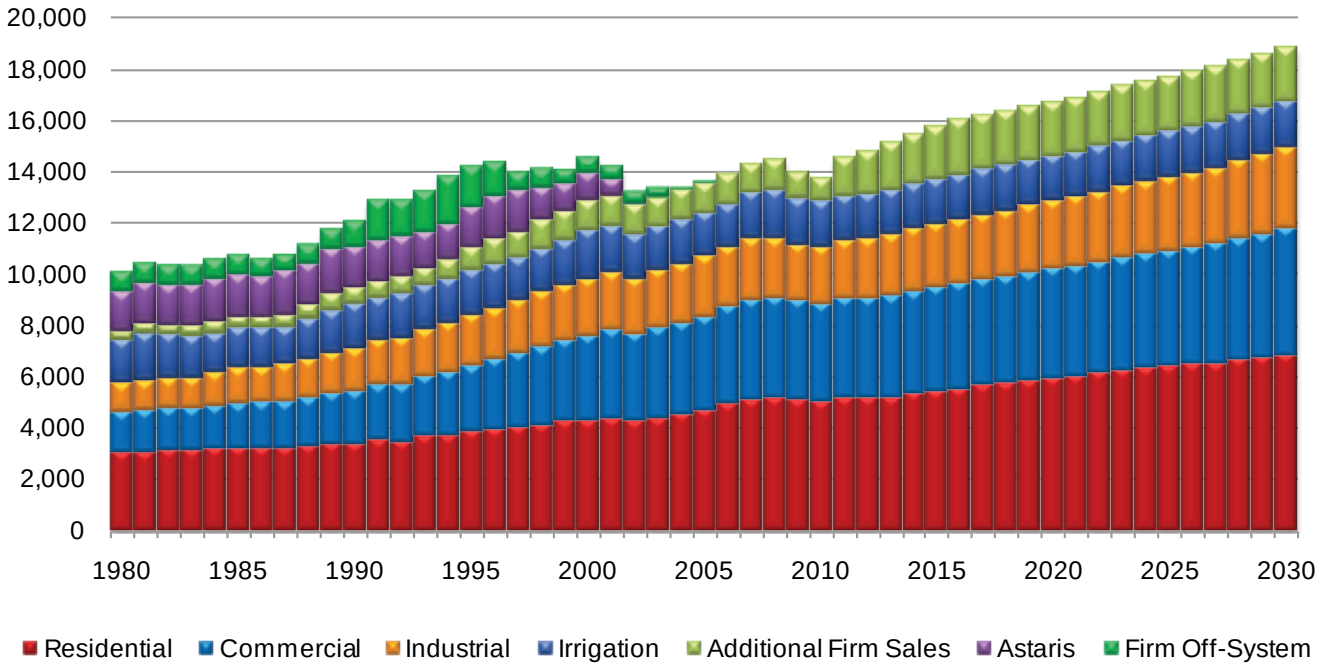


**Figure 16. Composition of total company electricity sales**
*(thousands of MWh)*

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River) is forecast to grow by 47 percent over the 2011–2030 time period, largely due to the addition of Hoku Materials and Idaho Power's newest "Special" contract customer as special contract customers.

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# DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs that reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are considered in the 2011 IRP *Appendix A–Sales and Load Forecast*; however, demand response programs are accounted for in the 2011 IRP load and resource balance and not in the load forecast. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which were used to develop portfolios for the 2011 IRP.

## Energy Efficiency Programs

The 2011 IRP *Appendix A–Sales and Load Forecast* follows the methodology established in an Itron white paper[3], "Incorporating DSM into the Load Forecast". The authors discussed methods for adjusting load forecasts to account for DSM programs. According to Itron, there are several potential econometric frameworks that can be applied to account for DSM in the forecast period. The methods are designed to adjust the load forecast by accounting for the amount and continuing momentum of the historic DSM contained in the load forecast model.

The "DSM trend" method was chosen as the preferred method to incorporate DSM into the load forecasts for the commercial, industrial, and irrigation sectors. The alternative methods make explicit efforts to adjust DSM out of the history and out of the forecast. The DSM trend takes a different approach by recognizing that historical DSM and DSM trends are embedded in the actual sales data. Forecasting models built on these data implicitly assume that the levels and trends for DSM savings in the history continue into the forecast at approximately the same rate. As a result, the forecast needs to be adjusted only if DSM impacts are expected to be greater or less than the historical trends.

In the final step of the DSM trend method, the forecast is adjusted if the cumulative impacts of past and future programs are expected to accelerate or decelerate relative to the DSM trend line. In this method, the forecast is adjusted up or down by the difference between the DSM trend line and the cumulative impact of past and future programs.

If the total cumulative impact of past and future programs is expected to fall short of the historical trend, then the energy forecast should be adjusted upward by the amount of the deceleration below the DSM trend line.

In another improvement to this year's forecast, Idaho Power used Itron's residential SAE model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process. When applying the SAE framework, DSM activity is naturally incorporated in the efficiency assumptions and the calibration to historic sales data. Efficiency assumptions incorporate national-level DSM impacts. Calibration incorporates specific utility DSM impacts. Therefore, additional adjustments to the residential energy forecast for existing DSM programs were not made.

When using an econometric or SAE model, historical DSM investments influence the historical sales data, the forecast model parameters, and the resulting sales projections. As DSM investment increases,

[3] Stuart McMenamin and Mark Quan. "Incorporating DSM into the Load Forecast." Itron , https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

forecasters need to adjust their sales forecasts to account for this acceleration relative to the historic DSM implicitly included in an unadjusted forecast.

The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customers' meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customers' meter.

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

## Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed in *Appendix C–Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2011 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B–Demand Side Management 2010 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

### Residential Load

**Historical Residential Sales and Load, 1970–2010**
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 132,135 | | 9,944 | 1,314 | | 151 |
| 1971 | 138,071 | 4.5% | 10,392 | 1,435 | 9.2% | 165 |
| 1972 | 145,208 | 5.2% | 10,838 | 1,574 | 9.7% | 182 |
| 1973 | 152,957 | 5.3% | 11,501 | 1,759 | 11.8% | 202 |
| 1974 | 160,151 | 4.7% | 12,099 | 1,938 | 10.1% | 224 |
| 1975 | 167,622 | 4.7% | 12,871 | 2,158 | 11.3% | 249 |
| 1976 | 175,720 | 4.8% | 13,544 | 2,380 | 10.3% | 273 |
| 1977 | 184,561 | 5.0% | 13,594 | 2,509 | 5.4% | 288 |
| 1978 | 194,650 | 5.5% | 14,427 | 2,808 | 11.9% | 325 |
| 1979 | 202,982 | 4.3% | 14,821 | 3,008 | 7.1% | 343 |
| 1980 | 209,629 | 3.3% | 14,741 | 3,090 | 2.7% | 352 |
| 1981 | 213,579 | 1.9% | 14,416 | 3,079 | -0.4% | 352 |
| 1982 | 216,696 | 1.5% | 14,627 | 3,170 | 2.9% | 362 |
| 1983 | 219,849 | 1.5% | 14,430 | 3,172 | 0.1% | 366 |
| 1984 | 222,695 | 1.3% | 14,438 | 3,215 | 1.4% | 364 |
| 1985 | 225,185 | 1.1% | 14,375 | 3,237 | 0.7% | 371 |
| 1986 | 227,081 | 0.8% | 14,244 | 3,234 | -0.1% | 368 |
| 1987 | 228,868 | 0.8% | 14,037 | 3,213 | -0.7% | 365 |
| 1988 | 230,771 | 0.8% | 14,282 | 3,296 | 2.6% | 376 |
| 1989 | 233,370 | 1.1% | 14,463 | 3,375 | 2.4% | 386 |
| 1990 | 238,117 | 2.0% | 14,236 | 3,390 | 0.4% | 393 |
| 1991 | 243,207 | 2.1% | 14,654 | 3,564 | 5.1% | 404 |
| 1992 | 249,767 | 2.7% | 14,062 | 3,512 | -1.5% | 405 |
| 1993 | 258,271 | 3.4% | 14,392 | 3,717 | 5.8% | 419 |
| 1994 | 267,854 | 3.7% | 13,957 | 3,738 | 0.6% | 433 |
| 1995 | 277,131 | 3.5% | 14,067 | 3,898 | 4.3% | 440 |
| 1996 | 286,227 | 3.3% | 13,759 | 3,938 | 1.0% | 456 |
| 1997 | 294,674 | 3.0% | 13,692 | 4,035 | 2.4% | 464 |
| 1998 | 303,300 | 2.9% | 13,727 | 4,164 | 3.2% | 475 |
| 1999 | 312,901 | 3.2% | 13,616 | 4,260 | 2.3% | 488 |
| 2000 | 322,402 | 3.0% | 13,409 | 4,323 | 1.5% | 500 |
| 2001 | 331,009 | 2.7% | 13,156 | 4,355 | 0.7% | 476 |
| 2002 | 339,764 | 2.6% | 12,616 | 4,286 | -1.6% | 487 |
| 2003 | 349,219 | 2.8% | 12,639 | 4,414 | 3.0% | 507 |
| 2004 | 360,462 | 3.2% | 12,689 | 4,574 | 3.6% | 525 |
| 2005 | 373,602 | 3.6% | 12,687 | 4,740 | 3.6% | 543 |
| 2006 | 387,707 | 3.8% | 12,872 | 4,991 | 5.3% | 568 |
| 2007 | 397,286 | 2.5% | 12,940 | 5,141 | 3.0% | 585 |
| 2008 | 402,520 | 1.3% | 12,858 | 5,176 | 0.7% | 594 |
| 2009 | 405,144 | 0.7% | 12,696 | 5,144 | -0.6% | 585 |
| 2010 | 407,551 | 0.6% | 12,441 | 5,070 | -1.4% | 582 |

## Residential Load

### Projected Residential Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 411,162 | 0.9% | 12,677 | 5,212 | 2.8% | 595 |
| 2012 | 415,787 | 1.1% | 12,514 | 5,203 | -0.2% | 594 |
| 2013 | 423,098 | 1.8% | 12,350 | 5,225 | 0.4% | 598 |
| 2014 | 432,043 | 2.1% | 12,425 | 5,368 | 2.7% | 614 |
| 2015 | 440,364 | 1.9% | 12,441 | 5,478 | 2.1% | 626 |
| 2016 | 447,754 | 1.7% | 12,425 | 5,563 | 1.6% | 636 |
| 2017 | 454,724 | 1.6% | 12,468 | 5,669 | 1.9% | 648 |
| 2018 | 461,592 | 1.5% | 12,473 | 5,757 | 1.6% | 658 |
| 2019 | 468,394 | 1.5% | 12,530 | 5,869 | 1.9% | 671 |
| 2020 | 475,070 | 1.4% | 12,568 | 5,971 | 1.7% | 682 |
| 2021 | 481,514 | 1.4% | 12,578 | 6,056 | 1.4% | 692 |
| 2022 | 487,734 | 1.3% | 12,627 | 6,159 | 1.7% | 704 |
| 2023 | 493,690 | 1.2% | 12,703 | 6,271 | 1.8% | 717 |
| 2024 | 499,477 | 1.2% | 12,737 | 6,362 | 1.4% | 727 |
| 2025 | 505,167 | 1.1% | 12,722 | 6,427 | 1.0% | 734 |
| 2026 | 510,811 | 1.1% | 12,745 | 6,510 | 1.3% | 743 |
| 2027 | 516,404 | 1.1% | 12,691 | 6,554 | 0.7% | 749 |
| 2028 | 521,918 | 1.1% | 12,851 | 6,707 | 2.3% | 766 |
| 2029 | 527,380 | 1.0% | 12,849 | 6,776 | 1.0% | 774 |
| 2030 | 532,835 | 1.0% | 12,908 | 6,878 | 1.5% | 786 |

## Commercial Load

**Historical Commercial Sales and Load, 1970–2010**
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 21,375 | | 42,773 | 914 | | 105 |
| 1971 | 22,077 | 3.3% | 45,388 | 1,002 | 9.6% | 115 |
| 1972 | 22,585 | 2.3% | 46,142 | 1,042 | 4.0% | 120 |
| 1973 | 23,286 | 3.1% | 48,144 | 1,121 | 7.6% | 128 |
| 1974 | 24,096 | 3.5% | 49,027 | 1,181 | 5.4% | 136 |
| 1975 | 25,045 | 3.9% | 51,218 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,512 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,414 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,474 | 1,460 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,389 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,141 | 1,559 | -1.6% | 178 |
| 1981 | 29,567 | 2.7% | 54,282 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,126 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,684 | 1,621 | -0.7% | 186 |
| 1984 | 31,554 | 2.5% | 53,410 | 1,685 | 3.9% | 191 |
| 1985 | 32,417 | 2.7% | 54,076 | 1,753 | 4.0% | 201 |
| 1986 | 33,208 | 2.4% | 53,747 | 1,785 | 1.8% | 203 |
| 1987 | 33,975 | 2.3% | 53,312 | 1,811 | 1.5% | 206 |
| 1988 | 34,723 | 2.2% | 54,432 | 1,890 | 4.4% | 216 |
| 1989 | 35,638 | 2.6% | 55,285 | 1,970 | 4.2% | 226 |
| 1990 | 36,785 | 3.2% | 55,761 | 2,051 | 4.1% | 236 |
| 1991 | 37,922 | 3.1% | 56,076 | 2,127 | 3.7% | 243 |
| 1992 | 39,022 | 2.9% | 56,359 | 2,199 | 3.4% | 253 |
| 1993 | 40,047 | 2.6% | 57,970 | 2,321 | 5.6% | 263 |
| 1994 | 41,629 | 4.0% | 58,246 | 2,425 | 4.4% | 280 |
| 1995 | 43,165 | 3.7% | 58,555 | 2,528 | 4.2% | 287 |
| 1996 | 44,995 | 4.2% | 61,960 | 2,788 | 10.3% | 322 |
| 1997 | 46,819 | 4.1% | 62,038 | 2,905 | 4.2% | 333 |
| 1998 | 48,404 | 3.4% | 62,713 | 3,036 | 4.5% | 347 |
| 1999 | 49,430 | 2.1% | 64,186 | 3,173 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 66,043 | 3,310 | 4.3% | 383 |
| 2001 | 51,501 | 2.8% | 67,454 | 3,474 | 5.0% | 384 |
| 2002 | 52,915 | 2.7% | 64,719 | 3,425 | -1.4% | 390 |
| 2003 | 54,194 | 2.4% | 64,320 | 3,486 | 1.8% | 399 |
| 2004 | 55,577 | 2.6% | 63,898 | 3,551 | 1.9% | 407 |
| 2005 | 57,145 | 2.8% | 63,527 | 3,630 | 2.2% | 415 |
| 2006 | 59,050 | 3.3% | 63,487 | 3,749 | 3.3% | 427 |
| 2007 | 61,640 | 4.4% | 63,330 | 3,904 | 4.1% | 445 |
| 2008 | 63,492 | 3.0% | 62,249 | 3,952 | 1.2% | 451 |
| 2009 | 64,151 | 1.0% | 59,635 | 3,826 | -3.2% | 437 |
| 2010 | 64,421 | 0.4% | 58,851 | 3,791 | -0.9% | 434 |

## Commercial Load

### Projected Commercial Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 64,995 | 0.9% | 59,059 | 3,839 | 1.2% | 439 |
| 2012 | 66,265 | 2.0% | 58,734 | 3,892 | 1.4% | 445 |
| 2013 | 67,892 | 2.5% | 58,122 | 3,946 | 1.4% | 451 |
| 2014 | 69,600 | 2.5% | 57,471 | 4,000 | 1.4% | 457 |
| 2015 | 71,252 | 2.4% | 56,873 | 4,052 | 1.3% | 463 |
| 2016 | 72,840 | 2.2% | 56,204 | 4,094 | 1.0% | 468 |
| 2017 | 74,398 | 2.1% | 55,579 | 4,135 | 1.0% | 472 |
| 2018 | 75,950 | 2.1% | 54,977 | 4,176 | 1.0% | 477 |
| 2019 | 77,497 | 2.0% | 54,399 | 4,216 | 1.0% | 482 |
| 2020 | 79,031 | 2.0% | 53,841 | 4,255 | 0.9% | 486 |
| 2021 | 80,551 | 1.9% | 53,342 | 4,297 | 1.0% | 491 |
| 2022 | 82,058 | 1.9% | 52,929 | 4,343 | 1.1% | 496 |
| 2023 | 83,549 | 1.8% | 52,592 | 4,394 | 1.2% | 502 |
| 2024 | 85,030 | 1.8% | 52,307 | 4,448 | 1.2% | 508 |
| 2025 | 86,505 | 1.7% | 52,116 | 4,508 | 1.4% | 515 |
| 2026 | 87,976 | 1.7% | 52,022 | 4,577 | 1.5% | 523 |
| 2027 | 89,445 | 1.7% | 51,979 | 4,649 | 1.6% | 531 |
| 2028 | 90,906 | 1.6% | 52,057 | 4,732 | 1.8% | 541 |
| 2029 | 92,365 | 1.6% | 52,166 | 4,818 | 1.8% | 550 |
| 2030 | 93,823 | 1.6% | 52,363 | 4,913 | 2.0% | 561 |

## Irrigation Load

### Historical Irrigation Sales and Load,1970–2010

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 7,319 | | 126,039 | 922 | | 105 |
| 1971 | 7,518 | 2.7% | 136,020 | 1,023 | 10.9% | 117 |
| 1972 | 7,815 | 4.0% | 131,163 | 1,025 | 0.2% | 117 |
| 1973 | 8,341 | 6.7% | 140,226 | 1,170 | 14.1% | 134 |
| 1974 | 8,971 | 7.6% | 147,179 | 1,320 | 12.9% | 151 |
| 1975 | 9,480 | 5.7% | 154,226 | 1,462 | 10.7% | 167 |
| 1976 | 9,936 | 4.8% | 152,340 | 1,514 | 3.5% | 172 |
| 1977 | 10,238 | 3.0% | 160,870 | 1,647 | 8.8% | 188 |
| 1978 | 10,476 | 2.3% | 152,800 | 1,601 | -2.8% | 183 |
| 1979 | 10,711 | 2.2% | 159,986 | 1,714 | 7.1% | 195 |
| 1980 | 10,854 | 1.3% | 154,900 | 1,681 | -1.9% | 191 |
| 1981 | 11,248 | 3.6% | 165,138 | 1,857 | 10.5% | 212 |
| 1982 | 11,312 | 0.6% | 150,370 | 1,701 | -8.4% | 194 |
| 1983 | 11,133 | -1.6% | 143,424 | 1,597 | -6.1% | 182 |
| 1984 | 11,375 | 2.2% | 131,427 | 1,495 | -6.4% | 170 |
| 1985 | 11,576 | 1.8% | 133,730 | 1,548 | 3.6% | 177 |
| 1986 | 11,308 | -2.3% | 134,686 | 1,523 | -1.6% | 174 |
| 1987 | 11,254 | -0.5% | 127,375 | 1,433 | -5.9% | 164 |
| 1988 | 11,378 | 1.1% | 136,257 | 1,550 | 8.2% | 176 |
| 1989 | 11,957 | 5.1% | 137,704 | 1,647 | 6.2% | 188 |
| 1990 | 12,340 | 3.2% | 144,106 | 1,778 | 8.0% | 203 |
| 1991 | 12,484 | 1.2% | 133,777 | 1,670 | -6.1% | 191 |
| 1992 | 12,809 | 2.6% | 139,469 | 1,786 | 7.0% | 203 |
| 1993 | 13,078 | 2.1% | 126,585 | 1,655 | -7.3% | 189 |
| 1994 | 13,559 | 3.7% | 128,848 | 1,747 | 5.5% | 199 |
| 1995 | 13,679 | 0.9% | 125,761 | 1,720 | -1.5% | 196 |
| 1996 | 14,074 | 2.9% | 123,537 | 1,739 | 1.1% | 198 |
| 1997 | 14,383 | 2.2% | 114,002 | 1,640 | -5.7% | 187 |
| 1998 | 14,695 | 2.2% | 112,933 | 1,660 | 1.2% | 189 |
| 1999 | 14,912 | 1.5% | 117,103 | 1,746 | 5.2% | 199 |
| 2000 | 15,253 | 2.3% | 125,903 | 1,920 | 10.0% | 219 |
| 2001 | 15,522 | 1.8% | 115,103 | 1,787 | -7.0% | 204 |
| 2002 | 15,840 | 2.0% | 109,768 | 1,739 | -2.7% | 198 |
| 2003 | 16,020 | 1.1% | 108,979 | 1,746 | 0.4% | 199 |
| 2004 | 16,297 | 1.7% | 106,547 | 1,736 | -0.5% | 198 |
| 2005 | 16,936 | 3.9% | 98,843 | 1,674 | -3.6% | 191 |
| 2006 | 17,062 | 0.7% | 96,848 | 1,652 | -1.3% | 189 |
| 2007 | 17,001 | -0.4% | 104,905 | 1,783 | 7.9% | 204 |
| 2008 | 17,428 | 2.5% | 108,350 | 1,888 | 5.9% | 215 |
| 2009 | 17,708 | 1.6% | 100,186 | 1,774 | -6.0% | 203 |
| 2010 | 17,846 | 0.8% | 99,148 | 1,769 | -0.3% | 202 |

## Irrigation Load

### Projected Irrigation Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 18,264 | 2.3% | 94,526 | 1,726 | -2.4% | 197 |
| 2012 | 18,541 | 1.5% | 93,518 | 1,734 | 0.4% | 197 |
| 2013 | 18,821 | 1.5% | 91,968 | 1,731 | -0.2% | 198 |
| 2014 | 19,101 | 1.5% | 90,686 | 1,732 | 0.1% | 198 |
| 2015 | 19,379 | 1.5% | 90,049 | 1,745 | 0.7% | 199 |
| 2016 | 19,655 | 1.4% | 89,212 | 1,753 | 0.5% | 200 |
| 2017 | 19,932 | 1.4% | 88,237 | 1,759 | 0.3% | 201 |
| 2018 | 20,212 | 1.4% | 87,324 | 1,765 | 0.4% | 201 |
| 2019 | 20,487 | 1.4% | 86,337 | 1,769 | 0.2% | 202 |
| 2020 | 20,767 | 1.4% | 85,426 | 1,774 | 0.3% | 202 |
| 2021 | 21,045 | 1.3% | 84,531 | 1,779 | 0.3% | 203 |
| 2022 | 21,323 | 1.3% | 83,591 | 1,782 | 0.2% | 203 |
| 2023 | 21,601 | 1.3% | 82,745 | 1,787 | 0.3% | 204 |
| 2024 | 21,878 | 1.3% | 81,991 | 1,794 | 0.4% | 204 |
| 2025 | 22,157 | 1.3% | 81,160 | 1,798 | 0.2% | 205 |
| 2026 | 22,437 | 1.3% | 80,269 | 1,801 | 0.2% | 206 |
| 2027 | 22,712 | 1.2% | 79,463 | 1,805 | 0.2% | 206 |
| 2028 | 22,988 | 1.2% | 78,494 | 1,804 | 0.0% | 205 |
| 2029 | 23,268 | 1.2% | 77,943 | 1,814 | 0.5% | 207 |
| 2030 | 23,547 | 1.2% | 77,079 | 1,815 | 0.1% | 207 |

## Industrial Load

### Historical Industrial Sales and Load, 1970–2010

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 49 | | 9,173,784 | 445 | | 52 |
| 1971 | 50 | 3.3% | 10,474,941 | 525 | 17.9% | 60 |
| 1972 | 56 | 12.1% | 10,944,714 | 615 | 17.2% | 71 |
| 1973 | 63 | 12.3% | 10,889,056 | 687 | 11.7% | 79 |
| 1974 | 65 | 2.2% | 11,464,249 | 739 | 7.6% | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,310,726 | 2,220 | -0.2% | 254 |

## Industrial Load

### Projected Industrial Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 121 | -0.2% | 18,958,898 | 2,294 | 3.3% | 262 |
| 2012 | 125 | 3.3% | 18,768,661 | 2,346 | 2.3% | 268 |
| 2013 | 125 | 0.0% | 19,133,471 | 2,392 | 1.9% | 273 |
| 2014 | 126 | 0.8% | 19,320,558 | 2,434 | 1.8% | 278 |
| 2015 | 128 | 1.6% | 19,318,966 | 2,473 | 1.6% | 283 |
| 2016 | 131 | 2.3% | 19,155,425 | 2,509 | 1.5% | 286 |
| 2017 | 134 | 2.3% | 18,997,015 | 2,546 | 1.4% | 291 |
| 2018 | 134 | 0.0% | 19,256,620 | 2,580 | 1.4% | 295 |
| 2019 | 136 | 1.5% | 19,239,155 | 2,617 | 1.4% | 299 |
| 2020 | 139 | 2.2% | 19,087,337 | 2,653 | 1.4% | 302 |
| 2021 | 140 | 0.7% | 19,218,638 | 2,691 | 1.4% | 308 |
| 2022 | 142 | 1.4% | 19,241,280 | 2,732 | 1.5% | 312 |
| 2023 | 142 | 0.0% | 19,514,996 | 2,771 | 1.4% | 317 |
| 2024 | 145 | 2.1% | 19,391,910 | 2,812 | 1.5% | 321 |
| 2025 | 147 | 1.4% | 19,454,919 | 2,860 | 1.7% | 327 |
| 2026 | 148 | 0.7% | 19,673,262 | 2,912 | 1.8% | 333 |
| 2027 | 149 | 0.7% | 19,892,894 | 2,964 | 1.8% | 339 |
| 2028 | 152 | 2.0% | 19,876,216 | 3,021 | 1.9% | 344 |
| 2029 | 155 | 2.0% | 19,862,920 | 3,079 | 1.9% | 352 |
| 2030 | 156 | 0.6% | 20,124,445 | 3,139 | 2.0% | 359 |

## Additional Firm Sales and Load*

### Historical Additional Firm Sales and Load, 1970–2010

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 319 | | 36 |
| 1971 | 295 | -7.5% | 34 |
| 1972 | 284 | -3.7% | 32 |
| 1973 | 291 | 2.2% | 33 |
| 1974 | 282 | -2.9% | 32 |
| 1975 | 314 | 11.1% | 36 |
| 1976 | 277 | -11.8% | 31 |
| 1977 | 311 | 12.4% | 36 |
| 1978 | 357 | 14.9% | 41 |
| 1979 | 373 | 4.3% | 43 |
| 1980 | 360 | -3.4% | 41 |
| 1981 | 377 | 4.7% | 43 |
| 1982 | 367 | -2.5% | 42 |
| 1983 | 425 | 15.8% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 483 | 2.5% | 55 |
| 1987 | 503 | 4.2% | 57 |
| 1988 | 531 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | -6.8% | 71 |
| 1991 | 661 | 5.7% | 75 |
| 1992 | 681 | 3.0% | 78 |
| 1993 | 689 | 1.2% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,119 | -2.1% | 128 |
| 2002 | 1,139 | 1.8% | 130 |
| 2003 | 1,120 | -1.6% | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,176 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,142 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |
| 2009 | 965 | -13.4% | 110 |
| 2010 | 907 | -6.1% | 103 |

*Includes Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2011–2030**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 1,449 | 59.9% | 165 |
| 2012 | 1,627 | 12.3% | 185 |
| 2013 | 1,799 | 10.6% | 205 |
| 2014 | 1,902 | 5.7% | 217 |
| 2015 | 2,002 | 5.3% | 229 |
| 2016 | 2,071 | 3.4% | 236 |
| 2017 | 2,065 | -0.3% | 236 |
| 2018 | 2,070 | 0.2% | 236 |
| 2019 | 2,075 | 0.2% | 237 |
| 2020 | 2,073 | -0.1% | 236 |
| 2021 | 2,075 | 0.1% | 237 |
| 2022 | 2,082 | 0.3% | 238 |
| 2023 | 2,089 | 0.4% | 238 |
| 2024 | 2,096 | 0.3% | 239 |
| 2025 | 2,101 | 0.2% | 240 |
| 2026 | 2,112 | 0.5% | 241 |
| 2027 | 2,113 | 0.0% | 241 |
| 2028 | 2,119 | 0.3% | 241 |
| 2029 | 2,119 | 0.0% | 242 |
| 2030 | 2,125 | 0.3% | 243 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, "Special", and Raft River Rural Electric Cooperative, Inc.

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1970–2010**
*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 3,915 | | 494 |
| 1971 | 4,279 | 9.3% | 539 |
| 1972 | 4,540 | 6.1% | 573 |
| 1973 | 5,027 | 10.7% | 634 |
| 1974 | 5,461 | 8.6% | 690 |
| 1975 | 6,001 | 9.9% | 758 |
| 1976 | 6,395 | 6.6% | 806 |
| 1977 | 6,817 | 6.6% | 858 |
| 1978 | 7,199 | 5.6% | 912 |
| 1979 | 7,766 | 7.9% | 976 |
| 1980 | 7,796 | 0.4% | 977 |
| 1981 | 8,066 | 3.5% | 1,015 |
| 1982 | 8,033 | -0.4% | 1,009 |
| 1983 | 8,009 | -0.3% | 1,012 |
| 1984 | 8,144 | 1.7% | 1,018 |
| 1985 | 8,367 | 2.7% | 1,053 |
| 1986 | 8,382 | 0.2% | 1,050 |
| 1987 | 8,434 | 0.6% | 1,056 |
| 1988 | 8,813 | 4.5% | 1,104 |
| 1989 | 9,257 | 5.0% | 1,164 |
| 1990 | 9,507 | 2.7% | 1,201 |
| 1991 | 9,740 | 2.5% | 1,218 |
| 1992 | 9,949 | 2.1% | 1,254 |
| 1993 | 10,237 | 2.9% | 1,275 |
| 1994 | 10,599 | 3.5% | 1,340 |
| 1995 | 11,045 | 4.2% | 1,375 |
| 1996 | 11,387 | 3.1% | 1,437 |
| 1997 | 11,669 | 2.5% | 1,469 |
| 1998 | 12,116 | 3.8% | 1,517 |
| 1999 | 12,461 | 2.8% | 1,564 |
| 2000 | 12,888 | 3.4% | 1,627 |
| 2001 | 13,022 | 1.0% | 1,592 |
| 2002 | 12,745 | -2.1% | 1,593 |
| 2003 | 13,000 | 2.0% | 1,633 |
| 2004 | 13,287 | 2.2% | 1,668 |
| 2005 | 13,571 | 2.1% | 1,703 |
| 2006 | 13,906 | 2.5% | 1,738 |
| 2007 | 14,336 | 3.1% | 1,795 |
| 2008 | 14,439 | 0.7% | 1,810 |
| 2009 | 13,933 | -3.5% | 1,746 |
| 2010 | 13,758 | -1.3% | 1,732 |

## Company System Load (including Astaris)

**Historical Company System Sales and Load, 1970–2010 Astaris Sales and Load (1970–2002)**
*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) | Astaris Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 5,572 | | 693 | 1,657 | | 189 |
| 1971 | 5,787 | 3.9% | 720 | 1,508 | -9.0% | 172 |
| 1972 | 6,359 | 9.9% | 791 | 1,819 | 20.6% | 207 |
| 1973 | 6,672 | 4.9% | 831 | 1,645 | -9.6% | 188 |
| 1974 | 7,105 | 6.5% | 887 | 1,643 | -0.1% | 188 |
| 1975 | 7,558 | 6.4% | 945 | 1,557 | -5.3% | 178 |
| 1976 | 7,970 | 5.5% | 995 | 1,575 | 1.2% | 179 |
| 1977 | 8,234 | 3.3% | 1,028 | 1,418 | -10.0% | 162 |
| 1978 | 8,741 | 6.2% | 1,097 | 1,542 | 8.8% | 176 |
| 1979 | 9,160 | 4.8% | 1,143 | 1,395 | -9.6% | 159 |
| 1980 | 9,309 | 1.6% | 1,157 | 1,513 | 8.5% | 172 |
| 1981 | 9,700 | 4.2% | 1,211 | 1,634 | 8.0% | 186 |
| 1982 | 9,587 | -1.2% | 1,195 | 1,554 | -4.9% | 177 |
| 1983 | 9,619 | 0.3% | 1,205 | 1,610 | 3.6% | 184 |
| 1984 | 9,845 | 2.4% | 1,221 | 1,701 | 5.7% | 194 |
| 1985 | 9,980 | 1.4% | 1,247 | 1,614 | -5.1% | 184 |
| 1986 | 9,935 | -0.5% | 1,236 | 1,554 | -3.7% | 177 |
| 1987 | 10,126 | 1.9% | 1,259 | 1,692 | 8.9% | 193 |
| 1988 | 10,448 | 3.2% | 1,300 | 1,635 | -3.4% | 186 |
| 1989 | 10,961 | 4.9% | 1,368 | 1,703 | 4.2% | 194 |
| 1990 | 11,111 | 1.4% | 1,394 | 1,604 | -5.8% | 183 |
| 1991 | 11,349 | 2.1% | 1,411 | 1,609 | 0.3% | 184 |
| 1992 | 11,519 | 1.5% | 1,442 | 1,570 | -2.4% | 179 |
| 1993 | 11,674 | 1.3% | 1,448 | 1,437 | -8.4% | 164 |
| 1994 | 12,019 | 3.0% | 1,510 | 1,420 | -1.2% | 162 |
| 1995 | 12,612 | 4.9% | 1,563 | 1,567 | 10.4% | 179 |
| 1996 | 13,076 | 3.7% | 1,639 | 1,689 | 7.8% | 192 |
| 1997 | 13,297 | 1.7% | 1,664 | 1,628 | -3.6% | 186 |
| 1998 | 13,389 | 0.7% | 1,670 | 1,273 | -21.8% | 145 |
| 1999 | 13,512 | 0.9% | 1,690 | 1,051 | -17.4% | 120 |
| 2000 | 13,942 | 3.2% | 1,753 | 1,054 | 0.3% | 120 |
| 2001 | 13,681 | -1.9% | 1,671 | 658 | -37.5% | 75 |
| 2002 | 12,757 | -6.8% | 1,594 | 11 | -98.3% | 1 |
| 2003 | 13,000 | 1.9% | 1,633 | 0 | -100.0% | 0 |
| 2004 | 13,287 | 2.2% | 1,668 | 0 | 0.0% | 0 |
| 2005 | 13,571 | 2.1% | 1,703 | 0 | 0.0% | 0 |
| 2006 | 13,906 | 2.5% | 1,738 | 0 | 0.0% | 0 |
| 2007 | 14,336 | 3.1% | 1,795 | 0 | 0.0% | 0 |
| 2008 | 14,439 | 0.7% | 1,810 | 0 | 0.0% | 0 |
| 2009 | 13,933 | -3.5% | 1,746 | 0 | 0.0% | 0 |
| 2010 | 13,758 | -1.3% | 1,732 | 0 | 0.0% | 0 |

**Company System Load**

**Projected Company System Sales and Load, 2011–2030**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 14,521 | 5.5% | 1,819 |
| 2012 | 14,803 | 1.9% | 1,852 |
| 2013 | 15,093 | 2.0% | 1,890 |
| 2014 | 15,437 | 2.3% | 1,932 |
| 2015 | 15,751 | 2.0% | 1,970 |
| 2016 | 15,991 | 1.5% | 1,998 |
| 2017 | 16,174 | 1.1% | 2,023 |
| 2018 | 16,348 | 1.1% | 2,045 |
| 2019 | 16,545 | 1.2% | 2,070 |
| 2020 | 16,726 | 1.1% | 2,090 |
| 2021 | 16,898 | 1.0% | 2,114 |
| 2022 | 17,098 | 1.2% | 2,139 |
| 2023 | 17,313 | 1.3% | 2,166 |
| 2024 | 17,511 | 1.1% | 2,189 |
| 2025 | 17,694 | 1.0% | 2,214 |
| 2026 | 17,912 | 1.2% | 2,241 |
| 2027 | 18,084 | 1.0% | 2,263 |
| 2028 | 18,385 | 1.7% | 2,298 |
| 2029 | 18,606 | 1.2% | 2,329 |
| 2030 | 18,870 | 1.4% | 2,362 |

## Contract Off-System Load

### Historical Contract Off-System Sales and Load, 1970–2010

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 386 | | 44 |
| 1971 | 439 | 13.6% | 50 |
| 1972 | 448 | 2.0% | 51 |
| 1973 | 489 | 9.3% | 56 |
| 1974 | 501 | 2.3% | 57 |
| 1975 | 568 | 13.5% | 65 |
| 1976 | 613 | 7.9% | 70 |
| 1977 | 659 | 7.5% | 75 |
| 1978 | 684 | 3.7% | 78 |
| 1979 | 759 | 11.1% | 87 |
| 1980 | 762 | 0.3% | 87 |
| 1981 | 752 | -1.2% | 86 |
| 1982 | 736 | -2.2% | 84 |
| 1983 | 710 | -3.5% | 81 |
| 1984 | 747 | 5.2% | 85 |
| 1985 | 779 | 4.3% | 89 |
| 1986 | 670 | -13.9% | 77 |
| 1987 | 644 | -4.0% | 73 |
| 1988 | 675 | 4.9% | 77 |
| 1989 | 740 | 9.7% | 84 |
| 1990 | 968 | 30.8% | 111 |
| 1991 | 1,537 | 58.8% | 175 |
| 1992 | 1,348 | -12.3% | 154 |
| 1993 | 1,557 | 15.5% | 178 |
| 1994 | 1,811 | 16.3% | 207 |
| 1995 | 1,583 | -12.6% | 181 |
| 1996 | 1,285 | -18.8% | 146 |
| 1997 | 674 | -47.5% | 77 |
| 1998 | 716 | 6.2% | 82 |
| 1999 | 568 | -20.6% | 65 |
| 2000 | 587 | 3.3% | 67 |
| 2001 | 538 | -8.4% | 61 |
| 2002 | 454 | -15.7% | 52 |
| 2003 | 346 | -23.6% | 40 |
| 2004 | 19 | -94.4% | 2 |
| 2005 | 10 | -47.0% | 1 |
| 2006 | 0 | -100.0% | 0 |
| 2007 | 0 | 0.0% | 0 |
| 2008 | 0 | 0.0% | 0 |
| 2009 | 0 | 0.0% | 0 |
| 2010 | 0 | 0.0% | 0 |

### Projected Contract Off-System Sales and Load, 2011–2030

| | | | |
|---|---|---|---|
| 2011–2030 | 0 | 0.0% | 0 |

## Total Company Load

**Historical Total Company Sales and Load, 1970–2010**
*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 5,958 | | 738 |
| 1971 | 6,226 | 4.5% | 772 |
| 1972 | 6,807 | 9.3% | 844 |
| 1973 | 7,162 | 5.2% | 889 |
| 1974 | 7,605 | 6.2% | 946 |
| 1975 | 8,126 | 6.8% | 1,012 |
| 1976 | 8,583 | 5.6% | 1,067 |
| 1977 | 8,894 | 3.6% | 1,106 |
| 1978 | 9,425 | 6.0% | 1,178 |
| 1979 | 9,920 | 5.2% | 1,233 |
| 1980 | 10,071 | 1.5% | 1,247 |
| 1981 | 10,453 | 3.8% | 1,300 |
| 1982 | 10,323 | -1.2% | 1,282 |
| 1983 | 10,329 | 0.1% | 1,289 |
| 1984 | 10,592 | 2.5% | 1,309 |
| 1985 | 10,759 | 1.6% | 1,339 |
| 1986 | 10,605 | -1.4% | 1,315 |
| 1987 | 10,770 | 1.5% | 1,335 |
| 1988 | 11,123 | 3.3% | 1,379 |
| 1989 | 11,701 | 5.2% | 1,455 |
| 1990 | 12,079 | 3.2% | 1,508 |
| 1991 | 12,886 | 6.7% | 1,592 |
| 1992 | 12,867 | -0.1% | 1,601 |
| 1993 | 13,231 | 2.8% | 1,632 |
| 1994 | 13,830 | 4.5% | 1,724 |
| 1995 | 14,195 | 2.6% | 1,750 |
| 1996 | 14,361 | 1.2% | 1,790 |
| 1997 | 13,971 | -2.7% | 1,744 |
| 1998 | 14,105 | 1.0% | 1,754 |
| 1999 | 14,081 | -0.2% | 1,757 |
| 2000 | 14,529 | 3.2% | 1,822 |
| 2001 | 14,219 | -2.1% | 1,735 |
| 2002 | 13,210 | -7.1% | 1,648 |
| 2003 | 13,347 | 1.0% | 1,674 |
| 2004 | 13,306 | -0.3% | 1,670 |
| 2005 | 13,581 | 2.1% | 1,704 |
| 2006 | 13,906 | 2.4% | 1,738 |
| 2007 | 14,336 | 3.1% | 1,795 |
| 2008 | 14,439 | 0.7% | 1,810 |
| 2009 | 13,933 | -3.5% | 1,746 |
| 2010 | 13,758 | -1.3% | 1,732 |

**Total Company Load**

**Projected Total Company Sales and Load, 2011–2030**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 14,521 | 5.5% | 1,819 |
| 2012 | 14,803 | 1.9% | 1,852 |
| 2013 | 15,093 | 2.0% | 1,890 |
| 2014 | 15,437 | 2.3% | 1,932 |
| 2015 | 15,751 | 2.0% | 1,970 |
| 2016 | 15,991 | 1.5% | 1,998 |
| 2017 | 16,174 | 1.1% | 2,023 |
| 2018 | 16,348 | 1.1% | 2,045 |
| 2019 | 16,545 | 1.2% | 2,070 |
| 2020 | 16,726 | 1.1% | 2,090 |
| 2021 | 16,898 | 1.0% | 2,114 |
| 2022 | 17,098 | 1.2% | 2,139 |
| 2023 | 17,313 | 1.3% | 2,166 |
| 2024 | 17,511 | 1.1% | 2,189 |
| 2025 | 17,694 | 1.0% | 2,214 |
| 2026 | 17,912 | 1.2% | 2,241 |
| 2027 | 18,084 | 1.0% | 2,263 |
| 2028 | 18,385 | 1.7% | 2,298 |
| 2029 | 18,606 | 1.2% | 2,329 |
| 2030 | 18,870 | 1.4% | 2,362 |







# *Appendix B—Demand-Side Management 2010 Annual Report*

For the 2011 Integrated Resource Plan

**June 2011**

IDAHO POWER®
An IDACORP Company

Printed on recycled paper

# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... iii
List of Figures ..... iv
List of Supplements ..... iv
Glossary of Acronyms ..... v
Executive Summary ..... 1
Introduction ..... 3
Demand-Side Management Programs ..... 3
Demand Response Programs ..... 5
Energy Efficiency Programs ..... 6
Market Transformation ..... 6
Other Programs and Activities ..... 6
Program Performance ..... 7
2010 Activities ..... 8
Energy Efficiency Advisory Group ..... 9
Smart Meter Project ..... 10
Regulatory Initiatives ..... 10
DSM Expenditures ..... 10
Future Plans ..... 12
Marketing ..... 12
Program Evaluation ..... 13
Customer Satisfaction ..... 13
Cost-Effectiveness ..... 15
DSM Annual Report Structure ..... 15
Residential Sector Overview ..... 17
Description ..... 17
Programs ..... 18
A/C Cool Credit ..... 20
Ductless Heat Pump Pilot ..... 24
Energy Efficient Lighting ..... 28
Energy House Calls ..... 31
ENERGY STAR® Homes Northwest ..... 34

Heating & Cooling Efficiency Program ....38
Home Improvement Program ....44
Home Products Program ....47
Oregon Residential Weatherization ....51
Rebate Advantage ....53
See ya later, refrigerator® ....55
Weatherization Assistance for Qualified Customers ....59
Weatherization Solutions for Eligible Customers ....62
Commercial/Industrial Sector Overview ....67
Description ....67
Programs ....67
Building Efficiency ....71
Custom Efficiency ....74
Easy Upgrades ....78
FlexPeak Management ....84
Holiday Lighting Program ....87
Oregon Commercial Audits ....89
Irrigation Sector Overview ....91
Description ....91
Programs ....92
Irrigation Efficiency Rewards ....93
Irrigation Peak Rewards ....98
Market Transformation ....103
Northwest Energy Efficiency Alliance ....103
NEEA Activities ....103
Other Programs and Activities ....107
Residential Energy Efficiency Education Initiative ....107
Easy Savings® Program ....110
Commercial Education Initiative ....112
Local Energy Efficiency Funds ....113
Students for Energy Efficiency ....114
Regional Technical Forum ....115
Boise City Home Audit Project ....115
Regulatory Initiatives ....117

Fixed-Cost Adjustment Pilot....117
Irrigation Peak Rewards Filings in Idaho and Oregon....118
Demand-Side Resource Business Model Filing....118
Energy Efficiency Rider—Prudency....120
Energy Efficiency Rider—Oregon....120
Continued Commitment....121
Continued Expansion and Broad Availability of Efficiency and Demand Response Programs....121
Building-Code Improvement Activity....121
Pursuit of Appliance Code Standards....122
Promotion of Energy Efficiency through Electricity Rate Design....122
Third-Party, Independent Verification....122
Idaho Power's Internal Energy Efficiency Commitment....123
CAES Energy Efficiency Research Initiative....124
Sustainable Operations/Sustainability....124
Green Team....124
Appendices....125
Appendix 1. Idaho Rider, Oregon Rider, and NEEA funding balances....127
Appendix 2. 2010 DSM expenses by funding source (dollars)....128
Appendix 3. 2010 DSM program activity....129
Appendix 4. DSM expense and performance 2002–2010....131
Appendix 5. 2010 DSM program activity by state jurisdiction....143

## LIST OF TABLES

Table 1. 2010 DSM, sectors, programs, operational type, and energy savings....7
Table 2. 2010 Program Sector Summary and Energy Use....8
Table 3. 2010 funding source and energy impact....11
Table 4. 2010 Idaho and Oregon Rider expenditures by category....11
Table 5. 2010 Residential Program Summary....18
Table 6. 2010 Weatherization Solutions for Eligible Customers: individual measure breakdown....64
Table 7. 2010 Commercial/Industrial program summary....67
Table 8. Custom Efficiency annual energy savings by measure....75
Table 9. 2010 Irrigation program summary....92

Table 10. Option incentives ....99
Table 11. Total program daily MW reduction without distribution losses using realization rates ....100

## LIST OF FIGURES

Figure 1. Annual demand response reduction 2004–2010 (MW) ....4
Figure 2. Annual energy savings 2002–2010 (MWh) ....4
Figure 3. DSM expense history 2002–2010 (millions of dollars) ....5
Figure 4. 2010 Oregon and Idaho Rider expenditures by category ....11
Figure 5. 2010 Idaho and Oregon Rider incentives by sector ....12
Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts ....14
Figure 7. How customers heard about See ya later, refrigerator® ....58

## LIST OF SUPPLEMENTS

Supplement 1: Cost-Effectiveness
Supplement 2: Evaluation
NEEA Market Effects Evaluations (included on CD with Supplement 2)

# GLOSSARY OF ACRONYMS

aMW—Average Megawatt

A/C—Air Conditioning

ACB, Inc—Advertising Checking Bureau, Inc.

AMI—Advanced Metering Infrastructure

ARRA—American Reinvestment and Recovery Act

B/C—Benefit Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of South East Idaho

BCASWI—Building Contractors Association of Southwestern Idaho, Inc.

BOP—Builder Option Package

BOMA—Building Owners and Managers Association International

BPA—Bonneville Power Administration

CAES—Center for Advanced Energy Studies

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CAIS—Certified Agricultural Irrigation Specialist

CD—Compact Disc

CEE—Consortium for Energy Efficiency, Inc.

CEERI—CAES Energy Efficiency Resource Initiative

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CIS—Customer Information System

CLRIS—Customer and Load Research Information System

COP—Coefficient of Performance

CRM—Customer Relationship Management

CSI—Crime Scene Investigation

CSR—Customer Service Representative

DEER—Database for Energy Efficiency Resources

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

DSR—Demand-Side Resource

EA4—Energy Audit 4

ECM—Electronically Commutated Motor

EEAG—Energy Efficiency Advisory Group

EECBG—Energy Efficiency Conservation Block Grant

EISA—*Energy Independence and Security Act of 2007*

ESI—Energy Scene Investigation

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

FCA—Fixed-Cost Adjustment

GMPG—Green Motors Practice Group

GPM—Gallons per Minute

H&CE—Heating & Cooling Efficiency Program

hp—Horsepower

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

ICL—Idaho Conservation League

IDL—Integrated Design Lab in Boise

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IOER—Idaho Office of Energy Resources

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

IRS—Internal Revenue Service

iSTEM–Idaho Science, Technology, Engineering and Mathematics

IT—Information Technology

kW—Kilowatt

kWh—Kilowatt-hour

LCD—Liquid Crystal Display

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

MOU—Memorandum of Understanding

MHAFB—Mountain Home Air Force Base

MPER—Market Progress Evaluation Report

MW—Megawatt

MWh—Megawatt-hour

NAHB—National Association of Home Builders

NEEM—Northwest Energy Efficient Manufactured Housing Program

NEEA—Northwest Energy Efficiency Alliance

NEMA—National Electrical Manufacturers Association

NPCC—Northwest Power and Conservation Council

NW EM Demo—Northwest Energy Management Demonstration Project

NWES—Northwest ENERGY STAR®

OPUC—Public Utility Commission of Oregon

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PECI—Portland Energy Conservation, Inc.

PLC—Power-Line Carrier

PLMA—Peak Load Management Alliance

PTCS—Performance Tested Comfort System

QA—Quality Assurance

RAD—Responsible Appliance Disposal

RAP—Resource Action Programs

RFP—Request for Proposal

RIM—Ratepayer Impact Measure Test

RS&E—Runyon, Saltzman & Einhorn

RTF—Regional Technical Forum

RTUG—Commercial Rooftop Unit Work Group

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

SCCT—Simple-Cycle Combustion Turbine

SCO—State-Certifying Organization

SEE—Students for Energy Efficiency

SEEARP—State Energy Efficient Appliance Rebate Program

SIC—Standard Industrial Classification Codes

SIR—Savings-to-Investment Ratio

$SO_2$—Sulfur Dioxide

SRA—Snake River Alliance

SRVBCA—Snake River Valley Building Contractors Association

TLS—Transport Layer Security

TOU—Time-of-Use

TRC—Total Resource Cost

UC—Utility Cost

USA—Utility Service Agreement

W—Watt

WAQC—Weatherization Assistance for Qualified Customers

# EXECUTIVE SUMMARY

In 2010, Idaho Power achieved a year of increased energy savings, reduced demand, increased evaluation and research, and enhanced energy efficiency education and customer outreach. Demand-side management (DSM) activities focused on evaluation, savings, program participation, customer satisfaction, and energy efficiency awareness. Through program expansion and improvements, the company's DSM portfolio of programs and energy savings opportunities have increased.

Idaho Power's overall annual energy savings from energy efficiency activities increased in 2010. Energy savings for 2009 were 143,146 megawatt hours (MWh), including the Northwest Energy Efficiency Alliance (NEEA) savings. In 2010, these savings increased over 31 percent to 187,626 MWh. From Idaho Power's energy efficiency programs alone, the savings increased 30 percent, from 132,443 MWh in 2009 to 172,292 MWh in 2010. This is enough energy to supply over 13,500 average homes in Idaho Power's service area. Since 2002, Idaho Power's DSM efforts have accumulated energy savings and demand response reduction greater than any other time in the company's history. Demand reduction for Idaho Power's demand response programs increased from 218 megawatts (MW) in 2009 to 336 MW in 2010. This is more than twice as large as the capacity of Idaho Power's Bennett Mountain peaker plant located near Mountain Home, Idaho. Total expenditures on DSM-related activities increased from almost $35 million in 2009 to $46 million in 2010.

Idaho Power's focus on program evaluation and research in 2010 resulted in process evaluations completed on five commercial, industrial, and irrigation programs and on four residential programs. Two different independent third-party contractors conducted these evaluations. The company also contracted with a third-party consultant to conduct a residential home energy use survey. Idaho Power continued to participate with other research and evaluation organizations, such as NEEA, the Regional Technical Forum (RTF), and the Idaho Integrated Design Lab (IDL in Boise). Also in 2010, Idaho Power developed a new integrated database with a unified table structure to store DSM program data and more effectively track program performance.

The percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts continued to increase, indicated by the results of Idaho Power's 2010 quarterly customer relationship survey. Results showed steady improvement over recent years. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003 to 57 percent in late 2010. Idaho Power continued to expand its customer satisfaction measurement activities, which enabled Idaho Power to identify actionable areas for improvement.

Pursuit of cost-effective energy efficiency is a primary objective for Idaho Power. Energy efficiency and demand response provides economic and operational benefits to the company and its customers. Enhancement of information and programs helps ensure customers have opportunities to learn about their energy use and participate in programs. To optimize the acquisition of cost-effective DSM, Idaho Power has advanced a progressive regulatory model and expanded its educational initiatives. Additionally, Idaho Power played a key role in the launching of the Center for Advanced Energy Studies (CAES) Energy Efficiency Research Initiative (CEERI).

The *Demand Side Management 2010 Annual Report* provides a review of the company's DSM activities and finances throughout 2010, outlines Idaho Power's plans for DSM activities, and satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419.

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# INTRODUCTION

Idaho Power's *Demand Side Management* (DSM) *2010 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for the 2010 calendar year. The company provides a wide range of opportunities for all customer classes to participate in programs, to be informed about energy use, and to reduce their energy consumption.

Idaho Power's two main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency resources to meet its electrical system's energy and demand needs and to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the development, implementation, and prudent management of programs that provide energy and demand savings, and through outreach and education. When possible, Idaho Power implements identical programs in its Idaho and Oregon service areas.

Customer participation in Idaho Power's energy efficiency and demand response programs continues to increase, as do energy savings and demand reduction. The energy savings exclusively from Idaho Power's energy efficiency programs in 2010 was 172,292 megawatt-hour (MWh), a 30 percent increase over the 132,443 MWh energy savings in 2009. Demand reduction for the demand response programs also substantially increased in 2010. Combined, the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs resulted in an estimated summer peak reduction of 336 megawatt (MW), which is a 54 percent increase from the reduction achieved in 2009.

In a continuing effort to fulfill the objectives of the Memorandum of Understanding (MOU) which was signed by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities on January 25, 2010, Idaho Power has made several additions to this year's report. Included this year is a new appendix attached to this document, titled Appendix 5. This appendix shows program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. The other addition is the *2010 DSM Detailed Expenses by Program* table that reports expenses by funding source and cost category. This table is included in *Supplement 1: Cost Effectiveness*. Supplement 1 shows all of the standard cost-effectiveness tests for its programs, including the calculation of the Ratepayer Impact Measure (RIM) Test for each program. The company also continued to enhance its third-party evaluation activities. In 2010, all Idaho Power energy efficiency programs are shown to be cost-effective, and all of its demand response programs are cost-effective from both a long-term perspective and for 2010 under a one-year perspective.

## Demand-Side Management Programs

The programs within Idaho Power's energy efficiency and demand response portfolio are offered to four major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either sector. The sector is generally referred to as the commercial/industrial sector in this report.

Idaho Power categorized its DSM activities in four categories: demand response, energy efficiency, market transformation, and other programs and activities. The other programs and activities are generally to provide customer outreach and education concerning the efficient use of electricity. All of these activities are coordinated to forward Idaho Power's enhanced commitment to energy efficiency, demand response, and customer satisfaction.

Figures 1–3 show the historic energy savings, demand reduction, and DSM expenses.

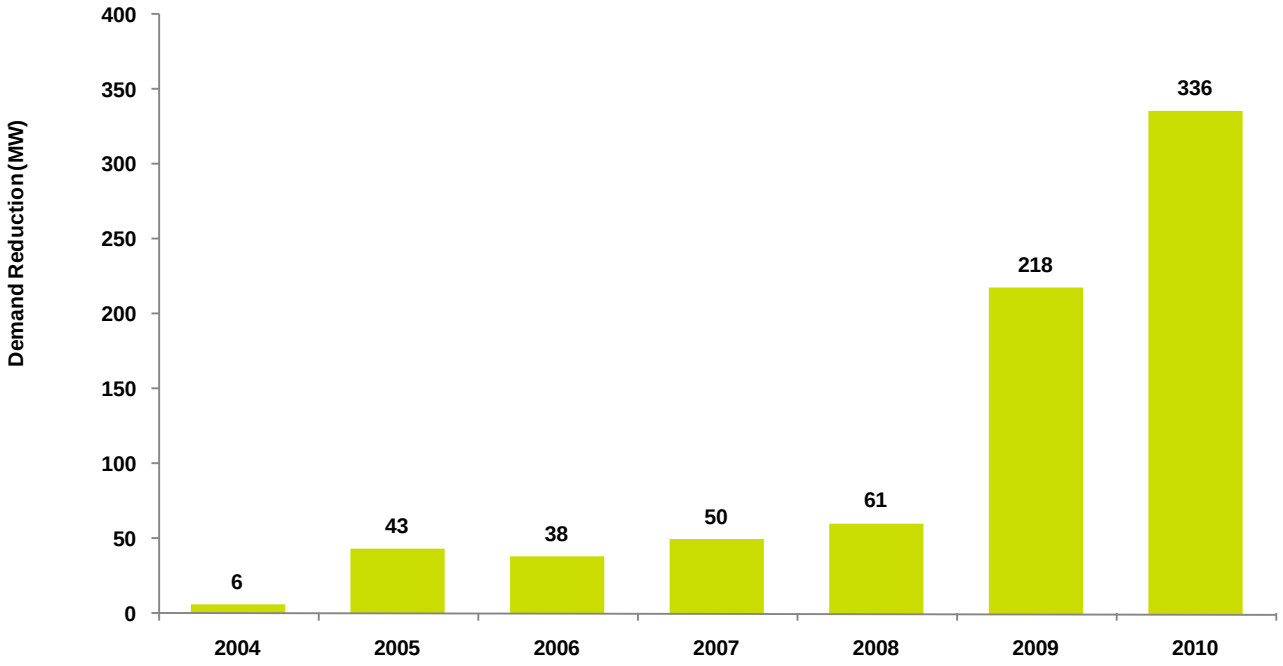


Figure 1. Annual demand response reduction 2004–2010 (MW)

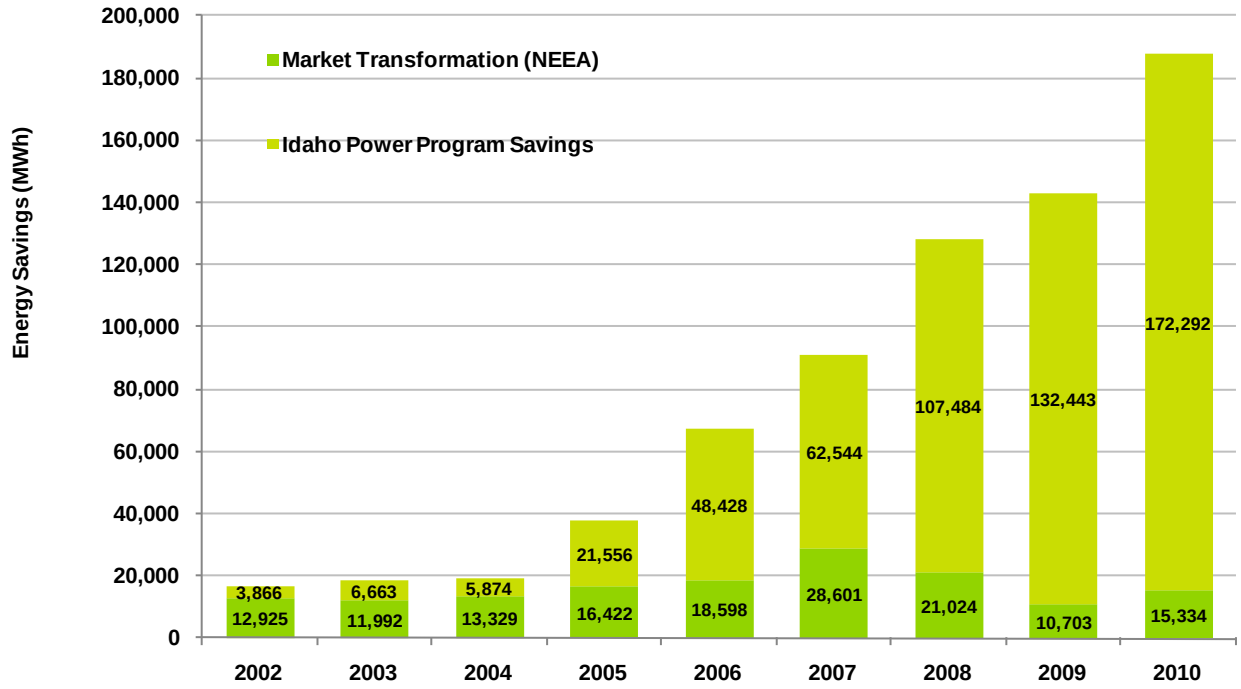


Figure 2. Annual energy savings 2002–2010 (MWh)




Figure 3. DSM expense history 2002–2010 (millions of dollars)

## Demand Response Programs

Demand response programs are considered a resource to reduce Idaho Power's demand for electricity at specific times of the day and year when electricity is normally in short supply. The new, all-time winter system peak of 2,528 MW was set on Thursday, December 10, 2009, at 8:00 a.m. The summer peak in 2010 was 2,930 MW set on Monday, June 28, 2010 at 7:00 p.m., below the Idaho Power's all-time system peak of 3,214 MW on Monday, June 30, 2008, at 3:00 p.m. Idaho Power estimates that if it did not have demand response programs, the summer system peak would have been approximately 3,087 MW on July 16, 2010 at 7:00 p.m.

In 2010, Idaho Power's Energy Efficiency and Demand Response personnel worked closely with representatives from other departments within the company on two distinct yet related projects. The first was to optimize the dispatch of the demand response programs on a day-to-day basis to achieve the greatest possible demand reduction over the longest time period while still having all programs dispatched at the time of the system peak. For this goal, representatives from the Energy Efficiency, Power Supply, Compliance, System Dispatch, Regulatory Affairs, Transmission Planning, and Generation Dispatch departments met weekly to determine a potential dispatch schedule for the following week. This team considered the upcoming load forecast, weather forecast, generation availability, and the magnitude of the forecast system peak in order to set a dispatch schedule. The actual decision to dispatch was made on a day-ahead basis by Power Supply Operations.

The second major demand response project for the company in 2010 was to work with members of Load Forecasting, Power Supply Planning, Load Research, Regulatory Affairs, and Energy Efficiency Programs to determine the optimum amount of demand response the company can and should plan for in the long-term Integrated Resource Plan (IRP) process. This research and analysis led to the filing of case number IPC-E-10-46 in Idaho and Advice number 11-1 in Oregon. Both of these regulatory filings

proposed that the company make substantial changes to the method by which the Irrigation Peak Reward participants are paid for their demand reduction.

The measure of demand response program performance is the number of MW of reduced electrical demand that the company needs to serve during system peak periods. In 2010, Idaho Power again offered three demand response programs. The A/C Cool Credit program was offered to residential customers and the FlexPeak Management program was offered to commercial/industrial customers. The Irrigation Peak Rewards program was available for irrigation customers. The Irrigation Peak Rewards program was modified in 2010 to add the ability to dispatch the program on Saturdays and to add the potential for the company to use the program starting at 1:00 p.m. instead of 2:00 p.m. The program season was also extended from ending on July 31 to ending on August 15.

## Energy Efficiency Programs

Energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components where energy-efficient design, replacement, or repair can yield energy savings. These programs are available to all customer sectors. Project measures range from entire building construction to simple light bulb replacement. Savings from these programs are measured in terms of reduced kilowatt-hour (kWh) usage, or MWh usage for larger projects. These programs usually supply energy benefits throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

## Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional companies and organizations. These organizations are in a position to affect the design of energy usage in products, services, and practices that affect electricity consumption. Idaho Power achieves market transformation savings primarily through its participation in Northwest Energy Efficiency Alliance (NEEA). Idaho Power also supports market transformation accomplished by appliance or building code modifications or enforcement.

## Other Programs and Activities

Other programs and activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Residential Energy Efficiency Education Initiative, the Easy Savings® Program, the Commercial Educational Initiative, the Local Energy Efficiency Funds (LEEF), and the Students for Energy Efficiency (SEE). These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a list of the DSM programs and their respective sectors, operational category, the state in which each was available in 2010, and energy savings.

Table 1. 2010 DSM, sectors, programs, operational type, and energy savings

| Program by Sector | Operational Type | State | Savings |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 39.0 MW |
| Ductless Heat Pump Pilot | Energy Efficiency | ID/OR | 364 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 28,083 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 1,199 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 883 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 1,104 MWh |
| Home Improvement Program | Energy Efficiency | ID | 3,986 MWh |
| Home Products Program | Energy Efficiency | ID/OR | 1,444 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | <1 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 165 MWh |
| Residential Energy Efficiency Education Initiative | Other Programs and Activities | ID/OR | n/a |
| See ya later, refrigerator® | Energy Efficiency | ID/OR | 1,568 MWh |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 3,742 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 313 MWh |
| **Commercial/Industrial** | | | |
| Building Efficiency | Energy Efficiency | ID/OR | 10,820 MWh |
| Commercial Education Initiative | Other Programs and Activities | ID/OR | n/a |
| Easy Upgrades | Energy Efficiency | ID/OR | 35,824 MWh |
| FlexPeak Management | Demand Response | ID/OR | 47.5 MW |
| Holiday Lighting Program | Energy Efficiency | ID/OR | 249 MWh |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| Custom Efficiency | Energy Efficiency | ID/OR | 71,580 MWh |
| **Irrigation** | | | |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 10,968 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 249.7 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 15,334 MWh |

## Program Performance

In 2010, energy savings increased as compared to 2009 for residential, commercial, and industrial by 65 percent, 13 percent, and 38 percent, respectively. There was a 17 percent reduction in the savings from the irrigation sector. The residential sector savings increased to 42,851 MWh; the commercial sector savings increased to 46,893 MWh; the industrial sector increased to 71,580 MWh; and the irrigation sector decreased to 10,968 MWh. The reduction in savings in the irrigation sector was primarily the result of program maturity and new program requirements that began in 2010. Additional energy savings continue to be realized through market transformation partnership activities with NEEA.

Customer participation increased in most of the existing programs during the year. The number of projects completed under the Easy Upgrades program increased from 1,224 projects in 2009 to 1,535 projects in 2010, a 25 percent increase. Participation in the Home Improvement Program increased by almost 200 percent, from 1,188 homes in 2009 to 3,537 in 2010. As a result of the continuation of the depressed housing market in 2010, the number of homes given incentives in the Rebate Advantage program decreased. Surprisingly, the ENERGY STAR® Homes Northwest program

participation increased by almost 33 percent by providing incentives for 630 homes in 2010 as compared to 474 homes in 2009.

A few individual programs were big contributors to overall energy savings. The Custom Efficiency program accounted for 42 percent of Idaho Power's energy savings from programs, resulting in an estimated 71,580 MWh of savings. The Easy Upgrades program in the commercial sector provided 21 percent, or 35,824 MWh, of estimated energy savings. In the residential sector, the Energy Efficient Lighting program saved 28,083 MWh, accounting for 16 percent of overall energy savings by giving incentives to over one million bulbs in 2010.

Table 2 shows the 2010 annual energy savings, percent of energy usage, number of customers, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2010 contribution of each sector in terms of energy usage and its respective size in number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customers' meter, excluding line losses.

Table 2. 2010 Program Sector Summary and Energy Use

| | Energy Efficiency Program Impacts[a] | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Direct Expenses | Energy Savings (MWh) | Average Energy (aMW) | Peak Load Reduction (MW)[b] | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $ 8,093,078 | 42,851 | 4.9 | | 4,983,423 | 36.70% | 408,754 |
| Commercial | 5,535,273 | 46,893 | 5.4 | 8.7 | 3,763,495 | 27.71% | 64,647 |
| Industrial | 8,778,125 | 71,580 | 8.2 | 9.5 | 3,126,504 | 23.02% | 121 |
| Irrigation | 2,200,814 | 10,968 | 1.3 | 3.3 | 1,706,632 | 12.57% | 18,547 |
| Market Transformation | 2,391,217 | 15,334 | 1.8 | n/a | n/a | n/a | n/a |
| **Total** | **$26,998,507** | **187,626** | **21.0** | **21.5** | **13,580,054** | **100.0%** | **492,069** |

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] Includes peak load reduction from both demand response and energy efficiency programs.

## 2010 Activities

In 2010, Idaho Power continued to expand its DSM programs in order to increase participation and energy savings. Many of the activities in 2010 also revolved around evaluation and research. The company was also engaged in enhanced regulatory reporting and filings.

Idaho Power's residential end-use survey or *Home Energy Survey* was completed in 2010. The survey was the latest in a series of periodic end-use studies conducted by Idaho Power, with the last survey completed in 2004. The primary objective of the 2010 study was to profile residential customers to better understand their housing and end-use characteristics that included home demographics, fuel source, home heating and cooling, and appliance and consumer electronics saturation. A copy of this report is included in *Supplement 2: Evaluation*.

In 2010, Idaho Power designed and developed a new comprehensive database that will more effectively store savings results, measure information, and allow for more efficient incentive processing for customers. The database was developed with a unified table structure across all energy efficiency programs on a SQL Server database platform that is easily scalable for future program additions and changes. The database structure allows for the integration of DSM program data with Idaho Power's customer information system (CIS) along with financial databases for tracking and processing customer incentive payments. Because of the unified and consistent table structure, the database is well positioned

for the future transition to the new CIS and customer relationship management (CRM) tool that will be implemented through the federal Smart Grid Investment Grant program. While the database table structure is consistent across programs, each program has the ability to track custom fields that are unique to their program. The database application was tested in late 2010 and completed for all but two programs by the beginning of 2011. The final programs will be integrated into the system in early 2011.

Idaho Power collaborated with the City of Boise to serve as the implementer for the Boise City Home Audit Project. Additionally, the company continued participation with NEEA's Ductless Heat Pump (DHP) Pilot. Idaho Power also modified the Irrigation Peak Rewards program.

During 2010, Idaho Power began its contractual participation in, and funding of, NEEA under the 2010 to 2014 agreement. NEEA's efforts in the northwest impact Idaho Power's customers by encouraging regional market transformation. Idaho Power representatives participated on several NEEA committees and events. Idaho Power also continued to help fund and participate in the Regional Technical Forum (RTF) and uses the results from the RTF's research in program development and cost-effectiveness analysis.

On March 16, 2010, Idaho Power filed case number IPC-E-10-09, which was a request for the IPUC to designate Idaho Power's expenditure of $50,701,740 in Idaho Rider funds in 2008 and 2009 as prudently incurred expenses. This prudency filing was the first designed to comply with the agreed-upon principles set forth in the MOU for Prudency Determination of DSM Expenditures. On November 16, 2010, in Order No. 32113, the IPUC found that the company acted prudently in the administration of its Rider-funded DSM programs and expenses.

## Energy Efficiency Advisory Group

Formed in 2002, the Energy Efficiency Advisory Group (EEAG) provides input on formulating and implementing energy efficiency and demand reduction programs funded by the Rider. Currently, the EEAG consists of 14 members from across Idaho Power's service area and the Pacific Northwest. Members represent a cross-section of customers, including individuals from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power.

In 2010, the EEAG met three times, February 18, May 26, and October 26. During the meetings, Idaho Power requested recommendations and discussion on new program proposals, marketing methods, and specific measure details; provided a status of the Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues. Idaho Power relies on input from the EEAG to provide a customer and public interest review of energy efficiency and demand response programs and expenses. The minutes from the 2010 EEAG meetings are included in *Supplement 2: Evaluation*.

In addition to the EEAG, Idaho Power solicits further customer input through meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

## Smart Meter Project

Idaho Power continued with the current Smart Meter Project by installing Advanced Meter Infrastructure (AMI). The Smart Meter Project will enhance Idaho Power's energy efficiency efforts in several ways. Hourly data is being collected by these meters and can be viewed by customers via the Internet. This will enable customers to be more informed and more wisely manage their use of electricity. Customer hourly energy data and monthly demand data will eventually help to evaluate energy efficiency and demand response programs. Idaho Power will continue to expand its use of the power-line communications technology to dispatch demand response programs.

As of February 2011, Idaho Power had installed 283,500 residential smart meters and 47,756 commercial Smart Meters, totaling 331,256 meters as part of the company's three-year AMI deployment. While 2009 saw meters installed primarily in the Treasure Valley area, 2010 continued to deploy meters into Canyon County as well as the Payette and Ontario, Oregon areas served by the company. By year-end, installations were completed in the Mountain Home area. Work commenced in the Pocatello area in January 2011 and will continue until the end of May. From June to December 2011, the Twin Falls and Hailey areas will be outfitted with AMI technology. To date, 83 of the expected 134 substations installations are completed. Overall, the project is on schedule.

## Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives in order for the company to have the opportunity to earn on the energy efficiency investments like other investments in which the company is engaged. Since 2002, Idaho Power has recovered its DSM program costs through the Rider with the intended result of providing more timely recovery of DSM costs. Coupled with cost recovery is a need for clear and achievable guidelines for prudency. To address the removal of financial disincentives, Idaho Power is testing the effects of a fixed-cost adjustment (FCA) mechanism in a five-year pilot initiative. The FCA pilot just completed year four.

To introduce an option to provide financial incentives for DSM, in October the company filed case number IPC-E-10-27 with the IPUC. Part of the filing establishes the company's proposal to move incentive payments for one DSM program to a regulatory asset account in order to begin earning its authorized rate of return on the DSM investment. This would allow some energy efficiency investments to be treated similar to supply-side investments and not treated as inferior investments. In that same filing, the company proposed moving the recovery of incentive payments of demand response programs out of the Rider and into the Power Cost Adjustment (PCA) mechanism. This move would treat the cost recovery of demand response payments similar to other supply-side resource expenses, such as fuel purchase power and surplus sales.

## DSM Expenditures

Funding for DSM programs in 2010 came from several sources. The Rider funds are collected directly from customers on their monthly bills. The Idaho Rider is currently 4.75 percent of base rate revenues. On March 5, 2010, Idaho Power filed with the Public Utilities Commission of Oregon (OPUC) to increase the Oregon Rider from 1.5 percent to 3.0 percent and to eliminate the monthly caps on the residential and irrigation bills. This was approved on June 1, 2010. Energy efficiency and demand response-related expenses not funded through the Rider, including costs for administration and

overhead, are included as part of Idaho Power's ongoing operation and maintenance costs. Total DSM expenses funded from all sources were $45.8 million in 2010.

Table 3 provides a summary of the 2010 expenses and energy savings by each funding category.

Table 3. 2010 funding source and energy impact

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider | $ 42,479,692 | 174,779 |
| Oregon Rider | 1,704,367 | 9,105 |
| Idaho Power Base Rates | 1,648,792 | 3,742 |
| **Total** | **$ 45,832,851** | **187,626** |

Table 4 and Figure 4 show Idaho Power's Rider expenses separated by expense category. The expenses in the Materials category are primarily A/C Cool Credit switches. Other Expenses includes marketing ($514 thousand), program evaluation ($293 thousand), and program training ($190 thousand). Purchased services includes payments made to NEEA and contract payments made to third-party contractors who help administer Idaho Power's programs, such as M2M for the Irrigation Peak Rewards program and JACO for the See ya later, refrigerator program.

Table 4. 2010 Idaho and Oregon Rider expenditures by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $32,048,751 | 73% |
| Labor/Administration | 2,828,287 | 6% |
| Materials | 345,066 | 1% |
| Other Expense | 1,040,237 | 2% |
| Purchased Services | 7,921,718 | 18% |
| **Total 2010 Rider Expenditures, by Category** | **$44,184,058** | **100%** |

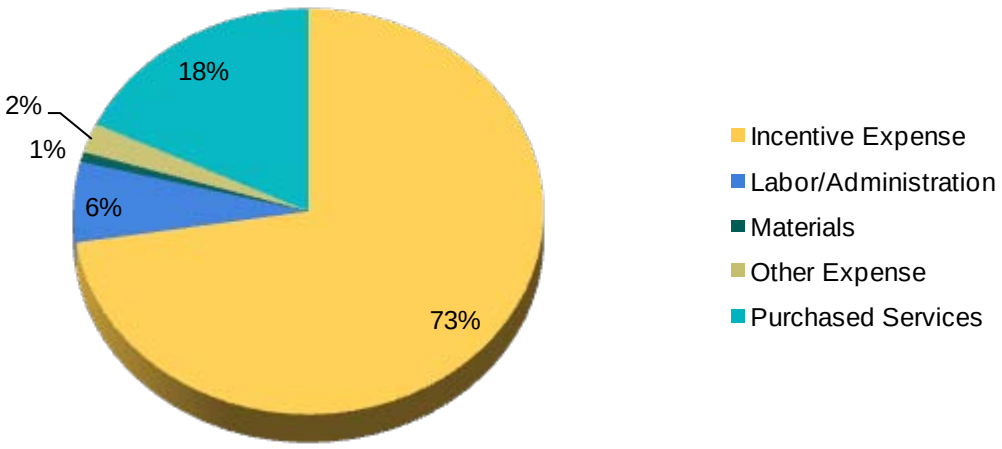


Figure 4. 2010 Oregon and Idaho Rider expenditures by category

Figure 5 shows Idaho Power Rider incentives expenses separated by type of program and by type of sector, either Demand Response (DR) or Energy Efficiency (EE).

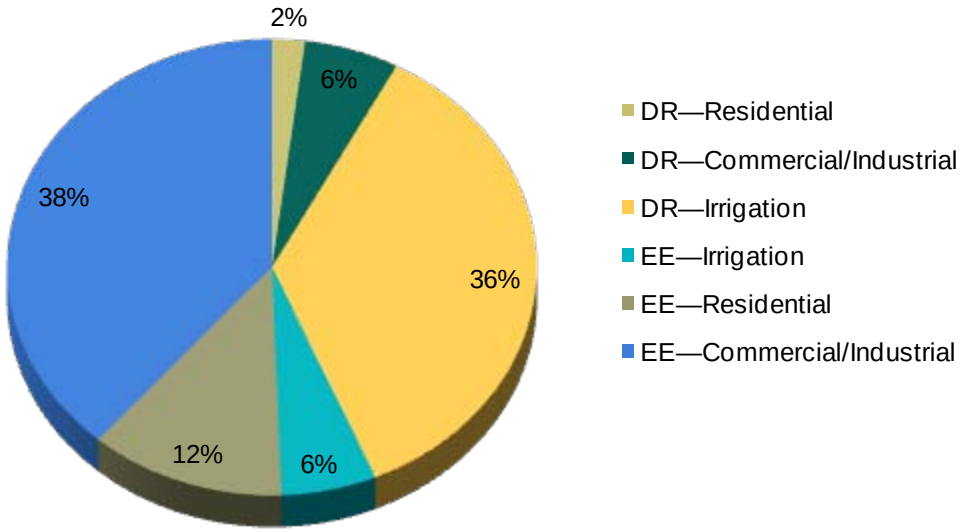


Figure 5. 2010 Idaho and Oregon Rider incentives by sector

## Future Plans

Many of Idaho Power's DSM programs are selected for implementation through its biennial IRP. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances cost, risk, and environmental concerns in developing a preferred portfolio of future resources that meet the specific energy needs of Idaho Power and its customers. In 2011, Idaho Power plans to continue to increase participation, energy savings, and demand reduction from existing energy efficiency and demand response programs. Additionally, the company will add measures as identified in the 2011 IRP to its existing programs and continue to expand its efforts in energy efficiency education. Idaho Power also plans to expand the FlexPeak Management program as defined in its contract with EnerNOC, Inc., the third-party demand response aggregator who administers this program.

## Marketing

DSM marketing plans are developed annually. These plans focus on distinct customer segments, including residential, commercial/industrial, and irrigation. Each segment's marketing plan includes the goals, strategy, tactics, previous marketing results/research, and budgets for each individual program within that segment. The plan is reviewed at the six-month mark to ensure tactics are being implemented and to update information as necessary. A variety of sources help inform marketing decisions. These include primary research, secondary research, historical performance, and third-party segmentation software.

As part of the company's awarded Smart Grid Investment Grant, work will continue on the CRM tool in 2011. This new marketing tool will track customer interactions and centralize customer marketing data, providing in-depth information about Idaho Power customers. This new technology will allow the

Customer Relations and Energy Efficiency department to better interact with customers, meet their needs, and accelerate energy efficiency and demand response program participation. Resource efficiencies in regard to the CRM tool will be gained in part by replacing current manual marketing processes with automated processes and workflows.

### *Program Evaluation*

Program evaluation is an important facet of Idaho Power's DSM operational activities. Idaho Power relies on evaluation by third-party contractors, internal analyses, and regional studies to ensure the ongoing cost-effectiveness of programs through validation of energy savings and demand reduction. The results of Idaho Power's evaluation efforts are used to enhance or initiate program changes. Throughout 2010, Idaho Power revised its comprehensive evaluation plan for energy efficiency and demand response programs. The current evaluation plan is included in *Supplement 2: Evaluation*. Although the evaluation plan is expected to be used for scheduling evaluations, the timing of specific program evaluations will be based on considerations of program evaluation needs, and other relevant regional studies.

In 2010, the company completed process evaluations on all of its commercial, industrial, and irrigation programs. It also completed process evaluations on four of its residential energy efficiency programs. Although Requests for Proposals (RFP) were issued in April 2010, the studies were completed in late 2010, and the final reports were received in early 2011. All of these studies were conducted under contract with third-party independent evaluation firms. The company is in the process of reviewing the recommendations and constructing implementation plans to incorporate the results of these evaluations into the program processes. Copies of these evaluations are included in *Supplement 2: Evaluation*.

## Customer Satisfaction

Since 1995, Idaho Power has employed an independent third-party research vendor to conduct customer relationship surveys. The intent of these surveys is to measure the overall customer relationship and satisfaction with Idaho Power. As such, consistency in survey format is an important aspect of being able to trend results over a period of time. Occasionally, when there are changes in Idaho Power operations that may significantly affect a customer's relationship with the company, slight changes or additions have been allowed to the survey instrument to accommodate new relationship attributes. Because of Idaho Power's increased activity with energy efficiency programs in 2003 and the impact those programs may have on a customer's satisfaction with the company, Idaho Power added two questions related to awareness of Idaho Power's energy efficiency efforts to the overall survey instrument. In 2010, again because of increased activity and interest in Idaho Power's energy efficiency programs, the company added three additional questions to the survey to measure customers' participation in, and satisfaction with, Idaho Power's energy efficiency programs. However, it is important to reiterate that the intent of this survey is not to measure all aspects of any or all energy efficiency programs offered by Idaho Power. The survey measures satisfaction of a number of different aspects of the customer's relationship with Idaho Power, including energy efficiency, at a very high level.

The 2010 results of Idaho Power's quarterly customer relationship survey showed steady improvement over recent years. The percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts continued to grow, with a 46 percent increase in positive customer perception from 2003 to 2010. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003 to 57 percent in late 2010. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for

improvement. Figure 6 depicts quarterly growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

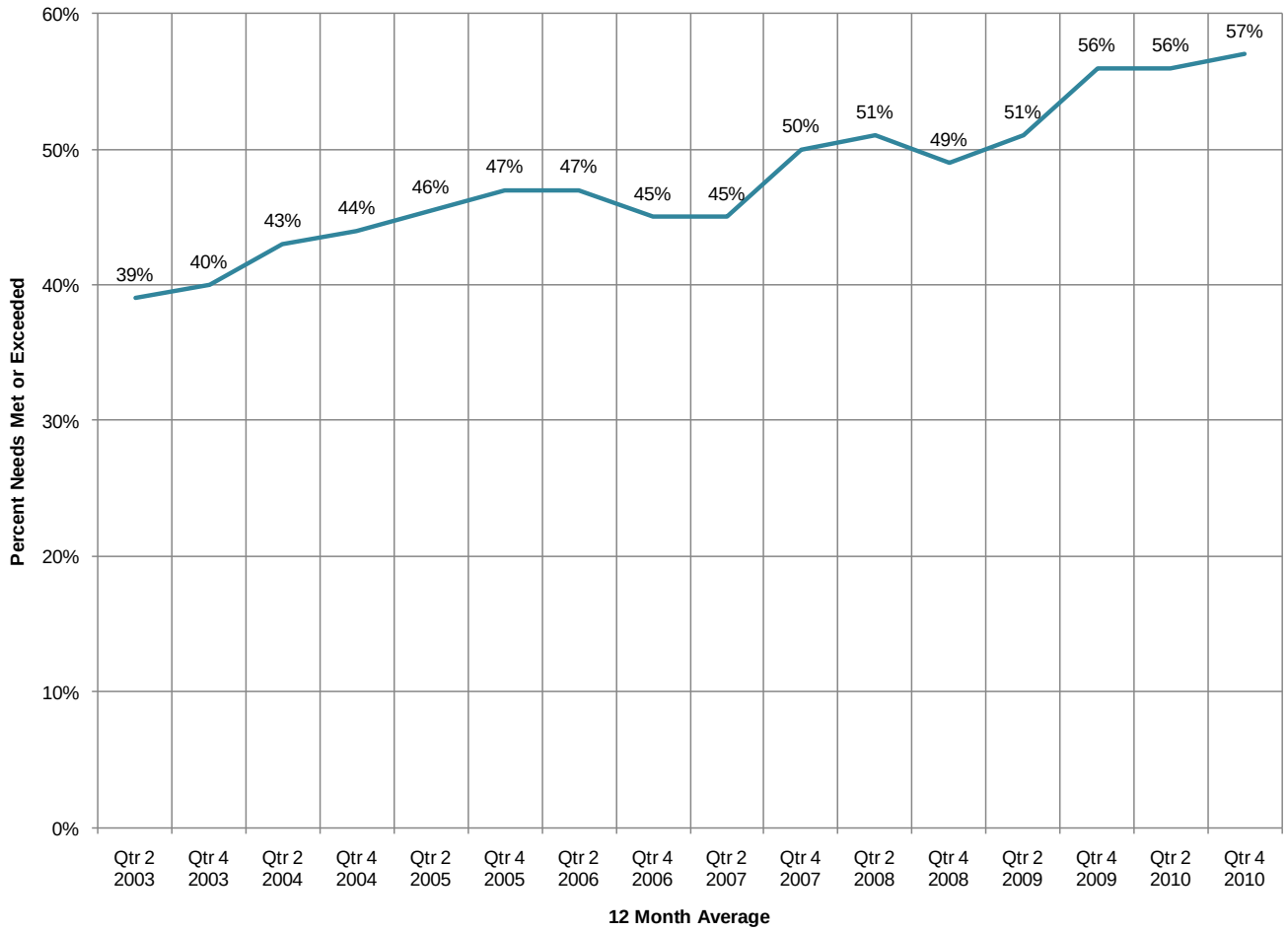


Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

In 2010, Idaho Power added three new questions to the general relationship survey related to energy efficiency programs: 1) Have you participated in any of Idaho Power's energy efficiency programs? 2) Which energy efficiency program did you participate in? 3) Overall, how satisfied are you with the energy efficiency program? Overall, 33 percent of the survey respondents across all sectors indicated they have participated in at least one Idaho Power energy efficiency program. Of survey respondents who have participated in at least one Idaho Power energy efficiency program, 95 percent are "very" or "somewhat" satisfied with the program.

Several surveys measured customer satisfaction with individual programs in 2010. The surveys also provide guidance for program modification, marketing, and evaluation. Survey results are presented in the following program descriptions in this report: DHP Pilot, Heating & Cooling Efficiency (H&CE) Program, Easy Savings Program, Residential Energy Efficiency Education Initiative, Weatherization Solutions for Eligible Customers, Easy Upgrades, and FlexPeak Management.

Idaho Power programs have ongoing customer satisfaction measurements as a follow-up to the application process. For example, Easy Upgrades provides an ongoing, Web-based customer survey for its participants. Results of these surveys indicate general satisfaction and help guide program

improvement and marketing efforts. After each session of the Energy Efficiency and Green Living Series, Idaho Power requests attendees fill out a customer feedback form rating the program. The H&CE Program provides an opportunity for customer and contractor feedback through surveys.

## Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. Because of Idaho Power's diversified portfolio of programs, most of the new potential for energy efficiency savings in the Idaho Power service area is based on measures being added to programs, rather than new programs. The process in the IRP for determining if additional measures should be adopted remains the same as it is for program inclusion. Specific programs or potential energy savings measures are screened by sector to determine if the levelized cost of these programs or measures is less than supply-side resource alternatives. If they are shown to be lower cost than supply-side resources from a levelized cost perspective, the hourly shaped energy savings is subsequently included in the IRP as a resource.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models is input from various sources in order to use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other companies in the region, or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all mature programs to have benefit/cost (B/C) ratios greater than 1.0 for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program level and the measure level. Only the program level tests are used in cases where there is significant interaction between measures. This year, Idaho Power has calculated the RIM test for each program, and the results of these calculations are included in *Supplement 1: Cost-Effectiveness*. Idaho Power may launch a pilot program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following implementation of a program, cost-effectiveness analyses are reviewed annually, including actual program information, such as actual program expenses, savings, or participation levels. If measures or programs are determined to not be cost effective after implementation, the program or measures are reexamined and modified based on input from the EEAG. In 2010, all of Idaho Power's energy efficiency programs are shown to be cost-effective from the TRC, UC, and PCT perspectives. All three of the company's demand response programs are cost-effective from both a long-term perspective as well as for 2010 under a one-year perspective.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2010. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

## DSM Annual Report Structure

The structure of Idaho Power's *Demand-Side Management 2010 Annual Report* remained for the most part unchanged from the 2009 report, aligning with the reporting requirements included in the MOU with the IPUC staff.

This main *Demand-Side Management 2010 Annual Report* document remains similar to previous years, organized primarily by customer sector categorized by residential, commercial/industrial, and irrigation. The sector descriptions are followed by information regarding programs in that sector. Each program description includes a chart containing 2010 and 2009 program metrics in tabular format, followed by a general description, 2010 activities, cost-effectiveness, customer satisfaction/evaluation, and 2011 plans. Each program section contains detailed information in relation to program changes and the reasoning behind those changes, including details on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. The appendices following the written sections contain tabular information on the 2010 expenses and savings and supply historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions; 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot and Salmon areas.

Idaho Power currently divides its service area into three geographic regions; 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the three, historical regions are referred to throughout this report.

Appendices 1–4 remain generally unchanged in form and contain financial, energy and demand savings, and levelized costs and program life B/C ratios from the UC and the TRC perspectives. In the main report, Appendix 5 has been added. It contains detailed financial and energy savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Also included this year are two supplements and an attached compact disc (CD). *Supplement 1: Cost-Effectiveness* contains detailed cost effectiveness information by program and energy-savings measure as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The RIM test is a new addition this year. The RIM test measures the impact to customer bills or rates due to changes in utility revenues and operating costs caused by an energy efficiency program. Idaho Power used the formula for the RIM test as provided in the *California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October 2001*. *Supplement 2: Evaluation* contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) provided by NEEA is attached to Supplement 2.

# RESIDENTIAL SECTOR OVERVIEW

## Description

The Idaho Power service area covers a population of a little more than one million people. At the end of 2010, Idaho Power was serving 408,754 residential customers in its Idaho and Oregon service areas. During 2010, Idaho Power added 2,123 residential customers, making it the third consecutive year of relatively modest growth of residential customers within the company's service area. These additional residential customers represented a slightly lower amount than the 2,258 residential customers added in 2009. A continued sluggish regional economy and few housing starts were the main drivers of this trend. In 2010, the residential segment represented 39 percent of Idaho Power's total electricity usage and contributed 45 percent of total revenue for the company.

Milder temperatures, a sluggish economy, energy efficiency activities, customer education, and successful dispatching of company-sponsored DSM programs led to a system peak of only 2,930 MW on June 28, 2010, at 7:00 p.m. For the second consecutive year, Idaho Power did not set a new summer system peak record. The record summer peak of 3,214 MW was established on June 30, 2008, at 3:00 p.m. Idaho Power continued its education and promotion of energy efficiency programs and information to all residential customers by participating in local and regional events as well as conducting target visits with trade allies, contractors, and vendors during the year. These tasks and activities contributed to increased program participation and improvement in customer satisfaction results.

Annual program savings in the residential sector of 42,850,839 kWh were recorded as part of 2010 program offerings to customers, with more than a 16-million kWh increase over 2009 program performance of 25,979,920 kWh. While several programs experienced increased savings in 2010, the increase in annual savings was driven mostly by growth in customer participation of both the Energy Efficient Lighting and Home Improvement Programs. The Energy Efficient Lighting program provided 1,190,139 discounted bulbs to customers through retailers during 2010, resulting in 28,082,738 kWh in annual savings, which more than doubled the sales of 549,846 bulbs in 2009. Participation in the Home Improvement Program, which offers incentives for increasing attic insulation, grew from 1,661 homes to 3,537 homes in 2010, resulting in 3,986,199 kWh of annual savings. Table 5 provides a summary of 2010 residential program performance for both energy efficiency programs and the one residential demand response program.

# Programs

Table 5. 2010 Residential Program Summary

| Program | Participants | | Total Costs Utility | Total Costs Resource | Savings Annual Energy (kWh) | Savings Peak Demand (MW) |
|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | |
| A/C Cool Credit | 30,803 | homes | $ 2,002,546 | $ 2,002,546 | n/a | 39.0 |
| **Total** | | | **$ 2,002,546** | **$ 2,002,546** | | **39.0** |
| **Energy Efficiency** | | | | | | |
| Ductless Heat Pump Pilot | 104 | homes | $ 189,231 | $ 439,559 | 364,000 | |
| Energy Efficient Lighting | 1,190,139 | bulbs | 2,501,278 | 3,976,476 | 28,082,738 | |
| Energy House Calls | 1,602 | homes | 762,330 | 762,330 | 1,198,655 | |
| ENERGY STAR® Homes Northwest | 630 | homes | 375,605 | 579,495 | 883,260 | |
| Heating & Cooling Efficiency Program | 217 | homes | 327,669 | 1,073,604 | 1,104,497 | |
| Home Improvement Program | 3,537 | homes | 944,716 | 2,112,737 | 3,986,199 | |
| Home Products Program | 16,322 | appliances/fixtures | 832,161 | 1,025,151 | 1,443,580 | |
| Oregon Residential Weatherization | 1 | home | 6,050 | 6,275 | 320 | |
| Rebate Advantage | 35 | homes | 39,402 | 66,142 | 164,894 | |
| See ya later, refrigerator® | 3,152 | refrigerators/freezers | 565,079 | 565,079 | 1,567,736 | |
| Weatherization Assistance for Qualified Customers | 400 | homes/non-profits | 1,321,132 | 2,927,898 | 3,741,652 | |
| Weatherization Solutions for Eligible Customers | 47 | homes | 228,425 | 228,425 | 313,309 | |
| **Total** | | | **$ 8,093,078** | **$ 13,763,171** | **42,850,839** | |

Notes:
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.

Programs available to residential customers include one demand response program, 12 energy efficiency programs, and an energy efficiency educational initiative. The demand response program A/C Cool Credit had more than 34,600 customers enrolled as of the end of 2010. The residential efficiency programs include Energy House Calls, Rebate Advantage, ENERGY STAR® Homes Northwest, Oregon Residential Weatherization, Home Products, Energy Efficient Lighting, See ya later, refrigerator®, Weatherization Assistance for Qualified Customers (WAQC), H&CE Program, DHP Pilot, Home Improvement, and Weatherization Solutions for Eligible Customers.

The Boise City Home Audit Project was initiated in 2010. Idaho Power partnered with the City of Boise, which received funding initiated by the American Reinvestment and Recovery Act (ARRA), to serve as the program implementer for the city. The combination of financial support through the act and Idaho Power Rider funds allows the program to be fuel neutral and target 600–700 homes within the city limits of Boise. The program is scheduled to be completed by spring 2012 and includes a blower-door test, customer education, installation of compact fluorescent light (CFL) bulbs, low-flow showerhead, and other energy efficiency measures for qualified customers.

Idaho Power continued to increase its participation in the number of retail and community outreach events during 2010. Many of these events were partnerships with community retailers, including Home Depot, Lowe's, Costco, and Fred Meyer. The company also participated in home and garden shows, several Parade of Homes events across Idaho Power's service area, the Idaho Green Expo, a library education series, and other community events across the company's service area.

Presentations to community groups and businesses were another emphasis during the year, with nearly 400 presentations conducted in 2010. For example, Idaho Power customer representatives made

approximately 130 presentations to civic and community groups, including chambers of commerce, school boards, service organizations, and businesses. The presentations took place during such times as staff meetings, business lunches, and Rotary luncheons; other examples of presentations are provided in the Residential Energy Efficiency Education Incentive section of this *Demand-Side Management 2010 Annual Report*. These partnerships and outreach activities created specific opportunities for the company to share the importance of energy efficiency and give customers information and options about participating in programs.

Idaho Power conducts the Burke Customer Relationship survey each year. Fifty-four percent of residential survey respondents in 2010 indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-three percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 37 percent of Idaho Power residential customers surveyed in 2010 indicated Idaho Power is meeting or exceeding their needs in offering energy efficiency programs; while 26 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 85 percent are “very” or “somewhat” satisfied with the program.

# A/C Cool Credit

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants)[a] | 30,803 | 30,391 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW)[a] | 39.0 | 38.5 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,854,979 | $3,305,814 |
| Oregon Energy Efficiency Rider | $74,071 | $144,622 |
| Idaho Power Funds | $73,496 | $1,552 |
| Total Program Costs—All Sources | $2,002,546 | $3,451,988 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.11 | |
| Total Resource Benefit/Cost Ratio | 1.11 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Program participation and demand reduction reflect enrollment as of July 31st. Year-end enrollment in the program was 34,640 homes, with 6,095 new participants joining the program.

## *Description*

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners (A/C) or heat pumps on and off via a direct-load control device installed on the A/C unit. Participants receive a monthly monetary incentive for participating in the program during the summer season. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high.

Individual radio-controlled or power-line carrier (PLC) switches are installed on customers' A/C units. These switches allow Idaho Power to cycle customers' A/Cs during a cycling event. As Idaho Power's Smart Meter project expands across its service area, more new switches will be PLC switches that will allow broader participation. Under this program, Idaho Power may cycle participants' A/Cs for up to 40 hours each month in the months of June, July, and August. In return, participants receive a $7 per-month credit on their Idaho Power bill during July, August, and September.

## *2010 Activities*

The program expanded its presence on the Mountain Home Air Force Base (MHAFB) housing from 522 to 803 total participants. There were three cycling events in 2010, one in each of the summer months. The three events in 2010 were on June 29 from 4:00 p.m. to 7:00 p.m., July 16 from 4:00 p.m. to 7:00 p.m., and August 5 from 4:28 p.m. to 7:00 p.m. Due to mild temperatures, all events were cycled at 50 percent.

Cycling event hours continued to be in three-hour periods, pinpointing the peak time with less potential impact on participants. Summer 2010 temperatures were mild. This resulted in fewer high-demand days, so there was less need for cycling to reduce demand. Generally, the need for cycling starts near the end of June when temperatures rise. With high temperatures milder in 2010, there was less need for A/C. Lower average temperatures also improve a home's ability to cool naturally overnight and retain less heat the following day.

Marketing approaches during 2010 covered a range of methods, including bill stuffers, direct mail, follow-up letters, and newspaper advertisements. One successful marketing piece was a letter accompanied by a dual-purpose piece: a magnet to record important phone numbers mounted to a cardstock reusable bookmark. This piece was sent out in three waves, with the results ranging from 1 percent to over 2.5 percent sign-up rates. All three waves had about the same response rate range. Idaho Power employees continued visiting large businesses, providing program information, and speaking at luncheon presentations.

The Smart Meter installations brought two new opportunities to market the A/C Cool Credit program. The first was to advertise the program on the back of the door hanger left at the customer's home when a Smart Meter was installed. This generated sign ups and added to the general awareness of the program. The second opportunity provided new areas for switch installation as the Smart Meter area expanded into areas previously unavailable due to no, or limited, paging reception for the radio-controlled switches.

A cause-related marketing approach, consisting of partnering with both the Idaho Foodbank and Southeast Oregon Regional Food Bank, was repeated in 2010. It provided customers an additional opportunity to sign up for the program. During a "limited time offer," a $20 contribution went to the food bank in the participant's location for enrolling in the A/C Cool Credit program. The winter promotion, from October 2009–February 2010, resulted in a total of $22,220, equal to 66,660 meals, for the Idaho Foodbank, and $1,080, equal to 5,400 pounds of food, for the Southeast Oregon Regional Food Bank. This marketing approach yielded 1,165 new A/C Cool Credit sign-ups in 2010.

The call center customer service representative (CSR) pilot continued into 2010. CSRs received training in signing up new A/C Cool Credit participants at the point of contact when an Idaho Power customer initiates or transfers his/her account by phone. This resulted in 86 sign ups in 2010.

Outreach to Heating, Ventilation, and A/C (HVAC) companies continued as-needed to provide their employees with training on the A/C Cool Credit switch. Increasing the HVAC technician's knowledge of switch boxes contributes to positive customer relations between the customer and the technician servicing the A/C Cool Credit program participant's A/C unit.

In 2010, the two paging providers discontinued their service to the Twin Falls and Pocatello areas. A search was conducted for alternative paging providers but none were available for that area. Alternative methods of communicating with the switches were researched. An adequate solution was not available. This resulted in the inability to cycle the participants in those two areas during summer 2010. In response, marketing to these areas and installation of new switches was halted.

At the May 26, 2010, EEAG meeting, Idaho Power explained some of the paging issues experienced by customers in the Twin Falls and Pocatello areas. Idaho Power asked EEAG members for feedback and suggestions on how to proceed with this issue. EEAG members supported crediting those affected customers on their bill with the use of non-Rider funds. The participants in these areas were paid an incentive dispite the lack of Smart Meter communication. The company determined that it was less

expensive to pay an incentive than to again recruit A/C Cool program participants. The Smart Meter deployment expanded into these affected areas in late 2010, and the company began to replace paging switches with smart grid-compatible switches. Switches started being changed out in late 2010 with plans to continue into early spring, with the new switches being operational before the start of cycling season 2011.

Idaho Power initiated a process improvement in 2010, by changing the method of transferring data to contractor, Honeywell, Inc., Utilities Solutions. In the past, each e-mail containing customer information had to be manually encrypted when sent. This required Honeywell, Inc., to log into a special system to access the information each time they received an encrypted e-mail. The process kept the customer data secure, but resulted in additional time and work for both parties. Idaho Power's Information Technology (IT) department determined that Transport Layer Security (TLS) was an equally secure method of transferring data between the two parties and did not require manually encoding and decoding. Once approved and in place, the new process allowed quicker transfer of data, which results in responding to customer requests in a timelier manner.

## Cost-Effectiveness

Although the B/C analysis for the A/C Cool Credit program is based on a 20-year model that uses financial and DSM alternative costs assumptions from the 2009 IRP, the company also tracks cost-effectiveness on an annual basis. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170-MW simple-cycle combustion turbine (SCCT) is used as an avoided resource cost. Idaho Power's A/C Cool Credit cost-effectiveness model is updated annually with actual benefits and costs. The benefits are based on peak reduction and shifted energy use. In 2010, the A/C Cool Credit model update included the expense of paying incentives to the Twin Falls and Pocatello participants for which no demand reduction was realized. This additional expense had no effect on the 20-year cost-effectiveness and no material effect on the 2010 annual cost-effectiveness. From a long-term perspective, the A/C Cool Credit program had a TRC ratio of 1.11 and from a one-year prospective a TRC ratio of 1.23. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

In 2010, 2,837 accounts ended participation in the A/C Cool Credit program. Of those, 2,807, or 98.9 percent, ended participation at approximately the same time as their Utility Service Agreement (USA) expired. The USA is the customer's agreement with Idaho Power for electrical service. It begins when they sign up for service, and ends when they end service.

Approximately 30 accounts, or 1 percent, stopped participating in the program for reasons other than the canceling of electric service. This was determined by an analysis of the end-dates for contract riders, which are the agreements to participate in the A/C Cool Credit program, and end-dates for USAs.

In early 2010, Idaho Power contracted with Paragon Consulting Services and received a detailed plan to evaluate the impacts of the 2010 A/C Cool Credit program. Idaho Power is using this evaluation plan as a basis for conducting a comprehensive impact evaluation in 2011.

## 2011 Strategies

In February 2011, Idaho Power issued an RFP to evaluate the impacts of the A/C Cool Credit program, including electrical demand reduction and energy impacts, effects of various curtailment strategies on

indoor air temperature of participants, strategies to balance load reduction with customer comfort, estimation of available load reduction as a non-spinning reserve resource, and identification of parameters to predict potential load reduction. Idaho Power plans to select a contractor in March 2011. Customer recruitment and data collection equipment installation will conclude in May before the curtailment season begins. Analysis of the data will begin in September with the final report delivered in December 2011.

The 2011 program target is to reach 40,000 total participants. Once the target is achieved, the company will continue A/C Cool Credit marketing and promotion to determine if saturation has been achieved or if it is possible to increase participation. As Smart Meters are installed in those areas where the paging signal is unavailable, the A/C Cool Credit program will be able to expand.

The remaining 1,565 paging switches will be changed out in the Twin Falls and Pocatello areas in early 2011, so all replacements for these areas will be completed before the start of cycling season 2011. The majority of Smart Meter substations in these areas will be completed and operational before June 1, 2011, with a few exceptions. Once the substation is active, communication to the new switches will be available. The substations not commissioned before the start of cycling season will either be brought online shortly thereafter, or serve very few A/C Cool Credit participants. The result is that Idaho Power can cycle most of the switches/participants in the Twin Falls and Pocatello areas.

# Ductless Heat Pump Pilot

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 104 | 96 |
| Energy Savings (kWh) | 364,000 | 409,180 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $181,969 | $192,264 |
| Oregon Energy Efficiency Rider | $7,262 | $9,740 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $189,231 | $202,004 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.044 | $.031 |
| Total Resource Benefit/Cost Ratio | $0.103 | $.086 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.47 | |
| Total Resource Benefit/Cost Ratio | 1.38 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area during 2009. The company extended the project as an Idaho Power DHP pilot through 2010. A main goal of the Northwest DHP pilot project was to promote the DHP technology as an energy-saving alternative for customers who primarily heat their homes with electric heating. Idaho Power offered customers a $1,000 incentive to participate.

The program targets homes heated with electric zonal systems. Typically, these homes do not have air ducting, therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboard, ceiling, and wall-mounted systems. Homes heated with natural gas forced-air systems or electric forced-air systems do not qualify. Qualifications include having one indoor unit installed in the main living area of the home. Since this is where most occupants spend the majority of their time, and DHP systems can serve up to 1,000 square feet, this is the most efficient application of the technology.

Other Northwest DHP Pilot goals are to determine how much energy this technology saves in order to validate an RTF deemed-savings and to obtain customer satisfaction and behavior patterns regarding the units.

Though the official pilot recruitment period concluded at the end of 2009, field monitoring on selected homes throughout the Pacific Northwest, billing data analysis, and other evaluations will continue through 2011.

## 2010 Activities

Idaho Power targeted 100 participants for NEEA's Northwest DHP Pilot. As participation levels neared the 100-application limit in 2009, the company announced to contractors that Idaho Power would extend the pilot and accept additional applications throughout 2010. Completed projects in 2010 exceeded 2009 by eight projects, or 8 percent.

Along with other utilities in the region, Idaho Power decided to continue the pilot to maintain the valuable momentum created in the marketplace among contractors and customers. Idaho Power promoted the pilot to customers through an article in its monthly residential customer newsletter, *Customer Connection*, and by sending direct mail letters to 28,492 targeted customers based on several factors, including energy usage during specific months and geographical region. The company also marketed the pilot to contractors by visiting with them and informing them of the pilot.

In November, Idaho Power held a one-day training session for contractors interested in the DHP Pilot. The Northwest DHP Pilot sponsored the event. The session covered product training and information on how to become a participating contractor. There were 31 attendees representing 21 HVAC companies.

In the fourth quarter, Idaho Power, through its new database, improved the method to process DHP incentive applications. Using the Customer and Load Research Information System (CLRIS), an existing software platform, a database was developed enabling all of the application data to be entered and stored for analysis. The database also initiated the incentive payment process. It has enabled the elimination of multiple files previously used to store data.

## Cost-Effectiveness

The Northwest DHP Pilot finished its second year in 2010. Complete details about the regional effort can be found at the project website at www.nwductless.com. Data collection will be completed for the 13 chosen sites in Idaho Power's service area during 2011, and the post-installation billing data will be compiled and analyzed by a regional contractor.

The RTF has released provisional annual savings, based on a one indoor-unit installation with at least one ton of heating capacity or greater and employ an inverted driven compressor. The savings per unit is estimated at 3,500 annual kWh until the pilot analysis is completed. The RTF deemed one savings metric regardless of prior cooling, whether the DHP is displacing electric-resistance heat or zonal heat, or in what climate zone the unit is located. Participant costs in 2009 were determined by taking the median price as reported on Idaho Power's applications. These participant prices were used because the units purchased in Idaho Power's service area were approximately $900 less than the provisionally deemed regional costs. In 2010 the RTF updated the participant costs to $3,400. This level of expense confirmed what Idaho Power's data indicated; consequently, the provisionally deemed cost was used for all cost-effective analysis in 2010. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see the *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the regional pilot, a NEEA contractor conducted quality assurance (QA) on-site verifications (OSV). The regional pilot targeted 10 percent of completed installations. In 2010, 13 DHP Pilot projects in Idaho Power's service area were inspected by NEEA's contractor to ensure projects complied with program requirements. The QAs proved beneficial for customers, contractors, and Idaho Power. For example, customers were shown how to operate their systems correctly, the contractors were able to

review the installation requirements of the DHPs, and Idaho Power was able to observe the installation process.

Idaho Power mailed a 12-question satisfaction survey to 52 participants in 2010, and 41 surveys were returned, resulting in a 79 percent response rate. Most respondents heard about the DHP Pilot from their heating and cooling contractor or a letter from Idaho Power. Sixty-eight percent of the respondents were aware that Idaho Power offered an incentive for the purchase of a DHP prior to their purchasing one. Seventy-three percent of the respondents indicated that the Idaho Power incentive influenced their purchasing decision "a lot." The most common reason cited for installing a DHP was "no ducting available for other heating sources." Ninety-eight percent of the respondents were "very satisfied" with the DHP Pilot, and 100 percent said they "definitely would" recommend the program to a friend or relative. Approximately 93 percent of homeowners rated their contractor as "very knowledgeable," while 7 percent of the contractors were rated as "somewhat knowledgeable." Results of the survey are in *Supplement 2: Evaluation*.

The surveys have played an important role in evaluating the types of marketing tactics being used. The results indicate most customers are learning about the incentive program prior to purchasing a ductless heat pump. This result substantiates the need to market the program. Of equal importance is that there is not one source but multiple sources needed to reach the customers. This supports the overall strategy of trying new ways to generate market awareness. It is also apparent that, without the incentive, these systems might not be installed at the current rate. The survey results also indicate the performance of the overall program is valued by the customer. This supports the value in providing further enhancements to make the program even more seamless. In addition, that the majority of the customers indicate they would recommend the incentive to others makes customers a valuable marketing voice.

Idaho Power is continuing its participation in the Northwest DHP Pilot and evaluation. This extensive evaluation effort is designed to provide a technical evaluation of DHP technology as a retrofit opportunity, measure achievable energy savings, assess market response, and provide a process evaluation of the pilot program.

In 2010, NEEA made available an MPER update for the DHP Pilot. The following are highlights included in the report. Fifty-nine utilities participated and installed 3,899 units, exceeding the pilot's installation goal of 2,500 units as of December 31, 2009. Participants reported high levels of satisfaction concerning understanding incentive information, finding a contractor, locating program information, and receiving their incentive checks in a reasonable time. Of the participants, 66 percent said they would not or might not have purchased a DHP without the incentive. Pilot participants were interviewed for the report. Nearly 99 percent of them indicated they have the displaced electric heating equipment in place but use their DHP as the primary heating source. Of the 20 percent of participants who were planning to purchase some type of A/C equipment, none of them continued with that plan after they installed their DHP. Most participants reported receiving non-energy benefits with the DHPs, such as increased comfort, air filtration, and simple equipment control. The adaptation to large-scale integration projects remain limited due to the concern of DHPs' performance in severe climate conditions. A copy of the report is in *Supplement 2: Evaluation*.

## 2011 Strategies

Idaho Power will continue offering incentives to customers, in 2011. Idaho Power will increase participation in local manufacturer-training events held by local wholesalers. These training events enable Idaho Power to reach and align with contractors not yet familiar with this pilot.

For contractors to be eligible to participate in the DHP Pilot, they must receive mandatory DHP factory-product training for each of the brands they sell and attend a mandatory Idaho Power orientation. Product training is attainable via local HVAC wholesalers, manufacturer representatives, or Idaho Power-sponsored events. The Idaho Power orientation describes specific product features and installation methods required for incentive application approval. The company orientation further describes required installation features, such as a DHP with an inverter-driven compressor, inverter-driven or variable-speed blower, and R410A refrigerant. Rigid line set covers are also required. The orientation also describes the requirements to qualify the home, install the DHP in the main living area, submit all paperwork, and teach the homeowner how to use the DHP. Contractors are alerted that their first installation will be inspected.

Changes to the pilot in 2011, include modifying the incentive value from $1000 to $750 for installations completed after January 31, 2011. Idaho Power redistributed the funds to increase the incentive amount for electric-furnace to air-source heat pump incentive option in the H&CE Program. Idaho Power will work closely with participating contractors to help them understand and apply the incentive process with their clients. DHPs remain an emerging technology in the Idaho Power service area.

New marketing methods will be used in 2011 to reach the target audience. Methods include participating in residential coupon mailer packets reaching all of the Idaho Power service area, posting articles about DHPs on social media sites that Idaho Power participates in, and advertising the pilot in newspapers that service specific areas not generally serviced with natural gas. The traditional ongoing methods, such as bill inserts and direct mail, will also continue in 2011.

Satisfaction surveys will be mailed to all 2011 incentive recipients. The response data will be compiled and analyzed to help improve all facets of the pilot. The final pilot evaluation report is expected to be available in 2012. The regional DHP Pilot team will provide limited QA inspections for the region in 2011. Idaho Power will investigate augmenting the regional QA inspection with its own QA inspections.

# Energy Efficient Lighting

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 1,190,139 | 549,846 |
| Energy Savings (kWh) | 28,082,738 | 13,410,748 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,442,931 | $1,190,065 |
| Oregon Energy Efficiency Rider | $58,347 | $17,300 |
| Idaho Power Funds | $0 | $1 |
| Total Program Costs—All Sources | $2,501,278 | $1,207,366 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.020 | $0.020 |
| Total Resource Benefit/Cost Ratio | $0.031 | $0.024 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.54 | |
| Total Resource Benefit/Cost Ratio | 3.49 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

ENERGY STAR® qualified CFLs are an alternative to standard incandescent light bulbs that result in saved money, energy, and time. Bulbs come in a variety of wattages, colors, and styles, including bulbs for three-way lights and dimmable fixtures. ENERGY STAR bulbs use up to 75 percent less energy and last up to 10 times longer than incandescent bulbs.

The Energy Efficient Lighting program achieves residential energy savings by replacing less-efficient lighting with more-efficient technology. According to research performed by NEEA, the average older home has 38 light bulbs. New homes have an average of 77 light bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

## *2010 Activities*

There was record participation in 2010 in the Energy Efficient Lighting program, with incentives provided on over one million bulbs. This represents approximately three bulbs per residential account.

Two promotions, one for spiral bulbs and the other for specialty bulbs, such as globes, three-way, and reflector bulbs, were held during 2010. Idaho Power continued to run an independent retailer promotion focusing on spiral bulbs priced at about 99 cents per bulb. Fluid Market Strategies (Fluid) managed this promotion.

In August, the program achieved a contract sales threshold that lowered the administrative fee paid to Fluid by $0.48 per bulb, resulting in significant cost-savings for the rest of the promotion year. Savings are estimated at $133,005.

Idaho Power participated in the Bonneville Power Administration (BPA) Change a Light promotion focused on specialty bulbs. Portland Energy Conservation, Inc. (PECI), managed this promotion from January to March 2010. BPA awarded the promotion contract to Fluid, beginning April 1, 2010. Fluid administered the promotion for the remainder of 2010 under a new name, Simple Steps, Smart Savings™.

Both PECI and Fluid provided enhanced field support as part of their promotions. Contractor staff from these two organizations visited stores on a regular schedule to check pricing, stock, and signage. The result was better visibility of Idaho Power's promotions.

Additional 2010 program activities included direct distribution, in-store events, and an on-air radio interview. Idaho Power has a small direct distribution program, whereby bulbs are given directly to customers at approved venues. The idea is that, if given a free bulb, customers might try CFLs for the first time or be encouraged to replace additional lamps. Guidelines for approved venues and direct distribution have been developed to ensure customer fairness. Eight considerations are used to evaluate the appropriateness of distributing CFL bulbs to customers and include identifying venues that have an energy efficiency tie, a residential focus, and allow for an Idaho Power presence.

During 2010, Idaho Power participated in five in-store events with large and small national retailers designed to communicate directly to customers at the point of sale. Idaho Power had light displays at the entrances of stores, and Idaho Power staff was available to answer questions about CFLs.

Idaho Power participated on The HomeFix Show with Joe Prin on 670 KBOI AM. The show reaches an audience estimated at 19,320 listeners. Program staff from Idaho Power spent an hour on air answering phone-in questions about lighting. This is an effective, low-cost marketing and education opportunity.

## Cost-Effectiveness

In 2010, the RTF updated savings assumptions for CFLs to differentiate the savings between the typical twist bulbs and the various specialty bulb types. The RTF determined that specialty CFL use differed from standard CFL use. While standard twist-CFLs have a storage rate of 36 percent, the RTF voted to reduce the storage rate for specialty bulbs to 20 percent to account for higher costs, smaller package size, and reduced socket saturation. Take-back for specialty bulbs was reduced from 5 percent to 0 percent. While the annual savings for retail spiral bulbs remained at 24 kWh after accounting for storage and take-back, annual savings for specialty-bulbs range from 12.9 kWh to 38 kWh, depending on their application. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2010, NEEA released the 2009–2010 *Residential Lighting Market Research Study* prepared by the energy consulting, testing, and certification company KEMA. The study concluded that sales of ENERGY STAR CFLs declined in the Northwest between 2008 and 2009 and identified several potential factors for this, including the economy and a "leveling off" of the market. Sales of utility discounted CFLs declined less significantly than non-utility discounted CFLs. In the NEEA study, the 2010 sales in the Northwest were expected to be higher than 2009. The study also concluded consumer satisfaction with CFLs remains fairly high. A copy of this report is included in NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

## 2011 Strategies

No major changes are anticipated for the Energy Efficient Lighting program in 2011. Idaho Power plans to continue in-store promotions for buy downs and markdowns of bulbs. The spiral bulb promotion with Fluid has been extended through December 2011. Since Fluid is the contractor for both promotions, the Change a Light contract extension was negotiated to leverage the cost-savings associated with the regional promotion. The administrative fee for this Idaho Power-only promotion will be at the same rate as the BPA specialty promotion.

The specialty bulb promotion with BPA will go through September 2011 and may be extended beyond. Idaho Power will continue to distribute limited quantities of bulbs directly to customers at approved public energy efficiency events and continue to participate in in-store educational events. The company will monitor the market and emerging technologies.

Idaho Power is monitoring industry trends and federal regulations to determine impacts to utility lighting programs, such as impacts on market transformation, cost-effectiveness, and value of utility programs. Specifically, Idaho Power is monitoring implementation of the *Energy Independence and Security Act of 2007* (EISA) and the new lighting technologies, such as light-emitting diode (LED) and new energy-efficient EISA-compliant incandescent bulbs.

EISA requires, by 2012–2014, specific light bulbs use 30 percent less energy than today's incandescent bulbs. For traditional A-lamp, the standards will apply to 100-watt (W) bulbs in January 2012 and end with 40-W bulbs in January 2014. By 2020, a Tier 2 would become effective requiring bulbs to be at least 70 percent more efficient, effectively equal to today's CFLs.

The EISA, CFLs will be one of the options for customers. The market is unlikely to change immediately for several reasons. First, the efficiency standards are phased in over several years starting in 2012. The 75-W bulbs must meet the standards by 2013 and 60-W bulbs by 2014. Second, many specialty bulbs, such as reflectors, globes, and three-way bulbs are exempt from the law. Third, an incandescent bulb or other bulb technology that is 30 percent more efficient could satisfy the law; however, CFLs are 75 percent more efficient. In 2010, manufacturers introduced a halogen bulb that meets the requirements but offers only the minimum energy savings required under the law.

LED light bulbs are on display at many major retailers. In 2010, ENERGY STAR released criteria for LED replacement bulbs. As of January 2011, there were approximately 40 products on this list; 87 percent are reflectors. Market prices for LED products are significantly higher than CFLs and EISA-compliant halogens. Idaho Power will continue to evaluate the price, availability, savings, and cost effectiveness to see if a cost-effective program could be offered. Idaho Power will continue to monitor trends and developments in LED technologies.

# Energy House Calls

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 1,602 | 1,266 |
| Energy Savings (kWh) | 1,198,655 | 928,875 |
| Demand Reduction (MW) | | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $724,895 | $479,174 |
| Oregon Energy Efficiency Rider | $37,435 | $90,420 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $762,330 | $569,594 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.054 | $0.052 |
| Total Resource Benefit/Cost Ratio | $0.054 | $0.052 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.06 | |
| Total Resource Benefit/Cost Ratio | 3.06 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program helps manufactured and mobile home owners with electric heat reduce electricity use by improving the home's efficiency. This energy efficiency program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home and use an electric furnace or heat pump.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing five CFL bulbs; providing two furnace filters, along with replacement instructions; testing water heater temperature for proper setting; and distributing energy efficiency educational materials for manufactured home occupants. The value of the service is not charged to the customer. The value of a typical cost range of the average service call would be $325 to $550, depending on the complexity of the repair. Idaho Power provides the customer with the sub-contractor contact information. Customers access the service by directly calling one of the recognized, certified sub-contractors specially trained to provide these services in their region.

Program delivery is under contract with Ecos IQ, Inc., a company with experience managing and supplying duct-sealing service programs. Ecos IQ, Inc., coordinates the sub-contractors performing local weatherization and energy efficiency services, processes sub-contractor paperwork, invoices Idaho Power, and pays sub-contractors for work performed.

## 2010 Activities

Idaho Power renegotiated the contract with Ecos IQ, Inc., for continuing delivery of the Energy House Calls program during 2010. Energy House Calls serviced approximately 1,600 manufactured homes during 2010, resulting in over 1,000,000 kWh savings. Eighty percent of the homes serviced were located in the Treasure Valley. Twenty percent were outside the Treasure Valley, consisting of 13 percent in Southern Idaho and 7 percent in Eastern Idaho. QA was conducted on 5 percent of the homes serviced in the program.

In 2010, lower participation was expected in areas outside the Treasure Valley, based on the assumption those areas were saturated. However, Idaho Power continued to market to all locations within the company's service area. Throughout the year, it became evident that there is still potential in areas outside of the Treasure Valley.

Marketing campaigns included a bill stuffer sent to all Idaho Power residential customers, a radio spot on the The HomeFix Show with Joe Prin on 670 KBOI, a new program brochure to be used by Idaho Power representatives in the field and at Idaho Power-sponsored events, and a redesign of the direct-mail letter, including a Spanish version. The direct-mail letters were sent to specific customers four times during 2010. These additional marketing efforts created increased participation above expectations. The bill insert was sent in August; the radio spot occurred in March; the brochure was completed in June; the direct-mail letter was revised in March; and direct mailings were sent in January, April, May, and July.

## Cost-Effectiveness

Savings for Energy House Calls are primarily based on the savings of the duct-sealing of an electrically heated home. The savings are specific to the different climate zones within the company's service area. Different savings are also used based on differing types of heating and cooling equipment in the homes where the measures are installed. Additional savings are gained from the up-to-five CFL bulbs directly installed in the homes at the time that the duct-sealing is done.

The RTF reviewed the savings assumptions for duct sealing in manufactured homes in 2010; however, the regional utilities are still reporting the 2007 RTF deemed savings to BPA through its Planning, Tracking, and Reporting website. To align with the savings reported by the region to BPA, the 2007 RTF deemed savings have been applied to all Idaho Power homes serviced in 2010. The updated RTF savings assumptions will be applied to the program in 2011. The revised savings have been reviewed, and the program remains cost-effective. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

To monitor QA in 2010, third-party audits, with a survey question, were conducted in 5 percent of the homes served. Of the 78 homes inspected, 76 homes of those customers expressed that the Energy House Call was a positive experience. Twenty-three of the 78 homes received a "fail," requiring the sub-contractor to return to the home to remedy the situation.

Based on the review of the "failed" homes by an Ecos IQ, Inc., representative, 23 homes out of 78 was not an acceptable failure rate. Twenty-one of the 23 failed homes were the result of a single sub-contractor. An Ecos IQ, Inc., representative raised the concern to the contractor after each series of QAs throughout the year. Since the last of the QAs conducted were at the end of 2010, it was apparent

the issues had not been resolved. Ecos IQ, Inc., took corrective action against the sub-contractor after the final results were received.

The remedy to these issues—after the first QA inspections completed in February 2010—was to halt the use of the worker who had the majority of the problems until he received intensive training from a master trainer and met the master trainer's criteria post-training. The sub-contractor's performance seemed to improve during the second round of QA inspections in June, but worsened during the December inspections, which was followed by termination of the contractor from the program.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Energy House Calls program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and indicated that the program "is successful despite a declining base of eligible participants," and "is surpassing its participation goals." The report also noted that the program "is well designed," and "has an invested project specialist." The program "incorporates several best practices," and "has an actionable marketing plan." Additionally, "the majority of participants recommend the program to others." The main recommendation for improvement was to develop a more accurate estimate of the eligible market for this program. Idaho Power intends to incorporate this recommendation using the recently completed residential end-use survey results. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in next year's *Demand-Side Management 2011 Annual Report*.

## 2011 Strategies

Plans for the upcoming year include continuing the direct-mail campaign to all of the Idaho Power service area to improve participation. Because of the rapid turnover of customers in manufactured homes, Idaho Power will update the mailing list currently used for the direct-mail letters. The list is generated from homes designated as being manufactured or mobile identified from the Idaho Power's CIS. That list is analyzed for homes that appear to use electric heat, based on kWh usage during certain months of the year. The company will also continue to explore low-cost methods of marketing this program to all residential customers believed to have electrically heated manufactured homes. This form of marketing may yield additional word-of-mouth promotion to new, potential program participants.

In June 2011, the contract with Ecos IQ, Inc., expires. Idaho Power may not renew the contract because it may be possible that the program could be fully administered internally after that date. The logistics of such a decision will be evaluated in advance of the contract expiration.

# ENERGY STAR® Homes Northwest

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 630 | 474 |
| Energy Savings (kWh) | 883,260 | 705,784 |
| Demand Reduction (MW) | | 1.1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $369,344 | $348,829 |
| Oregon Energy Efficiency Rider | $6,093 | $5,928 |
| Idaho Power Funds | $168 | $866 |
| Total Program Costs—All Sources | $375,605 | $355,623 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.033 | $0.039 |
| Total Resource Benefit/Cost Ratio | $0.051 | $0.055 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.68 | |
| Total Resource Benefit/Cost Ratio | 2.05 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA to improve energy-efficient construction practices for new, single-family homes. This program targets the lost opportunity savings and summer-demand reduction that result from energy-efficient new construction codes and building practices. Idaho Power accomplishes this by increasing the efficiency of the residential building envelope and air-delivery system.

The ENERGY STAR Homes Northwest residential construction program builds homes that are at least 15 percent more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes Northwest are verified by independent, third-party home performance specialists (HPS) and are certified by Advanced Energy, an organization that conducts the certification inspections for Idaho and the US Environmental Protection Agency (EPA). The homes are more efficient, comfortable, and durable than standard homes constructed according to local building codes.

Homes that earn the ENERGY STAR label include six required specifications. The specifications found in all ENERGY STAR qualified homes are 1) effective insulation, 2) high-performance windows, 3) tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR-qualified appliances, and 6) efficient heating and cooling equipment.

In 2010, builders involved in ENERGY STAR Homes Northwest receive a $400 incentive per home built to the Northwest Builder Option Package (BOP) standards, for both gas- and electric-heated homes in Idaho Power's service area. Builders who enter their homes in a Parade of Homes received the

standard $400 incentive plus an additional $600 incentive to encourage builders to construct ENERGY STAR homes and enter those homes in future Parade of Homes events.

The Idaho Power program collaborates with many local entities for program management, such as ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2010 was conducting education and training activities for residential new construction industry partners.

## 2010 Activities

Although the 2010 housing market was still in a downturn throughout the Idaho Power service area, 630 ENERGY STAR homes were certified. This is the highest number of homes ever certified in the Idaho Power service area in a single year. Idaho Power believes the increase in certifications during 2010 is due to builders' understanding of the value in building to ENERGY STAR standards.

Idaho Power implemented a process improvement in 2010 by moving from paper to paperless certification and incentive processing. HPS electronically entered all field certification data on the Northwest ENERGY STAR (NWES) database. The Idaho Power program specialist then pulled data from the database to process incentives. This new process allowed builders to receive their ENERGY STAR certifications and their Idaho Power incentives more quickly. It alleviated misplaced paperwork and increased HPS accountability regarding placing certification information into the database in a timely manner.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2010. The company presented energy efficiency awards at the Building Contractors Association of Southwest Idaho , Inc., (BCASWI) Parade of Homes awards banquet and at the Snake River Valley Building Contractors Association (SRVBCA) Parade of Home awards banquet.

The company maintained a presence in the building industry by supporting the Building Contractors Associations (BCA), throughout Idaho Power's service area. Specifically, the company participated in the BCASWI Builder's Expo, the SRVBCA Builder's Expo, the Magic Valley Builders Association Parade of Homes, the BCASWI Parade of Homes, SRVBCA Parade of Homes, Building Contractors Association of South East Idaho (BCASEI) Parade of Homes, and the Idaho BCA Convention.

Media campaigns were used as a method to heighten awareness of the ENERGY STAR Homes Northwest program. The program specialist was a guest on The HomeFix Show with Joe Prin on 670 KBOI AM, discussing the benefits and values of the ENERGY STAR Homes Northwest program for both builders and potential homeowners.

Other marketing projects involved adding a message about this program to residential customers' electric bills. These bill messages encouraged Idaho Power customers to visit ENERGY STAR qualified homes in their local Parade of Homes events. A program bill stuffer sent information to all residential customers in the Idaho Power service area.

Idaho Power was a sponsor of the 2010 St. Jude Dream Home in conjunction with NWES. This ENERGY STAR qualified home was also certified as a National Association of Home Builders (NAHB) green home and was the first certified and tested net-zero-energy home in Idaho. Idaho Power and NWES produced a media campaign consisting of radio and newspaper advertising promoting ENERGY STAR Homes and the St. Jude Dream Home. *A Healthy Homes Guide,* a booklet—targeting consumers—containing tips and information on healthy, energy-efficient homes, was produced and distributed throughout the valley as a part of this campaign. In addition, a bill insert promoting

ENERGY STAR Homes and the St. Jude Home was sent out during the campaign. The media campaign culminated in June with the St. Jude Dream Home raffle, with proceeds benefiting the St. Jude Children's Hospital.

In October 2010, the St. Jude Dream Home 2011 kickoff and groundbreaking took place. The Dream Home will be a ENERGY STAR qualified home. This 2011 home will also be raffled off to benefit the St. Jude Children's Hospital. Idaho Power will again collaborate on a smaller scale with Northwest ENERGY STAR to support the St. Jude Dream Home project.

Idaho Power also sponsored Realtor and builder trainings. Two trainings were held in the Boise area during 2010 to train both builders and HPS on the new 2011 ENERGY STAR specifications. Northwest ENERGY STAR and Energy Inspectors delivered these trainings respectively. Northwest ENERGY STAR trainers in the Boise area delivered two additional ENERGY STAR Homes Realtor trainings. One class toured and received training in the "net-zero" St. Jude Dream Home. Fifty area Realtors attended both sessions combined. Informal conversation with participants indicated positive feedback regarding the training.

## Cost-Effectiveness

Cost-effectiveness analysis assumptions for the 2010 ENERGY STAR Homes Northwest program remain the same as 2009. There were no changes in building codes and standards or program specifications that impacted the program. In summer 2010, the RTF released updated savings for this program accounting for the new 2011 higher baseline of building standards for ENERGY STAR homes. These new savings estimates will be incorporated in the 2011 program analysis. Savings for the 2010 analysis were estimated to be 1,400 annual kWh for a typical home built to ENERGY STAR home standards based on a 2008 analysis provided by Ecotope, Inc,. The report was provided in the *Demand-Side Management 2009 Annual Report Supplement 2: Evaluation*. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

The HPS works with builders to ensure the constructed home is compliant with the Northwest electric-only BOP. Along with verifying the installation of building components and equipment through on-site inspections, prior to being qualified, the home must pass a blower door test, air-duct leakage test, and combustion back-draft tests.

Ten percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed for QA purposes.

The State-Certifying Organization (SCO) performs QA. Energy Inspectors was the SCO for the State of Idaho from May 2009 to December 31, 2010. Energy Inspectors is not renewing their contract for 2011. The Washington State University Energy Extension Program has been contracted by NEEA to assume QA and technical assistance duties within the State of Idaho. QA results from 2010 are in *Supplement 2: Evaluation.*

## 2011 Strategies

The ENERGY STAR Homes Northwest program will be undergoing some changes for 2011. Due to the 2009 International Energy Conservation Code (IECC) implementation on January 1, 2011, and adoption by the State of Idaho, gas-heated homes are no longer cost effective. As a result, Idaho Power will no

longer be paying incentives on gas-heated homes. The program will be transitioning to an electrically heated homes program, effective January 1, 2011. Builders involved in ENERGY STAR Homes Northwest will receive a $1,000 incentive per home built to the Northwest BOP, electric-only standards in Idaho Power's service area. Builders showcasing their electric-only home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive. During the October 26, 2010, EEAG meeting, incentive payments on all electric homes and the new code specifications on other utilities was discussed.

Idaho Power plans to continue marketing efforts to help sell ENERGY STAR homes, including educating consumers, Realtors, and appraisers about the benefits and features of ENERGY STAR homes. Results will be influenced by the housing market's potential improvements. The company is planning a media campaign in conjunction with Northwest ENERGY STAR in late spring/early summer 2011 throughout the Idaho Power service area. This campaign will promote the 2011 St. Jude Dream Home, ENERGY STAR Homes Northwest, and the program builders. This campaign will include sending a bill stuffer in June to all residential customers.

# Heating & Cooling Efficiency Program

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 217 | 349 |
| Energy Savings (kWh) | 1,104,497 | 1,274,829 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $314,963 | $458,216 |
| Oregon Energy Efficiency Rider | $12,706 | $20,032 |
| Idaho Power Funds | $0 | $125 |
| Total Program Costs—All Sources | $327,669 | $478,373 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.025 | $0.034 |
| Total Resource Benefit/Cost Ratio | $0.083 | $0.054 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.50 | |
| Total Resource Benefit/Cost Ratio | 1.22 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The H&CE Program provides incentives for the purchase and proper installation of qualified heating and cooling equipment and services to residential customers.

The objective of the H&CE Program is to acquire kWh savings and provide customers an energy efficient alternative to other forms of electric space heating. Incentives are provided to residential customers and HVAC contractors who install eligible equipment and services. The eligible measures in 2010 included air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Participating HVAC companies are required to perform all installations and services, with the exception of evaporative coolers, which can be self-installed. The program continued through 2010 with the same portfolio of incentives.

## *2010 Activities*

The H&CE Program's list of measures and incentives during 2010 included the following:

- Air-source heat pump customer incentives for replacing an existing air-source heat pump with a new air-source heat pump are $200 for minimum efficiency 8.2 heating seasonal performance factor (HSPF), and $250 for minimum efficiency 8.5 HSPF.

- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump are $300 for minimum efficiency 8.2 HSPF, and $400 for minimum

efficiency 8.5 HSPF. Homes with oil or propane heating systems must be located in areas where natural gas is not available.

- Incentives for customers or builders for new construction installing an air-source heat pump in a new home are $300 for minimum efficiency 8.2 HSPF, and $400 for minimum efficiency 8.5 HSPF.

- Open-loop water-source heat pump customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump is $500 for minimum efficiency 3.5 coefficient of performance (COP).

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump is $1,000 for minimum efficiency 3.5 COP. Homes with oil or propane heating systems must be located in areas where natural gas is not available.

- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home is $1,000 for minimum efficiency 3.5 COP.

- The evaporative cooler customer incentive is $150.

To build and maintain relationships with participating contractors, the program specialist visited several participating contractor shops throughout the year to promote the program, check for program understanding, and offer support. The program performed 19 random OSV, 8.6 percent of the total applicants, to verify the information submitted on the paperwork matched what was actually installed at customers' sites. Overall, OSV results were favorable with respect to the contractors; however, a few contractors had not installed the required sensor to lock-out strip heat above a certain outdoor temperature. The program continues to work with contractors to help them understand why this requirement is necessary.

The federal tax credits, available to qualifying homeowners who install energy-efficient products as outlined in Section 25C of the Internal Revenue Service (IRS), continued through 2010. It included a credit of up to $1,500 toward the installation of high-efficiency residential heating and cooling systems. Feedback from contractors to Idaho Power indicated that the tax credit influenced the ratio of applications received by Idaho Power relative to the HSPF rating of the equipment being installed. The federal tax credit program required a minimum HSPF of 8.5. Approximately 95 percent of the applications received by Idaho Power in 2010 for air source heat pumps were for the 8.5 HSPF rating. The balance of applications was for the 8.2 HSPF rating.

The program was promoted at various home and garden trade shows and at other community events, such as the Idaho Green Expo and St. Luke's Women's Show. These opportunities provided direct access to customers, creating the opportunity to raise awareness of Idaho Power's energy efficiency incentives.

A new, color brochure was developed, printed, and distributed. It is tailored to the residential homeowner. The brochures were given to contractors as selling tools when they meet with their residential clients. Idaho Power also provides the brochures to interested customers at trade shows and events. The flier addressed the need for a marketing resource describing the availability of the incentives, provided guidance on heat pumps, and described important purchase considerations.

Idaho Power held training sessions for contractors in February, March, June, and September that provided general instruction on heat pumps and program guidelines. Approximately 25 people attended the sessions. These training sessions remain an important part of the program for two reasons. First, trainings create opportunities to invite additional contractors into the program. Second, trainings support the existing participating contractors with an increased ability to leverage the incentive program to residential clients.

Idaho Power improved the method to process heat pump incentive applications. Using CLRIS, a database was developed that allowed for all of the application data to be entered and stored for analysis and for immediate initiation of the incentive payment process. The process improvement enabled the program specialist to eliminate multiple files previously used to store, manage, and evaluate data.

Idaho Power uses a third-party contractor to process the incentive applications and provide trade-ally support. In March 2010, Honeywell, Inc., was selected as the new contractor. This change was made to decrease costs, shorten turnaround time for processing incentive applications, and improve the contractor and customer satisfaction. The contractors received increased local support because the Honeywell, Inc., representative could visit contractors at their businesses as needed.

In addition, Honeywell, Inc., provides a variety of timely contractor services, such as picking up incentive applications, returning calls quickly, and responding to questions in a thorough and customer-oriented fashion. Honeywell, Inc., has a local presence, so Idaho Power uses them to help troubleshoot customer/contractor issues via the representative for Honeywell, Inc., resulting in quicker resolution and increased contractor and customer satisfaction. Idaho Power developed a portal that Honeywell, Inc., uses as a program database to process incentive applications. This allows Idaho Power to maintain the database within the company's system that is secure and yet accessible to the third-party contractor.

## Cost-Effectiveness

In August 2010, the RTF reviewed savings and costs for air-source heat pumps along with proper sizing and installation saving specific to the Northwest. Idaho Power adopted the updated savings and calculated savings for all air-source heat pump conversions with an HSPF rating of 8.5 using the 2010 deemed-savings. These savings are specific to climate zone and the presence or absence of central A/C prior to conversion. The updated RTF analysis replaced prior year's savings that were based on an independent third-party analysis conducted for Idaho Power by Ecotope, Inc., in 2009.

Savings estimates for the conversion from electric forced-air furnaces or upgrades from older air-source heat pumps to open-loop water-source heat pumps were not analyzed by the RTF. The savings for these measures are unchanged from the 2009 report. While savings for air-source heat pump upgrades were also analyzed and released by the RTF in 2010, the savings were not adopted because the analyzed baseline efficiency was an HSPF of 8.5, which is not aligned with the 2010 program design. In 2010, the H&CE Program gave incentives for heat pump upgrades at two tiers of efficiency: tier 1 for air-source heat pumps with an efficiency of at least 8.2 HSPF and tier 2 for heat pumps greater than or equal to an HSPF of 8.5. Savings for open-loop water-source heat pumps and air-source heat pump upgrades are documented in the 2009 Ecotope, Inc., *Heat Pump Sizing Specifications and Heat Pump Measures Savings Estimates* that was provided in the *Demand-Side Management 2009 Annual Report Supplement 2: Evaluation*. For more detailed information about the cost effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Customer satisfaction surveys were mailed to 127 participants in the H&CE Program in 2010. Surveys containing responses to 14 questions were returned from 66 participants who received incentives for new heat pumps, resulting in a 52 percent response rate. Respondents were asked to rate the amount of influence the Idaho Power incentive had in their purchasing decision. Sixty-eight percent said it had "some" influence, while 13 percent said it had "a lot" of influence. The remaining 19 percent said it had influenced their decision "not at all." The participants were asked if they were aware of the incentive program prior to the purchase of their heat pump. Seventy percent said they were aware of the incentive, while 30 percent said they were not aware of the incentive program. When the participants were asked to rate their contractor's knowledge of the incentive program, 73 percent said their contractor was "very knowledgeable." Another 15 percent said their contractor was "somewhat knowledgeable." The balance of respondents rated their response as "neutral," or "not very knowledgeable," or "not knowledgeable at all," with percentages of 5 percent, 5 percent, and 3 percent respectively. The majority of respondents, 77 percent, indicated that they heard about the H&CE Program from their heating and cooling contractor. Seventy-seven percent of the respondents indicated they are "very satisfied" with the H&CE Program, and 83 percent said they "definitely would" recommend the program to a friend or relative.

The survey results indicate the incentive program continues to have substantial influence in customers' decision process about purchasing a new heat pump. This is further supported in that the majority claimed being aware of the incentive program prior to the purchase. The current marketing efforts, therefore, will be continued, and new tactics will be added. In addition, the incentive process will be further streamlined to continue the favorable opinion the customers conveyed regarding installing contractors. The contractors' success with the program relies on their ability to understand it, thereby encouraging more of their customers to participate in it. The survey responses also indicate the majority of market awareness is being generated by the efforts of the contractors. This would indicate that other marketing efforts through Idaho Power will further the message while reducing the program dependency on the contractors' efforts.

Surveys containing eight questions were also sent to the nine incentive recipients for new evaporative coolers. Five surveys, a 55 percent response rate, were received from these recipients. When they were asked if they were aware of the incentive prior to their purchase, 60 percent said they were, and 40 percent said they were not. When asked to rate how much influence the incentive had in the purchasing decision, 60 percent said the incentive had "a lot" of influence, while 40 percent said it had influenced the decision "not at all." Sixty percent of the respondents indicated they heard about the H&CE Program from a retail store.

For ongoing QA, Honeywell, Inc., is the third-party contractor responsible for performing OSVs. Honeywell, Inc., inspected approximately 22 percent of the projects completed in 2010 for the H&CE Program. Honeywell, Inc., performed OSVs on 48 installations. Of these 48 installations, 77 percent, or 37 installations, were either compliant or were brought into compliance. Contractors for the remaining 11 projects that had difficulty passing the OSV did not receive an incentive payment.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the H&CE Program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and noted that this program is "successful" and "well designed." The program "is meeting its goals," "incorporates several best practices," and "has an actionable marketing plan and satisfied participants." Recommendations for program

improvement centered on enhancing relationships with HVAC contractors, especially those who have not yet participated in this program. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

## 2011 Strategies

New program marketing tactics will be used in 2011 to reach the target audience. Tactics include direct mail to target customers, participating with companies distributing coupon packets from local businesses to the Idaho Power service area, posting articles about the heat pump incentives on social media sites that Idaho Power participates in, and advertising in newspapers in specific areas not generally serviced with natural gas. The ongoing method of using bill inserts will continue in 2011.

Idaho Power and the program specialist will work closely with the participating contractors to help them maximize their ability to market the program incentives with their clients. The development of a premium group of participating contractors is a vital component to the success of the program. The program specialist and residential customer representatives will visit these contractors and prospective contractors throughout 2011.

Satisfaction surveys will be mailed to all 2011 incentive recipients. The response data will be compiled and analyzed to help improve all facets of the program.

Enhancements are being made to the incentives available for air-source heat pumps. The first change will help reduce complexity in the program. Currently there are incentives for two efficiency levels, heat pumps with minimum HSPF of 8.2 or 8.5. Only 4.8 percent of the incentives paid in 2010 were for heat pumps with the minimum 8.2 HSPF. The 95.2 percent balance of paid incentives were for heat pumps with a minimum 8.5 HSPF. In response to this trend and due to the measure's non-cost-effectiveness, the 8.2 HSPF option is being eliminated in first quarter 2011. This includes all the types of program equipment being replaced, such as old air-source heat pumps, electric furnaces, oil furnaces, and oil/propane furnaces. It also includes new heat pumps being installed in new home construction. The second modification will be to increase the incentive for changing electric furnaces to air-source heat pumps. This incentive will increase from $400 to $1000. In 2010, about 35 percent of the air-source heat pump incentives paid were for the replacement of electric furnaces. The goal is to increase participation by 30 percent in this particular category.

Idaho Power will hold several training sessions for contractors. General instruction on heat pumps as well as program guidelines will be provided. These training sessions remain an important component of the program. Sessions create opportunities to invite additional contractors into the program while fortifying the abilities of the existing participating contractors to promote the incentive program to residential clients.

Continuous process improvement during 2011 will focus on maximizing the productivity of Idaho Power staff and participating contractors involved with the program, and enable more time to be placed on tasks that add direct value to the program. The goal is to identify opportunities for complexity-reduction related to tasks performed by Idaho Power and participating contractors. Initial areas of focus will be on program information and distribution through the H&CE Program website pages. The navigation and display of content will be reviewed and improved to simplify access and

comprehension. This is necessary due to the amount of technical information and forms contained in this program.

# Home Improvement Program

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 3,537 | 1,188 |
| Energy Savings (kWh) | 3,986,199 | 1,338,876 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $944,716 | $321,140 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $944,716 | $321,140 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.019 |
| Total Resource Benefit/Cost Ratio | $0.035 | $0.032 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 8.66 | |
| Total Resource Benefit/Cost Ratio | 4.39 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Home Improvement Program offers incentives to homeowners for installing attic insulation that reduces energy-use throughout the year while impacting summer peak demand by reducing A/C use. The program pays an incentive of 15 cents per-square-foot to Idaho residential customers in the Idaho Power service area for additional attic insulation professionally installed after June 1, 2009. Any insulation contractor can provide this service and there is no preferred-contractor list associated with this program. New insulation must increase the R-value by R-10 or greater.

A large majority of Idaho Power's residential customers qualify for the program, though specific program qualifications are required to receive the incentive. Only existing, single-family homes qualify for an incentive. This includes duplexes and townhomes with the attic area over conditioned space. Homes must have central A/C or be electrically heated. Only attic insulation installed over conditioned space qualifies for an incentive. An insulation contractor must professionally install the insulation. Incentives are paid on added attic insulation up to an R-50.

## *2010 Activities*

In May 2010, a process improvement was implemented when Idaho Power outsourced the program incentive processing to Advertising Checking Bureau (ACB), Inc., a third-party incentive-processing company. ACB, Inc., receives, enters, and processes all incentive applications for the Home Improvement Program. The change resulted in improved incentive processing and payment time.

Various marketing techniques were employed in 2010. A targeted direct-mail campaign began in May 2010 and ran through July 2010. The direct-mail letter was sent to targeted customers using the

PRIZM marketing segmentation software. Response to this direct-mail piece was very positive with large numbers of incentive applications coming in during those months. Between May 2010 and July, 640 insulation incentive payments were received and paid.

A Val-Pak Advertisement, in conjunction with the See ya later, refrigerator® program, was sent out in August, September, and October to select zip codes in the Treasure Valley and Eastern Idaho. Phone-call volume increased substantially within days of each of the three mailings.

A bill insert went out in July, followed by a dual-program bill insert in conjunction with the See ya later, refrigerator program in November. Both bill inserts resulted in an increased volume of calls regarding program details and provided opportunities for customer education.

The Home Improvement Program paid 3,537 incentives during 2010, the first full year of the program's implementation.

## Cost-Effectiveness

Savings estimates for the Home Improvement Program attic-insulation measure were based on a simulation modeling and analysis performed by Ecotope Inc. Their modeling simulated homes with and without the duct work in the attic area of the home and focused on cooling energy savings benefits from increased attic insulation. A 2,200 square-foot house was used as the prototype similar to ENERGY STAR homes. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

During 2010, the RTF reviewed and deemed weatherization measures including attic insulation from a heating perspective by climate zone. Because this analysis did not include the impacts of central A/C, Idaho Power was unable to adopt these savings estimates for 2010 savings. As of February 2011, the RTF decided to review these measures again and make corrections in 2011. Idaho Power expects the savings from cooling will be included in the new deemed savings. The overall cost-effectiveness of the program measure can then be assessed by the presence of central A/C, electric heat, or both.

## Customer Satisfaction and Evaluations

Third-party contractors reviewed 7 percent of all insulation jobs completed in the Home Improvement Program for QA purposes. Of the QA completed in 2010, two installations were considered inadequate. These issues were addressed with the insulation installers and corrected.

In 2010, the Home Improvement Program was included in the residential process evaluation. Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Home Improvement Program. This evaluation included a program-data review, program-logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and showed that the program has "surpassed its participation goal," is "cost effective," has a "very low cost per kWh saved," and "is very affordable for customers." Recommendations for program improvement included the need to obtain more primary data from customers to determine customer/contractor satisfaction, barriers to participation, and customer receptiveness to offering additional measures. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. This program is scheduled to be included in an impact evaluation in 2011.

## 2011 Strategies

Plans for the upcoming year include a targeted direct-mailing campaign in May and June. An informational bill stuffer is being planned for June or July 2011. Due to the success of the Val-Pak mailing, similar mailings are being planned throughout the year with additional zip codes receiving the mailer. A marketing campaign consisting of newspaper advertisements and radio spots is planned for fall 2011.

In addition to the questions on the customer's program *Qualification Application*, a marketing question, "How did you hear about the program?" was added in 2011.

Analysis is currently underway to look at adding new measures to the Home Improvement Program in 2011. Measures being considered and analyzed are wall/floor insulation, windows, duct sealing, and air infiltration. These measures were discussed in the October 26, 2010, EEAG meeting.

# Home Products Program

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances/fixtures) | 16,322 | 9,499 |
| Energy Savings (kWh) | 1,443,580 | 1,638,038 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $813,171 | $498,980 |
| Oregon Energy Efficiency Rider | $18,990 | $12,283 |
| Idaho Power Funds | $0 | $50 |
| Total Program Costs—All Sources | $832,161 | $511,313 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.057 | $0.031 |
| Total Resource Benefit/Cost Ratio | $0.070 | $0.051 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.45 | |
| Total Resource Benefit/Cost Ratio | 1.67 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances, lighting, or other products. ENERGY STAR is a government-backed program that designates products as energy efficient. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards.

With the addition of ENERGY STAR qualified freezers in July 2010, current offerings and related incentives include clothes washers ($50), refrigerators ($30), freezers ($20), light fixtures (up to $15 per fixture), ceiling fans with light kits, or ceiling fan light-kit attachments (up to $20 per fixture). Program participation is a simple process for customers. The customer completes the brief incentive application, submits it with a copy of the sales receipt, and, if the purchase qualifies, receives an incentive check by mail.

The Home Products Program has two additional product offerings providing the retailer/manufacturer the incentive as opposed to the consumer. This can translate into lower retail prices on the most efficient units, such as those in the showerhead promotion. These products are select energy-efficient electronics and low-flow showerheads.

Incentive payments to retailers and manufacturers, rather than the end consumer, were intended to drive the manufacture, distribution, and promotion of more energy-efficient consumer electronics at the retail level. This mid/upstream incentive model is potentially powerful in changing those markets with a high volume of sales and small per-product incentive dollars.

## 2010 Activities

Marketing of the Home Products Program to customers occurs primarily through retail outlets. Idaho Power provided information to store managers and employees through training sessions at store staff meetings and through periodic visits by Idaho Power representatives. Collateral materials, such as program brochures with application forms, were distributed to nearly 100 retail stores as needed. In addition, program modifications were delivered via letters sent directly to store managers.

In May 2010, Idaho Power began outsourcing the processing of applications for the Home Products Program to a third-party vendor, ACB, Inc. Through an RFP process, a vendor was chosen and ACB, Inc., began receiving applications. The capability of this vendor allows customers to complete an online application, print the confirmation page, and mail it with a copy of the sales receipt.

Idaho Power promoted the program directly to residential customers via retail store salespeople, Idaho Power field staff, bill stuffers, community promotions, an updated Idaho Power program website, an hour-long interview on The HomeFix Show with Joe Prin on 670 KBOI, and other outreach activities. During 2010, bill stuffers detailing the program were mailed to all residential customers, one during the summer (July), and one during the holiday season (November).

With the addition of freezers and the new processing vendor, the program brochure was redesigned and distributed to retailers in July 2010. The brochure also serves as the application. The customer fills out the self-mailer application, includes the sales receipt in the built-in pouch, seals the application with the self-adhesive flap, and places a stamp on the application.

The brochure redesign allowed Idaho Power the opportunity to add an option for customers who wish to donate their entire incentive to Project Share, an energy assistance program in which Idaho Power partners with the Salvation Army to help those in need. From July through December, Home Products Program participants donated $170 to this cause. A Project Share donation thank you card was created for the Home Products Program and sent to customers who chose to donate.

In addition, hang-tags were produced and distributed to lighting showrooms and retailers who sell qualifying fixtures. Static clings—small, sticky decals—are also distributed to retailers for placement on qualifying clothes washers and refrigerators. The prominent focus for using hang tags and clings was to highlight the respective incentive amounts.

The Consumer Electronics Initiative, in partnership with NEEA, continued in 2010. The initiative provides an incentive to retailers who sell flat-screen televisions, monitors, and desktop computers that are 30 percent more energy efficient than the minimum ENERGY STAR standard (ENERGY STAR +30 percent). Computer monitors and desktop computers were added in 2010. NEEA managed all aspects of the program, while, in 2010 and beyond, the funding for the initiative is taken from NEEA partners' general funding. Only the retailers who signed contracts with NEEA are involved, though nearly all retail stores in Idaho Power's service area will have had the opportunity to participate. Idaho Power assisted in marketing the initiative through a bill insert during the holiday season (December) highlighting the new "Energy Forward" energy-efficient electronics marketing campaign.

The Home Products Program exceeded the targets for 2010. Idaho Power paid 16,322 incentives during 2010. Incentives were issued for approximately 8,885 clothes washers; 6,025 refrigerators; 223 freezers; 676 light fixtures; 36 ceiling fans; and three light kits.

In June 2010, Idaho Power began a retailer-based promotion for low-flow showerheads. Fluid Market Strategies (Fluid), as part of the BPA's regional Simple Steps, Smart Savings™ program, administers the program. The industry standard for showerheads is 2.5 gallons per minute (GPM). Showerheads in the Simple Steps, Smart Savings promotion use 2.0 GPM or less, resulting in less hot water per shower and less electricity used to make hot water. The promotion is similar to the lighting promotions with incentives paid to manufacturers, resulting in lower retail prices for the more efficient units.

The showerhead promotion began in June 2010. Marketing for this program includes point-of-purchase signs, Idaho Power Web content, and the BPA-sponsored website for the regional promotion. Fluid staff conducts retailer training, visits store site to check retail signs, and monitors sales. In 2010, there were 474 promotional showerheads sold in the Idaho portion of Idaho Power's service area, resulting in $3,318 in incentives and $199 in administrative costs. The break-out of showerheads sold included 198 of the 1.5 GPM showerheads and 276 of the 2.0 GPM showerheads. Savings realized included 20,935 kWh for the 1.5 GPM showerheads and 18,432 kWh for the 2.0 GPM showerheads.

## Cost-Effectiveness

Two new measures were added to the Home Products Program in 2010, ENERGY STAR freezers and low-flow showerheads. Savings and cost assumptions for freezers were based on deemed data from the RTF. The RTF savings methodology was also used for low-flow showerheads. After the original RTF savings were released in May 2010, Idaho Power adjusted the savings downward based on the electric hot water heater saturation in the Idaho Power service area. This adjustment was based on information from Idaho Power's *2004 Home Energy Survey*. The electric hot water heater saturation percentage has since been updated with the *2010 Home Energy Survey* results, and the low-flow showerheads still remain cost-effective.

Clothes washers and refrigerator savings and cost assumptions were also updated by the RTF in 2010. In summer 2010, the RTF approved changing the methodology and new baselines for calculating the saving for ENERGY STAR. In 2009, Idaho Power based annual savings of 215.19 kWh and 96.51 kWh for clothes washer and refrigerator respectively from the Nexant, *Demand Side Management Potential Study (2009)*. As a result of the RTF update, the annual energy savings for clothes washers was reduced to 121 kWh, while refrigerator savings was reduced to 44 kWh. These reductions in savings attributed to the program's overall reduction in annual savings between 2009 and 2010, despite the increase in participation.

While the measures reviewed by the RTF still remain cost-effective, it was discovered that the Idaho Power incentives for refrigerators and freezers are higher than the RTF's updated participant cost assumptions. Idaho Power plans to review these costs and incentive levels in 2011 and adjust the program accordingly.

The RTF also updated savings and cost assumptions of for ENERGY STAR lights and fixtures in 2010. These assumptions include LED down-light fixtures, which were unavailable prior to 2010. Of the 676 light fixtures processed in 2010, the 15 LED fixtures were shown to be not cost-effective. In addition to the LED light fixtures, the three ceiling fan light kits that received incentives in 2010 were also shown to be not cost-effective. There is little information on ceiling fan light kits, and the savings and cost assumptions are based on Idaho Power staff research and assumptions. Since the Home Products Program gives incentives to all ENERGY STAR products, the ceiling fan light kits and LED fixtures have remained in the program for consistency purposes and customer satisfaction; however, Idaho Power will determine if the measure will be removed or modified from the program's offerings when the other measures within Home Products Program are reviewed in 2011.

For more detailed information about the cost-effectiveness of these measures, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Retail salespeople assisted in promoting the program to Idaho Power's and the retailers' mutual customers. Information gathered from a question on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. In fact, 55 percent of the responses indicated salespeople were how they learned about the incentive program. This is followed by 20 percent learned from in-store materials (brochures), 11 percent from one of two bill inserts sent to all residential customers, 3 percent from the newspaper, 2 percent from the Idaho Power website, 8 percent from other means, and 1 percent from radio.

The *Demand-Side Management 2009 Annual Report* indicated that a process evaluation would be completed for the Home Products Program in 2010. Home Products Program was a relatively new program offering in 2010, and many process changes were implemented; therefore, it was decided to conduct a process evaluation on other residential programs in 2010. The descriptions and copies of the process evaluations conducted in 2010 are included in *Supplement 2: Evaluation*.

## 2011 Strategies

Based on 2010 successes, the marketing strategy for 2011 will remain similar with only minimal adjustments and updates as needed. The Home Products Program will cross-promote with other Idaho Power programs as opportunities arise and develop promotional materials. Idaho Power will continually review potential products for addition to the program during 2011 and beyond.

Participation for 2011 may not have the same spike as 2010; however, participation is expected to remain constant, or decrease slightly from 2010 numbers. The company speculates much of the increase in applications in 2010 was due not only to greater customer awareness of the program, but also due to the Idaho State Energy Efficient Appliance Rebate Program (SEEARP) available to Idaho residential customers beginning in March 2010. This state-run program offered incentives on many of the same products as Idaho Power, but at an even higher incentive. Therefore, Idaho Power customers could apply and receive both incentives, spurring purchases of these appliances during the time the SEEARP was in effect. Funds supporting the SEEARP program were exhausted in 2010 and are no longer available in 2011.

The Consumer Electronics Initiative partnership with NEEA will continue in 2011. Idaho Power will seek opportunities to promote this initiative, when applicable.

Idaho Power will continue to participate in the regional showerhead promotion, Simple Steps, Smart Savings. The BPA promotion will run through September 2011, with a likely extension through the remainder of 2011.

# Oregon Residential Weatherization

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 1 | 1 |
| Energy Savings (kWh) | 320 | 2,907 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $4,575 | $6,359 |
| Idaho Power Funds | $1,475 | $1,285 |
| Total Program Costs—All Sources | $6,050 | $7,644 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.011 | $0.203 |
| Total Resource Benefit/Cost Ratio | $0.062 | $0.223 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.28 | |
| Total Resource Benefit/Cost Ratio | 1.17 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1980 | |

## *Description*

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program offered under Oregon Rate Schedule No. 78. On a customer's request, an Idaho Power representative visits the home to analyze it for energy efficiency. An estimate of costs and savings for specific measures is given to the customer. Idaho Power offers financial assistance for a portion of the costs for weatherization measures, either as a cash incentive or with a 6.5 percent interest loan.

## *2010 Activities*

During the month of June, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. A total of 15 Oregon customers responded. Each of the 15 customers returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Twelve audits and responses to customer inquiries to the program were completed.

Idaho Power issued one rebate totaling $46.81 for 320 kWh savings. The rebate and related savings was for ceiling insulation. There were no loans made through this program during 2010. Two customer responses were directed to Cascade Natural Gas because their heating source was gas. No customers canceled their request.

## Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program as provided for in Oregon Rate Tariff No. 78. The cost-effectiveness of this program is defined within this tariff. Page 4 of Tariff No. 78 lists the measures that are determined to be cost effective and the required measure life cycles for specific measures. This tariff also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years. In 2010, the only project competed under the Oregon Residential Weatherization program was a ceiling insulation measure. The CEL for insulation is $1.34 per annual kWh saved, and the actual levelized cost of energy savings for the one 2010 project is just over 1 cent from the UC perspective and 6 cents from the TRC perspective, resulting in this program being considered cost effective.

## 2011 Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective rebate and loan applications.

# Rebate Advantage

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 35 | 57 |
| Energy Savings (kWh) | 164,894 | 247,348 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $34,283 | $43,954 |
| Oregon Energy Efficiency Rider | $5,119 | $5,571 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $39,402 | $49,525 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.018 | $0.015 |
| Total Resource Benefit/Cost Ratio | $0.031 | $0.029 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 8.61 | |
| Total Resource Benefit/Cost Ratio | 3.57 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

Idaho Power residential customers who purchase a new, all-electric ENERGY STAR® qualified manufactured home and site it in Idaho Power's service area are eligible for a $500 rebate through the Rebate Advantage program. Salespersons receive a $100 incentive for each qualified home they sell.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured Housing Program (NEEM) establishes quality-control and energy-efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

The Rebate Advantage program helps Idaho Power customers reduce the initial costs associated with purchasing a new, energy-efficient ENERGY STAR qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. In addition, Idaho Power encourages sales consultants to discuss energy efficiency with their customers during the sales process.

## *2010 Activities*

During 2010, Idaho Power paid 35 incentives on new manufactured homes, which accounted for approximately 165,000 kWh savings. The depressed housing economy in 2010 had a dramatic effect on all types of housing and contributed to a lower number of incentives than expected. At least nine of the previously participating dealerships closed between 2009 and 2010, which had a negative impact on the

program. Communications with other Northwest utilities conducting similar programs indicated they also saw a sharp decrease in participation.

The marketing strategy during 2010 was more customer-focused than in the past, as opposed to strictly using dealerships to promote the program. An Internet-based Google AdWords campaign was created mid-July, whereby specific keyword searches prompt potential program participants to click on an advertising link that guides them to the Idaho Power website where they learn more about energy efficiency programs. From July through December, the campaign received 302 clicks with 285,160 impressions.

Idaho Power continued to support dealerships in 2010 by providing them with Rebate Advantage brochures, applications, and call-out cards as needed. Customer representatives visited these dealerships to distribute material, promote the program, and answer salespersons' questions. In April, a letter was sent to all dealerships promoting the program, the benefits of ENERGY STAR qualified homes, and the qualifications to participate. This letter was intended as more of a reminder piece and to generate inquiries they may have since all of the dealerships are aware of the program and many of them participated in 2010.

## Cost-Effectiveness

ENERGY STAR manufactured home ratings are used to determine the energy savings of this program. These savings are specific to the heating and cooling zones in Idaho Power's service area where the home will be placed. In addition to varying by climate zone, savings vary depending on whether the customer purchases a home with or without central A/C or if a heat pump or forced-air furnace is chosen. For detailed lists of savings by climate zone and housing options, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power did not conduct any surveys or research on this program in 2010. A program impact evaluation of the Rebate Advantage program is planned in 2011. A process evaluation of the Rebate Advantage program was scheduled for 2010; however, due to the economic downturn and decreased participation in this program, evaluation funds were reallocated to Energy House Calls.

## 2011 Strategies

Idaho Power plans to continue the Rebate Advantage program in 2011, explore new marketing methods, and promote the program using internal resources and externally at the dealership level. Customer representatives will enhance relationships with dealerships by visiting each dealership quarterly, offering program support, answering questions, and distributing materials. The involvement of local Idaho Power personnel interacting with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

The company will continue to explore additional marketing strategies aimed directly at the end consumer. These will include continuing, and revising as needed, the Google AdWords campaign; sending a bill insert to all residential customers, which may be shared with the ENERGY STAR Homes Northwest program; and revisiting the direct-mail letter finalized in 2010. The letter will be sent to select Idaho Power customers using Claritas PRIZM segmentation methodology matched with company customer information.

# See ya later, refrigerator®

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (refrigerators/freezers) | 3,152 | 1,661 |
| Energy Savings (kWh) | 1,567,736 | 1,132,802 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $548,872 | $297,587 |
| Oregon Energy Efficiency Rider | $16,207 | $7,815 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $565,079 | $305,402 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.054 | $0.041 |
| Total Resource Benefit/Cost Ratio | $0.054 | $0.041 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.88 | |
| Total Resource Benefit/Cost Ratio | 1.88 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

The See ya later, refrigerator® program provides incentives to customers for recycling refrigerators and freezers. The program acquires energy savings through the removal of refrigerators and stand-alone freezers from residential homes throughout Idaho Power's service area, focusing on secondary and spare units commonly found in basements and garages. Customers receive a $30 incentive check mailed after removal of the unit. Although all qualified units are collected, the program is targeting older, extra units for maximum savings.

Idaho Power contracts with JACO to provide most services for this program. Idaho Power provides participant confirmation, supplemental marketing, and internal program administration. Marketing includes newspaper ads, bill inserts, *Customer Connection* articles, website content, and promotion at events.

JACO provides customer service, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Customers call the JACO customer service center regarding program questions and scheduling unit collections.

JACO crews pick up units at customers' homes. While still at the customers' homes, JACO cuts the cord, and the door seals so the refrigerator can no longer be used. JACO then transports and ships the units to the final recycler. JACO issues the incentive payments to customers and tracks the unit information at the account level. JACO contracts with Runyon, Saltzman & Einhorn (RS&E), a marketing firm, to provide marketing support. RS&E has experience marketing utility refrigerator recycling programs nationwide and brings expertise and proprietary market research to Idaho Power's program.

The See ya later, refrigerator name is trademarked by PacifiCorp. Through its JACO contract, Idaho Power has been granted the rights to use this trademark. In 2010, PacifiCorp issued brand guidelines specifying the capitalization, comma use, and trademark symbol for the name.

## 2010 Activities

During 2010, the program recycled 664 freezers and 2,488 refrigerators for an associated annual savings of 368,520 kWh and 1,199,216 kWh, respectively.

In 2010, Idaho Power made several program improvements and worked with JACO to refine program delivery. Early in 2010, Idaho Power and JACO refined the customer verification process to ensure timely evaluation of participant eligibility. This program requires some sharing of customer data with JACO. Customers enroll in the program directly with JACO. Idaho Power receives participant data daily, reviews the information, approves or denies the participant, and transfers completed files back to JACO. Several process improvements were made to this data transfer procedure. Idaho Power developed an archive system to store transferred files and refined a mechanism to search records. Programming adjustments were made by JACO to ensure data accuracy.

A second program improvement to increase customer satisfaction was the addition of an option for participants to donate their incentive to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army. Project Share helps customers in need pay for energy services including fuels, bills, and furnace repairs. Upon enrollment in See ya later, refrigerator, participants are given the option to receive their $30 incentive or to donate it to Project Share. Research on similar donation mechanisms show 2 percent of people choose this option[1]. The option was launched in April 2010. Since the option became available, 2.5 percent of participants have donated their incentive, raising $2,010 for Project Share.

The See ya later, refrigerator program also qualified Idaho Power for the US EPA Responsible Appliance Disposal (RAD) program. RAD is a voluntary partnership program that began in October 2006 to help protect the ozone layer and reduce emissions of greenhouse gases. Idaho Power joined as a RAD program partner in August 2010. The program is free of charge. Companies, such as utilities, involved in appliance recycling agree to report on units collected and materials recycled. JACO completes this report for Idaho Power at no charge. The benefits of the program include use of EPA RAD logo on marketing materials and opportunities for public recognition by EPA, which can serve as an additional free or low-cost marketing opportunity.

## Cost-Effectiveness

In early 2010, a regional review of refrigerator/freezer recycling programs was undertaken by the RTF. The results were approved in June. The previous savings assumption based on the average life was 682-kWh annual savings with a remaining measure life of eight years for either refrigerators or freezers. The updated savings split out the impacts between freezers and refrigerators and resulted in a differential remaining measure life. These changes were based on data collected from regional utility programs. Refrigerators were deemed to have an average remaining life of nine years with an annual average savings of 482 kWh, and freezers were assigned a shorter remaining life of six years with higher savings

[1] Source: http://www.taxadmin.org/fta/rate/checkoff.html

at 555 kWh of annual savings. Both program measures remained cost effective in 2010. For details, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

JACO tracks unit statistics for each unit collected, including information on how the customer heard about the program and when the customer enrolled. Unit statistics about the unit collected include the age of the unit, the location it is housed, and other data, which help to refine Idaho Power's assumptions regarding cost-effectiveness.

Results of the 2010 unit data showed that 21 percent of units the program picked up were stand-alone freezers, and 79 percent of the units were refrigerators. Forty-eight percent of the units were secondary, 33 percent primary, and 19 percent were unknown. The average vintage of units collected was 1983, with 63 percent of the units manufactured between 1965 and 1990, generally the least-efficient years of manufacture.

The program reclaims or recycles up to 95 percent of the components of each unit collected. In 2010, this translated into over 425,489 pounds of material. Reclaimed materials may include oils or refrigerants that can be distilled and then reused.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 45 percent of customers report learning of the program through bill inserts, which ran in March, July, and October. Twenty percent of customers report learning of the program through a friend or neighbor. Other word-of-mouth activities, such as events and utility personnel, account for an additional 2 percent of signups. Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because a retailer selling a new unit will usually pick up and recycle the old one. Newspaper advertisements comprise seven percent of enrollments. Eighty-one percent of customers enrolling in the program use the toll-free telephone number. Nineteen percent use the online enrollment form.

Idaho Power uses the customer information that JACO and the company collect to target future marketing efforts and increase effectiveness of marketing while reducing the cost. Figure 7 indicates information sources and percentage of responses regarding the 3,152 customers reporting hearing about the program through particular sources. The category "Other" includes sources, such as community events, electric utility offices, marketing services, repeat customers, truck ads, Web Internet searches, and unknown sources.

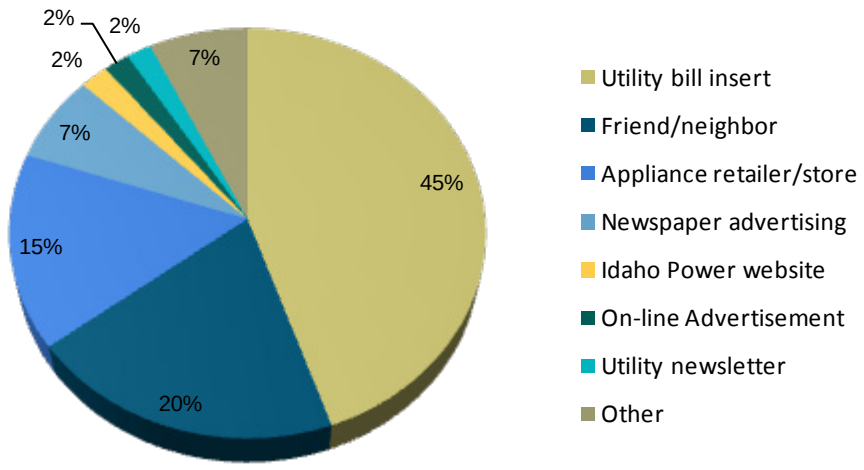


Figure 7. How customers heard about See ya later, refrigerator®

## 2011 Strategies

Idaho Power plans to continue implementing the program and managing the contract with JACO. The media plan for 2011 includes newspaper ads, bill inserts, Valpak ads, and customer newsletters, pending available space. Keyword pay-per-click ads will be on Google all year. Idaho Power through RS&E will also run Yahoo behavioral target online ads. The company will continue promotion at energy efficiency and community outreach events and on the Idaho Power website.

A process evaluation of the See ya later, refrigerator program is scheduled for 2011.

# Weatherization Assistance for Qualified Customers

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 400 | 437 |
| Energy Savings (kWh) | 3,741,652 | 4,678,815 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,321,132 | $1,294,862 |
| Total Program Costs—All Sources | $1,321,132 | $1,294,862 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.027 | $0.021 |
| Total Resource Benefit/Cost Ratio | $0.035 | $0.035 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.68 | |
| Total Resource Benefit/Cost Ratio | 3.22 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

## *Description*

The WAQC program provides funding to install cost-effective weatherization measures in qualified owner-occupied and rental homes that are electrically heated. In 2010, qualified households included those with incomes up to 200 percent of the federal poverty level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment, while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy-efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house nonprofit organizations who serve special needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the Community Action Partnership (CAP) agencies to administer the WAQC program in its service area.

WAQC is modeled after the US Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. While Idaho Power funds the program, CAP agencies in the Idaho Power service area serve as the administrators of WAQC. Federal funds are allocated to the Idaho Department of Health and Welfare and Oregon Housing and Community Services, then to CAP agencies based on US Census data of qualifying household income within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. WAQC allows these state agencies to leverage their federal weatherization dollars and serve more residents by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds. Homes participating in this program must be electrically heated.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Consistent with the State of Idaho Weatherization Assistance Program, WAQC offers several measures that have costs but do not save energy or savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer home or compromise a household's existing indoor air quality. Other non-energy savings measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Nonprofit building measures that have costs, but do not save energy or savings cannot be measured, are health and safety, vents, furnace repair, and home energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2009 Annual Report*, April 1, 2010, located in *Supplement 2: Evaluation.*

## 2010 Activities

During 2010, CAP agencies weatherized 373 electrically heated homes in Idaho and 27 in Oregon, totaling 400 weatherized homes. Annual energy savings were 3,452 MWh for Idaho and 289 MWh for Oregon. There were no buildings housing nonprofit organizations that serve special needs populations weatherized in 2010. The dollar allotment for this fund will carry over and be available for use in 2011.

## Cost-Effectiveness

The cost-effectiveness for the WAQC program is determined using an energy savings audit program known as Energy Audit 4 (EA4). The EA4 audit program is used by state weatherization programs and is approved for use by the DOE. During an initial audit of a potential home, the auditor begins the use of an EA4. The EA4 compares efficiency of measures prior to weatherization to the efficiency after the proposed improvement. The output of the EA4 savings-to-investment ratio (SIR) is analogous to a B/C ratio. If the EA4 computes a SIR of 1.0 or higher, where the energy-savings benefits of the measures outweigh the cost of the project, the CAP agency is authorized to complete that energy-saving measure(s). In addition to the individual measure SIR, the entire home weatherization job is required to show a SIR of 1.0 or higher. In some cases, the SIR accounts for measures that provide no actual savings, but are provided for either the health or safety of the customer or are required to make the other measures with savings more effective. Cost-effectiveness details are located in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

The Idaho Power program specialist participates in the Idaho state peer review process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and the Idaho State Department of Health and Welfare reviewing homes weatherized by each of the other CAP agencies. Results show that all CAP agency weatherization departments are weatherizing in accordance with federal guidelines.

Idaho Power personnel reviews weatherized homes with special needs customers as needed or requested by customers. Annually, Idaho Power participates in the audits of 5 percent of the homes weatherized under the WAQC program. Additionally, the DOE audits the state agencies each year. The DOE audits include field work as well as paperwork and billing audits.

## 2011 Strategies

Idaho Power will continue program funding and participate in the review of WAQC. The company is involved with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho.

# Weatherization Solutions for Eligible Customers

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 47 | 41 |
| Energy Savings (kWh) | 313,309 | 211,720 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $216,202 | $160,459 |
| Oregon Energy Efficiency Rider | $2,306 | $0 |
| Idaho Power Funds | $9,917 | $2,536 |
| Total Program Costs—All Sources | $228,425 | $162,995 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.056 | $0.059 |
| Total Resource Benefit/Cost Ratio | $0.056 | $0.059 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.98 | |
| Total Resource Benefit/Cost Ratio | 1.98 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho[a] | |
| Program Inception | 2008 | |

[a] Oregon Rider balance of $2,306 will be re-classed to the Idaho Rider in 2011.

## *Description*

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are slightly above poverty level and, therefore, do not financially qualify for the company's larger weatherization program, WAQC. The program measures and implementation process mirrors WAQC. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a SIR of 1.0 or higher or that ensure the savings due to interaction between measures. The amount spent on each home is limited to an annual average per home. Homes considered for this program will be electrically heated and either owned or rented. If rented, the landlord's permission is needed, backed with an agreement of not increasing the unit's rent for a minimum of two years.

Idaho customers eligible for this program earn income just above the federal poverty level, which is adjusted annually. They typically do not have expendable income to participate in other residential energy efficiency programs and live in similar housing as WAQC customers.

## *2010 Activities*

Home Energy Management, LLC, is the contractor who administers the program throughout Idaho Power's southern region. The total budget for this area was $200,000, which includes a 10 percent administrative fee for Home Energy Management, LLC. Qualifying guidelines for the year were between 175 percent and 250 percent of the federal poverty level.

By year end, Home Energy Management, LLC, weatherized 40 electrically heated homes of eligible Idaho Power customers, at no cost to the customer. Energy savings achieved was 259,100 kWh/year, with an average home savings of 6,477 kWh/year. Total costs were $182,478, with an average job production cost of $4,147. Twenty manufactured homes, 17 single-family homes, two duplexes, and one multi family unit were weatherized in 2010. Thirty-six of the 40 weatherized homes in the Southern region were owner occupied, and four were renter occupied.

In October 2010, Energy Zone, LLC, started weatherizing homes for this program in Idaho Power's Canyon region. By year-end, Energy Zone, LLC, weatherized seven homes saving 54,209 kWh per year, or 7,744 average kWh per home. Energy Zone, LLC, averaged $4,494 per home production costs. Total spending was $34,607, which included administrative fees for the contractor. Of the seven homes weatherized, three were single-family homes and four were manufactured homes. Six of the homes were owner occupied, and one was renter occupied.

Marketing of the program was done several ways without additional costs to the program. The contractors advertised the program in their regions by creating program fliers that were distributed by contractor employees throughout mobile home parks and at specific property management Realtor offices. Fliers were also left with previous customers who spread information about the program to families and friends who might qualify. Word-of-mouth continued to be an effective marketing tool for the program in 2010.

## Cost-Effectiveness

Like the WAQC program, Weatherization Solutions for Eligible Customers program uses the energy audit software program, EA4. During an initial audit of a potential home, the auditor completes an energy-savings audit using the EA4. The EA4 audit program is used by state weatherization programs and approved for use by the DOE. If the EA4 computes a SIR of 1.0 or higher, Home Energy Management, LLC, and Energy Zone, LLC, are authorized to complete that energy-saving measure. In addition to the individual measure SIR, the entire home weatherization job project is required to show a SIR of 1.0 or higher. Idaho Power customer representatives in the Southern and Canyon region verify installed measures in homes of participating customers using actual job sheets submitted by Home Energy Management, LLC, and Energy Zone, LCC. In addition to the job screening done by the agency, Idaho Power also assesses cost-effectiveness, looking at the UC test of each measure that is allowed as part of the contract with Home Energy Management, LLC, that currently includes windows, doors, insulation, venting, infiltration, ducts, health and safety measures, water heater, pipes, furnace repair, furnace replacement, and CFL installation. The cost-effectiveness testing by measure is consistent with standard methods used in other programs. Actual savings and cost measure submitted by CAP agencies is used in place of deemed measure values to asses cost-effectiveness. The actual average annual savings estimates are considered more accurate than a deemed number because of the number of inputs that are applied from the EA4 data analysis. The final savings numbers per measure and a complete list of cost-effectiveness assumptions can be reviewed in *Supplement 1: Cost-Effectiveness*.

Table 6. 2010 Weatherization Solutions for Eligible Customers: individual measure breakdown

| Measure | Instances installed | kWh Savings | Cost of measures |
|---|---|---|---|
| Windows | 19 | 49,343 | $ 27,399 |
| Doors | 19 | 27,514 | 14,936 |
| Wall Insulation | 4 | 13,317 | 4,774 |
| Ceiling Insulation | 27 | 48,565 | 23,863 |
| Floor Insulation | 33 | 62,075 | 45,887 |
| Venting | 23 | | 2,981 |
| Infiltration | 27 | 39,965 | 14,455 |
| Ducts | 26 | 28,152 | 7,774 |
| Health and Safety | 29 | | 10,326 |
| Water heater | 14 | 2,825 | 1,345 |
| Pipes | 36 | 1,822 | 3,605 |
| Furnace repair | 8 | | 1,829 |
| Furnace replacement | 6 | 32,808 | 24,984 |
| CFL install | 44 | 6,923 | 972 |
| Audit invest | 46 | | 12,221 |
| **Total** | | **313,309** | **$ 197,351** |

## Customer Satisfaction and Evaluations

Of the 47 participants, all customers provided written positive feedback about the work done in their home. Each customer filled out a Customer Response/Job Completion Form provided to them at the final visit and completion of weatherization services at their home. Most customers made positive comments about how professional the weatherization crew was during the weatherization of their home. Many customers thanked Idaho Power for the program and reported learning more about using energy wisely.

## 2011 Strategies

The program will continue to be offered to Idaho Power customers in the Southern and Canyon regions in 2011. Home Energy Management, LLC, is under contract to weatherize 28 homes in Idaho Power's Southern region, and Energy Zone, LLC, is under contract to weatherize 56 homes in Idaho Power's Canyon region. Idaho Power will begin efforts to expand the program into the Eastern region.

The annual average cost of $6,500 per home will be used in 2011 in order to ensure a whole-house approach. All measures will meet the minimum savings-to-investment threshold when applied through the state-approved energy audit.

Eligible customers will include Idaho Power customers who heat their homes electrically and earn an income between 175 percent and 250 percent of the federal poverty level. Customers either purchasing or renting their homes may be eligible. Idaho Power plans to save an average of 9,000 kWh per weatherized home per year for a total energy savings of 756,000 kWh annually.

As in 2010, identification of potential participants will be made through several means. Energy Assistance/LIHEAP applicants at CAP agencies who do not meet income qualifications are sent denial letters. Program contractors will use this list of denied customers at CAP agencies to market the Weatherization Solutions for Eligible Customers program. Contractors will distribute fliers explaining

the program and qualifying guidelines to customers heating their homes with electricity provided by Idaho Power in both regions.

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# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

Idaho Power's commercial and industrial sector consists of over 64,000 customers. In 2010, the commercial sector's number of new customers increased by 298, an increase of 0.5 percent. The energy usage of the commercial customers varies from a few kWh each month to several hundred thousand kWh per month. Commercial customers represent approximately 28 percent of billed sales.

Industrial customers and the special contract sector are Idaho Power's largest individual energy consumers. There are approximately 121 industrial customers. These customers can use millions of kWh per month and account for about 23 percent of Idaho Power's system sales.

Energy efficiency annual energy savings increased by 27 percent to 118,473,001 kWh in 2010 when compared to 2009 program results. Custom Efficiency represented the highest change in magnitude of savings by increasing program 2010 annual savings by 19,744,463 kWh over 2009 annual savings, with 91 additional projects over 2009. Building Efficiency saw the highest percentage increase amongst commercial and industrial programs, with annual savings increasing by 43 percent over 2009 annual savings. Table 7 is a summary of savings and expenses from the four commercial and industrial energy efficiency programs and one demand response program.

## Programs

Table 7. 2010 Commercial/Industrial program summary

| Program | Participants | | Total Costs | | Savings | |
|---|---|---|---|---|---|---|
| | | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | | |
| FlexPeak Management | 60 | sites | $ 1,902,680 | $1,902,680 | n/a | 47.5 |
| **Total** | | | **$ 1,902,680** | **$1,902,680** | | **47.5** |
| **Energy Efficiency** | | | | | | |
| Building Efficiency | 70 | projects | $ 1,509,682 | $ 3,312,963 | 10,819,598 | 0.9 |
| Easy Upgrades | 1,535 | projects | 3,974,410 | 7,655,397 | 35,824,463 | 7.8 |
| Holiday Lighting | 25 | projects | 46,132 | 65,308 | 248,865 | 0.0 |
| Custom Efficiency | 233 | projects | 8,778,125 | 17,172,176 | 71,580,075 | 9.5 |
| **Total** | | | **$14,308,349** | **$28,205,844** | **118,473,001** | **18.2** |

Note: See Appendix 3 for notes on methods and column definitions.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. These energy-saving measures give customers the option of personally choosing the best selections for incorporating energy efficiency into their business. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost opportunity savings. This program continues to be successful, incorporating qualified energy savings improvements for lighting, cooling, building shell, and energy-control options. Participants in the Building Efficiency and Easy Upgrades programs can receive incentives of up to $100,000 per site per year for any approved, completed projects. The Custom

Efficiency program offers financial incentives for large commercial and industrial energy users undertaking projects that are more complex to improve the efficiency of their electrical systems or processes. Incentive levels are 70 percent of the project cost or 12 cents per kWh for first-year savings, whichever is less.

The Holiday Lighting program encourages commercial customers to purchase more-efficient LED holiday lights. This program is offered to both Idaho and Oregon Customers. In 2010, the Holiday Lighting program was evaluated from several perspectives, including customer participation, access to LEDs in the market place, and cost-effectiveness. Based on the outcome of the research, the Holiday Lighting program will not be offered in 2011.

Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

FlexPeak Management is a demand response program offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracts directly with Idaho Power's commercial and industrial customers to achieve demand reduction. In May 2010, Idaho Power received the Demand Response Program Achievement Award from the Peak Load Management Alliance (PLMA) for its FlexPeak Management demand response program. PLMA is a non-profit group of organizations with a business interest in electrical load that is dedicated to creating a community of expertise on demand response and its role in creating efficient electricity markets.

The Green Rewind measure is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 56 Green Rewind motors achieved a total savings of 243,091 kWh in 2010, with 20 commercial/industrial sector motors contributing 55,126 kWh and 36 irrigation sector motors contributing 187,965 kWh.

Ten service centers in Idaho Power's service area have the necessary equipment and training to perform Green Rewinds. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, five service centers have signed on as Green Motors Practice Group (GMPG) members. GMPG also will expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2.00 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA) Standard hp rated motor between 15 and 5,000 hp that receives a verified Green Rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with quality check and QA.

Idaho Power continues to use the IDL in Boise to advance energy efficiency practices relating to building retrofits, remodels, and new construction. Additionally, the IDL in Boise continues to provide clients with current and accurate information regarding energy efficiency technologies and best practices through monthly newsletters, blog updates, and by hosting and facilitating constituent meetings.

In 2010, Idaho Power contracted with the IDL in Boise to perform the following tasks:

- Develop climate design resources specific to Idaho that can be used to facilitate passive strategies in new commercial and industrial construction projects.

- Conduct research and write a white paper describing a strategy for developing an energy efficiency labeling program for all commercial, industrial, and retail buildings in Idaho.
- Conduct 17 education sessions for architects, engineers, and other design and construction professions on energy efficiency topics.
- Facilitate the Idaho Building Simulation Users' Group to improve the energy efficiency-related skills of design and engineering professionals.
- Conduct research for developing a high-performance speaker's bureau.
- Complete post-occupancy evaluations on three facilities that have incorporated energy efficiency measures.
- Create a demonstration and training area for electrical contractors to learn the necessary skills to successfully install and commission daylight harvesting lighting control systems.
- Research common plug load use profiles in office buildings to identify strategies to reduce plug loads.
- Provide building efficiency consultations, design analyses, and plan reviews to Idaho Power customers.

A considerable amount of time was spent in 2010 reviewing the measure offerings and incentive levels in Easy Upgrades, Building Efficiency, and Custom Efficiency. Several measure changes were made to Building Efficiency due to the state adoption of the 2009 IECC. Both measure offerings and incentive levels within Building Efficiency were changed to address the new code. With a large percentage of lighting projects completed in both Easy Upgrades and Custom Efficiency, lighting was a focus in 2010. Based on that review, several changes will be implemented in 2011 to both programs' lighting offerings. The changes are designed to make the programs more consistent in their application and review process and with the program terms and conditions. Additionally, an increased focus was placed on pre- and post-project inspections on lighting projects.

Other customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. In the 2010 surveys, 55 percent of Idaho Power's large commercial and industrial customers surveyed in 2010 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Forty-five percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-eight percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 74 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated that 35 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Forty-nine percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-five percent of respondents

indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 16 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 87 percent are "very" or "somewhat" satisfied with the program.

In 2011, Idaho Power will focus on successfully integrating all of the new program changes across the sector programs. That focus will include identifying process improvements, supplying energy efficiency specific education to Idaho Power trade allies, contractors, and customers, and completing more pre- and post-project inspections. Additionally, the programs will analyze recommendations from the process evaluations conducted on the commercial and industrial programs in 2010.

Effective July 14, 2012, there will be new Standards for General Service Fluorescent Lamps. Idaho Power is reviewing the new requirements and will consider them when deciding what changes to make for the lighting measures and respective incentives for the 2012 commercial/industrial lighting measures.

# Building Efficiency

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 70 | 72 |
| Energy Savings (kWh) | 10,819,598 | 6,146,139 |
| Demand Reduction (MW) | 0.9 | 1.3 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,466,179 | $$1,300,466 |
| Oregon Energy Efficiency Rider | $43,422 | $26,323 |
| Idaho Power Funds | $81 | $339 |
| Total Program Costs—All Sources | $1,509,682 | $1,327,128 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.024 |
| Total Resource Benefit/Cost Ratio | $0.035 | $0.043 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.62 | |
| Total Resource Benefit/Cost Ratio | 2.69 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions can receive incentives up to $100,000. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special-contract customers are eligible to participate. Program marketing is targeted at architects, engineers, and other local design professionals.

Idaho Power is a primary sponsor of the IDL in Boise, which provides technical assistance and training seminars to local architects, engineers, and designers. Much of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the biannual BetterBricks awards held in October in Boise. The BetterBricks awards recognize leaders whose work supports the design and operations of high-performance buildings and their commitment to energy efficiency. The Building Efficiency program also sponsors technical lunch-and-learn sessions geared to educate design professionals and the Idaho Building Simulation Users' Group. The Building Simulation Users' Group is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

## 2010 Activities

The Building Efficiency program completed 68 Idaho and two Oregon projects in 2010, resulting in 10,552,135 kWh in energy savings in Idaho and 267,493 kWh in energy savings in Oregon. The increase in energy savings is attributed to an increase in the number of projects incorporating energy management control systems for lighting and HVAC.

New construction and major renovation project design and construction life is much longer than small retrofits and requires consistency in program measures and operation. To reduce confusion for customers with long construction projects, the Building Efficiency program did not change in 2010, maintaining a consistent and clear program for customers.

Fourteen measures are offered through this program and include reduced-power-density lighting, daylight photo controls, occupancy sensors, high-efficiency exit signs, premium efficiency HVAC units, additional unit efficiency bonus, efficient complex cooling systems, air-side economizers, reflective roof treatment, high-performance windows, window shading, energy management control system, demand-control ventilation, and variable-speed drives.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Seventeen technical training lunches were completed in 2010, with 338 attendees, including architects, engineers, interior designers, and project managers. Topics included Integrated Design Principals, Commissioning, Benchmarking + Measurement and Verification, Daylight in Buildings: Getting the Details Right, Demand Control Ventilation, Daylight Sensing Electric Lighting Controls, High Performance Classrooms, The Role of Life Cycle Cost Assessment in Idaho, and Hybrid Cooling and Performance Modeling.

In 2010, Idaho Power evaluated program changes and modifications to be implemented beginning 2011. The 2009 IECC was implemented in the State of Idaho effective January 1, 2011. The impact of IECC 2009 on program measure savings and incentives were researched and reviewed. The existing measures were evaluated along with the current participation levels for each measure. Customer and customer representative feedback indicated the need to simplify incentive payment calculations. The 2011 Building Efficiency program has been modified to reflect the impact of these recommendations and implementation of IECC 2009.

## Cost-Effectiveness

To calculate energy savings, the Building Efficiency program measures the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters for both the measure at code and at efficiency.

The other method for calculating savings in the program is based on industry-standard assumptions when precise measurements are not available. Since Building Efficiency is a prescriptive program, and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry standard assumptions from regional and national sources including the RTF, the Database for Energy Efficiency Resources (DEER), and the Consortium for Energy Efficiency, Inc. (CEE) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kilowatt (kW) reduction as the unit being used. Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Building Efficiency program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, and conclusions and recommendations. The final report was received in February 2011 and noted that Idaho Power, as a primary sponsor of the IDL in Boise, provided free technical assistance and training to local architects and designers through the Building Efficiency program. The report also noted that this program increased in participation by 20 percent in the last year. Recommendations for program improvement included the need to update program collateral materials and conduct additional market research with program participants and non-participants. Idaho Power is currently analyzing all recommendations. The complete report is provided in *Supplement 2: Evaluation.*

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis indicates the Building Efficiency program is currently exceeding the savings potential estimates, especially in the HVAC sector. The analysis also shows current program costs per MWh are approximately one-half of the costs estimated in the potential study. The complete report is provided in *Supplement 2: Evaluation*.

The IDL in Boise also performed additional post occupancy evaluations of the program in 2010. The post-occupancy evaluation specifically focused on opportunities for pre- and post-intervention studies and on identifying opportunities for education and further research. The final report is scheduled for delivery in March 2011, and Idaho Power will consider all viable recommendations identified in the report.

## 2011 Strategies

In 2011, Idaho Power will implement program changes and modifications to align with IECC 2009 as the base line for energy-savings calculations. The 2011 program will have simplified incentive calculations and increased energy efficiencies for qualification. A briefing on the modifications was presented at the October 26, 2010, EEAG meeting, and questions were addressed.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

The Building Efficiency program will continue to sponsor technical training through the IDL in Boise. Technical trainings will expand to include two to four education sessions based on energy efficiency education needs of design professionals in the Pocatello, Twin Falls, and Sun Valley markets.

# Custom Efficiency

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 223[a] | 132 |
| Energy Savings (kWh) | 71,580,075 | 51,835,612 |
| Demand Reduction (MW) | 9.5 | 6.7 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $8,046,168 | $5,816,305 |
| Oregon Energy Efficiency Rider | $717,132 | $236,910 |
| Idaho Power Funds | $14,825 | $8,252 |
| Total Program Costs—All Sources | $8,778,125 | $6,061,467 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.014 | $0.013 |
| Total Resource Benefit/Cost Ratio | $0.027 | $0.024 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.85 | |
| Total Resource Benefit/Cost Ratio | 3.29 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Does not include Green Motor Rewinds

## *Description*

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy-efficient projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education on energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power, or by the customer as applicable to the facility. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application, followed by the finalization of the terms and conditions of the applicant's and Idaho Power's obligations. In some cases, large, complex projects may take as long as two years to complete. Oftentimes, Idaho Power conducts follow-up or post-inspection validation via third-party engineering firms. Incentive levels for the Custom Efficiency program stayed at 70 percent of the project cost, or 12 cents per kWh first-year savings, whichever is less.

## 2010 Activities

A total of 223 projects were completed in 2010 by 152 companies, including 19 Oregon projects from 12 different companies. Program energy savings increased in 2010 by 38 percent over the prior year, from 51,836 MWh to 71,525 MWh. Completed projects increased by 74 percent in 2010. The increase in program participation and energy savings was a direct result of increased participation of lighting and fan projects. As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency and ensures an efficient use of electricity to run the motor. There were 20 Green Rewind motors in the commercial/industrial sector in 2010, contributing 55,126 kWh in savings.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. Because the link between energy audits and completion of projects is historically significant, Idaho Power continued expanding the number of contractors available for customer scoping audits from six companies in 2009 to eight companies in 2010. Selection of engineering firms is based on the firm's expertise in all major equipment areas and their ability to provide resources for customers throughout Idaho Power's service area.

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. A total of 10 technical training classes were completed in 2010. Topics included compressed air, chilled water systems, pumping systems, variable frequency drives, and refrigeration. The level of attendance at these classes remains high with a total of 234 customers attending the workshops.

The Custom Efficiency program has achieved a high service area penetration rate. Through 2010, approximately 73 percent of the large power service customers submitted an application for a project. Idaho Power engineers met with another 18 percent of the customers to discuss energy efficiency programs and opportunities within customer facilities. In summary, 91 percent of large power service customers submitted projects to, or met, with Idaho Power.

Table 8 shows the Custom Efficiency program's annual energy savings by end use, number of projects, and kWh saved.

Table 8. Custom Efficiency annual energy savings by measure

| Program Summary By Measure | Number of projects | kWh saved |
|---|---|---|
| Lighting | 159 | 33,234,770 |
| Fan | 28 | 13,614,289 |
| Compressed Air | 5 | 6,738,503 |
| Pump | 3 | 2,567,460 |
| Refrigeration | 14 | 10,387,189 |
| Other | 21 | 4,982,738 |
| **Total** | **223** | **71,524,949**[a] |

[a] Does not include Green Motor Rewinds

## Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires

all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the projects progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes utilized via a Scoping Audit, Detailed Audit, or engineering measurement and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is thoroughly reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculates the energy savings. The verification process requires end-use measure information, project photographs, and project costs are collected.

On many projects, and especially larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process ensures achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs, based on the actual installed equipment and performance.

The measurement and verification reports provided to Idaho Power include verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Custom Efficiency program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and stated that "overall, the program is operating smoothly from design to implementation," and "in many ways, the Custom Efficiency program exemplifies a quality efficiency program compared to similar efforts across the country." Recommendations for program improvement included the completion of the program manual including pre- and post-inspection protocols and standards and the need to conduct additional market research with program and trade ally participants. Idaho Power is currently analyzing all recommendations. Any program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis shows that the Custom Efficiency program is currently meeting the forecasted achievable potential savings and the costs per MWh are similar to the forecast in the potential study. The complete report is provided in *Supplement 2: Evaluation*.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or major customer representatives solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to

participate in the Custom Efficiency program posting the customer's *Success Stories* on the Idaho Power website. At the end of 2010, 14 additional *Success Stories* describing 2010 projects were posted on the company's website. An example of a success story posted in 2010 refers to a project Roaring Springs completed early in the year. Idaho Power provided Roaring Springs a $75,665 incentive for energy efficiency upgrades that reduce Roaring Springs costs and is expected to save about $65,000 in electric bills per year, according to the owner. The estimated total savings of the project was 822,825 kWh per year. The owner said, "I can't thank these guys at Idaho Power enough. They really went above and beyond." Copies of the 2010 *Success Stories* are provided in *Summary 2: Evaluation.*

## 2011 Strategies

In 2011, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities. These activities will include direct marketing of the Custom Efficiency program by Idaho Power major customer representatives to inform the customers of the Idaho Power energy efficiency programs available and ways the customer can reduce energy costs. In addition, Idaho Power will continue to provide site visits and energy audits for project identification; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored energy improvement practices to customers.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The company plans on conducting an impact evaluation in 2011.

Both the Custom Efficiency and Easy Upgrades programs offer lighting incentives to commercial and industrial customers. Having lighting programs with different characteristics can cause confusion among field staff, contractors, and customers. In 2011, Idaho Power will continue to make program changes to lighting projects within both Custom Efficiency and Easy Upgrades. The objectives will be to develop a single lighting calculator, standardize terms and conditions, and follow a similar project verification protocol between programs. Better alignment of the incentives between the two programs will lessen program confusion and potentially increase participant satisfaction.

# Easy Upgrades

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,535 | 1,224 |
| Energy Savings (kWh) | 35,824,463 | 35,171,627 |
| Demand Reduction (MW) | 7.8 | 6.1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $3,862,653 | $3,213,388 |
| Oregon Energy Efficiency Rider | $111,757 | $108,533 |
| Idaho Power Funds | $0 | $3,584 |
| Total Program Costs—All Sources | $3,974,410 | $3,325,505 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.013 | $0.011 |
| Total Resource Benefit/Cost Ratio | $0.024 | $0.032 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.93 | |
| Total Resource Benefit/Cost Ratio | 2.94 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2006 | |

## *Description*

The Easy Upgrades program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering incentives up to $100,000 per-site, per-year. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. Although Easy Upgrades is designed to be "easy" for Idaho Power customers, it is one of the company's largest and most complex programs, containing 143 separate measures. A complete listing of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial or industrial customers taking service under Rate Schedule 7 (Small General Service), Rate Schedule 9 (Large General Service), Rate Schedule 19 (Large Power Service), and special-contract customers are eligible. Potential participants first assess their energy-saving opportunities by talking with their equipment supplier, contractor, or Idaho Power customer representatives. For projects with expected incentive payments of more than $1,000, applicants must submit a preliminary application prior to initiating the project. In that case, the customer or contractor completes the preliminary application form and submits it with relevant worksheet(s) describing the location and planned scope of their project. On Idaho Power's review and acceptance, the preliminary application allows a customer to collect an incentive if the project is completed within 90 days. For smaller projects with expected incentive payments of less than $1,000, customers may elect to skip the preliminary application and just submit their final application for payment. These projects must have been completed no more than six months prior to submitting their application for payment. Under the Easy Upgrades program, incentive payments may be made to the customer's contractor; however, the customer must specifically assign the payment to the contractor in the application process.

## 2010 Activities

To Idaho Power's trade allies, contractors, and customers who participated in Easy Upgrades, 2010 appeared to be a relatively normal year. From Idaho Power's perspective, 2010 was a year that presented many challenges and opportunities. Challenges were created as the program continued to experience strong growth in the number of projects being submitted. Opportunities were created when Idaho Power expanded the responsibility of day-to-day program operations to multiple internal program specialists. Having multiple program specialists involved benefited the program by streamlining processes, enhancing employee development, leveraging staff experience, and creating more consistent program management across Idaho Power's commercial and industrial energy efficiency programs. To ensure projects met the terms and conditions of the program, more pre-project and post-project inspections were conducted by Idaho Power. In July, a new program specialist was selected to lead Easy Upgrades. Idaho Power hired a contract employee to conduct pre- and post-project inspections. Due to the increase in program participation, employee resources almost doubled from 2009.

As existing program specialists and energy efficiency engineers became involved in day-to-day operations, process improvements such as streamlining application processing became an initial focus. The incentive check letter mailed to customers on completed projects was automated, saving valuable staff time. Additionally, data-entry processes were automated, making them more efficient and improving accuracy.

In 2010, Idaho Power focused on data-gathering and analysis. In preparation for the 2011 program-change rollout, Idaho Power contracted with Evergreen Consulting to advise Idaho Power on lighting options within Easy Upgrades. Evergreen Consulting is a regionally and nationally recognized energy efficiency consulting group that specializes in energy-efficient lighting program implementation. This work included redesigning the lighting tool customers and trade allies use in calculating and submitting incentives for lighting projects.

Idaho Power worked with the company's customer representatives and external trade allies to obtain feedback on the 2010 program changes being considered for implementation in 2011.

In addition to developing a new lighting tool, other changes to the program for 2011 included updating the program terms and conditions, revising incentive levels on some measures, and adding new lighting measure to encourage customers to install technologies that are more efficient.

Easy Upgrades conducted four workshops in December targeting to trade allies and large commercial customers to review the 2011 proposed program changes. These workshops were held across Idaho Power's service area. Workshop topics included new program terms and conditions, application processing, and a demonstration of the new lighting tool. In addition to program-specific material, a 90-minute lighting technology training session was given. Trade allies appreciated receiving the information in advance of the 2011 program rollout. The lighting tool demonstration and the lighting training were two highlights of the workshop. Trade allies provided feedback that they would like to see more lighting training in classes.

Four *Business-Specific Energy Savings Tips* brochures were developed for grocery stores, health care facilities, restaurants, and hotels. These tip sheets provide information and ideas on how to save energy, serving as a resource for specific businesses. Additionally, Idaho Power customer representatives use the brochures when meeting with these businesses.

Presentations were made to various business and professional groups. Idaho Power participates in the local Building Owners and Managers Association International (BOMA) chapter. The Easy Upgrades program was promoted at other events, including sponsoring the 2010 Idaho Better Bricks awards and the Idaho Smart Growth awards.

## Cost-Effectiveness

In 2010, Idaho Power did not make changes to the measures offered under the Easy Upgrades program. For most of the measures, deemed savings and cost from the Nexant *Demand Side Management Potential Study (2009)* were used for the cost-effectiveness analysis. For the balance of the measures, engineering estimates were used to calculate expected savings results. In preparation for the program modifications for 2011, a cost-effectiveness review or analysis was conducted on all current measures.

For 2011, several measures that were determined to be not cost-effective were either removed from the program or modified. The Nexant *Demand Side Management Potential Study (2009)* identified six measures that may not be cost effective. These measures were the window shading, flat-panel liquid crystal display (LCD), occupancy sensor controls for office equipment, high-efficiency coin-operated washers without electric water, air-cooled multiplex systems, and evaporative-cooled multiplex systems. After further internal review in consultation with the EEAG, these measures were removed from the program's offerings for 2011. As for 2010, only three out of the six measures were used by the customers and comprise 0.2 percent of the measures receiving incentives. The four lighting measures determined not cost effective in 2009 as well as the other lighting measures were updated for 2011 with the new lighting tool. Additionally, a new custom line item is now included within the lighting tool to accept combinations not captured by the prescriptive approach. This new custom option allows the customer to enter specific information, such as wattages of existing and proposed fixtures, hours of operations, and costs for a proposed a lighting project. The determination of cost-effectiveness of these measures is based on these entries.

For current detailed cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the ongoing evaluation process, surveys were sent to 382 program participants in mid-October, and 113 responded to the survey, resulting in a 30 percent response rate. The purpose of the survey was to collect customer feedback on the program and on the products they installed as well as the contractor used for their project. Over 61 percent of the 113 survey respondents said they learned about the program "from a contractor, supplier, or vendor." Another 17 percent of these customers indicated they learned about the program "from an Idaho Power employee."

When asked a series of questions about their experience with Idaho Power and the Easy Upgrades program, 60 percent "strongly agreed" that Idaho Power staff provided accurate and helpful information. Sixty-six percent "strongly agreed" that Idaho Power staff was helpful; 53 percent "strongly agreed" that the Easy Upgrades incentive application forms were easy to follow; and 63 percent "strongly agreed" that their application was processed in a timely manner.

Ninety-one percent of the respondents indicated they are "very satisfied" with the energy efficiency equipment they installed under the Easy Upgrades program.

Only 17 percent of the respondents indicated their project would not have changed at all if they had not participated in the Easy Upgrades program. Of those who said their project would have changed if they

had not participated in the Easy Upgrades program, 40 percent said they would have "kept using existing equipment," 27 percent would have "canceled the project altogether;" 21 percent said they would have had to "postpone the project for more than 1 year;" and 16 percent said they would have "repaired existing equipment." Sixty-six percent of the respondents said they could not have paid the full cost of the project without the Easy Upgrades incentive. When asked a series of questions about what influenced their decision about whether or not to do the project, 76 percent said the Easy Upgrades incentive was "very influential;" and 54 percent said the amount of energy-savings potential was "very influential."

Respondents were asked a series of questions about the contractor they used for the Easy Upgrades project. The majority of respondents ranked their contractor "excellent" on quality of work, courteousness and professionalism, knowledge of equipment and knowledge of the Easy Upgrades program, completing work in a timely manner, and explaining efficiency aspects of new equipment. Fifty-five percent said they used the contractor because they had "used them for other projects;" and 86 percent said they "definitely would" recommend the contractor to a business associate.

Ninety percent of respondents said they were "very likely" to participate in the Easy Upgrades program again and were "very likely" to recommend the Easy Upgrades program to a business associate.

Copies of these surveys and survey results can be found in *Supplement 2: Evaluation*.

Results of the customer satisfaction survey were reviewed by the program specialist as part of the process of identifying changes to the program for 2011. The specialist wanted to know if there were any issues with the program to address in the 2011 program changes; there were none. The specialist presented a few key survey results at Trade Ally Workshops held throughout the Idaho Power service area early in December 2010. These results included the following:

- The important role the trade allies serve for promoting the Easy Upgrades program to their customers
- The significant function the Idaho Power incentive played in helping customers implement their retrofit projects
- The customers' needs for the contractors to provide more information on energy efficiency measures and how to best use their energy efficiency equipment

The Easy Upgrades program specialist will continue to monitor customer satisfaction with the program throughout 2011.

Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Easy Upgrades program. This evaluation included a program data review, program logic model, internal-customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and indicated that this program had high appeal to Idaho Power customers and has grown rapidly. Recommendations for program improvement included the need to conduct additional market research with program and trade ally participants, update program marketing and outreach materials, and improve program data tracking and QA efforts. Idaho Power is currently analyzing all recommendations. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis indicates current savings from the Easy Upgrades program are outpacing the forecasted achievable potential and this program has significant potential for growth. The study also predicts this gap to narrow in 2014 and recommends more aggressive marketing activities may be required in the future. The complete report is provided in *Supplement 2: Evaluation*.

## 2011 Strategies

Several program changes will be implemented in 2011. Program participants will be required to sign a MOU to be eligible to participate in Easy Upgrades. The MOU addresses the terms and conditions participants are required to follow. More detailed project information will be required on applications. The additional information will assist in verifying the scope of each project.

Measure changes for 2011 will include the following.

### Lighting

Several administrative and program requirements for lighting projects will be implemented in 2011. Changes will include a new lighting tool. Submission of the new lighting tool will be required for project applications. Manufacturer cut-sheets on equipment being installed will also be required at the time new projects are submitted. A "custom" option for non-standard lighting applications will be included in the lighting tool. For example, cost-effective outdoor lighting measures will be eligible for program incentives under the new non-standard option. Based on cost-effective analysis, several incentive levels will be modified. Additionally, more pre- and post-installation site verifications will be performed. The program will develop a detailed inspection process for lighting projects.

### Building Shell

Premium windows are redefined as those with a Solar Heat Gain Coefficient of 0.30 or less and a U-factor of 0.30 or less. Window-shade film was removed based on cost-effective analysis. Insulated and high-speed automatic door measures were removed from Easy Upgrades and moved to the Custom Efficiency program.

### Grocery Refrigeration

The incentives for anti-sweat heat controls, Electronically Commutated Motor (ECM) case fan motors, and LED display case lighting were increased. Air-cooled multiplex and evaporative-cooled multiplex systems were removed based on cost-effective analysis.

### Plug Load

Flat panel LCD displays, office equipment occupancy sensors, and coin-operated washing machines (without electric hot water) were removed based on cost-effective analysis.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February, 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

Plans include the provision of educational topics at trade ally workshops. Topics will be focus on maximizing energy-savings opportunities and increasing customer satisfaction.

Effective July 14, 2012, there will be new Standards for General Service Fluorescent Lamps. Idaho Power is aware of these new requirements and will work with regional market players to develop strategies in deciding what changes to make for the lighting measures and respective incentives for the 2012 Easy Upgrades program.

# FlexPeak Management

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (sites) | 60 | 33 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 47.5 | 19.3 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,807,527 | $528,681 |
| Oregon Energy Efficiency Rider | $95,153 | $0 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $1,902,680 | $528,681 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.14 | |
| Total Resource Benefit/Cost Ratio | 1.14 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

FlexPeak Management is a voluntary demand response program targeting Idaho Power's industrial and large commercial customers that are capable of reducing their electrical energy loads for short periods during summer peak days. The program became available to the company's Idaho customers in May 2009 and to the company's Oregon customers in May 2010. The program objective is to reduce the demand on Idaho Power's system during peak times through customers' voluntary electrical use reduction. The program is active June 1 to August 31, between the hours of 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand reduction event two hours prior to the start of the event, and events last between two and four hours.

In November 2008, EnerNOC, Inc., was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours without negative impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week, EnerNOC commits a demand reduction level in MW to Idaho Power that EnerNOC is obligated to meet in a demand reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand reduction event in aggregate. Customers can also continuously monitor their demand reduction performance using their individual, near real-time energy-usage data.

## 2010 Activities

On February 26, 2010, as part of Case No. IPC-E-09-02, the company filed with the IPUC a *FlexPeak Management 2009 Preliminary Report* dated February 24, 2010, in accordance with the request in IPUC Order No. 30805 for a preliminary evaluation of the program prior to making a request for prudency of program expenditures. A copy of this report is included in *Supplement 2: Evaluation*.

Also on February 26, 2010, as part of the same case IPC-E-09-02, the company filed a petition requesting the IPUC approve an amendment to the agreement between Idaho Power and EnerNOC. The contract changes accomplished clarification of language regarding accrual of energy payments, adjustment of language regarding baseline calculations, correction of an error in EnerNOC penalty calculations, and addition of a non-solicitation clause.

On June 2, 2010, under Order No. 31098, the IPUC granted the company's Petition for Approval of the Amendment to the Agreement in June 2010.

In March 2010, the company filed an application with the OPUC to approve the FlexPeak Management program in its Oregon service area to be made available to Idaho Power Oregon customers. The OPUC opened docket UM 1473 to evaluate the application, which was approved on June 2, 2010, in Order No. 10-206.

The first week of the program, EnerNOC committed to provide a reduction of 29.96 MW. This weekly commitment, or "nomination," was comprised of 49 facility sites, of which 30 participated in the program in 2009 and 19 added in 2010. The reduction at the end of the season was 30.80 MW, comprised of 64 facility sites. The commitment peaked in July at 34.2 MW.

Idaho Power called four demand response events for the FlexPeak Management program. In each case, EnerNOC successfully exceeded the committed MW reduction. One event occurred in June, two in July, and one in August. The highest hourly reduction achieved was in July, at 47.5 MW, which exceeded the target reduction for the summer of 2010 of 30 MW.

## Cost-Effectiveness

Although the B/C analysis for the FlexPeak Management program is based on a 10-year model, the company also tracks cost-effectiveness on an annual basis. Both calculations use financial assumptions and DSM alternative costs from the 2009 IRP. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as the alternative resource in Idaho Power's cost-effectiveness analysis. This analysis is updated annually with actual benefits and costs. For the FlexPeak Management program, the benefits are based on measured demand reduction at the participants' meter. The costs include the fees paid to EnerNOC and Idaho Power administration for the program. The 2010 cost-effective analysis demonstrated the FlexPeak program has a TRC ratio of 1.14

from a long-term perspective and a TRC ratio of 1.33 for 2010. *Supplement 1: Cost-Effectiveness* contains details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

In early 2010, EnerNOC sent an Annual Customer Survey to 27 of the 2009 participants via e-mail. Nine participants responded for a 33 percent response rate. On a scale of 1 to 10, 10 being "very satisfied," the average level of satisfaction with EnerNOC's communication with the participants was 7.1, the average level of satisfaction with how EnerNOC managed the demand response events was 8.3, the average level of satisfaction with the installation and maintenance of equipment installed at participants' facilities was 8.1, and the average level of overall satisfaction with EnerNOC was 7.7. On a scale of 1 to 10, 10 being "extremely likely," when asked how likely they would be to recommend EnerNOC to a colleague or business partner, the average result was 8.0. Of the nine responses, three reported no difference in their opinion of Idaho Power based on their participation in the program, five reported an improved opinion of Idaho Power, and one gave no response.

EnerNOC sent a post-event survey via e-mail after the first event in June 2010 to 125 participants at 53 sites representing all the sites enrolled in the event. Ten participants responded for an 8 percent response rate. Results were positive. When asked how prepared they felt for the demand response event, on a scale of 1 to 10, 10 being "fully prepared," the average response was 9.1. When asked how likely they were to recommend EnerNOC to a peer or business partner, on a scale of 1 to 10, 10 being "definitely will," the average response was 9.1. When asked how clear the initial notification they received from EnerNOC was on the day of the event, on a scale of 1 to 10, 10 being "very clear," the average response was 9.9. When asked how satisfied they were with how EnerNOC managed the demand response event, on a scale of 1 to 10, 10 being "very satisfied," the average response was 9.2. When asked about their overall satisfaction with EnerNOC, on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.9.

Copies of these surveys and survey results can be found in *Supplement 2: Evaluation*.

## 2011 Strategies

EnerNOC plans to conduct a post-season customer satisfaction survey for the 2010 season first quarter 2011. The results will be made available to Idaho Power. Idaho Power will continue to evaluate the best use of the program to meet the program objectives, maximize the benefit to Idaho Power's system, and refine internal criteria to call demand reduction events.

# Holiday Lighting Program

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 25 | 32 |
| Energy Savings (kWh) | 248,865 | 142,109 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $45,816 | $33,673 |
| Oregon Energy Efficiency Rider | $316 | $257 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $46,132 | $33,930 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.024 | $0.031 |
| Total Resource Benefit/Cost Ratio | $0.034 | $0.066 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.63 | |
| Total Resource Benefit/Cost Ratio | 1.87 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Holiday Lighting program offers incentives to commercial customers to replace incandescent lighting with more efficient LED holiday lighting. Customers turn in their strings of holiday lights for recycling at various Pacific Recycling locations and receive a receipt verifying the type and count of lights. The customer initiates the incentive process by submitting an application to Idaho Power, along with their recycling receipt and new bulb purchase receipt.

## *2010 Activities*

A 2010 analysis of the program identified that an increasing ratio of mini-incandescent lights to C7 and C9 lights being turned in for recycling was having a significant impact on program cost-effectiveness. Additionally, several market observations were taken into account. Feedback from participants indicated a preference for LEDs in the future because of the durability and reduced hazard provided by LED technology. The increased availability of LED lighting in wholesale and retail stores, and use of the technology in the marketplace led to the acceptance of the LED technology. These factors combined to indicate that LED usage for holiday displays was becoming the standard choice in the market. Based on those factors, two program decisions were made: 1) beginning in mid-2010, incentives for mini-incandescent lights were not offered; and 2) customers were notified that 2010 would be the last year Idaho Power would offer the program. A bill stuffer went out in October 2010 notifying commercial customers of these program changes.

In 2010, there were 25 participants in the Holiday Lighting program with a total savings of 248,865 kWh/year. This is approximately half the energy savings achieved in 2009.

The largest program participant was the Idaho Botanical Garden, with an estimated annual savings of 46,899 kWh. Their Winter Garden Aglow holiday display recycled over 23,000 incandescent lights, and replaced them with approximately 10,000 LED lights. It is estimated that over 36,500 visitors attended this event.

Although the incentive was available only to commercial customers, the program was useful as a means of introducing Idaho Power customers to the advantages of LED technology and helped make LED lighting the preferred choice when it comes to replacing existing holiday lighting. LED lighting has now become readily available at most stores supplying holiday lighting to both commercial and residential markets.

As LED technology developed, LED replacement bulbs became available. When the Holiday Lighting program originally launched, LED light strings did not have replaceable bulbs. LED replacement bulbs for use in existing C7 and C9 strings were also not widely available at the time of program startup. In the past two years, increasing number of customers wanted to turn in bulbs yet keep their strings of sockets. Idaho Power staff was involved in counting and picking up these bulbs for disposal. This logistical step would have become an increasing concern had the program continued.

## Cost-Effectiveness

In the original program design, savings estimates were computed for both commercial grade LED C7/C9 and mini-LED bulbs. Based on a review of manufacturing specifications of the LED C7/C9 bulbs, it was calculated they use 5 W less per bulb over a comparable incandescent C7/C9 bulb. LED mini bulbs were calculated to have 0.41 W of reduction per bulb. With an assumed 12 hours of use daily, seasonal savings per bulb were estimated to be 2.9 kWh for C7/C9 bulbs and 0.24 kWh for mini LEDs.

As part of the 2009 cost-effective analysis conducted in 2010, mini LEDs were found not cost-effective and were discontinued from the program midway through 2010 before the holiday season. The cost of mini LEDs decreased, and the availability of commercial-grade, non-LED mini bulbs declined, indicating a transformed market. This commercial trend or market transformation of mini-LED bulbs was mirrored by the emergence of residential programs through large retailers that provided discounts to customers purchasing LED bulbs and recycling incandescent similar to Holiday Lighting. The Holiday Lighting program was discontinued after the 2010 holiday season. Cost-effective model assumptions and analysis are included in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Overall, customers conveyed their appreciation for the program. Some customers were disappointed that incentives on the mini-incandescent were no longer offered. Customers were informed that a major goal of the program was to achieve market transformation in holiday lighting and with so many displays now being supported by LEDs, it was clear that LEDs have become a viable and acceptable option.

## 2011 Strategies

The Holiday Lighting incentive will no longer be offered. However, information regarding the use of LED technology for holiday displays will be provided on customers' request.

# Oregon Commercial Audits

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 22 | 41 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $5,049 | $20,732 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $5,049 | $20,732 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program offered under Oregon Rate Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2010 Activities*

Idaho Power sent out its annual mailing to approximately 3,400 Oregon commercial customers in October 2010. Customers were notified of the availability of no-cost energy audits and provided the Idaho Power publication *Saving Energy Dollars*. Twenty-two customers requested an audit, with 15 audits completed by Idaho Power and seven completed by a third-party contractor.

EnerTech Services, the third-party energy auditing contractor, delivered Idaho Power energy efficiency program information to customers during the audits they conducted. During the delivery of information, EnerTech Services discussed maintenance and efficiency opportunities that may be available to meet customer needs.

## *Cost-Effectiveness*

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Rate Schedule No. 82. Since the required parameters of the Commercial Energy Audit Program

are specified in Schedule No. 82, and the company abides by these specifications, this program is deemed to be cost effective. Idaho Power claims no energy savings from this program.

## Customer Satisfaction and Evaluations

An excellent example of the value of an audit is the identification of actual savings opportunities and incentives in the customer's facility. This was demonstrated during a restaurant audit completed in 2010. This example describes customer engagement in energy efficiency opportunities.

During the walk-through evaluation, the customer representative and the customer discussed potential lighting conversions, refrigeration positioning and temperature control, and window-glazing options. If the customer followed through on the lighting suggestions by upgrading from T-12 lamps with magnetic ballasts to T-8 lamps with electronic ballasts, the conversion would save approximately 30 percent of the energy used for lighting.

After the audit, the customer verbally indicated to the customer representative satisfaction with the discussion regarding potential energy efficiency opportunities at the site. A follow-up call revealed that the customer was interested in using the Idaho Power energy efficiency programs and conducting a lighting retrofit. Program requirements and contact information was provided.

## 2011 Strategies

In 2011, Idaho Power's audit contractor will continue to introduce participants to energy efficiency through lighting and HVAC system maintenance by suggesting customers seek alternatives that are more efficient as they support and replace their existing equipment. EnerTech Services will continue to help customers identify projects that save energy and help meet the customers' other needs, such as improving space comfort. The audit process will continue to be used as a way to introduce customers to available Idaho Power incentive programs.

# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is composed of agricultural customers operating water pumping or water delivery systems to irrigate agricultural crops or pasturage. The end-use equipment primarily consists of agricultural irrigation pumps and center pivots. This customer group does not include water pumping for non-agricultural purposes, such as irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2010, the active and inactive irrigation service locations totaled 18,547 system-wide. This is a reduction of 1.4 percent compared to 2009, due to removal of some irrigation meters that were not used for multiple years. Irrigation customers accounted for 1,706,632 MWh of energy usage in 2010, which was up from 2009 by over 3 percent. This sector represented about 13 percent of Idaho Power's total electricity usage and about 23 percent of peak demand. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in demand due primarily to the impact of weather on irrigation needs.

Idaho Power currently offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to decrease peak demand; and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind, which is a measure that ensures the motor's original efficiency is maintained if it is rewound at an approved service center. Table 9 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

The Irrigation Peak Rewards program was able to reduce peak summer demands by almost 250 MW during the program's peak performance event during the summer of 2010, an increase of 90 MW over last summer's program performance. More than 500 additional service point locations were enrolled for the 2010 season.

Irrigation Efficiency Rewards program, which has been in operation since 2003, saw its annual savings drop by 2,189,189 kWh to 10,968,430 kWh of annual savings as compared to 2009 reported savings. The reduction in savings in 2010 was primarily the result of fewer menu projects being submitted in 2010. Generally, there seem to be fewer irrigation systems that need to replace or repair the 11 menu items offered as a result of the program being available or the past four years. In addition, a few applications were not approved in 2010 due to the new rule adopted in 2010 requiring measures to have been installed within a year.

# Programs

Table 9. 2010 Irrigation program summary

| Program | Participants | Total Costs | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| Demand Response | | | | | |
| Irrigation Peak Rewards | 2,038 service points | $13,330,826 | $13,330,826 | n/a | 249.7 |
| **Total** | | **$13,330,826** | **$13,330,826** | **n/a** | **249.7** |
| Energy Efficiency | | | | | |
| Irrigation Efficiency Rewards | 753 projects | $2,200,814 | $6,968,598 | 10,968,430[a] | 3.3 |
| **Total** | | **$2,200,814** | **$6,968,598** | **10,968,430** | **3.3** |

[a] See Appendix 3 for notes on methods and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 50 percent of Idaho Power irrigation customer surveyed in 2010 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-eight percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-six percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 36 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 92 percent are “very” or “somewhat” satisfied with the program.

# Irrigation Efficiency Rewards

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 753[a] | 887 |
| Energy Savings (kWh) | 10,936,463 | 13,157,619 |
| Demand Reduction (MW) | 3.3 | 3.4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,059,676 | $2,112,391 |
| Oregon Energy Efficiency Rider | $110,034 | $152,134 |
| Idaho Power Funds | $31,104 | $29,371 |
| Total Program Costs—All Sources | $2,200,814 | $2,293,896 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.030 | $0.026 |
| Total Resource Benefit/Cost Ratio | $0.096 | $0.077 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.22 | |
| Total Resource Benefit/Cost Ratio | 1.61 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Does not include Green Motor Rewinds

## *Description*

The Irrigation Efficiency Rewards program encourages energy efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help the customer recover a portion of the costs of installation of a new, more efficient irrigation system and energy efficient improvements to an existing irrigation system.

Two separate options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per first year kWh saved above standard installation methods, not to exceed 10 percent of total project cost. For existing system upgrades, the incentive is 25 cents per first year kWh saved or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the pumping hp requirement or hours of operation.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in most situations, post-usage demand data, is available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which

small maintenance upgrades provide energy savings from 11 separate measures. These measures include the following:

- New flow control nozzles
- Replacement of worn brass or plastic nozzles
- Rebuilt or new impact sprinklers
- Rebuilt or new wheel line levelers
- New low-pressure or rotating type sprinklers
- New low-pressure regulators
- New drains, riser caps, and gaskets
- New wheel line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on predetermined average kWh savings per component. Idaho Power reviews and analyzes each proposal for a system or component modification, determining and verifying the energy savings.

The Green Rewind program enables customers to maintain the motor's original efficiency and ensures an efficient use of electricity to run the motor. Motor service centers are paid $2.00 per hp for each NEMA Standard hp-rated motor between 15 and 5,000 hp that receives a verified Green Rewind. The RTF originally approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings in July 2007 for industrial applications. In July 2009, the RTF reviewed and approved savings for motor rewinds for industrial and agricultural applications. The new savings were posted in 2010.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power agricultural representatives sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits, conducted by Idaho Power agricultural representatives, evaluate prospective customers' potential savings. Agricultural representatives from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing awareness of the program and promoting it through the irrigation equipment distribution channels. Marketing efforts include direct mailings, advertisements in agricultural publications, and participation in agricultural workshops and conferences. Idaho Power's agricultural representatives are funded approximately 30 percent by the Riders and 70 percent from base rates.

## 2010 Activities

There were no major changes made to the basic structure of the program during 2010. However, a modification regarding the time frame in which irrigation components are eligible for an incentive was made for all menu payments effective January 4, 2010, with approval from the OPUC. Going forward from January 4, 2010, the new eligibility states that customer invoices must be provided to the company no later than one year after the purchase date of the equipment.

Idaho Power agricultural representatives, program specialist, and agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2010, Idaho Power provided six workshops promoting the Irrigation Efficiency Reward program throughout the service area. Approximately 180 customers attended workshops in Blackfoot, Aberdeen, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Fairfield, Shoshone, Nampa, and Jackpot, Nevada. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri Action Ag show, the Idaho Ag Summit, and the Idaho Irrigation Equipment Association show and conference.

Of the 753 irrigation efficiency projects completed in 2010, the 610 associated with the Menu Incentive Option provided 5,219 MWh of energy savings and 1.02 MW of demand reduction. The Custom Incentive Option had 143 projects, of which 68 were new irrigation systems and 75 were on existing systems. This option provided 5,561 MWh of energy savings and 2.23 MW of demand reduction for the year. Also during 2010, irrigation customers contributed 187,965 kWh of energy savings from 36 motors participating in the Green Motor Rewind measure.

In 2010, Idaho Power reviewed the cost-effectiveness of continuing the Green Motor Rewind initiative for both industrial and agricultural motors. Based on the new RTF-approved energy savings, it was determined that some of the smaller motors did not pass the PCT. For 2011, rewinds on motors less than 25 hp have been removed from the initiative.

## Cost-Effectiveness

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customers' participation in the program. To estimate the effectiveness of a project, Idaho Power uses a service point's previous five years of electricity usage history and, based on the specific equipment to be installed, calculates the estimated post-installation energy consumption of the system. The company also verifies the completion of the system design through aerial photographs, maps, and field visits by Idaho Power agricultural representatives to ensure the irrigation system is used in the manner the documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure savings are achieved. Payments are calculated on predetermined average kWh savings per measure. In some cases, the energy savings estimated in the Menu Incentive Option are adjusted downward to reflect how the components are actually being used.

In 2010, RTF provisionally deemed updated savings and cost assumptions for several irrigation hardware measures. Idaho Power reviewed the savings and costs for measures identified for the western Idaho region. Several RTF measures were either averaged or combined to align with Idaho Power's program offering. Some measures annual gross energy savings increased and improved the measure's cost-effectiveness. For instance, the hub replacement measure was identified as not cost-effective in the 2009 *Supplement 1: Cost-Effectiveness*. RTF increased savings from 40 kWh/year, to 69 kWh/year which improved the measure's TRC from 0.71 to 1.14.

Nearly all the measures remained cost effective, despite the changes made to the measure savings and cost assumption. However, the rebuilt and new wheel line levelers appeared to not be cost effective using the new savings assumptions. The RTF reduced savings from 20 kWh per year to 2 kWh per year. This significant decrease in savings contributed to the TRC dropping from 1.34 in 2009 to 0.27 in 2010. One factor contributing to the measure's non-cost-effectiveness is the participant cost. RTF assumes the cost to be $3.25 per unit. However, according to invoices received by Idaho Power through the program, leveler rebuilding kits cost less than $1.00 while new levelers cost about $12.00. A majority of the levelers that are eligible for incentives through the program are for the rebuilt levelers; however, the cost of the new levelers is driving up the average participant cost. Idaho Power is currently reviewing this measure to determine if the measure is, in fact, cost-effective, or if it will be removed from the menu offerings. A decision will be made by the summer of 2011 when Idaho Power reviews other changes to the program.

For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

On January 5, 2010 an RTF subcommittee, composed of the Energy Trust of Oregon (ETO), the RTF, Rocky Mountain Power, and Idaho Power, presented a methodology for calculating the deemed irrigation hardware measures. The methodology was approved by the RTF. The RTF included a suggestion that utilities should make appropriate adjustments to the inputs for calculating energy savings for unique service area characteristics. The RTF's decision stated that the deemed irrigation measures should be reviewed in 13 months. At the RTF meeting on January 5, 2010, Rocky Mountain Power announced they were conducting an evaluation of savings from its irrigation hardware program and that information will be available from the Idaho market. Idaho Power is waiting for the results of this evaluation before designing additional evaluation. Idaho Power is considering partnering with an Idaho university to further evaluate and test irrigation equipment that will aid in determining individual measure savings.

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Irrigation Efficiency Rewards program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and noted that this is "a robust, ambitious, and leading-edge irrigation program," and that the program has "strong relationships with customers and trade allies, credibility, and high demand." Recommendations for program improvement included the need to conduct additional surveys to provide on-going data regarding program satisfaction, operation, and market trends. It was also recommended that Idaho Power consider expanding outreach and assistance efforts to capitalize on the technical strength of a "well-trained" Idaho Power program staff. Idaho Power is currently analyzing all recommendations. Any program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

## 2011 Strategies

Marketing plans for 2011 include conducting three to five customer-based irrigation workshops and three to five training sessions for irrigation dealers and manufacturers. These workshops and training sessions enable discussions between Idaho Power representatives, the company's customers, and irrigation dealers, while continually educating them about the program and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power is also reviewing the program with input from customers regarding other energy-saving measures that can be offered in the Menu Incentive Option. It is also planned to further review information provided by the RTF and other research to make improvements to the program.

Final reports from The Cadmus Group's, Inc., 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

# Irrigation Peak Rewards

| | 2010 | 2009 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 2,038 | 1,512 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 249.7 | 160 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $13,096,946 | $9,131,929 |
| Oregon Energy Efficiency Rider | $184,075 | $451,673 |
| Idaho Power Funds | $49,805 | $71,681 |
| Total Program Costs—All Sources | $13,330,826 | $9,655,283 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.43 | |
| Total Resource Benefit/Cost Ratio | 1.37 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

Idaho Power's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to produce a decrease in the company's system summer peak by turning off specified irrigation pumps with the use of one or more load control devices during the program season June 15 through August 15.

Idaho Power has operated its Irrigation Peak Rewards program since starting with a pilot program in 2004. Since that time, Idaho Power has made changes to the program many times with the largest change being the dispatch option that was added before the 2009 irrigation season.

In 2010, the program was active from June 15 to August 15. All Idaho Power irrigation customers taking service under Schedule 24 in both Idaho and Oregon were eligible and participants chose between three options: 1) the Electric Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn participants' pumps off, or 3) a Manual Dispatch Option designed for large service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during summer peak hours.

Participants in the Electronic Timer Option can choose to have all irrigation pumps on a single, metered service point turned off one, two, or three times per week. Interruptions occur from 4:00 p.m. to 8:00 p.m., and Idaho Power determines the specific weekday or weekdays to schedule the interruption of all pumps at each service point. Installation fees between $250 and $500 are applied to participating service locations less than 75 hp.

For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. For 2010, dispatchable load control events could happen between 1:00 p.m. and 8:00 p.m. on weekdays and Saturday. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. Installation fees between $500 and $1,000 were applied to participating service points with less than 30 hp.

A customer's incentive appeared as a bill credit that sums the demand credit and energy credit applied to a customer's monthly bills. Credits are prorated for periods when reading/billing cycles do not align with the program season dates from June 15 to August 15. All customer incentives participating in the Electric Timer, Automatic Dispatch, or Manual Dispatch Options are calculated using Idaho Power meter billing data. In addition, manual option customers' incentives are calculated using interval metering data. The demand credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount for the interruption option selected by the customer. The energy credit is calculated by multiplying the monthly billing kWh usage by the energy related incentive amount for the interruption option selected by the customer. Installation fees and opt-out penalties are completed through manual bill adjustments. Incentives determined from interval meter data for service points classified as large service locations are completed through a manual process and customers received the incentives in the form of a check in 2010. Incentives offered are listed in Table 10.

Table 10. Option incentives

| Option | Demand Credit ($ per billing kW) | | Energy Credit ($ per billing kWh) |
|---|---|---|---|
| Timer Option Incentives | | | |
| One day | $3.15 | | |
| Two days | $4.65 | plus | $0.002 |
| Three days | $4.65 | plus | $0.007 |
| Automatic & Manual Dispatch Options Incentives | $4.65 | plus | $0.031 |

Under the rules of the Automatic and Manual Dispatch Options, participants have the ability to opt out of dispatch events five times per service point. Each opt-out incurs a fee of $0.005 per kWh based in the current month's billing kWh, which may be pro-rated to correspond with the dates of program operation and are completed through manual bill adjustments.

## 2010 Activities

In 2010 most of the challenges surrounding the dispatch devices and communications that occurred in the prior year were resolved, working with Idaho Power's third-party contractor. This resulted in the Irrigation Peak Rewards dispatch load control system working much better. In 2010, the program achieved a maximum peak load reduction of approximately 249.7 MW. This represents a 38 percent increase from 2009. Participation has been very good with this program. Of all eligible irrigation service locations, approximately 11 percent are participating in the program. In 2010, there were 2,038 metered service points enrolled in the program. Of the 2,038 enrolled service points, approximately 14 percent were enrolled in the Electric Timer Option and 86 percent were enrolled in the Automatic and Manual Dispatch Options.

Changes in 2010 included moving the program season from June 1–July 31, to June 15–August 15. Additionally, the days of the week the program can be activated was extended to include Saturdays.

These changes were made to help align the program availability to better match Idaho Power's system peaks.

Idaho Power attempted to distribute the Electric Timer Option participating service points evenly throughout each weekday, based on cumulative demand reduction potential. However, due to service point size variability, enrollment requests by customers, enrollment opt-outs, and other variables, the load reduction could not be exactly balanced. All participants in the Automatic and Manual Dispatch Options were grouped into five regional areas to be dispatched on each scheduled event day. Table 11 shows the MW reduction achieved daily on a week-by-week basis.

Table 11. Total program daily MW reduction without distribution losses using realization rates

| | Monday | Tuesday | Wednesday | Thursday | Friday |
|---|---|---|---|---|---|
| June 15–18 | 0.7 | 0.8 | 0.9 | 0.8 | 0.7 |
| June 21–25 | 0.7 | 0.8 | 0.9 | 0.8 | 0.7 |
| June 28–July 2 | 7.0 | 192.4[a] | 8.9 | 7.5 | 7.3 |
| July 5–9 | 7.0 | 8.5 | 8.9 | 7.5 | 221.0 |
| July 12–16 | 7.0 | 8.5 | 8.9 | 7.5 | 7.3 |
| July 19–23 | 6.2 | 7.5 | 7.8 | 6.6 | 6.4 |
| July 26–30 | 6.2 | 7.5 | 7.8 | 6.6 | 6.4 |
| August 2–6 | 3.5 | 4.2 | 4.4 | 143.2 | 3.6 |
| August 9–13 | 3.5 | 4.2 | 4.4 | 3.8 | 3.6 |

[a] Shaded cells are days when dispatch events occurred.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2010, Idaho Power provided six workshops promoting the Irrigation Peak Rewards program throughout the service area. Approximately 180 customers attended workshops in Blackfoot, Aberdeen, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Fairfield, Shoshone, Nampa, and Jackpot, Nevada. Exhibitor booths were also displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri Action Ag show, the Idaho Ag Summit, and the Idaho Irrigation Equipment Association show and conference.

In February 2010, a customer mailing was sent to all eligible Idaho Power irrigation customers with at least one service point over 30 hp. The mailing included a program explanation, a program application, the program's incentive structure, a listing of the customer's eligible service points, and a potential incentive estimate for each program option based on the customer's 2009 usage. A second mailing of the program brochure was sent to all eligible customers with pumps under 30 hp. These customers with less than 30 hp are less likely to participate because of the installation fees resulting in multi-year payback from the incentive. If these customers had a desire to participate, all additional information including application and contract agreement was mailed to them at their request. Additionally, numerous one-on-one conversation with Idaho Power agriculture representatives familiarized customers with the new technology and program details.

Based on the results of the 2009 Irrigation Peak Rewards customer survey, process improvement changes implemented in 2010 included redesigning the program application and rewriting the program brochure to clarify the program information. The 2010 application worksheet was expanded to contain actual incentives received for participating service points with the corresponding previous year's

enrollment option. Customers who participated in 2009 were automatically re-enrolled at their option for the 2010 season.

In addition, Manual Dispatch Option customers received their incentives in the form of a check in 2010. This payment process change limited errors and customer confusion in 2010.

## Cost-Effectiveness

Although the B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model, the company also tracks cost-effectiveness on an annual basis. Both calculations use financial and DSM alternative costs assumptions from the IRP. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170 MW SCCT is used as the alternative resource for avoided cost. Idaho Power's cost-effectiveness model representing the program over a 20-year period is updated annually with actual benefits and costs. The benefits are based on peak reduction and shifted energy use. In 2010, the company included an estimate of customer costs in the cost-effective analysis. This change in inputs made the UC and TRC ratios differ. Updating the cost-effectiveness model in 2010 resulted in a UC B/C ratio of 1.43 from the 20-year perspective and 1.14 for 2010. The UC B/C ratio is 1.37 from the 20-year perspective and 1.12 for 2010. For details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness.*

## Customer Satisfaction and Evaluations

In 2010, Idaho Power conducted a review of the Irrigation Peak Rewards in an effort to ensure the program's design was aligned with the resource needs identified by the IRP. Analysts and engineers from Idaho Power's Customer Relations & Energy Efficiency, Power Supply Planning, and Load Forecasting departments conducted this review. Based on this review, Idaho Power determined there is an optimum amount of demand response that can be effectively used on Idaho Power's system and there is a more economical way of paying for the program.

## 2011 Strategies

Substantial program changes have been proposed by Idaho Power and were filed with the IPUC on December 10, 2010, under Case No. IPUC IPC-E-10-46 and the OPUC on January 7, 2011, under Advice No. 11-01. These program modifications are a result of Idaho Power's internal review and input from the Idaho Irrigation Pumpers Associations, Integrated Resource Plan Advisory Council (IRPAC), and the EEAG.

Seven program changes are proposed for 2011 implementation:

- Change the incentive structure to a fixed and variable payment that pays customers a portion of their incentive for participating and a portion of their incentive based on how much the company uses the program.
- Include one program event in the fixed portion of the payment.
- Allow the company to pay the variable portion of the incentive through a check at the end of the season.
- Require participants in the Manual Dispatch Option (>1000 hp) to nominate the amount of kW they are enrolling in the program.

- Change the baseline calculation for the Manual Dispatch Option from maximum demand in 24 hours prior to the average demand between 10:00 p.m. and 11:00 a.m. prior to an event.

- Modify the opt-out penalty for the program to $1 per kW per opt-out.

- Add the 8:00 p.m. to 9:00 p.m. hour as an option that customers can sign up for that pays a higher variable incentive.

Marketing plans for 2011 will be to maintain customer participation through what will likely be a transition year from the past incentive structure to the proposed structure if state regulators approve Idaho Power's proposed changes. Idaho Power will continue to educate customers on the program, through workshops and agriculture shows, though may have to limit participation levels to near current levels, based on the overall need for demand response as a resource to meet future loads.

# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates marketplace adoption of energy ,saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. 2010 was the first year of NEEA's new, five-year plan. Thus, it was a year of realignment and expansion.

NEEA performs several Market Progress Evaluation Reports (MPER) on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market research reports for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the *NEEA Market Effects Evaluations* in *Supplement 2: Evaluation*.

In 2010, Idaho Power energy efficiency staff attended advisory meetings, served on sub-committees, attended the first-ever conference in Seattle, Washington, and participated in NEEA sponsored studies and research.

### *NEEA Activities*

#### Commercial and Industrial NEEA Activities in Idaho

NEEA continued to provide support for commercial energy efficient activities in Idaho in 2010. This included partial funding of the IDL in Boise and local BetterBricks® trainings and workshops. Idaho Power's commercial sector programs, Building Efficiency and Easy Upgrades, are designed to leverage NEEA, BetterBricks, and the IDL in Boise activities.

In the industrial sector, NEEA expanded the Continuous Energy Improvement (CEI) efforts to the small-to-medium-sized businesses, defined as less than 250 employees per site. CEI is a multi-year strategic effort designed to improve energy efficiency in the industrial sector. Prior CEI efforts focused on two regional industries considered heavy energy users, 1) the food processing and 2) the pulp and paper industries. Participants achieve cost savings through the adoption of energy-efficient business practices. CEI provides expert support, resources, and services, supplying companies with the training and tools for making energy efficiency a core business value. This effort is supported by providing technical knowledge to organizations and to Idaho Power customers collaborating on energy efficiency implementation.

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. Ten technical training classes were completed in 2010. Topics included compressed air, chilled water systems, pumping systems, variable frequency drives, and refrigeration. The level of attendance at these classes remains high with 234 customers attending the workshops.

A program specialist for the Custom Efficiency program attended two NEAA-sponsored trainings for The Northwest Energy Management Demonstration Pilot Project. The specialist served as a utility support, while gathering information regarding the pending energy-management standard.

The NEEA is partnering with the US DOE to conduct the Northwest Energy Management Demonstration project (NW EM Demo), an energy management pilot for industrial companies. One of Idaho Power's large customers is one of the four companies participating in the pilot. The goal of the project is for participants in the project to help shape the new US energy-management system standard through their experiences and may play a role refining the pending global energy management standard for participating industrial companies. Key findings from the NW EM Demo may help inform the new ISO 50001 International Energy Management Standard for industry, which may impact how companies worldwide manage energy.

### Residential NEEA Activities in Idaho

NEEA's Residential Advisory Committee is comprised of representatives from various utilities, the BPA, NEEA staff, and occasional representatives from program partner firms and consultants. The committee meets quarterly to discuss upcoming projects, potential programs, and initiatives.

The residential programs leader usually attends this meeting or sends a residential team member when topics warrant staff participation. These meetings are a useful mechanism for networking with other utility peers, getting updates on regional activities and similar utility program efforts, and providing feedback to NEEA to use in their planning efforts.

NEEA continues to provide support for the ENERGY STAR® Homes Northwest program offered by Idaho Power. NEEA offers technical assistance, funding for certifications, and builder and market support.

In 2009, NEEA launched a Consumer Electronics Initiative. Idaho Power contributed $160,000 to this multi-year effort, which included manufacturer support and consumer marketing for ENERGY STAR televisions that are 30 percent more efficient than baseline ENERGY STAR models. Computer monitors and desktop computers were included in the program in 2010. In 2010 and beyond, the funding for the Initiative is provided by NEEA's multiple Northwest utilities partners' general funding. Eligible models and point-of-purchase marketing collateral were placed in Idaho Power's service area.
NEEA representatives throughout 2010 conducted in-store training of sales staff. Energy savings are being tracked by NEEA, and 2010 data will be available the mid-year 2011.

In 2010, NEEA conducted a series of focus groups around the Northwest, including Boise, to help develop the most effective marketing message. With the results, a new marketing campaign , Energy Forward was developed by NEEA to highlight that the products with the designated Energy Forward are the most advanced energy-saving products available. New point-of-purchase marketing materials were created and placed on qualifying units by NEEA representatives throughout the Northwest. A new website was created to describe the campaign: http://www.energyefficientelectronics.org.

Idaho Power also participated in a NEEA-sponsored DHP study in 2009. The first MPER on the DHP Pilot became available in 2010. Detailed information about this project is provided in the DHP Pilot description in this *Demand-Side Management 2010 Annual Report*.

In December 2010, Idaho Power program specialists, analysts, and leadership attended the Efficiency Connections Northwest conference in Seattle, Washington. This conference was created by the region's utilities and NEEA with the goal to advance energy efficiency awareness and its integration in the Northwest. Topics at the conference included methods to promote energy efficiency, increasing collaboration between utilities, new and emerging technologies, market transformation, and energy codes.

During 2010, the Idaho Power DHP Pilot program specialist participated in the monthly Web-based seminar conferences held by NEEA. The goal of the Web-based seminar was to update the Northwest utilities participating in the DHP incentive program. Topics included year-to-date updates on the number of incentives paid, NEEA marketing strategies for the program, QA evaluations, contractor performance, energy evaluation plans, and general feedback from the utilities.

### Other NEEA Activities in Idaho

Each year, NEEA underwrites the Idaho Energy Conference through a contract with the Association of Idaho Cities. In addition, in 2010 NEEA provided $25,000 in support to the IDL in Boise, which provides energy consulting services to commercial customers throughout Idaho Power's service area.

The Residential Energy Efficiency Education Initiative specialist represented Idaho Power on the NEEA Conduit Online Community Steering Team in 2010. Conduit (www.conduitnw.org) will be an online resource to facilitate information sharing, coordination, and collaboration among energy efficiency professionals in the Northwest. Pilot testing is targeted for March 2011. Idaho Power is involved in this testing. Conduit is slated for a general launch in May 2011.

Idaho Power's customer research and analyst leader is an active participant in NEEA's Cost-Effectiveness Advisory Committee. This committee meets three to four times a year to review NEEA cost-effectiveness models, assumptions, and, ultimately, energy-savings estimates. Idaho Power's energy efficiency analyst participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally.

### NEEA Funding

In 2010, Idaho Power began the first year of the 2010–2014 Regional Energy Efficiency Initiative Agreement with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses, up to the five-year total direct funding amount of $16.5 million, in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2010, 100 percent was funded through the Idaho and Oregon Riders.

In 2010, Idaho Power paid $2,391,217 to NEEA. The Idaho jurisdictional share of the payments was $2,271,656, while $119,561 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

Preliminary estimates reported by NEEA indicate that Idaho Power's share of regional market transformation MWh savings for 2010 is 15,334 MWh, or 1.8 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at www.nwalliance.org.

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# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavior change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative's goal is promoting energy efficiency to the residential community sector. This goal is achieved by creating and delivering educational programs that increase Idaho Power's energy efficiency program participation and result in energy efficient and conservation-oriented behaviors and choices.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of communication methods during 2010. Increased customer awareness of energy-saving ideas was accomplished via distribution of approximately 8,750 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. The book was updated and reprinted. Searchable versions of both the English and Spanish texts were uploaded to Idaho Power's website during 2010. Customers may now also download or request hard copies of the book via the Web.

Through August of 2010, Idaho Power continued to provide weekly energy efficiency messages each Saturday morning on The HomeFix Show with Joe Prin on 670 KBIO AM. Additionally, energy efficiency messages aired on KBSU radio through February and March.

In May, Idaho Power launched a new educational project partnership with the Idaho Commission for Libraries, Avista, and Rocky Mountain Power. The three utilities worked together to make Energy Efficiency Kits available to all Idaho residents through the public library checkout system. Idaho Power customers represent 60 percent of the population served. There were 245 kits sent to 140 public libraries. The kits contain a Kill A Watt™ Meter, instructions, and energy-saving tips. Based on the first two quarterly reports, with 71 percent and 89 percent of jurisdictions reporting respectively, Idaho Power customers represented 80 percent of the total circulation with 546 checkouts. When library staff members were asked to estimate the satisfaction of their customers, the majority of the responses were positive with 18 percent indicating "very satisfied" and 76 percent indicating "satisfied."

In addition to these activities, Idaho Power was one of the sponsors of the third annual Idaho Green Expo in May. As part of Idaho Power's commitment to the Expo, the company distributed 5,000 re-usable shopping bags with the message "Reduce Your Use" to the more than 8,500 people who attended the 2010 Expo. Idaho Power's educational emphasis this year at the Expo was about *ENERGY Tools*, a full-featured suite of energy efficiency tools available on the company's website. Participants who visited the booth had the opportunity to sign up for *Account Manager* and view near-real-time data of the energy use in their homes. This prompted personal discussion about how individual attendees could reduce their consumption and gave Idaho Power employees the opportunity to introduce the myriad of available tools, such as the Energy Library, Energy Calculators, Home Audit, and other customer resources. The message was well-received. Idaho Power staff at the booth interacted with just over 7 percent of all attendees. *Account Manager* sign-ups for the Expo weekend were up 37 percent and 53 percent, respectively, from the two weekends just prior to the Expo. Moreover, the seven-day period beginning May 8 showed a 23 percent increase in signups over the seven-day period beginning May 1. Idaho Power presented three educational workshops at this event 1) Smart Meters = Smarter Idaho, 2) Renewable Energy for Your Home or Business, and 3) Building Your Home Energy Plan. The company also participated on a residential panel that presented

Building a Greener Idaho. Lastly, Idaho Power partnered with GreenWorks Idaho to develop and administer an exit survey. Information collected about Green Expo attendees centered primarily on why they attended the show. There were 318 surveys completed. The Green Expo participant profiles will be used to improve messaging and goals and increase Idaho Power's return-on-investment for future sponsorship of this event. It will also establish a baseline so Idaho Power can begin to track trends among Green Expo attendees and the population they represent over time. Although 36 percent of the respondents reported having participated in an energy efficiency program and/or A/C Cool Credit, this behavior ranked seventh out of the eight sustainable practices surveyed.

In September 2010, Idaho Power participated in the St. Luke's Women's Show for the third consecutive year. The event was important due to the size of the audience and because its demographic component aligned with Idaho Power's residential energy efficiency target audience. However, the nature of the show did not allow for the desired depth of interaction as in past years. In 2010, Idaho Power focused on drawing participants into the booth to complete an in-depth survey, providing Idaho Power with participant profiles and key market data. The company collected 496 completed surveys, exceeding the goal of 400. Idaho Power plans on refining the survey for this event in upcoming years and using it to inform Idaho Power's educational efforts, program marketing activities, and program design.

Key findings were 13 percent of those surveyed stopped at the booth to learn about energy efficiency, 9 percent said they stopped to learn about Idaho Power's programs, and 4 percent said they stopped to ask a question of the Idaho Power employees at the booth.

Respondents were asked if they had installed or replaced various equipment in their homes in the past three years. Forty percent of respondents said they had replaced a clothes washer, 37 percent a refrigerator, and 30 percent a dishwasher. They were also asked a series of demographic questions like whether they pay the electricity bill at home, what role they play in purchasing or upgrade decisions at their home, whether they own or rent their home, and their gender, age, and education levels.

Idaho Power further increased its energy efficiency presence in the community by providing program information at 116 special events. As part of process improvement accomplishments, the Outreach Tracking System was implemented during the second quarter of the year. It captured details of a variety of outreach activities and requests.

Field staff throughout Idaho Power's service area gave dozens of energy efficiency presentations. The Customer Relations and Energy Efficiency department provided 20 presentations on Idaho Power's energy efficiency programs and energy saving ideas to businesses, schools, and community organizations. The Power to Make a Difference program was delivered 98 times in public schools and 10 times for various civic groups.

Seven of these presentations were part of the 2010 Energy Efficiency & Green Living Series. This series was re-designed to improve the return on investment. Fewer topics were presented at more locations. The residential program specialist along with other program specialists presented content. Publicity was conducted primarily via the Internet and posters/fliers distributed at the venues. In addition to the Boise Public Library, sessions were conducted at the Meridian, Eagle, and Ada Community Libraries. In Twin Falls, the College of Southern Idaho's Sustainability Council hosted two sessions at the College of Southern Idaho. This year's topics were titled *Simple Changes Make Cents: Tips, Tricks & Tools to Reduce Electricity Bills*, and *Get Ready, Get Set, Go: Powering Homes with Alternative Energy*.

The seven sessions combined attracted 135 participants. The Residential Energy Efficiency Education Initiative collected participant evaluations at the 2010 Energy Efficiency & Green Living Series. The survey return rate was 69 percent, with 93 participants completing a survey following the presentations.

Overall, 79 percent of attendees "strongly agree" the information presented was useful, and 66 percent "strongly agree" the information presented met their expectations. Fifty-six percent said they "definitely would" and 44 percent said they "probably would" recommend the session to a friend or family member. Sixty percent said they "very likely" would attend future Energy Efficiency and Green Living Series presentations, and 36 percent said they are "somewhat likely" to attend future presentations. When asked what topic they "would attend" the future, 61 percent responded renewable energy; 49 percent responded landscaping for energy efficiency; 44 percent said Idaho Power rebates and incentive programs; 43 percent said energy-efficient window coverings; and 41 percent said energy efficiency for older homes. Comments related to what actions they would take as a result of attending the session included more energy awareness, changing existing light bulbs, making other home improvements, exploring solar energy options, and looking for ways to better educate themselves.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and for various Idaho Power publications, such as the *Green Power Newsletter*, the A*/C Cool Credit Newsletter*, *Customer Connection*, the high bill/tiered rate customer letters, the AMI door hangers, and *News Scans*.

Idaho Power sponsored two general education efforts during the year. The first was the publication of the 2010 Energy Efficiency insert for use in *The Idaho Statesman* in June. The insert presented Idaho Power's Energy Efficiency Programs, introduced the SEE program and the Kill A Watt Meter program, discussed the reasons why energy efficiency is important, and offered energy efficiency tips regarding choosing a contractor and dealing with the summer heat. It also emphasized *ENERGY Tools* and energy use data available through *Account Manager* as a result of the smart meter installations. The second campaign began in late November and early December. It promoted Energy Efficient Gift Giving ideas through various print media and bill inserts to help educate people regarding considerations when purchasing electronics for their homes.

Idaho Power frequently made additional educational presentations about energy efficiency, Idaho Power programs, and energy efficiency tips. The company created an energy efficiency presentation to educate students about the efficient use of energy in their homes. The program targets fourth- to sixth-grade student audiences. During 2010, the Idaho Power community education team presented *The Power to Make a Difference* in 103 classrooms across the service area. Idaho Power is planning to continue making revisions and improvements to the presentation.

Also during 2010, Idaho Power community education conducted 42 presentations and programs regarding energy efficiency to senior centers and civic groups within the company's service area. *The Power to Make a Difference* presentation demonstrated the importance of energy efficiency in the community. The other component of educational outreach was reviewing energy efficiency program options as well as low- and no-cost ways for customers to save energy and money in their homes or businesses.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Residential Energy Efficiency Education Initiative. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and found that the

program "conducted a wide variety of marketing and outreach to residential customers," and "is well received by the customers reached." Recommendations for program improvement included the need for prioritization of desired behavior changes and the need to gather additional data to enhance the measurement of success of activities the program undertakes. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

During 2011, the initiative's goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. Plans for 2011 include working with other Idaho Power program specialists and participating contractors to distribute the book *30 Simple Things You Can Do To Save Energy* to program participants when energy efficiency upgrades are made. Idaho Power will continue the partnership with the Idaho Commission for Libraries, Avista, and PacifiCorp to provide Kill A Watt Meters to libraries throughout Idaho for lending to library patrons and will work with the libraries to establish another distribution channel for *30 Simple Things You Can Do To Save Energy*. Stand-alone energy efficiency education tools, such as newsletter fillers, public service announcements, and one-page discussion starters will be developed and marketed to sustainably-minded businesses and organizations. Contacts will be made with high schools and other educational institutions to see what additional opportunities there may be to provide energy efficiency education and materials for students. The Residential Energy Efficiency Initiative will continue to develop the Outreach Tracking System to improve the quality of data captured and to continue to increase the effectiveness of outreach efforts.

## Easy Savings® Program

As a result of IPUC Order No. 30772, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP. Case No. IPC E-08-10 specified that $125,000 be paid to CAP agencies in the Idaho Power service area on a pro-rated basis. In addition, the target for the educational information is qualified families who heat their homes with electricity provided by Idaho Power. As in 2009, CAPAI, signed a contract with Resource Action Programs (RAP) for provision of the Easy Savings® Program in 2010.

Two main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes to reduce energy usage and to allow hands-on experience installing low-cost measures.

The primary target for the program is households qualifying for energy assistance who do not contain household members who meet criteria for weatherization prioritization. The criteria for a household prioritized for weatherization services include elderly, disabled individuals, and families with children.

The Easy Savings Program provides a kit containing low-cost/no-cost energy-saving items to customers qualifying to receive a LIHEAP benefit on their Idaho Power bill. Kit items include the following:

- CFLs
- Hot water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers

- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets and stickers for the laundry and lights
- *Quick Start Guide* to installation (printed in English and Spanish)
- Educational materials and information on Idaho Power energy efficiency programs
- Easy Savings Survey (printed in Spanish and English)

In 2010, payments totaling $125,000 were sent to regional CAP agency executive directors by Idaho Power. The agencies are allowed to keep 10 percent of their portion of the $125,000 to cover expenses for additional time spent on the Easy Savings Program.

Kits were delivered to CAPAI prior to January 2010. Throughout the year, 2,594 kits were distributed to Idaho Power customers approved to receive energy assistance benefits on their Idaho Power bills.

A participant survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits during 2010. Tracking was done via kit/survey numbering system. Returned surveys were used to track educational impact of the program. A drawing from all returned surveys was held and six families won a $100 gift certificate each, provided by CAPAI.

Of the 2,594 surveys distributed, 273 completed surveys were received back from customers describing their experience installing kit items in their homes, resulting in a 10.5 percent response rate. Nine questions referred to the customer taking a suggested action to reduce energy use, and two other questions confirming installation of kit items.

Overall, survey results show that over 64 percent of the customers who received the kits and returned a survey installed five or more kit items. Over 76 percent of the 268 families answering the question "How much have you learned about saving energy and money in your home?" reported "I learned a lot."

Survey results indicated that 256 families reported recycling or unplugging a second or old refrigerator or freezer. Information about how to apply for a rebate from Idaho Power's See ya later, refrigerator® program was included in kit.

Additionally, 258 families reported they lowered, or will lower, their heat during the day and at night. Other energy efficiency actions taken by participants include 247 families who reported installing both CFLs and the 231 families who reported installing the high-efficiency showerhead included in the kit. Most families reported adjusting water, refrigerator, or freezer temperature as suggested by the *Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

In November 2010, CAPAI signed an agreement with RAP to provide 2,127 energy kits for the 2011 program. The kits will be delivered to the CAPAI warehouse before January 2011 for distribution to each agency and to qualified Idaho Power customers throughout the year.

In 2011, each agency will retain 30 percent of their portion of the $125,000 to be used to help pay the salary of a certified educator, as agreed upon by Idaho Power and the CAPAI agencies. Educators from each CAP agency will complete the Home Energy Conservation Certification curriculum taught by CAPAI's Energy Programs coordinator prior to distributing kits to customers. The 2011 program allows agencies 30 percent of the total funds as opposed to the 2010 program, which allowed 10 percent.

Educators in regional agencies will distribute kits and conduct seminars for targeted recipients in order to have all kits distributed prior to the upcoming heating season in the fall.

Continuing in 2011, customers will be encouraged to return the surveys included in the kits in order to be entered into a drawing for prizes provided by CAPAI.

## Commercial Education Initiative

Idaho Power continued to enhance its Commercial Education Initiative, established in 2008. The main objectives are to inform and educate commercial customers regarding energy efficiency, enhance awareness and increase participation in existing commercial energy efficiency and demand response programs, and enhance customer satisfaction regarding the company's energy efficiency initiatives. To accomplish these objectives, the program specialist works in tandem with Idaho Power customer representatives assigned to commercial market segments to capitalize on their established strategic customer relationships.

The program specialist oversees the distribution of informational materials and works directly with trade allies, who in turn support and promote Idaho Power's energy efficiency programs. Additionally, the program specialist routinely conducts individual site visits in an effort to customize energy efficiency recommendations for individual customers or customer segment. Site visits also serve as field and staff training opportunities for future site visits.

In 2010, Idaho Power implemented the use of the Equipment Efficiency Specification Sheets developed by the company in 2009 for customer use. The information contained on these specification sheets focus on common commercial facility equipment and energy efficiency opportunities.

Idaho Power carried out its plan to capitalize on effective customer projects by creating success stories that highlight customers' energy efficiency projects. Nineteen customer *Success Stories* were added in 2010 to the Custom Efficiency webpage on the Idaho Power website at www.idahopower.com/EnergyEfficiency/Business/Programs/CustomEfficiency/customEfficiency_SuccessStories.cfm and are included in *Supplement 2: Evaluation*.

Also in 2010, Idaho Power developed Energy Efficiency Tip Sheets for use by commercial customers. These tip sheets provide standardized energy efficiency recommendations tailored to specific commercial market segments, which included restaurants, health care facilities, hotels, and grocery stores. Market segments were identified using the North American Industry Classification System's Standard Industrial Classification (SIC) codes for each segment. Informational materials, including the health care, hotel, and grocery tip sheets were given to customers during site visits. The restaurant tip sheet was used in a mass mailing to over 2,100 customer locations. Because of the low return for the cost required to do target mailings, distribution of the other three target pieces will be done through site visits and customer request for information.

By year-end, the Commercial Education Initiative staff performed a total of 96 walkthrough evaluations, contractor visits, and presentations to municipalities and professional groups. Idaho Power provided input and funding for 48 presentations and training sessions, in collaboration with the IDL in Boise.

Another important part of the education initiative is identifying challenges in the delivery of efficiency education messages to commercial customers. A newly emerging challenge has been locating appropriate audiences. As the industry matures, audiences needing energy information are not readily identifiable. The accessibility to receptive audiences has become much more difficult over the past few

years. Two years ago, almost any energy topic presentation appropriately marketed was well attended. In 2010, there were energy efficiency presentations and trainings offered industry-wide with limited new content, provided to audiences knowledgeable about energy efficiency. Often, attendees were energy efficiency authorities or established contractors. In most presentations and trainings in 2010, knowledgeable and experienced attendees outnumbered the audience needing energy efficiency ideas and practices.

A possible solution for locating untapped markets in need of energy efficiency training was identified through interactions with another organization that Idaho Power collaborated with in 2010. Idaho Power conducted a joint presentation/training in McCall in 2010 with the Snake River Alliance (SRA). This well-attended event generated numerous requests for information and services. The SRA targets smaller markets where training and resources are less available. They identified participant fatigue as an issue, which plagues other organizations concerned with efficiency information and training. Because of the event, a potential market emerged; the smaller commercial markets in rural areas. Another use of the smaller market approach in 2010 was an Idaho Power presentation for the Idaho Commission for Libraries, resulting in high attendance and further requests for information and services.

Idaho Power contracted with The Cadmus Group, Inc. to provide a process evaluation of the Commercial Education Initiative. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011. The report noted that this initiative provides valuable educational and technical services to commercial customers and supports many of the programs in Idaho Power's commercial/industrial portfolio. Recommendations for program improvement included the need to have more clearly defined goals, update marketing materials, enhance program tracking capabilities, and gather customer feedback. Idaho Power is currently analyzing all recommendations. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

In 2011, the Commercial Education Initiative will seek future opportunities to assist small communities interested in learning more about energy efficiency. The initiative will continue to conduct site visits, use the Equipment Efficiency Specification Sheets, distribute target market information tip sheets, and present at professional meetings. Additionally, the initiative will continue to work with education programs. such as Boise State University's Small Business Development Center, supporting their efficiency evaluations for small businesses. Also in 2011, the initiative will provide consultation to energy efficiency education programs at local colleges, including College of Western Idaho and the College of Southern Idaho. A sixth tailored Energy Efficiency Tip Sheet, designed for schools, will be distributed in 2011, along with the other five tailored tip sheets providing standardized and specialized energy efficiency recommendations.

Final reports from The Cadmus Group's, Inc., 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs, but that still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

In 2010, Idaho Power sponsored one LEEF project. A payment of $250 was made to the Idaho Conservation League (ICL) to sponsor 50 percent of the cost of a home audit and weatherization demonstration, in support of ICL's 10/10/10 energy efficiency initiative. The initiative was part of a national effort by conservation organizations to highlight global warming by sponsoring various demonstrations and activities on October 10, 2010. The day's events in Hailey, Idaho, included a public educational forum that Idaho Power personnel participated in and the home-audit demonstration.

## Students for Energy Efficiency

Idaho Power created the SEE program in 2009. Idaho students participate in energy assessments of their schools and homes using science and math skills to evaluate and provide recommendations regarding energy improvements and energy efficiency. At numerous presentations, including EEAG, the success of this program has been praised.

There were two primary initiatives in 2010. The first one was a program for high school students. The project is designed as a "learning lab" where students gain a better understanding of energy, how it is measured, and how to use it more efficiently. The second initiative was an elementary program focused on sixth-grade students. Students receive a tool kit and exercises that the sixth graders work on in their classroom, as well as take-home exercises to work on with their families.

During the 2010–2011 school year, over 300 students are participating in the high school program, and over 6,500 students are participating in the elementary program.

The SEE program promotes targeted educational standards that reinforce the Idaho Department of Education Content Standards for Science. The four main topics addressed are: 1) defining energy, 2) identifying how energy is used, 3) describing energy measurement methods, and 4) determining how energy can be used more efficiently.

Schools participating in the SEE program provide benefits to their communities in the form of reduced energy use and reduced operating costs. Evaluations by program participants were conducted following the completion of the students' assessment reports, presentations, and participation.

During the summer of 2010, a review of the program activities for the 2009–2010 school year was conducted with the assistance of the SEE Community Advisory Group, participating teachers and students, Idaho Power's customer research and analysis leader, customer research coordinator, and energy efficiency evaluator. Teacher survey results, as compiled and analyzed by the customer research coordinator, indicate overwhelming approval and continued interest in the program.

The in-school training schedule was adjusted to include two training sessions per school. The first two-hour session introduces the program and the Crime Scene Investigation (CSI)/Energy Scene Investigation (ESI) concept to students; acquaints them with the equipment; and introduces concepts on assessing lighting, building envelope, plug and phantom loads, and energy usage per square foot. A second one-hour session assists students in analyzing and understanding energy assessment data they have collected; using the Easy Upgrades Calculator to determine current energy usage and potential energy and cost savings based on their recommendations; and determining report format and target audiences for presentations.

Presentations promoting the SEE program were made to the Idaho Science, Technology, Engineering and Mathematics (iSTEM) conference, the Idaho Environmental Education Association conference, and the Idaho Science Teachers Association conference.

The development of the SEE program followed the IPUC Order No. 30760, dated March 27, 2009, directing the use of a portion of the proceeds from 2007 sulfur dioxide ($SO_2$) emissions credits sold by Idaho Power. The order called for delivery of the energy education program for two years and a report summarizing the results. Idaho Power will produce the report following the close of the 2010–2011 school year.

## Regional Technical Forum

The BPA and the Northwest Power and Conservation Council (NPCC) established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating in various subcommittees.

The forum's purpose is advising BPA, the NPCC, the region's utilities, and organizations, including NEEA and the ETO on technical matters related to energy efficiency and renewable-resources development. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and renewable resource goals. Providing feedback and suggestions for improving the effectiveness of regional energy efficiency and renewable resource development programs are additional activities of the RTF. The RTF also recommends a list of eligible conservation measures and the estimated savings associated with those measures. Idaho Power takes the information provided by the RTF into consideration when conducting research and analysis on new and current measures. The RTF meets 10–12 times annually to review and provide comments on analyses and other materials prepared by NPCC and BPA staff and RTF contractors. Idaho Power uses the savings estimate and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics.

In 2010, Idaho Power staff participated in all of the RTF's meetings and was involved in various subcommittees. Idaho Power has been involved in the ongoing Commercial Rooftop Unit Work Group (RTUG) subcommittee since 2007. Currently, nine sites in Idaho Power's service area have been metered since 2008 and is part of the nation's largest publically available rooftop unit data set. A commercial program specialist actively participates in the RTUG subcommittee meetings. The Idaho Power Irrigation sector specialists contributed to the irrigation measure analysis while on the Irrigation Hardware Subcommittee during 2009 and early 2010. An Idaho Power Custom Efficiency program specialist was solicited for the Grocery Refrigeration Subcommittee in 2010 and will remain on the subcommittee during 2011. Also in 2011, the H&CE Program specialist will participate on the Ground-Source Heat Pump Subcommittee.

## Boise City Home Audit Project

The City of Boise received stimulus dollars via the US DOE Energy Efficiency Conservation Block Grant (EECBG). Idaho Power is partnering with the city to create a limited-term, residential energy audit project that will include installation of some low-cost energy-saving measures for 650 homes. The audits will identify larger efficiency needs. Homeowners will be provided information on programs that can assist them with the costs of implementing these additional measures, such as information on the City of Boise's Home Improvement Loan Program.

Idaho Power will design and manage the project, with City approval, and contract with HPS to perform the energy audits and installation of measures.

The energy audit will include a blower door test, a visual inspection of crawl space and attic, and a collection of data regarding the home and its energy use. Potential low-cost energy-saving measures that

could be installed in each home include limited sealing of air leaks, such as mastic around furnace unit; installing CFLs; insulating water pipes that are three feet or less between the water heater and the structure; and installing a low-flow showerhead. The visit will include educating customers on a variety of items, such as how to replace their furnace filter or lower the temperature on their water heater.

Participating customers pay $49 for the audit and installation of measures, with the remaining cost covered by the EECBG funds. This is a great value for the customer. Energy audits of this type normally cost $300 and more, not including the measures, materials, and labor. The cost of the materials potentially installed at each home is approximately $100.

Target audience for this project is Boise City residential customers living in single-family, site-built homes under 3,000 square feet. The homes must be owner-occupied as a year-round residence. It is necessary for the customer to have lived in the home for at least 12 months, allowing retrieval of a full year of historical data prior to installation of any measures related to this project. In addition, it is desirable that the customer plans to stay in the home for the next year or two. This would allow post-installation data collection based on the same family/electric use style. Twenty-five percent of targeted homes must be all electric.

Participants will be selected on a first-come, first-served basis. Applicants received beyond the allotment will be placed on a standby list to be used if an accepted applicant decides not to participate or does not qualify.

In 2010, the project design was complete. An RFP for auditors was sent, applicants reviewed, and three companies selected. The selected auditors and QA company completed contracts. In October 2010, the auditors were trained on the project and process. The project launched mid-November, and marketing letters were sent to a small randomly selected group from a larger target group. The audits and QA of the audits began after that. Reporting to the city is done monthly and quarterly. Audits and QA will continue through approximately May 2011. At that time, the analysis process will begin.

# REGULATORY INITIATIVES

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives.

Since 2002, Idaho Power has recovered its DSM program costs through the Rider with the intended result of providing more timely recovery of DSM costs. To address the removal of financial disincentives, Idaho Power is testing the effects of a FCA mechanism in a five-year pilot initiative. The FCA pilot just completed year four. To introduce an option to provide financial incentives for DSM, the company filed in October Case IPC-E-10-27 to move incentive payments for one DSM program to a regulatory asset account in order to begin earning its authorized rate of return on the DSM investment. This will allow some energy efficiency investments to be treated similar to supply-side investments and not treated as inferior investments. In the same filing, the company also proposed moving the recovery of incentive payments of demand response programs out of the Rider mechanism and into the PCA mechanism. This move would treat the cost recovery of demand response incentive payments similar to other supply-side resource expenses such as fuel, purchase power, and surplus sales. These mechanisms are discussed in more detail below.

## Fixed-Cost Adjustment Pilot

Under the FCA, rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in energy efficiency and demand response resources. The FCA Pilot is limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through their energy charges.

During the initial three-year period in which the FCA, Schedule 54, was in effect, Idaho Power made strong progress toward improving and enhancing its efforts to promote energy efficiency and DSM activities. The company increased the number of energy efficiency and demand response programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained through these activities. Results from the first three years of the pilot indicated that the true-up mechanism was working as intended.

On October 1, 2009, the company filed an application with the IPUC to convert the FCA to an ongoing and permanent rate schedule. On April 29, 2010, the IPUC issued Order No. 31063 extending the FCA as a pilot for an additional two years, effective January 1, 2010.

On May 28, 2010, the IPUC issued Order No. 31081 approving the company's request to implement FCA rates for fixed-cost deferrals in 2009. Beginning June 1, 2010, the company implemented an overall rate adjustment of 1.85 percent to residential and small general service customers to collect a combined $6.3 million in under-collected fixed costs. Residential customers experienced a rate increase of 0.1218 cents/kWh, while small general service customers experienced an increase of 0.1535 cents/kWh. The rate adjustments resulted in a collection of an additional $3.6 million over the then current billed amounts and will be in place until May 31, 2011.

## Irrigation Peak Rewards Filings in Idaho and Oregon

In 2010, Idaho Power enhanced its traditional annual review of the Irrigation Peak Rewards program by conducting an additional study in conjunction with its 2011 IRP analysis. This study was conducted in an effort to ensure that the program's design is aligned with the resource needs identified by the IRP.

After a thorough review of resource need and demand-reduction potential, the company concluded that its need for demand response extended beyond 8:00 p.m. to at least 9:00 p.m. Further, the company concluded that its annual capacity need during the highest 60 hours of demand was expected to vary by more than 50 percent (167 MW) during the next five years. Based on these findings, the company filed program modifications to its Irrigation Peak Rewards programs in Idaho (Case No. IPC-E-10-46) and Oregon (Advice No. 11-01).

In its filings, Idaho Power first sought to include the 8:00 p.m. to 9:00 p.m. hour as an "Extended Interruption" option on a voluntary basis. Customers willing to accept an extended interruption period would receive a higher incentive payment for event hours. In return, Idaho Power would be able to reduce loads across the entire peak period.

Second, in an effort to better align annual program costs with the annual capacity need, the company proposed to change the incentive structure for the program from a fixed incentive payment methodology to a methodology that combined a fixed and variable incentive payment. Having a portion of the incentive based on the actual utilization of the resource would more closely align the cost of demand response with the variable capacity needed.

Third, to encourage equipment testing and participant familiarity with the program, Idaho Power recommended the program be modified to allow one program test event per program season that is not subject to a variable payment.

Overall, the proposed program modifications are reflective of a collaborative process in which Idaho Power received feedback from numerous stakeholder groups, including the Idaho Irrigation Pumpers Association, the Commission Staff, the EEAG, and the IRPAC. The revised program, as proposed, will more closely align program incentives with the company's need for demand response. The company will continue to monitor the program's performance and report on program results next year through the *Demand-Side Management 2011 Annual Report*.

## Demand-Side Resource Business Model Filing

On October 22, 2010, Idaho Power filed Case No. IPC-E-10-27 with the IPUC requesting authorization to implement a demand-side resource (DSR) business model that would 1) move demand response incentive payments into the PCA on a prospective basis beginning June 1, 2011; 2) establish a regulatory asset for Custom Efficiency program incentive costs beginning January 1, 2011; and 3) change the carrying charge on the Idaho Energy Efficiency Rider (Rider) from the customer deposit rate to the company's authorized rate of return. Idaho Power requested an order by March 15, 2011.

Idaho Power stated in the filing that from a regulatory standpoint, successful DSR business activities require clear and achievable guidelines for prudency. There must be a timely recovery of out-of-pocket expenditures that appropriately recognizes the time value of money and does not negatively impact cash flow in a significant way. Economic disincentives to reduce load must be mitigated through better pricing, decoupling, or some other mechanism that does not strand fixed cost recovery. Finally,

the company must have the ability to earn on the energy efficiency investments just like any other business activity in which the company is engaged.

The Rider balance is presently negative by more than $17 million and has been negative since April 2008. The large growing balance reflects success associated with increasing programs, expenditures, and savings in DSR. However, continuing to increase the negative balance is problematic. A Rider account with an extended negative balance breaks the symmetry of the mechanism and negatively impacts the company's cash flow. The company believes there is a more appropriate path that would allocate some of the expenses to more suitable alternatives for recovery.

All costs for the demand response programs are presently recovered through the Rider. Currently, the Idaho Rider charge is 4.75 percent of base rates applied to all customer groups. In this filing, Idaho Power requested authority to remove recovery of customer and demand-aggregator contractor incentive payments for all company demand response programs from the Rider balancing account and transfer these costs to the PCA for 100 percent recovery on a prospective basis. Idaho Power proposed to begin shifting the recovery of the demand response incentive costs to the PCA beginning with the company's forecast of April 2011 through March 2012 power supply costs, currently expected to be approximately $14.6 million. Idaho Power proposes to include these costs in the PCA in a manner consistent with the current PCA methodology. The company would forecast Idaho demand response incentive payments just as it does for its forecast of fuel, purchased power, and surplus sales. This forecasted amount of demand response incentive costs would be included in PCA rates, effective June 1, 2011.

In addition to moving demand response incentive costs to the PCA, Idaho Power proposed to change the method of recovering a portion of the energy efficiency program incentive costs. Currently, all energy efficiency incentive costs are recovered through the Rider balancing accounts. The company proposed to capitalize the direct incentive payments associated with the Custom Efficiency program to enable the company to earn a return on a portion of its DSR activities. The company proposed to start booking incentive payments to a regulatory asset account beginning January 1, 2011. The balance in the account would be included in the company's revenue requirement at the time of a future rate case and would be amortized over four years. The then-current commission authorized rate of return would be applied as a carrying charge during the deferral period and the amortization period. This treatment will keep the selected DSR assets on par with supply-side assets.

Because of the large negative balance existing in the Rider and because it will take almost two years to work this balance down given the prospective nature of the company's previously stated requests, Idaho Power requests that the IPUC authorize the carrying charge on the remaining balance to reflect the company's authorized rate of return (currently 8.18 overall rate of return with a 10.5 return on equity component) instead of the interest rate on customer deposits (currently 1.0 percent). Changing the current carrying charge is particularly important should the IPUC decide against part or all of the company's requests.

If the IPUC implements the company's two proposals, the 2010 negative Rider balance of $17,592,938 is projected to shrink to a negative $3,356,306 in 2011 and, in the middle of 2012, it is expected that this account will approach zero.

On March 3, 2011, Idaho Power filed testimony in support of a settlement Stipulation in this case. Terms of the Stipulation include moving demand response program incentives associated with the A/C Cool Credit program, the Irrigation Peak Rewards program, and the FlexPeak Management program to the PCA on a prospective basis beginning June 1, 2011. A one-year interim per kWh tariff

rate will be implemented for each customer class in order to recover the same amount of revenue from each class as would have been recovered through a DSM Rider charge. The parties agree that incentive payments of the Custom Efficiency program would be capitalized as a regulatory asset beginning January 1, 2011, with a carrying charge equal to the current IPUC authorized rate of return. Once placed in rates, this regulatory asset will be amortized over seven years and will earn the then-current, commission-approved authorized rate of return. The parties also agree that the Idaho Rider carrying charge will remain at the customer deposit rate. The parties signing the Stipulation were Idaho Power, IPUC Staff, the ICL, Northwest Energy Coalition, SRA, and CAPAI. The Idaho Irrigation Pumpers Association, Inc., did not sign the Stipulation, but do not oppose it. The industrial customers of Idaho Power did not sign the Stipulation and are expected to file testimony in opposition to the Stipulation. At this time, the IPUC has not issued a final order in this case.

## Energy Efficiency Rider—Prudency

On March 16, 2010, Idaho Power, under Case No., IPC-E-10-09 filed an application to the IPUC for an order designating Idaho Power's expenditure of $50,701,740 in Idaho Rider funds in 2008 and 2009 as prudently incurred expenses. This prudency filing was the first designed to comply with the agreed-upon principles set forth in the MOU for Prudency Determination of DSM Expenditures. The filing included as attachments to the *Demand-Side Management 2009 Annual Report*, along with two new documents, *Supplement 1: Cost-Effectiveness* and *Supplement 2: Evaluation*. On November 16, 2010, in Order No. 32113, the IPUC found that the company acted prudently in the administration of its DSM programs and found its 2008 and 2009 Rider expenditures were approved for ratemaking purposes. On page 9 of the Order, the IPUC states; "The Commission exhorts Idaho Power to continue on this path toward improvement. Idaho Power should seek to employ independent evaluators for all of its DSM programs and take affirmative steps toward achieving measurable improvements in its documentation, verification and record-keeping processes for these programs."

## Energy Efficiency Rider—Oregon

On March 5, 2010, Idaho Power filed a request with the OPUC under Tariff Advice 10-03 to increase the Rider from 1.5 percent of base rates to 3.0 percent of base rates and to eliminate the funding caps on residential and irrigation bills. On April 27, this request was approved, effective June 1, 2010.

# CONTINUED COMMITMENT

Every year, Idaho Power enhances its commitment to providing DSM programs that offer broader opportunities for Idaho Power's customers to manage their energy and demand use. Idaho Power also continues its effort to make its own facilities more energy efficient and to find ways to promote energy efficiency in its communities and its employees' lives. A review of specific efforts is listed in the following sections.

## Continued Expansion and Broad Availability of Efficiency and Demand Response Programs

In 2010, Idaho Power broadened the portfolio of programs offered to customers. Programs continue to add service areas where they are available to customers and continue to add new measures for customer participation. This expansion of programs and offerings helps ensure more customers each year have the opportunity to participate in programs. Some highlights for 2010 are as follows:

- Weatherization Solutions for Eligible Customers program expanded to the Idaho counties of Canyon, Gem, Payette, Boise, Washington, Valley, and Adams.
- Idaho Power partnered with City of Boise to implement the Boise City Home Audit Project to provide reduced priced audits for 600–700 residents.
- Idaho Power was a major sponsor of Idaho's first Net-Zero Energy Home promotion in conjunction with the St. Jude Dream Home campaign.
- In June 2010, as part of the Home Products Program, Idaho Power began a showerhead promotion program for 1.5 GPM and 2.0 GPM units and added freezers to the program's offerings.
- The successful SEE program completed a second year of operation with 300 high school and 6,000 elementary students participating.
- New educational material was developed for several programs including a Healthy Homes Guide and Energy Efficiency Kits available at local libraries.
- More information was available on the Web for customers interested in energy efficiency, including the booklet *30 Simple Things You Can Do To Save Energy* and access to individualized *Energy Tools*.
- Energy Efficiency Tip Sheets were developed for different sectors of commercial customers.
- Custom Efficiency participants' *Success Stories* were posted to the Idaho Power website.

## Building-Code Improvement Activity

Idaho Power was supportive of the legislative effort in the Idaho State legislature to enact the 2009 IECC for implementation January 1, 2011.

## Pursuit of Appliance Code Standards

In 2010, Idaho Power provided support for efforts for national appliance standards. Letters of support were provided to both Senator Mike Crapo and Senator James Risch pointing to the broad economic, operational, and environmental benefits of energy efficiency to the citizens of Idaho.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power continues to support a policy of gradually moving all customers into rates designed to provide cost-based price signals and to encourage the wise and efficient use of energy.

In 2010, Idaho Power took a new look at its policy for how to work with new and expanding large-load customers. A policy was established that provides service consistent with system capability, that offers a suite of flexible services, including seasonal shaping and standby service, that provides some mitigation of rate impacts on existing customers and that considers sustainability, economic development goals, and environmental effects of using the company's resources. As part of this effort, in August, the company filed to change the eligibility cap for Schedule 19 customers from 25 MW to 20 MW. By lowering the size limit, the company can address these service issues to new large loads that may be coming into the service area. In December 2010, under Order No. 32132, the IPUC approved the request.

On March 1, 2010, as per Order 10-064 in General Rate Case UE 213, Idaho Power implemented mandatory time-of-use rates (TOU) for all customers on Schedule 9 Primary and Schedule 9 Transmission. With this rate change, all industrial customers on Schedule 19 and Schedule 9 P and T across the Idaho Power service area are on TOU rates. Idaho Power also implemented a load-factor pricing rate structure for irrigation customers on Schedule 24 in Oregon. These rate change proposals were driven by the explicit Idaho Power objective of providing customers with cost-based price signals, which encourage the wise and efficient use of energy.

## Third-Party, Independent Verification

Idaho Power understands that credible and transparent program evaluations are critical to ensuring maximum program performance. Independent, third-party consultants are used to provide impact and process evaluations to verify that program specifications are met, provide viable recommendations for program improvement, and validate energy savings achieved through Idaho Power's programs.

In 2010, process evaluations were completed by third-party consultants on nine programs, including H&CE Program, Energy House Calls, Home Improvement Program, Residential Energy Efficiency Education Initiative, Easy Upgrades, Building Efficiency, Custom Efficiency, Commercial Energy Efficiency Education Initiative, and Irrigation Efficiency Rewards. Copies of these reports can be found in *Supplement 2: Evaluation*.

Idaho Power uses independent, third-party contractors for QA and OSV for several programs. The H&CE Program uses a third-party contractor to perform QA and OSV of approximately 10 percent of completed customer projects. The Energy House Calls program contracts with third-party experts to perform QA analysis on approximately 5 percent of homes serviced by the program. These contractors visit the customer site within approximately one month of the energy house call to verify that the energy efficiency measures were performed to program specifications. And the ENERGY STAR® Homes Northwest program uses contractors for third-party verification, ensuring that each ENERGY STAR

qualified home is built to ENERGY STAR standards. Another third-party contractor provides QA and certifies each qualifying home as an ENERGY STAR home.

Throughout 2010, Idaho Power participated with NEEA to conduct several third-party evaluations. These studies included evaluation of the DHP Pilot, Residential Lighting Market Research, Market for Energy Efficient Electronics, Evaluation of Codes and Standards Market Progress, Northwest ENERGY STAR Homes Northwest, and several market effects evaluations in the residential, commercial, and industrial sectors.

The company also funds and participates in the RTF. The RTF is an advisory committee that was established in 1999 to develop regional standards for verifying and evaluating savings from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information regarding energy efficiency programs and measures and uses the RTF databases to provide deemed savings for a portion of the energy efficiency measures implemented by the company's customers.

## Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, providing incentives, and educating its customers.

Idaho Power's corporate headquarters (CHQ) participated in strategic elimination of power loads during peak use through the FlexPeak Management program. In August, Idaho Power entered into an agreement with EnerNOC to enroll the CHQ in FlexPeak Management—Idaho Power's commercial/industrial demand response program. EnerNOC enlists and contracts with Idaho Power's commercial and industrial customers to voluntarily reduce their electricity use primarily during times of Idaho Power system peaks. EnerNOC provides participants with auditing assistance, energy monitoring software, demand reduction performance monitoring, coaching, and other related services. The agreement with Idaho Power to enroll the CHQ was executed in early August 2010. Unlike other program participants, Idaho Power does not receive any financial incentives to participate. By the end of August, the company received usage data through EnerNOC's energy monitoring software and performed CHQ site-testing to establish the amount of load available for reduction. The amount of reduction EnerNOC commits to achieve on Idaho Power's behalf will be based on the demand reduction available at the CHQ each week during the active program season beginning in June 2011. EnerNOC is obligated to achieve the reduction they nominate, or commit to, each week if Idaho Power calls an event. EnerNOC works closely with its program participants to estimate their reduction potential accurately. Idaho Power now has a facility reduction plan in place that could be executed at any time to reduce electricity use if necessary.

During 2010, the company continued with the multi-year remodel and retrofit of the CHQ, completing the second floor of the building. The project included installing T-5 lighting that uses 60 percent less energy than old lighting packages. Natural light supplemented the T-5 lighting, accomplished through light harvesting near the exterior walls. Additionally, use of shorter 53-inch cubical partitions allowed more daylight while reducing lighting costs. Further retrofits included occupancy and vacancy sensors in all enclosed office and meeting spaces, low-flow toilets and automatic sink faucets in the restrooms, and window blinds that are 60 percent opaque with a horizontal range of motion that never needs closed. Other projects included the ongoing Payette Operations Center upgrades from T-12 to T-8 high-bay fluorescent lighting in the garage and materials area. The Canyon Operations Center lighting retrofit from T-12 to T-8 throughout the facility was completed in 2010. Twin Falls Operations Center's garage and materials areas received upgrades, from T-12 fixtures to high-bay fluorescent T-8 fixtures.

Numerous energy efficiency projects are budgeted for 2011. The remodel of the CHQ will continue with a focus on the first floor. A completion of the lighting retrofit at the Payette Operations Center is planned. Though it will take several years to complete lighting retrofits in the company's sub-stations across the service area, planning is underway in 2011. The company is engineering a new energy-efficient chilled water system for the CHQ with implementation planned during 2012 through 2013.

## CAES Energy Efficiency Research Initiative

The Center for Advanced Energy Studies (CAES) is a public–private technical and policy research partnership based in Idaho Falls, and comprised of Boise State University, Idaho State University, University of Idaho, the DOE, and Idaho National Laboratory (INL). The State of Idaho launched the newest activity under the CAES umbrella on October 27, 2010 when Idaho Governor C.L. "Butch" Otter announced the formation of the CAES Energy Efficiency Research Initiative (CEERI).

Idaho Power was involved in the initial discussion and planning for CEERI, and joined Governor Otter and other representatives of participating entities in signing a proclamation in support of the initiative's formation. Signatories included Boise State University, University of Idaho, Boise Metro Chamber of Commerce, National Resources Defense Council, Idaho Office of Energy Resources (IOER), Idaho Innovation Council, Micron Technology, and other Idaho-based companies.

The initiative's initial focus is in four main areas: 1) public outreach and education, 2) workforce development, 3) college-level curriculum, and 4) research/technical development. Idaho Power's involvement in CEERI enables the company to positively influence energy-efficiency education and research. The company will also benefit from educational opportunities for Idaho Power customers and employees and from the development of a workforce with relevant skills.

## Sustainable Operations/Sustainability

In 2010, Idaho Power began an internal sustainability effort with a mission to promote and support exceptional financial, environmental, and social stewardship across Idaho Power business practices. A Sustainability Council was formed with members representing major company departments with the expressed vision to make sustainability a corporate value. A sustainability charter containing an operational definition, mission, vision, and objectives was drafted for review and endorsement by executive council. The objectives for 2011 include development of a sustainability plan. This plan included internal and external reporting, and determination of baseline operating parameters for several Idaho Power facilities, including energy use.

## Green Team

During spring 2010, Idaho Power employees started an internal Green Team. The mission of the Green Team was to champion sustainable activities by Idaho Power and its employees that promoted energy efficiency, environmental and community stewardship, and the wise use of resources. Some of the projects worked on during 2010 included a company-wide recycling initiative, the Refugee Community Garden Project, a no-idling campaign, and a monthly Green Bag educational seminar effort.

# APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2010, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders, BPA funding, and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2010. Appendix 4 shows similar data as Appendix 3, but also includes data for past years' program performance, B/C ratios from the utility perspective, and from the TRC perspectives for active programs. An addition to this year's report is Appendix 5. This new appendix shows program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost effectiveness information by program and energy savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. A new table, *2010 DSM Detailed Expenses by Program*, reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of various third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information included with each supplement.

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## **Appendix 1.** Idaho Rider, Oregon Rider, and NEEA funding balances

| | |
|---|---|
| **Idaho Energy Efficiency Rider** | |
| 2010 Beginning Balance | $ (9,718,518) |
| 2010 Funding plus Accrued Interest | 34,605,272 |
| **Total 2010 Funds** | 24,886,751 |
| 2010 Expenses | (42,479,692) |
| **2010 Year-End Balance** | $ (17,592,938) |
| **Oregon Energy Efficiency Rider** | |
| 2010 Beginning Balance | $ (866,772) |
| 2010 Funding plus Accrued Interest | 697,464 |
| **Total 2010 Funds** | (169,308) |
| 2010 Expenses | (1,704,367) |
| **2010 Year-End Balance** | $ (1,873,675) |
| **NEEA Payments and Escrow Credit Funds Balance** | |
| 2010 Idaho Power Contractual Obligation[a] | $ 2,391,217 |
| **2010 Year-End Balance** | $ 2,391,217 |

[a] Idaho Power shall prepay estimated expenses quarterly, where the amount shall be amortized over the respective quarter. Funding of NEEA, approved by IPUC Order 31080, dated 5/12/10. Reconciliation between the estimated expenditures and the actual expenditures for the quarter will be completed 30 days after the quarter end or by March 1st for year-end. A true-up of the variance will be included in the next quarter's invoice, not to exceed 125% of its five-year total direct funding contribution.

## **Appendix 2.** 2010 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Idaho Power | Total Program |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit | $ 1,854,979 | $ 74,071 | $ 73,496 | **$ 2,002,546** |
| Ductless Heat Pump Pilot | 181,969 | 7,262 | 0 | **189,231** |
| Energy Efficient Lighting | 2,442,931 | 58,347 | 0 | **2,501,278** |
| Energy House Calls | 724,895 | 37,435 | 0 | **762,330** |
| ENERGY STAR® Homes | 369,344 | 6,093 | 168 | **375,605** |
| Heating & Cooling Efficiency Program | 314,963 | 12,706 | 0 | **327,669** |
| Home Improvement Program | 944,716 | 0 | 0 | **944,716** |
| Home Products Program | 813,171 | 18,990 | 0 | **832,161** |
| Oregon Residential Weatherization | 0 | 4,575 | 1,475 | **6,050** |
| Rebate Advantage | 34,283 | 5,119 | 0 | **39,402** |
| See ya later, refrigerator® | 548,872 | 16,207 | 0 | **565,079** |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 1,321,132 | **1,321,132** |
| Weatherization Solutions for Eligible Customers[a] | 216,202 | 2,306 | 9,917 | **228,425** |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,466,179 | 43,422 | 81 | **1,509,682** |
| Easy Upgrades | 3,862,653 | 111,757 | 0 | **3,974,410** |
| FlexPeak Management | 1,807,527 | 95,153 | 0 | **1,902,680** |
| Holiday Lighting | 45,816 | 316 | 0 | **46,132** |
| Oregon Commercial Audits | 0 | 5,049 | 0 | **5,049** |
| Custom Efficiency | 8,046,168 | 717,132 | 14,825 | **8,778,125** |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 2,059,676 | 110,034 | 31,104 | **2,200,814** |
| Irrigation Peak Rewards | 13,096,946 | 184,075 | 49,805 | **13,330,826** |
| **Energy Efficiency Total** | **$ 38,831,290** | **$ 1,510,049** | **$ 1,502,003** | **$ 41,843,342** |
| **Market Transformation** | | | | |
| NEEA[b] | 2,271,656 | 119,561 | 0 | **2,391,217** |
| **Market Transformation Total** | **$ 2,271,656** | **$ 119,561** | **$ 0** | **$ 2,391,217** |
| **Other Programs and Activities** | | | | |
| **Residential** | | | | |
| Residential Energy Efficiency Education Initiative | 211,695 | 10,397 | 0 | **222,092** |
| **Commercial** | | | | |
| Commercial Education Initiative | 65,327 | 3,438 | 0 | **68,765** |
| **Other** | | | | |
| Energy Efficiency Direct Program Overhead | 100,087 | 7,831 | 9,956 | **117,874** |
| Local Energy Efficiency Funds | 238 | 13 | 0 | **251** |
| **Other Programs and Activities Total** | **$ 377,347** | **$ 21,679** | **$ 9,956** | **$ 408,982** |
| **Indirect Program Expenses** | | | | |
| Residential Overhead | 132,082 | 6,941 | 0 | **139,023** |
| Commercial/Industrial/Irrigation Overhead | 143,140 | 7,543 | 0 | **150,683** |
| Energy Efficiency Accounting and Analysis | 698,907 | 37,068 | 136,833 | **872,808** |
| Energy Efficiency Advisory Group | 2,651 | 112 | 0 | **2,763** |
| Special Accounting Entries | 22,619 | 1,414 | 0 | **24,033** |
| **Indirect Program Expenses Total** | **$ 999,399** | **$ 53,078** | **$ 136,833** | **$ 1,189,175** |
| **Totals** | **$ 42,479,692** | **$ 1,704,367** | **$ 1,648,792** | **$ 45,832,851** |

[a] Oregon Rider balance of $2,306 will be reclassed to the Idaho Rider in 2011.

[b] NEEA funding addressed in IPUC per Order No. 31080, dated 5/12/10. 2011 annual expense expected at $3.3 m (see footnote, Appendix 1 for additional information).

## **Appendix 3.** 2010 DSM program activity

| Program | Participants | | Total Costs: Utility[b] | Total Costs: Resource[c] | Savings: Annual Energy (kWh) | Savings: Peak Demand[d] (MW) | Measure Life | Nominal Levelized Costs[a]: Utility ($/kWh) | Nominal Levelized Costs[a]: Total Resource ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | | | | |
| A/C Cool Credit | 30,803 | homes | $ 2,002,546 | $ 2,002,546 | n/a | 39.0 | n/a | n/a | n/a |
| Irrigation Peak Rewards | 2,038 | service points | 13,330,826 | 13,514,246 | n/a | 249.7 | n/a | n/a | n/a |
| FlexPeak Management | 60 | sites | 1,902,680 | 1,902,680 | n/a | 47.5 | n/a | n/a | n/a |
| **Total** | | | **$ 17,236,052** | **$17,419,472** | **n/a** | **336.2** | | | |
| **Energy Efficiency** | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Ductless Heat Pump Pilot | 104 | homes | $ 189,231 | $ 439,559 | 364,000 | | 20 | $ 0.044 | $ 0.103 |
| Energy Efficient Lighting | 1,190,139 | bulbs | 2,501,278 | 3,976,476 | 28,082,738 | | 5 | 0.020 | 0.031 |
| Energy House Calls | 1,602 | homes | 762,330 | 762,330 | 1,198,655 | | 20 | 0.054 | 0.054 |
| ENERGY STAR® Homes Northwest | 630 | homes | 375,605 | 579,495 | 883,260 | | 25 | 0.033 | 0.051 |
| Heating & Cooling Efficiency Program | 217 | homes | 327,669 | 1,073,604 | 1,104,497 | | 20 | 0.025 | 0.083 |
| Home Improvement Program | 3,537 | homes | 944,716 | 2,112,737 | 3,986,199 | | 45 | 0.016 | 0.035 |
| Home Products Program | 16,322 | appliances/fixtures | 832,161 | 1,025,151 | 1,443,580 | | 15 | 0.057 | 0.070 |
| Oregon Residential Weatherization | 1 | home | 6,050 | 6,275 | 320 | | 30 | 0.011 | 0.062 |
| Rebate Advantage | 35 | homes | 39,402 | 66,142 | 164,894 | | 25 | 0.018 | 0.031 |
| See ya later, refrigerator® | 3,152 | refrigerators/freezers | 565,079 | 565,079 | 1,567,736 | | 8 | 0.054 | 0.054 |
| Weatherization Assistance for Qualified Customers | 400 | homes/non-profits | 1,321,132 | 2,927,898 | 3,741,652 | | 25 | 0.027 | 0.035 |
| Weatherization Solutions for Eligible Customers | 47 | homes | 228,425 | 228,425 | 313,309 | | 25 | 0.056 | 0.056 |
| **Sector Total** | | | **$ 8,093,078** | **$13,763,171** | **42,850,839** | | **12** | **$ 0.021** | **$ 0.036** |
| **Commercial** | | | | | | | | | |
| Building Efficiency | 70 | projects | 1,509,682 | 3,312,963 | 10,819,598 | 0.9 | 12 | 0.016 | 0.035 |
| Easy Upgrades | 1,535 | projects | 3,974,410 | 7,655,397 | 35,824,463 | 7.8 | 12 | 0.013 | 0.024 |
| Holiday Lighting | 25 | projects | 46,132 | 65,308 | 248,865 | 0.0 | 10 | 0.024 | 0.034 |
| Oregon Commercial Audits | 22 | audits | 5,049 | 5,049 | n/a | | n/a | n/a | n/a |
| **Sector Total** | | | **$ 5,535,273** | **$11,038,718** | **46,892,926** | **8.7** | **12** | **$ 0.013** | **$ 0.027** |
| **Industrial** | | | | | | | | | |
| Custom Efficiency[1] | 223 | projects | 8,778,125 | 17,172,176 | 71,580,075 | 9.5 | 12 | 0.014 | 0.027 |
| **Sector Total** | | | **$ 8,778,125** | **$17,172,176** | **71,580,075** | **9.5** | **12** | **$ 0.014** | **$ 0.027** |

# Appendix 3. 2010 DSM program activity (continued)

| Program | Participants | Total Costs: Utility[b] | Total Costs: Resource[c] | Savings: Annual Energy (kWh) | Savings: Peak Demand[d] (MW) | Measure Life | Nominal Levelized Costs[a]: Utility ($/kWh) | Nominal Levelized Costs[a]: Total Resource ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| Irrigation | | | | | | | | |
| Irrigation Efficiency Rewards[2] | 753 projects | 2,200,814 | 6,968,598 | 10,968,430 | 3.3 | 8 | 0.030 | 0.096 |
| **Sector Total** | | **$ 2,200,814** | **$ 6,968,598** | **10,968,430** | **3.3** | **8** | **$ 0.030** | **$ 0.096** |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance[3] | | $ 2,391,217 | $ 2,391,217 | 15,334,073 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Residential Energy Efficiency Education Initiative | | $ 222,092 | $ 222,092 | | | | | |
| **Commercial** | | | | | | | | |
| Commercial Education Initiative | | 68,765 | 68,765 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 117,874 | 117,874 | | | | n/a | n/a |
| Local Energy Efficiency Funds | 1 project | 251 | 251 | | | | | |
| **Total Program Direct Expense** | | **$ 44,643,541** | **$69,162,332** | **187,626,344** | **357.7** | | | |
| Indirect Program Expense | | 1,189,310 | | | | | | |
| **Total DSM Expense** | | **$ 45,832,851** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2009 IRP, and calculations include line loss adjusted energy savings.

[b] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers.

[d] Summer Peak Demand is reported where program MW reduction is documented. Demand response program reductions are reported with 13% peak loss assumptions Demand Response reduction is non-coincident.

[1] Custom Efficiency savings includes 20 Green Motors Rewsindparticipants totaling 55,126 kWh of annual savings not counted in project totals.

[2] Irrigation Efficiency includes 36 Green Motors participants totaling 187,965 kWh of annual savings not counted in project totals.

[3] Savings are preliminary estimates provided by NEEA.

## **Appendix 4.** DSM expense and performance 2002–2010

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs [a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3.1 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6.3 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12.2 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 25.5 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 38.5 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39.0 | | | | | |
| **Total** | | **$13,402,500** | **$13,402,500** | | | | | | | **1.11** | **1.11** |
| FlexPeak Management | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19.3 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 47.5 | | | | | |
| **Total** | | **$ 2,431,361** | **$ 2,431,361** | | | | | | | **1.14** | **1.14** |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 5.6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40.3 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 31.8 | | | | | |
| 2007 | 947 | 1,615,881 | 1,615,881 | | | 37.4 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35.1 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160.2 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,514,246 | | | 249.7 | | | | | |
| **Total** | | **$29,171,244** | **$29,354,664** | | | | | | | **1.43** | **1.37** |
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | $ 202,004 | $ 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| **Total** | **200** | **$ 391,235** | **$ 891,164** | **773,180** | | | **20** | **$ 0.043** | **$ 0.098** | **3.47** | **1.38** |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs: Utility[c] | Total Costs: Resource[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levilized Costs[a]: Total Utility ($/kWh) | Levilized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy Efficient Packets | | | | | | | | | | | |
| 2002 | 2,925 | $ 755 | $ 755 | 155,757 | 0.02 | | 7 | $ 0.001 | $ 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | | |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,619 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,663 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| **Total** | **2,642,513** | **$ 6,214,162** | **$ 8,082,552** | **77,943,613** | | | **5** | **$ 0.018** | **$ 0.023** | **4.54** | **3.49** |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | 26,053 | 26,053 | 25,989 | 0.00 | | 20 | 0.082 | 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 67,616 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |
| 2010 | 1,602 | 762,330 | 762,330 | 1,198,655 | 0.14 | | 20 | 0.054 | 0.054 | | |
| **Total** | **8,522** | **$ 3,784,096** | **$ 3,515,340** | **9,215,987** | | | **20** | **$ 0.035** | **$ 0.032** | **3.06** | **3.06** |
| ENERGY STAR® Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | 0.1 | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | 0.4 | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | 0.9 | 25 | 0.038 | 0.049 | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential Efficiency** | | | | | | | | | | | |
| ENERGY STAR® Homes Northwest | | | | | | | | | | | |
| 2007 | 303 | $ 475,044 | $ 400,637 | 629,634 | 0.07 | 0.6 | 25 | $ 0.056 | $ 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | 0.6 | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | 1.1 | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| **Total** | **2,344** | **$ 2,384,809** | **$ 3,120,758** | **4,116,678** | | | **25** | **$ 0.045** | **$ 0.059** | **2.68** | **2.05** |
| Heating & Cooling Efficiency Program | | | | | | | | | | | |
| 2006 | | 17,444 | 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | 27.344 | 27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,441 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.10 | | 20 | 0.025 | 0.083 | | |
| **Total** | **929** | **$ 1,785,249** | **$ 2,950,479** | **2,942,362** | | | **20** | **$ 0.056** | **$ 0.092** | **2.50** | **1.22** |
| Home Improvement Program | | | | | | | | | | | |
| 2008 | 282 | 123,454 | 157,866 | 317,814 | 0.04 | | 25 | 0.029 | 0.037 | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | |
| **Total** | **1,470** | **$ 444,594** | **$ 708,014** | **1,656,690** | | | **45** | **$ 0.018** | **$ 0.028** | **8.66** | **4.39** |
| Home Products Program | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | | | 15 | 0.044 | 0.082 | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | | | 15 | 0.031 | 0.051 | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | | | 15 | 0.057 | 0.070 | | |
| **Total** | **28,855** | **$ 1,603,609** | **$ 2,347,293** | **3,623,233** | | | **15** | **$ 0.044** | **$ 0.064** | **2.45** | **1.67** |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2002 | 24 | -662 | 23,971 | 4,580 | 0.00 | | 25 | 0.010 | 0.389 | | |
| 2003 | | -943 | | | | | | | | | |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs: Utility[c] | Total Costs: Resource[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levilized Costs[a]: Total Utility ($/kWh) | Levilized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2005 | 4 | $ 612 | $ 3,608 | 7,927 | 0.00 | | 25 | $ 0.006 | $ 0.034 | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | [3] |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | |
| 2009 | 1 | 7,644 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | |
| **Total** | **38** | **$ 29,083** | **$ 81,789** | **47,901** | | | **30** | **$ 0.044** | **$ 0.124** | **2.28** | **1.17** [4] |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | 27,372 | 79,399 | 227,434 | 0.03 | | 45 | 0.008 | 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| **Total** | **700** | **$ 408,088** | **$ 1,011,955** | **2,470,593** | | | **25** | **$ 0.013** | **$ 0.032** | **8.61** | **3.57** |
| See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | 305,402 | 305,401 | 1,132,802 | 0.13 | | 8 | 0.041 | 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| **Total** | **4,813** | **$ 870,481** | **$ 870,480** | **2,700,538** | | | **8** | **$ 0.049** | **$ 0.049** | **1.88** | **1.88** |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 48,162 | 71,680 | 0.01 | | 25 | 0.055 | 0.050 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,720 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 288,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| **Total** | **104** | **$ 444,227** | **$ 439,582** | **596,708** | | | **25** | **$ 0.058** | **$ 0.057** | **1.98** | **1.98** |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs: Utility[c] | Total Costs: Resource[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levilized Costs[a]: Total Utility ($/kWh) | Levilized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Window A/C Trade Up Pilot | | | | | | | | | | | |
| 2003 | 99 | $ 6,687 | $ 10,492 | 14,454 | 0.00 | | 12 | $ 0.051 | $ 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.005** | **$ 0.082** | | |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | 235,048 | 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | 0.029 | 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.033 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.037 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.029 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.025 | 0.032 | | |
| 2009 | 427 | 1,260,922 | 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.021 | 0.033 | | |
| 2010 | 373 | 1,207,705 | 2,814,471 | 3,452,025 | 0.39 | | 25 | 0.027 | 0.035 | | |
| **Total** | **3,420** | **$ 8,956,705** | **$14,258,403** | **22,785,189** | | | **25** | **$ 0.030** | **$ 0.048** | **5.24** | **3.59** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.027 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.016 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.035 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.035 | 0.047 | | |
| 2006 | | | | | | | | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.054 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.040 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.023 | 0.031 | | |
| 2010 | 27 | 113,427 | 113,427 | 289,627 | 0.03 | | 25 | 0.030 | 0.025 | | |
| **Total** | **167** | **$213,321** | **$ 336,712** | **524,612** | | | **25** | **$ 0.031** | **$ 0.050** | **4.12** | **3.00** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.013 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.017 | 0.036 | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs: Utility[c] | Total Costs: Resource[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levilized Costs[a]: Total Utility ($/kWh) | Levilized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2004 | 40 | $ 69,409 | $ 105,021 | 125,919 | 0.01 | | 25 | $ 0.041 | $ 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.020** | **$ 0.038** | | |
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | $ 5,764 | $ 9,061 | 33,976 | 0.00 | | 10 | $ 0.021 | $ 0.033 | | |
| 2004 | | 344 | $344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.023** | **$ 0.035** | | |
| Building Efficiency | | | | | | | | | | | |
| 2004 | | 28,821 | 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | 0.043 | 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 130,591 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,128 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| **Total** | **276** | **$ 5,157,747** | **$ 8,197,104** | **27,579,888** | | | **12** | **$ 0.021** | **$ 0.034** | **4.62** | **2.69** |
| Easy Upgrades | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| **Total** | **3,529** | **$7,061,079** | **$22,086,718** | **66,283,658** | | | **12** | **$ 0.012** | **$ 0.038** | **7.93** | **2.94** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| **Total** | **46** | **$ 62,712** | **$ 145,982** | **650,066** | | | **10** | **$ 0.020** | **$ 0.047** | **3.63** | **1.87** |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Oregon Commercial Audits | | | | | | | | | | | |
| 2002 | 24 | $ 5,200 | $ 5,200 | | | | | | | | |
| 2003 | 21 | 0 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| **Total** | **128** | **$ 38,470** | **$ 42,470** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,858** | **223,368** | | | **12** | **$ 0.012** | **$ 0.046** | | |
| **Industrial** | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | |
| 2003 | | $ 1,303 | $ 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | $ 0.058 | $ 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| **Total** | **570** | **$24,914,034** | **$59,407,144** | **225,703,208** | | | **12** | **$ 0.013** | **$ 0.030** | **7.85** | **3.29** |
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency | | | | | | | | | | | |
| 2005 | 38 | $ 150,577 | $ 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | $ 0.014 | $ 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| **Total** | **4,049** | **$11,692,468** | **$37,821,084** | **67,015,012** | | | **8** | **$ 0.026** | **$ 0.085** | **5.22** | **1.61** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | $ 48,853 | $ 48,853 | 1,825,000 | 0.21 | | 5 | $ 0.006 | $ 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| **Total** | | **$ 297,070** | **$ 297,070** | | | | | | | | |
| Distribution Efficiency | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Other Programs** | | | | | | | | | | | |
| Distribution Efficiency | | | | | | | | | | | |
| 2008 | | $ -1,913 | $ -1,913 | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | 56,909 | 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| **Total** | | **$ 509,651** | **$ 509,651** | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | 55,722 | 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |
| Residential Energy Efficiency Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |
| 2010 | | 222,092 | 222,092 | | | | | | | | |
| **Total** | | **$ 630,887** | **$ 630,887** | | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 45,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 45,522** | | | | | | | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs: Utility[c] | Total Costs: Resource[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levilized Costs[a]: Total Utility ($/kWh) | Levilized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Local Energy Efficiency Funds | | | | | | | | | | | |
| 2003 | 56 | $ 5,100 | $ 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $0.024 | $0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | $0.009 | $0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | $0.135 | $0.135 | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | | 15 | $0.019 | $0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | | 12 | $0.064 | $0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | | | n/a | n/a | | |
| **Total** | **543** | **$ 83,259** | **$ 130,909** | **232,298** | | | **10** | **$0.046** | **$0.072** | **n/a** | **n/a** |
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | $1,286,632 | $ 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,729 | 2.40 | | | | | | [8] |
| 2009 | | 968,263 | 968,263 | 10,702,998 | 1.22 | | | | | | [8] |
| 2010 | | 2,391,217 | 2,391,217 | 15,334,073 | 1.75 | | | | | | [9] |
| **Total** | | **$10,438,170** | **$ 10,438,170** | **148,929,041** | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2009 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | **$ 1,932,520** | **$ 2,366,591** | **16,791,100** | **1.92** | **0.0** | | | | | |
| 2003 | | **2,566,229** | **3,125,573** | **18,654,343** | **2.13** | **0.0** | | | | | |
| 2004 | | **3,827,212** | **4,860,912** | **19,202,780** | **2.19** | **6.6** | | | | | |
| 2005 | | **6,523,349** | **10,383,578** | **37,978,035** | **4.34** | **44.3** | | | | | |

## **Appendix 4**. DSM expense and performance 2002–2010 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levilized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility[c] | Resource[d] | Annual Energy *(kWh)* | Average Energy[e] *(aMW)* | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Annual Totals** | | | | | | | | | | | |
| 2006 | | **$ 11,174,181** | **$ 20,950,111** | **67,026,303** | **7.65** | **44.4** | | | | | |
| 2007 | | **14,896,816** | **26,182,014** | **91,145,357** | **10.40** | **58.5** | | | | | |
| 2008 | | **20,213,215** | **44,771,182** | **128,508,579** | **14.61** | **74.9** | | | | | |
| 2009 | | **33,821,062** | **53,090,852** | **143,146,364** | **16.15** | **236.6** | | | | | |
| 2010 | | **44,643,541** | **69,162,333** | **187,626,344** | **21.23** | **357.7** | | | | | |
| **Total Direct Program** | | **$139,598,124** | **$ 234,893,146** | **710,079,205** | | | | | | | |
| **Indirect Program Expense** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | $ 128,855 | | | | | | | | | |
| 2003 | | -41,543 | | | | | | | | | |
| 2004 | | 142,334 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,175 | | | | | | | | | |
| **Total** | | **$ 4,677,850** | | | | | | | | | |
| **Total Expense** | | | | | | | | | | | |
| 2002 | | **$ 2,061,375** | | | | | | | | | |
| 2003 | | **2,524,686** | | | | | | | | | |
| 2004 | | **3,969,549** | | | | | | | | | |
| 2005 | | **6,700,973** | | | | | | | | | |
| 2006 | | **11,484,013** | | | | | | | | | |
| 2007 | | **15,662,377** | | | | | | | | | |
| 2008 | | **21,193,520** | | | | | | | | | |
| 2009 | | **34,846,766** | | | | | | | | | |
| 2010 | | **45,832,851** | | | | | | | | | |
| **Total 2002–2010** | | **$63,596,492** | | | | | | | | | |

End notes:

[a] Levelized Costs are based on financial inputs from IPC's 2009 IRP, and calculations include line loss adjusted energy savings.

[b] Program life B/C ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by IPC to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of IPC and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13% peak line losses and is non-coincident.

[1] Peak MW achieved based on mid-week load reduction schedule.

[2] Utility cost reflects collected funds on previous bad loan write-offs.

[3] Utility cost reflects only audit and administration costs; there was no further activity in 2006.

[4] Levelized cost calculation includes bad loan write-off expense and funds collected from previously written off loans.

[5] Beginning in 2005, BPA funds were no longer applied to CAP agency payments.

[6] Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

[7] Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

[8] Savings were adjusted by NEEA in 2010.

[9] Savings are preliminary estimates provided by NEEA.

## **Appendix 5.** 2010 DSM program activity by state jurisdiction

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Demand Response** | | | **(MW)** | | | **(MW)** |
| A/C Cool Credit | 30,482 homes | $ 1,928,447 | 38.6 | 321 homes | $ 74,099 | 0.4 |
| Irrigation Peak Rewards | 2,005 service points | 13,144,261 | 245.5 | 33 service points | 186,565 | 4.2 |
| FlexPeak Management | 56 sites | 1,807,527 | 36.1 | 4 sites | 95,153 | 11.4 |
| **Total** | | **$16,880,235** | **320.2** | | **$ 355,817** | **16.0** |
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Residential** | | | | | | |
| Ductless Heat Pump Pilot | 101 homes | $ 181,969 | 353,500 | 3 homes | $ 7,262 | 10,500 |
| Energy Efficient Lighting | 1,171,010 bulbs | 2,442,931 | 27,618,937 | 19,129 bulbs | 58,347 | 463,800 |
| Energy House Calls | 1,525 homes | 724,895 | 1,157,871 | 77 homes | 37,435 | 40,784 |
| ENERGY STAR® Homes Northwest | 630 homes | 369,504 | 883,260 | 0 homes | 6,101 | 0 |
| Heating & Cooling Efficiency Program | 212 homes | 314,963 | 1,081,875 | 5 homes | 12,706 | 22,622 |
| Home Improvement Program | 3,537 homes | 944,716 | 3,986,199 | 0 homes | 0 | 0 |
| Home Products Program | 16,061 appliances/fixtures | 813,171 | 1,418,905 | 261 appliances/fixtures | 18,990 | 24,675 |
| Oregon Residential Weatherization | 0 home | 0 | 0 | 1 home | 6,050 | 320 |
| Rebate Advantage | 30 homes | 34,283 | 145,578 | 5 homes | 5,119 | 19,316 |
| See ya later, refrigerator® | 3,070 refrigerators/freezers | 548,872 | 1,527,190 | 82 refrigerators/freezers | 16,207 | 40,546 |
| Weatherization Assistance for Qualified Customers | 373 homes/non-profits | 1,205,446 | 3,452,025 | 27 homes/non-profits | 115,686 | 289,627 |
| Weatherization Solutions for Eligible Customers | 47 homes | 226,119 | 313,309 | 0 homes | 2,306 | 0 |
| **Total** | | **$ 7,806,869** | **41,938,649** | | **$ 286,209** | **912,190** |
| **Commercial** | | | | | | |
| Building Efficiency | 6 projects | 1,466,256 | 10,552,135 | 2 projects | 43,426 | 267,463 |
| Easy Upgrades | 1,487 projects | 3,862,653 | 35,200,511 | 48 projects | 111,757 | 623,952 |
| Holiday Lighting | 25 projects | 45,816 | 248,865 | 0 projects | 316 | 0 |
| Oregon Commercial Audits | 0 audits | 0 | 0 | 22 audits | 5,049 | 0 |
| **Total** | | **$ 5,374,725** | **46,001,511** | | **$ 160,548** | **891,415** |
| **Industrial** | | | | | | |
| Custom Efficiency | 204 projects | 8,060,252 | 65,148,471 | 19 projects | 717,873 | 6,431,604 |
| **Total** | | **$ 8,060,252** | **65,148,471** | | **$ 717,873** | **6,431,604** |

## **Appendix 5**. 2010 DSM program activity by state jurisdiction (continued)

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings (kWh) | Oregon Participants | Oregon Utility Costs | Oregon Demand Reduction/ Annual Energy Savings (kWh) |
|---|---|---|---|---|---|---|
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Irrigation** | | | | | | |
| Irrigation Efficiency Rewards | 728 projects | $ 2,089,225 | 10,575,018 | 25 projects | $ 111,589 | 393,412 |
| **Total** | | **$ 2,089,225** | **10,575,018** | | **$ 111,589** | **393,412** |
| **Market Transformation** | | | | | | |
| Northwest Energy Efficiency Alliance [1] | | $ 2,271,656 | 14,567,370 | | $ 119,561 | 766,704 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Residential Energy Efficiency Education Initiative | | 211,695 | | | $ 10,397 | |
| **Commercial** | | | | | | |
| Commercial Education Initiative | | 65,327 | | | 3,438 | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 109,545 | | | 8,329 | |
| Local Energy Efficiency Funds | 1 project | 238 | | 0 projects | 13 | |
| **Total Direct Program Expense** | | **$42,869,767** | | | **$ 1,773,774** | |
| Indirect Program Expense | | 1,129,390 | | | 59,920 | |
| **Total Annual Savings** | | | **178,231,019** | | | **9,395,325** |
| **Total DSM Expense** | | **$43,999,157** | | | **$ 1,833,694** | |

[1] Savings are preliminary estimates provided by NEEA. Oregon is credited with 5% of annual NEEA savings.



# *Appendix C—Technical Appendix*

For the 2011 Integrated Resource Plan

**June 2011**

IDAHO POWER®
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# TABLE OF CONTENTS

Introduction....1
IRP Advisory Council Roster....2
Sales and Load Forecast Data....3
Average Annual Forecast Growth Rates....3
Expected-Case Load Forecast....4
70th Percentile Load Forecast....13
Load and Resource Balance Data....22
Monthly Average Energy Load and Resource Balance....22
Monthly Average Energy Surplus/Deficit Charts....42
Peak-Hour Load and Resource Balance....44
Peak-Hour Surplus/Deficit Charts....64
Demand-Side Resource Data....66
Cost Effectiveness....66
Alternate Costs....67
Supply-Side Resource Data....80
Key Financial and Forecast Assumptions....80
Cost Inputs and Operating Assumptions....82
Levelized Cost of Production....83
Resource Advantages and Disadvantages....84
Camp Process....86
Brownlee Reservoir Inflow Record....90
Fuel Data....91
Natural Gas and Coal Price Forecast....91
Existing Resource Data....93
Hydroelectric and Thermal Plant Data....93
Qualifying Facility Data (PURPA)....94
Power Purchase Agreement Data....95
Hydro Modeling Results (PDR580)....96
Portfolio Analysis, Results, and Supporting Documentation....126
Initial Resource Portfolios (2011–2020)....126
Initial Resource Portfolios (2021–2030)....126
Detailed Resource Portfolio Design Sheets....127

Stochastic Analysis Results ....146
Regulatory Environmental Compliance Costs....165
Portfolio Incremental Transmission Analysis....167
Loss of Load Expectation Analysis ....186
Boardman to Hemingway Tipping Point Analysis Data....187
State of Oregon IRP Guidelines....188
Summary of Northwest Utility Planning Criteria ....196

# INTRODUCTION

*Appendix C—Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2011 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2011 IRP sales and load forecast is contained in *Appendix A—Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B—Demand-Side Management 2010 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2011.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning
1221 West Idaho Street
Boise, Idaho 83702
208-388-2483

# IRP ADVISORY COUNCIL ROSTER

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2011 IRP, Idaho Power hosted a field trip covering wind, hydro, and natural gas resources, two portfolio-design workshops, and nine monthly IRPAC meetings. The IRPAC meetings served as an open forum for discussions related to the development of the IRP and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is very rewarding and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

### Customer Representatives

Agricultural Representative .....Sid Erwin
Boise State University.....John Gardner
Heinz Frozen Foods .....Steve Munn
INL.....Tom Moriarty
Micron.....Michael Bick
Simplot.....Don Sturtevant

### Public Interest Representatives

Boise Metro Chamber of Commerce .....Bill Connors
Idaho Conservation League .....Ben Otto
Idaho Department of Commerce.....Lane Packwood
Idaho Office of Energy Resources .....John Chatburn
Idaho State House of Representatives.....Representative Elaine Smith
Idaho State Senate.....Senator Russ Fulcher
Northwest Power and Conservation Council.....Jim Yost/Shirley Lindstrom
Oil/Gas Industry Advisor.....David Hawk
Snake River Alliance .....Ken Miller
Water Issues Advisor .....Vince Alberdi

### Regulatory Commission Representatives

Idaho Public Utilities Commission .....Rick Sterling
Public Utility Commission of Oregon .....Erik Colville

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2011–2016 | 2011–2021 | 2011–2030 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.31% | 1.51% | 1.47% |
| Commercial Sales | 1.30% | 1.13% | 1.31% |
| Irrigation Sales | 0.31% | 0.30% | 0.26% |
| Industrial Sales | 1.81% | 1.61% | 1.66% |
| Additional Firm Sales | 7.40% | 3.65% | 2.03% |
| System Sales | 1.95% | 1.53% | 1.39% |
| Total Sales | 1.95% | 1.53% | 1.39% |
| **Loads** | | | |
| Residential Load | 1.35% | 1.52% | 1.48% |
| Commercial Load | 1.29% | 1.13% | 1.30% |
| Irrigation Load | 0.26% | 0.30% | 0.26% |
| Industrial Load | 1.74% | 1.60% | 1.66% |
| Additional Firm Sales | 7.40% | 3.65% | 2.03% |
| System Load Losses | 1.47% | 1.33% | 1.32% |
| System Load | 1.89% | 1.51% | 1.38% |
| Total Load | 1.89% | 1.51% | 1.38% |
| **Peaks** | | | |
| System Peak | 2.23% | 1.93% | 1.76% |
| Total Peak | 2.23% | 1.93% | 1.76% |
| Winter Peak | 1.09% | 1.10% | 1.13% |
| Summer Peak | 2.23% | 1.93% | 1.76% |
| **Customers** | | | |
| Residential Customers | 1.72% | 1.59% | 1.37% |
| Commercial Customers | 2.31% | 2.17% | 1.95% |
| Irrigation Customers | 1.48% | 1.43% | 1.35% |
| Industrial Customers | 1.60% | 1.47% | 1.35% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 810 | 684 | 575 | 490 | 450 | 490 | 636 | 614 | 494 | 479 | 596 | 819 |
| Commercial | 474 | 432 | 405 | 387 | 398 | 430 | 503 | 487 | 433 | 400 | 418 | 493 |
| Irrigation | 2 | 1 | 1 | 59 | 286 | 524 | 611 | 501 | 314 | 50 | 1 | 1 |
| Industrial | 261 | 261 | 253 | 244 | 250 | 271 | 269 | 270 | 266 | 268 | 265 | 271 |
| Additional Firm | 136 | 155 | 172 | 181 | 176 | 153 | 146 | 154 | 170 | 175 | 180 | 185 |
| Loss | 165 | 148 | 133 | 128 | 150 | 184 | 217 | 201 | 163 | 129 | 138 | 171 |
| **System Load** | 1,848 | 1,682 | 1,540 | 1,489 | 1,709 | 2,054 | 2,381 | 2,228 | 1,839 | 1,501 | 1,598 | 1,941 |
| Light Load | 1,702 | 1,553 | 1,416 | 1,355 | 1,535 | 1,846 | 2,154 | 1,976 | 1,674 | 1,358 | 1,468 | 1,804 |
| Heavy Load | 1,974 | 1,778 | 1,629 | 1,588 | 1,858 | 2,205 | 2,577 | 2,409 | 1,972 | 1,613 | 1,703 | 2,048 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,848 | 1,682 | 1,540 | 1,489 | 1,709 | 2,054 | 2,381 | 2,228 | 1,839 | 1,501 | 1,598 | 1,941 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,499 | 2,394 | 2,090 | 1,888 | 2,833 | 3,325 | 3,494 | 3,171 | 3,004 | 2,053 | 2,169 | 2,693 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,499 | 2,394 | 2,090 | 1,888 | 2,833 | 3,325 | 3,494 | 3,171 | 3,004 | 2,053 | 2,169 | 2,693 |
| | **1/2012** | **2/2012** | **3/2012** | **4/2012** | **5/2012** | **6/2012** | **7/2012** | **8/2012** | **9/2012** | **10/2012** | **11/2012** | **12/2012** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 806 | 679 | 571 | 487 | 448 | 491 | 640 | 618 | 495 | 478 | 594 | 819 |
| Commercial | 480 | 437 | 410 | 392 | 404 | 438 | 512 | 494 | 440 | 405 | 423 | 500 |
| Irrigation | 1 | 1 | 1 | 59 | 287 | 527 | 614 | 504 | 315 | 50 | 0 | 1 |
| Industrial | 266 | 257 | 259 | 250 | 256 | 277 | 275 | 276 | 272 | 275 | 271 | 276 |
| Additional Firm | 199 | 195 | 194 | 189 | 185 | 162 | 154 | 163 | 182 | 193 | 200 | 206 |
| Loss | 169 | 149 | 135 | 129 | 151 | 186 | 219 | 204 | 164 | 130 | 140 | 173 |
| **System Load** | 1,921 | 1,719 | 1,569 | 1,506 | 1,731 | 2,082 | 2,414 | 2,259 | 1,868 | 1,531 | 1,629 | 1,975 |
| Light Load | 1,769 | 1,587 | 1,443 | 1,370 | 1,555 | 1,871 | 2,184 | 2,004 | 1,700 | 1,386 | 1,497 | 1,836 |
| Heavy Load | 2,052 | 1,816 | 1,659 | 1,615 | 1,869 | 2,236 | 2,612 | 2,443 | 2,015 | 1,636 | 1,736 | 2,094 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,921 | 1,719 | 1,569 | 1,506 | 1,731 | 2,082 | 2,414 | 2,259 | 1,868 | 1,531 | 1,629 | 1,975 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,497 | 2,387 | 2,086 | 1,867 | 2,876 | 3,377 | 3,555 | 3,205 | 3,056 | 2,084 | 2,183 | 2,676 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,497 | 2,387 | 2,086 | 1,867 | 2,876 | 3,377 | 3,555 | 3,205 | 3,056 | 2,084 | 2,183 | 2,676 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 807 | 679 | 571 | 486 | 448 | 495 | 648 | 626 | 500 | 480 | 596 | 833 |
| Commercial | 485 | 441 | 415 | 397 | 410 | 445 | 520 | 502 | 446 | 411 | 429 | 507 |
| Irrigation | 1 | 1 | 0 | 59 | 286 | 526 | 613 | 503 | 315 | 50 | 0 | 1 |
| Industrial | 271 | 271 | 264 | 255 | 261 | 283 | 281 | 282 | 277 | 280 | 276 | 280 |
| Additional Firm | 213 | 211 | 207 | 202 | 198 | 193 | 202 | 200 | 201 | 206 | 213 | 219 |
| Loss | 170 | 151 | 136 | 130 | 153 | 189 | 224 | 207 | 167 | 132 | 141 | 176 |
| **System Load** | 1,948 | 1,753 | 1,593 | 1,529 | 1,756 | 2,130 | 2,487 | 2,319 | 1,906 | 1,559 | 1,656 | 2,016 |
| Light Load | 1,794 | 1,619 | 1,465 | 1,391 | 1,578 | 1,915 | 2,250 | 2,058 | 1,734 | 1,411 | 1,522 | 1,875 |
| Heavy Load | 2,069 | 1,854 | 1,693 | 1,630 | 1,897 | 2,303 | 2,674 | 2,508 | 2,056 | 1,666 | 1,765 | 2,138 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,948 | 1,753 | 1,593 | 1,529 | 1,756 | 2,130 | 2,487 | 2,319 | 1,906 | 1,559 | 1,656 | 2,016 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,506 | 2,395 | 2,101 | 1,866 | 2,924 | 3,478 | 3,662 | 3,298 | 3,130 | 2,113 | 2,202 | 2,690 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,506 | 2,395 | 2,101 | 1,866 | 2,924 | 3,478 | 3,662 | 3,298 | 3,130 | 2,113 | 2,202 | 2,690 |
| | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 827 | 693 | 583 | 497 | 460 | 510 | 671 | 648 | 516 | 493 | 612 | 851 |
| Commercial | 491 | 445 | 420 | 402 | 416 | 452 | 528 | 510 | 453 | 416 | 434 | 514 |
| Irrigation | 1 | 1 | 1 | 59 | 287 | 526 | 613 | 503 | 315 | 50 | 0 | 1 |
| Industrial | 276 | 276 | 269 | 259 | 266 | 288 | 286 | 287 | 282 | 285 | 281 | 285 |
| Additional Firm | 224 | 223 | 219 | 214 | 209 | 204 | 214 | 211 | 213 | 218 | 225 | 231 |
| Loss | 174 | 154 | 138 | 133 | 155 | 192 | 228 | 211 | 170 | 135 | 144 | 180 |
| **System Load** | 1,993 | 1,792 | 1,629 | 1,563 | 1,793 | 2,173 | 2,540 | 2,370 | 1,949 | 1,597 | 1,697 | 2,061 |
| Light Load | 1,836 | 1,655 | 1,499 | 1,422 | 1,610 | 1,953 | 2,298 | 2,103 | 1,774 | 1,446 | 1,559 | 1,916 |
| Heavy Load | 2,117 | 1,895 | 1,732 | 1,666 | 1,936 | 2,349 | 2,731 | 2,581 | 2,090 | 1,707 | 1,818 | 2,175 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,993 | 1,792 | 1,629 | 1,563 | 1,793 | 2,173 | 2,540 | 2,370 | 1,949 | 1,597 | 1,697 | 2,061 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,566 | 2,439 | 2,146 | 1,915 | 2,980 | 3,556 | 3,747 | 3,383 | 3,197 | 2,152 | 2,252 | 2,766 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,566 | 2,439 | 2,146 | 1,915 | 2,980 | 3,556 | 3,747 | 3,383 | 3,197 | 2,152 | 2,252 | 2,766 |
| **Monthly Summary** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 841 | 704 | 592 | 505 | 468 | 522 | 690 | 667 | 529 | 503 | 623 | 865 |
| Commercial | 497 | 449 | 424 | 406 | 421 | 459 | 537 | 517 | 460 | 422 | 439 | 520 |
| Irrigation | 2 | 1 | 1 | 59 | 289 | 530 | 617 | 507 | 317 | 50 | 1 | 1 |
| Industrial | 280 | 280 | 273 | 263 | 270 | 293 | 290 | 291 | 287 | 290 | 286 | 289 |
| Additional Firm | 236 | 234 | 230 | 225 | 221 | 216 | 225 | 223 | 224 | 229 | 237 | 243 |
| Loss | 176 | 156 | 141 | 135 | 158 | 195 | 232 | 215 | 173 | 137 | 147 | 182 |
| **System Load** | 2,032 | 1,824 | 1,661 | 1,594 | 1,827 | 2,215 | 2,591 | 2,420 | 1,990 | 1,632 | 1,732 | 2,100 |
| Light Load | 1,871 | 1,685 | 1,528 | 1,450 | 1,641 | 1,991 | 2,344 | 2,147 | 1,811 | 1,477 | 1,591 | 1,952 |
| Heavy Load | 2,158 | 1,929 | 1,766 | 1,699 | 1,987 | 2,379 | 2,786 | 2,635 | 2,134 | 1,744 | 1,856 | 2,216 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,032 | 1,824 | 1,661 | 1,594 | 1,827 | 2,215 | 2,591 | 2,420 | 1,990 | 1,632 | 1,732 | 2,100 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,606 | 2,470 | 2,180 | 1,945 | 3,035 | 3,629 | 3,831 | 3,459 | 3,260 | 2,188 | 2,290 | 2,815 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,606 | 2,470 | 2,180 | 1,945 | 3,035 | 3,629 | 3,831 | 3,459 | 3,260 | 2,188 | 2,290 | 2,815 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 851 | 711 | 598 | 510 | 474 | 532 | 706 | 683 | 540 | 511 | 632 | 880 |
| Commercial | 501 | 453 | 428 | 410 | 426 | 465 | 544 | 523 | 466 | 426 | 443 | 525 |
| Irrigation | 2 | 2 | 1 | 60 | 290 | 532 | 620 | 509 | 319 | 51 | 1 | 1 |
| Industrial | 284 | 274 | 277 | 267 | 274 | 297 | 295 | 295 | 291 | 295 | 290 | 293 |
| Additional Firm | 248 | 244 | 241 | 235 | 230 | 224 | 232 | 229 | 229 | 233 | 240 | 245 |
| Loss | 179 | 157 | 142 | 136 | 160 | 198 | 235 | 218 | 175 | 139 | 149 | 185 |
| **System Load** | 2,065 | 1,840 | 1,687 | 1,618 | 1,854 | 2,248 | 2,631 | 2,458 | 2,020 | 1,654 | 1,754 | 2,128 |
| Light Load | 1,901 | 1,699 | 1,552 | 1,472 | 1,665 | 2,021 | 2,380 | 2,180 | 1,838 | 1,497 | 1,612 | 1,979 |
| Heavy Load | 2,205 | 1,944 | 1,785 | 1,725 | 2,016 | 2,414 | 2,847 | 2,658 | 2,165 | 1,778 | 1,869 | 2,246 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,065 | 1,840 | 1,687 | 1,618 | 1,854 | 2,248 | 2,631 | 2,458 | 2,020 | 1,654 | 1,754 | 2,128 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,636 | 2,497 | 2,205 | 1,962 | 3,084 | 3,693 | 3,902 | 3,519 | 3,314 | 2,211 | 2,312 | 2,843 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,636 | 2,497 | 2,205 | 1,962 | 3,084 | 3,693 | 3,902 | 3,519 | 3,314 | 2,211 | 2,312 | 2,843 |
| | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 865 | 720 | 606 | 517 | 482 | 544 | 725 | 701 | 553 | 521 | 643 | 893 |
| Commercial | 505 | 455 | 432 | 413 | 431 | 471 | 550 | 529 | 471 | 430 | 447 | 530 |
| Irrigation | 2 | 2 | 1 | 60 | 291 | 533 | 621 | 510 | 320 | 51 | 1 | 1 |
| Industrial | 288 | 288 | 281 | 271 | 279 | 302 | 299 | 300 | 295 | 299 | 294 | 297 |
| Additional Firm | 248 | 246 | 241 | 235 | 230 | 223 | 232 | 229 | 229 | 233 | 240 | 244 |
| Loss | 181 | 160 | 144 | 138 | 161 | 200 | 238 | 221 | 178 | 141 | 151 | 187 |
| **System Load** | 2,089 | 1,869 | 1,704 | 1,634 | 1,873 | 2,274 | 2,666 | 2,491 | 2,046 | 1,675 | 1,775 | 2,153 |
| Light Load | 1,924 | 1,726 | 1,568 | 1,487 | 1,682 | 2,044 | 2,412 | 2,210 | 1,861 | 1,516 | 1,631 | 2,002 |
| Heavy Load | 2,231 | 1,977 | 1,803 | 1,752 | 2,023 | 2,442 | 2,885 | 2,694 | 2,193 | 1,800 | 1,891 | 2,283 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,089 | 1,869 | 1,704 | 1,634 | 1,873 | 2,274 | 2,666 | 2,491 | 2,046 | 1,675 | 1,775 | 2,153 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,662 | 2,510 | 2,223 | 1,978 | 3,124 | 3,751 | 3,967 | 3,579 | 3,365 | 2,232 | 2,335 | 2,879 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,662 | 2,510 | 2,223 | 1,978 | 3,124 | 3,751 | 3,967 | 3,579 | 3,365 | 2,232 | 2,335 | 2,879 |
| | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 876 | 727 | 613 | 522 | 488 | 554 | 741 | 718 | 564 | 529 | 652 | 908 |
| Commercial | 509 | 457 | 435 | 417 | 435 | 477 | 557 | 536 | 476 | 434 | 451 | 535 |
| Irrigation | 2 | 2 | 1 | 60 | 292 | 535 | 624 | 512 | 321 | 51 | 1 | 1 |
| Industrial | 292 | 291 | 284 | 275 | 282 | 306 | 303 | 304 | 299 | 303 | 298 | 301 |
| Additional Firm | 249 | 246 | 241 | 235 | 230 | 224 | 233 | 229 | 230 | 234 | 240 | 245 |
| Loss | 183 | 161 | 145 | 139 | 163 | 203 | 242 | 224 | 180 | 143 | 152 | 190 |
| **System Load** | 2,110 | 1,885 | 1,720 | 1,649 | 1,891 | 2,299 | 2,700 | 2,523 | 2,070 | 1,693 | 1,795 | 2,180 |
| Light Load | 1,943 | 1,741 | 1,582 | 1,500 | 1,699 | 2,066 | 2,442 | 2,238 | 1,884 | 1,533 | 1,648 | 2,027 |
| Heavy Load | 2,241 | 1,993 | 1,819 | 1,768 | 2,042 | 2,469 | 2,921 | 2,729 | 2,233 | 1,809 | 1,912 | 2,312 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,110 | 1,885 | 1,720 | 1,649 | 1,891 | 2,299 | 2,700 | 2,523 | 2,070 | 1,693 | 1,795 | 2,180 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,678 | 2,521 | 2,236 | 1,984 | 3,163 | 3,806 | 4,031 | 3,634 | 3,414 | 2,251 | 2,354 | 2,906 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,678 | 2,521 | 2,236 | 1,984 | 3,163 | 3,806 | 4,031 | 3,634 | 3,414 | 2,251 | 2,354 | 2,906 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 890 | 737 | 621 | 530 | 496 | 567 | 761 | 738 | 578 | 539 | 663 | 924 |
| Commercial | 513 | 460 | 439 | 420 | 440 | 482 | 564 | 542 | 482 | 438 | 455 | 540 |
| Irrigation | 2 | 2 | 1 | 60 | 292 | 536 | 625 | 513 | 321 | 51 | 1 | 1 |
| Industrial | 295 | 295 | 288 | 279 | 287 | 310 | 308 | 308 | 304 | 308 | 303 | 305 |
| Additional Firm | 249 | 247 | 242 | 236 | 231 | 224 | 233 | 230 | 230 | 234 | 241 | 245 |
| Loss | 185 | 163 | 147 | 140 | 165 | 205 | 245 | 228 | 183 | 145 | 154 | 192 |
| **System Load** | 2,134 | 1,903 | 1,738 | 1,665 | 1,911 | 2,326 | 2,736 | 2,558 | 2,097 | 1,715 | 1,817 | 2,208 |
| Light Load | 1,966 | 1,758 | 1,599 | 1,515 | 1,716 | 2,090 | 2,475 | 2,269 | 1,909 | 1,552 | 1,669 | 2,053 |
| Heavy Load | 2,267 | 2,013 | 1,847 | 1,775 | 2,064 | 2,514 | 2,942 | 2,766 | 2,263 | 1,832 | 1,935 | 2,341 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,134 | 1,903 | 1,738 | 1,665 | 1,911 | 2,326 | 2,736 | 2,558 | 2,097 | 1,715 | 1,817 | 2,208 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,704 | 2,538 | 2,255 | 2,000 | 3,203 | 3,865 | 4,098 | 3,695 | 3,464 | 2,273 | 2,378 | 2,943 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,704 | 2,538 | 2,255 | 2,000 | 3,203 | 3,865 | 4,098 | 3,695 | 3,464 | 2,273 | 2,378 | 2,943 |
| | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 902 | 746 | 629 | 536 | 504 | 579 | 780 | 756 | 591 | 549 | 674 | 937 |
| Commercial | 516 | 464 | 442 | 424 | 445 | 488 | 570 | 547 | 487 | 442 | 459 | 545 |
| Irrigation | 2 | 2 | 1 | 60 | 293 | 538 | 627 | 515 | 322 | 51 | 1 | 1 |
| Industrial | 299 | 289 | 292 | 283 | 291 | 315 | 312 | 312 | 308 | 312 | 307 | 309 |
| Additional Firm | 248 | 243 | 241 | 235 | 230 | 224 | 233 | 230 | 230 | 234 | 240 | 245 |
| Loss | 187 | 163 | 148 | 142 | 166 | 207 | 248 | 231 | 185 | 146 | 156 | 194 |
| **System Load** | 2,155 | 1,907 | 1,753 | 1,680 | 1,929 | 2,351 | 2,771 | 2,591 | 2,123 | 1,734 | 1,836 | 2,231 |
| Light Load | 1,985 | 1,761 | 1,613 | 1,528 | 1,733 | 2,113 | 2,506 | 2,299 | 1,932 | 1,569 | 1,687 | 2,075 |
| Heavy Load | 2,290 | 2,015 | 1,864 | 1,790 | 2,097 | 2,525 | 2,979 | 2,822 | 2,276 | 1,852 | 1,967 | 2,355 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,155 | 1,907 | 1,753 | 1,680 | 1,929 | 2,351 | 2,771 | 2,591 | 2,123 | 1,734 | 1,836 | 2,231 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,726 | 2,549 | 2,271 | 2,013 | 3,242 | 3,922 | 4,164 | 3,753 | 3,514 | 2,293 | 2,400 | 2,976 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,726 | 2,549 | 2,271 | 2,013 | 3,242 | 3,922 | 4,164 | 3,753 | 3,514 | 2,293 | 2,400 | 2,976 |
| | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 912 | 752 | 634 | 541 | 510 | 589 | 797 | 773 | 602 | 557 | 682 | 951 |
| Commercial | 520 | 465 | 446 | 427 | 449 | 494 | 577 | 554 | 493 | 446 | 463 | 550 |
| Irrigation | 2 | 2 | 1 | 61 | 294 | 540 | 628 | 516 | 323 | 51 | 1 | 1 |
| Industrial | 303 | 303 | 296 | 287 | 295 | 319 | 316 | 317 | 312 | 316 | 311 | 313 |
| Additional Firm | 249 | 246 | 242 | 236 | 231 | 225 | 234 | 230 | 230 | 234 | 241 | 245 |
| Loss | 189 | 165 | 150 | 143 | 168 | 210 | 251 | 234 | 187 | 148 | 158 | 197 |
| **System Load** | 2,176 | 1,934 | 1,769 | 1,694 | 1,947 | 2,376 | 2,804 | 2,624 | 2,148 | 1,753 | 1,856 | 2,258 |
| Light Load | 2,004 | 1,786 | 1,627 | 1,541 | 1,749 | 2,136 | 2,537 | 2,328 | 1,955 | 1,586 | 1,705 | 2,099 |
| Heavy Load | 2,324 | 2,045 | 1,871 | 1,806 | 2,117 | 2,552 | 3,015 | 2,857 | 2,303 | 1,884 | 1,977 | 2,383 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,176 | 1,934 | 1,769 | 1,694 | 1,947 | 2,376 | 2,804 | 2,624 | 2,148 | 1,753 | 1,856 | 2,258 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,743 | 2,563 | 2,285 | 2,021 | 3,282 | 3,978 | 4,229 | 3,809 | 3,564 | 2,312 | 2,418 | 3,004 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,743 | 2,563 | 2,285 | 2,021 | 3,282 | 3,978 | 4,229 | 3,809 | 3,564 | 2,312 | 2,418 | 3,004 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 925 | 760 | 641 | 547 | 517 | 601 | 817 | 792 | 615 | 566 | 693 | 967 |
| Commercial | 525 | 469 | 450 | 431 | 455 | 501 | 585 | 561 | 499 | 451 | 467 | 556 |
| Irrigation | 2 | 2 | 1 | 61 | 295 | 541 | 630 | 517 | 324 | 51 | 1 | 1 |
| Industrial | 308 | 308 | 301 | 291 | 299 | 324 | 321 | 322 | 317 | 321 | 316 | 317 |
| Additional Firm | 249 | 247 | 242 | 237 | 232 | 225 | 235 | 231 | 231 | 235 | 241 | 246 |
| Loss | 191 | 167 | 151 | 145 | 170 | 212 | 255 | 237 | 190 | 150 | 160 | 200 |
| **System Load** | 2,201 | 1,953 | 1,787 | 1,711 | 1,967 | 2,404 | 2,842 | 2,660 | 2,176 | 1,775 | 1,878 | 2,287 |
| Light Load | 2,027 | 1,804 | 1,644 | 1,557 | 1,767 | 2,161 | 2,571 | 2,360 | 1,980 | 1,606 | 1,725 | 2,126 |
| Heavy Load | 2,350 | 2,065 | 1,890 | 1,824 | 2,139 | 2,582 | 3,075 | 2,876 | 2,333 | 1,907 | 2,001 | 2,413 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,201 | 1,953 | 1,787 | 1,711 | 1,967 | 2,404 | 2,842 | 2,660 | 2,176 | 1,775 | 1,878 | 2,287 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,768 | 2,580 | 2,304 | 2,037 | 3,323 | 4,038 | 4,296 | 3,871 | 3,617 | 2,334 | 2,443 | 3,042 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,768 | 2,580 | 2,304 | 2,037 | 3,323 | 4,038 | 4,296 | 3,871 | 3,617 | 2,334 | 2,443 | 3,042 |
| | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 939 | 770 | 650 | 554 | 525 | 614 | 838 | 813 | 629 | 576 | 704 | 981 |
| Commercial | 530 | 473 | 454 | 436 | 460 | 508 | 593 | 568 | 506 | 456 | 472 | 562 |
| Irrigation | 2 | 2 | 1 | 61 | 295 | 542 | 631 | 519 | 325 | 52 | 1 | 1 |
| Industrial | 313 | 312 | 305 | 295 | 304 | 329 | 326 | 326 | 322 | 326 | 321 | 322 |
| Additional Firm | 250 | 248 | 243 | 238 | 233 | 226 | 235 | 232 | 232 | 236 | 242 | 247 |
| Loss | 194 | 169 | 153 | 146 | 172 | 215 | 259 | 241 | 192 | 152 | 162 | 202 |
| **System Load** | 2,227 | 1,973 | 1,807 | 1,730 | 1,989 | 2,434 | 2,881 | 2,698 | 2,206 | 1,798 | 1,902 | 2,315 |
| Light Load | 2,051 | 1,822 | 1,662 | 1,574 | 1,786 | 2,188 | 2,607 | 2,394 | 2,007 | 1,627 | 1,747 | 2,153 |
| Heavy Load | 2,379 | 2,087 | 1,911 | 1,854 | 2,148 | 2,614 | 3,118 | 2,918 | 2,365 | 1,932 | 2,026 | 2,455 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,227 | 1,973 | 1,807 | 1,730 | 1,989 | 2,434 | 2,881 | 2,698 | 2,206 | 1,798 | 1,902 | 2,315 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,800 | 2,601 | 2,326 | 2,060 | 3,365 | 4,100 | 4,367 | 3,938 | 3,671 | 2,358 | 2,471 | 3,089 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,800 | 2,601 | 2,326 | 2,060 | 3,365 | 4,100 | 4,367 | 3,938 | 3,671 | 2,358 | 2,471 | 3,089 |
| | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 949 | 776 | 655 | 559 | 531 | 624 | 856 | 831 | 641 | 585 | 713 | 992 |
| Commercial | 535 | 478 | 459 | 441 | 466 | 515 | 601 | 576 | 514 | 462 | 477 | 568 |
| Irrigation | 2 | 2 | 1 | 61 | 296 | 544 | 634 | 520 | 326 | 52 | 1 | 1 |
| Industrial | 317 | 306 | 310 | 299 | 308 | 334 | 331 | 331 | 326 | 331 | 325 | 327 |
| Additional Firm | 250 | 246 | 243 | 238 | 233 | 227 | 236 | 232 | 232 | 236 | 242 | 247 |
| Loss | 196 | 170 | 155 | 148 | 173 | 218 | 262 | 244 | 195 | 154 | 164 | 204 |
| **System Load** | 2,250 | 1,978 | 1,824 | 1,746 | 2,008 | 2,462 | 2,919 | 2,734 | 2,234 | 1,819 | 1,923 | 2,340 |
| Light Load | 2,072 | 1,827 | 1,677 | 1,588 | 1,804 | 2,213 | 2,641 | 2,426 | 2,033 | 1,646 | 1,767 | 2,176 |
| Heavy Load | 2,390 | 2,090 | 1,938 | 1,861 | 2,169 | 2,661 | 3,138 | 2,957 | 2,410 | 1,944 | 2,049 | 2,481 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,250 | 1,978 | 1,824 | 1,746 | 2,008 | 2,462 | 2,919 | 2,734 | 2,234 | 1,819 | 1,923 | 2,340 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,822 | 2,614 | 2,343 | 2,073 | 3,407 | 4,160 | 4,435 | 3,999 | 3,725 | 2,380 | 2,493 | 3,124 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,822 | 2,614 | 2,343 | 2,073 | 3,407 | 4,160 | 4,435 | 3,999 | 3,725 | 2,380 | 2,493 | 3,124 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 956 | 780 | 658 | 562 | 535 | 633 | 871 | 846 | 650 | 591 | 720 | 1,002 |
| Commercial | 541 | 482 | 465 | 446 | 473 | 524 | 610 | 584 | 522 | 468 | 483 | 576 |
| Irrigation | 2 | 2 | 1 | 61 | 297 | 545 | 635 | 522 | 327 | 52 | 1 | 1 |
| Industrial | 323 | 323 | 315 | 305 | 313 | 339 | 336 | 337 | 332 | 336 | 331 | 333 |
| Additional Firm | 251 | 249 | 244 | 239 | 234 | 228 | 237 | 233 | 234 | 237 | 243 | 248 |
| Loss | 198 | 172 | 156 | 149 | 175 | 220 | 265 | 247 | 198 | 156 | 166 | 207 |
| **System Load** | 2,271 | 2,007 | 1,840 | 1,762 | 2,028 | 2,489 | 2,954 | 2,769 | 2,262 | 1,840 | 1,944 | 2,367 |
| Light Load | 2,092 | 1,854 | 1,693 | 1,603 | 1,822 | 2,237 | 2,673 | 2,457 | 2,058 | 1,665 | 1,786 | 2,201 |
| Heavy Load | 2,413 | 2,122 | 1,956 | 1,878 | 2,190 | 2,690 | 3,176 | 3,015 | 2,425 | 1,966 | 2,083 | 2,498 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,271 | 2,007 | 1,840 | 1,762 | 2,028 | 2,489 | 2,954 | 2,769 | 2,262 | 1,840 | 1,944 | 2,367 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,837 | 2,628 | 2,356 | 2,079 | 3,448 | 4,218 | 4,501 | 4,056 | 3,779 | 2,401 | 2,512 | 3,150 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,837 | 2,628 | 2,356 | 2,079 | 3,448 | 4,218 | 4,501 | 4,056 | 3,779 | 2,401 | 2,512 | 3,150 |
| | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 965 | 785 | 663 | 566 | 541 | 643 | 888 | 863 | 662 | 599 | 728 | 1,011 |
| Commercial | 548 | 488 | 471 | 453 | 480 | 533 | 620 | 594 | 531 | 475 | 490 | 584 |
| Irrigation | 2 | 2 | 1 | 61 | 298 | 546 | 636 | 523 | 327 | 52 | 1 | 1 |
| Industrial | 329 | 329 | 321 | 310 | 319 | 345 | 342 | 343 | 338 | 342 | 337 | 339 |
| Additional Firm | 253 | 250 | 246 | 240 | 235 | 229 | 238 | 235 | 235 | 238 | 245 | 249 |
| Loss | 200 | 174 | 158 | 151 | 177 | 223 | 269 | 251 | 200 | 158 | 168 | 209 |
| **System Load** | 2,297 | 2,028 | 1,860 | 1,781 | 2,050 | 2,519 | 2,994 | 2,808 | 2,293 | 1,864 | 1,968 | 2,393 |
| Light Load | 2,116 | 1,873 | 1,711 | 1,620 | 1,841 | 2,264 | 2,709 | 2,491 | 2,087 | 1,687 | 1,808 | 2,225 |
| Heavy Load | 2,441 | 2,144 | 1,977 | 1,898 | 2,229 | 2,705 | 3,219 | 3,057 | 2,458 | 1,992 | 2,109 | 2,526 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,297 | 2,028 | 1,860 | 1,781 | 2,050 | 2,519 | 2,994 | 2,808 | 2,293 | 1,864 | 1,968 | 2,393 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,861 | 2,645 | 2,375 | 2,093 | 3,491 | 4,280 | 4,571 | 4,119 | 3,836 | 2,426 | 2,536 | 3,183 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,861 | 2,645 | 2,375 | 2,093 | 3,491 | 4,280 | 4,571 | 4,119 | 3,836 | 2,426 | 2,536 | 3,183 |
| | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 968 | 786 | 664 | 566 | 543 | 649 | 901 | 875 | 669 | 603 | 732 | 1,026 |
| Commercial | 556 | 494 | 478 | 460 | 488 | 543 | 631 | 604 | 541 | 483 | 497 | 593 |
| Irrigation | 2 | 2 | 1 | 61 | 298 | 547 | 638 | 524 | 328 | 52 | 1 | 1 |
| Industrial | 336 | 335 | 327 | 316 | 324 | 351 | 348 | 349 | 344 | 348 | 343 | 346 |
| Additional Firm | 252 | 250 | 246 | 240 | 236 | 229 | 239 | 235 | 235 | 239 | 245 | 249 |
| Loss | 202 | 175 | 159 | 152 | 179 | 225 | 272 | 254 | 203 | 160 | 170 | 212 |
| **System Load** | 2,316 | 2,042 | 1,875 | 1,796 | 2,068 | 2,545 | 3,028 | 2,841 | 2,320 | 1,884 | 1,987 | 2,427 |
| Light Load | 2,133 | 1,886 | 1,725 | 1,634 | 1,858 | 2,287 | 2,739 | 2,520 | 2,111 | 1,705 | 1,825 | 2,257 |
| Heavy Load | 2,473 | 2,159 | 1,983 | 1,914 | 2,248 | 2,733 | 3,255 | 3,093 | 2,487 | 2,025 | 2,117 | 2,561 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,316 | 2,042 | 1,875 | 1,796 | 2,068 | 2,545 | 3,028 | 2,841 | 2,320 | 1,884 | 1,987 | 2,427 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,865 | 2,650 | 2,382 | 2,088 | 3,532 | 4,336 | 4,635 | 4,169 | 3,890 | 2,446 | 2,549 | 3,197 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,865 | 2,650 | 2,382 | 2,088 | 3,532 | 4,336 | 4,635 | 4,169 | 3,890 | 2,446 | 2,549 | 3,197 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 988 | 799 | 676 | 577 | 554 | 667 | 928 | 902 | 688 | 617 | 747 | 1,041 |
| Commercial | 564 | 503 | 486 | 467 | 497 | 554 | 643 | 615 | 552 | 492 | 506 | 602 |
| Irrigation | 2 | 2 | 1 | 61 | 298 | 547 | 637 | 524 | 328 | 52 | 1 | 1 |
| Industrial | 343 | 331 | 333 | 322 | 330 | 357 | 354 | 356 | 350 | 354 | 349 | 352 |
| Additional Firm | 252 | 248 | 246 | 241 | 236 | 230 | 239 | 236 | 236 | 239 | 245 | 249 |
| Loss | 205 | 177 | 162 | 154 | 181 | 229 | 277 | 259 | 207 | 163 | 173 | 216 |
| **System Load** | 2,354 | 2,060 | 1,904 | 1,823 | 2,097 | 2,583 | 3,079 | 2,891 | 2,360 | 1,917 | 2,021 | 2,462 |
| Light Load | 2,168 | 1,902 | 1,751 | 1,658 | 1,884 | 2,322 | 2,786 | 2,565 | 2,148 | 1,735 | 1,856 | 2,289 |
| Heavy Load | 2,514 | 2,176 | 2,013 | 1,954 | 2,265 | 2,774 | 3,331 | 3,127 | 2,530 | 2,060 | 2,153 | 2,610 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,354 | 2,060 | 1,904 | 1,823 | 2,097 | 2,583 | 3,079 | 2,891 | 2,360 | 1,917 | 2,021 | 2,462 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,919 | 2,675 | 2,420 | 2,131 | 3,582 | 4,409 | 4,718 | 4,253 | 3,952 | 2,480 | 2,593 | 3,267 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,919 | 2,675 | 2,420 | 2,131 | 3,582 | 4,409 | 4,718 | 4,253 | 3,952 | 2,480 | 2,593 | 3,267 |
| | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 995 | 803 | 679 | 579 | 559 | 676 | 944 | 918 | 698 | 623 | 754 | 1,053 |
| Commercial | 573 | 510 | 494 | 476 | 506 | 565 | 655 | 627 | 563 | 502 | 514 | 613 |
| Irrigation | 2 | 2 | 1 | 62 | 300 | 550 | 641 | 526 | 330 | 52 | 1 | 1 |
| Industrial | 350 | 350 | 340 | 328 | 336 | 364 | 361 | 362 | 357 | 360 | 356 | 359 |
| Additional Firm | 252 | 250 | 246 | 241 | 237 | 230 | 240 | 237 | 236 | 239 | 245 | 249 |
| Loss | 208 | 180 | 163 | 156 | 184 | 232 | 281 | 263 | 210 | 165 | 175 | 219 |
| **System Load** | 2,379 | 2,094 | 1,923 | 1,842 | 2,121 | 2,617 | 3,122 | 2,933 | 2,394 | 1,942 | 2,045 | 2,495 |
| Light Load | 2,191 | 1,934 | 1,769 | 1,676 | 1,905 | 2,352 | 2,824 | 2,602 | 2,179 | 1,758 | 1,879 | 2,320 |
| Heavy Load | 2,528 | 2,214 | 2,034 | 1,975 | 2,291 | 2,810 | 3,378 | 3,172 | 2,583 | 2,075 | 2,179 | 2,645 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,379 | 2,094 | 1,923 | 1,842 | 2,121 | 2,617 | 3,122 | 2,933 | 2,394 | 1,942 | 2,045 | 2,495 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,936 | 2,702 | 2,435 | 2,138 | 3,628 | 4,472 | 4,792 | 4,315 | 4,010 | 2,505 | 2,614 | 3,293 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,936 | 2,702 | 2,435 | 2,138 | 3,628 | 4,472 | 4,792 | 4,315 | 4,010 | 2,505 | 2,614 | 3,293 |
| | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 1,006 | 810 | 685 | 585 | 566 | 688 | 965 | 939 | 712 | 632 | 764 | 1,069 |
| Commercial | 583 | 518 | 503 | 485 | 516 | 577 | 669 | 640 | 576 | 512 | 524 | 624 |
| Irrigation | 2 | 2 | 1 | 62 | 300 | 550 | 641 | 527 | 330 | 52 | 1 | 1 |
| Industrial | 357 | 357 | 347 | 335 | 342 | 370 | 368 | 369 | 364 | 367 | 362 | 367 |
| Additional Firm | 252 | 250 | 246 | 242 | 238 | 231 | 241 | 238 | 237 | 240 | 246 | 250 |
| Loss | 211 | 182 | 166 | 158 | 186 | 235 | 285 | 267 | 213 | 168 | 178 | 222 |
| **System Load** | 2,412 | 2,120 | 1,948 | 1,866 | 2,147 | 2,653 | 3,169 | 2,979 | 2,432 | 1,972 | 2,075 | 2,534 |
| Light Load | 2,221 | 1,958 | 1,792 | 1,698 | 1,929 | 2,384 | 2,867 | 2,643 | 2,213 | 1,785 | 1,906 | 2,356 |
| Heavy Load | 2,562 | 2,242 | 2,071 | 1,989 | 2,319 | 2,867 | 3,407 | 3,222 | 2,624 | 2,107 | 2,210 | 2,686 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,412 | 2,120 | 1,948 | 1,866 | 2,147 | 2,653 | 3,169 | 2,979 | 2,432 | 1,972 | 2,075 | 2,534 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,968 | 2,726 | 2,460 | 2,159 | 3,676 | 4,539 | 4,870 | 4,386 | 4,071 | 2,536 | 2,646 | 3,336 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,968 | 2,726 | 2,460 | 2,159 | 3,676 | 4,539 | 4,870 | 4,386 | 4,071 | 2,536 | 2,646 | 3,336 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,212,406 | 5,203,339 | 5,225,209 | 5,368,280 | 5,478,414 | 5,563,357 | 5,669,304 | 5,757,369 | 5,869,128 | 5,970,745 |
| Commercial | 3,838,581 | 3,892,057 | 3,946,012 | 3,999,968 | 4,052,337 | 4,093,919 | 4,134,970 | 4,175,514 | 4,215,706 | 4,255,106 |
| Irrigation | 1,726,426 | 1,733,923 | 1,730,933 | 1,732,192 | 1,745,054 | 1,753,457 | 1,758,741 | 1,765,002 | 1,768,786 | 1,774,046 |
| Industrial | 2,294,027 | 2,346,083 | 2,391,684 | 2,434,390 | 2,472,828 | 2,509,361 | 2,545,600 | 2,580,387 | 2,616,525 | 2,653,140 |
| Additional Firm | 1,449,272 | 1,627,180 | 1,798,947 | 1,901,753 | 2,002,406 | 2,070,809 | 2,065,176 | 2,069,629 | 2,074,558 | 2,073,248 |
| **System Sales** | 14,520,712 | 14,802,582 | 15,092,784 | 15,436,583 | 15,751,039 | 15,990,903 | 16,173,791 | 16,347,900 | 16,544,703 | 16,726,284 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 14,520,712 | 14,802,582 | 15,092,784 | 15,436,583 | 15,751,039 | 15,990,903 | 16,173,791 | 16,347,900 | 16,544,703 | 16,726,284 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,211,472 | 5,220,832 | 5,234,696 | 5,375,496 | 5,483,894 | 5,587,315 | 5,674,976 | 5,764,646 | 5,875,700 | 5,994,114 |
| Commercial | 3,842,581 | 3,906,684 | 3,949,996 | 4,003,861 | 4,055,659 | 4,108,526 | 4,138,224 | 4,178,743 | 4,218,887 | 4,269,976 |
| Irrigation | 1,726,429 | 1,733,968 | 1,730,933 | 1,732,196 | 1,745,056 | 1,753,504 | 1,758,743 | 1,765,003 | 1,768,788 | 1,774,094 |
| Industrial | 2,299,135 | 2,350,458 | 2,395,812 | 2,438,153 | 2,476,427 | 2,512,935 | 2,549,050 | 2,583,953 | 2,620,131 | 2,656,639 |
| Additional Firm | 1,449,272 | 1,627,180 | 1,798,947 | 1,901,753 | 2,002,406 | 2,070,809 | 2,065,176 | 2,069,629 | 2,074,558 | 2,073,248 |
| **System Sales** | 14,528,890 | 14,839,122 | 15,110,383 | 15,451,458 | 15,763,442 | 16,033,088 | 16,186,169 | 16,361,973 | 16,558,065 | 16,768,071 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 14,528,890 | 14,839,122 | 15,110,383 | 15,451,458 | 15,763,442 | 16,033,088 | 16,186,169 | 16,361,973 | 16,558,065 | 16,768,071 |
| Loss | 1,409,072 | 1,428,282 | 1,444,136 | 1,471,939 | 1,496,894 | 1,519,773 | 1,535,352 | 1,552,758 | 1,572,301 | 1,593,865 |
| **Required Generation** | 15,937,962 | 16,267,403 | 16,554,519 | 16,923,397 | 17,260,337 | 17,552,861 | 17,721,520 | 17,914,731 | 18,130,365 | 18,361,936 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 595 | 594 | 598 | 614 | 626 | 636 | 648 | 658 | 671 | 682 |
| Commercial | 439 | 445 | 451 | 457 | 463 | 468 | 472 | 477 | 482 | 486 |
| Irrigation | 197 | 197 | 198 | 198 | 199 | 200 | 201 | 201 | 202 | 202 |
| Industrial | 262 | 268 | 273 | 278 | 283 | 286 | 291 | 295 | 299 | 302 |
| Additional Firm | 165 | 185 | 205 | 217 | 229 | 236 | 236 | 236 | 237 | 236 |
| Loss | 161 | 163 | 165 | 168 | 171 | 173 | 175 | 177 | 179 | 181 |
| **System Load** | 1,819 | 1,852 | 1,890 | 1,932 | 1,970 | 1,998 | 2,023 | 2,045 | 2,070 | 2,090 |
| Light Load | 1,655 | 1,685 | 1,719 | 1,758 | 1,793 | 1,818 | 1,840 | 1,860 | 1,883 | 1,902 |
| Heavy Load | 1,948 | 1,984 | 2,023 | 2,069 | 2,110 | 2,140 | 2,167 | 2,190 | 2,216 | 2,238 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,819 | 1,852 | 1,890 | 1,932 | 1,970 | 1,998 | 2,023 | 2,045 | 2,070 | 2,090 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,494 | 3,555 | 3,662 | 3,747 | 3,831 | 3,902 | 3,967 | 4,031 | 4,098 | 4,164 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 3,494 | 3,555 | 3,662 | 3,747 | 3,831 | 3,902 | 3,967 | 4,031 | 4,098 | 4,164 |

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 6,056,407 | 6,158,656 | 6,271,445 | 6,361,683 | 6,426,776 | 6,510,492 | 6,553,819 | 6,707,410 | 6,776,381 | 6,877,650 |
| Commercial | 4,296,755 | 4,343,256 | 4,394,013 | 4,447,644 | 4,508,307 | 4,576,705 | 4,649,243 | 4,732,314 | 4,818,303 | 4,912,860 |
| Irrigation | 1,778,962 | 1,782,409 | 1,787,374 | 1,793,802 | 1,798,253 | 1,800,997 | 1,804,775 | 1,804,427 | 1,813,588 | 1,814,979 |
| Industrial | 2,690,609 | 2,732,262 | 2,771,129 | 2,811,827 | 2,859,873 | 2,911,643 | 2,964,041 | 3,021,185 | 3,078,753 | 3,139,413 |
| Additional Firm | 2,074,887 | 2,081,619 | 2,088,963 | 2,096,186 | 2,101,203 | 2,111,939 | 2,112,515 | 2,119,494 | 2,118,995 | 2,125,092 |
| **System Sales** | 16,897,620 | 17,098,202 | 17,312,925 | 17,511,142 | 17,694,413 | 17,911,776 | 18,084,393 | 18,384,830 | 18,606,020 | 18,869,995 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 16,897,620 | 17,098,202 | 17,312,925 | 17,511,142 | 17,694,413 | 17,911,776 | 18,084,393 | 18,384,830 | 18,606,020 | 18,869,995 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 6,062,999 | 6,165,952 | 6,277,197 | 6,384,350 | 6,432,065 | 6,513,037 | 6,563,818 | 6,730,858 | 6,782,814 | 6,885,381 |
| Commercial | 4,299,700 | 4,346,120 | 4,396,725 | 4,462,767 | 4,511,182 | 4,579,493 | 4,652,274 | 4,748,002 | 4,821,327 | 4,915,869 |
| Irrigation | 1,778,963 | 1,782,411 | 1,787,376 | 1,793,851 | 1,798,254 | 1,800,998 | 1,804,775 | 1,804,477 | 1,813,589 | 1,814,980 |
| Industrial | 2,694,287 | 2,735,521 | 2,774,365 | 2,815,511 | 2,863,696 | 2,915,340 | 2,967,964 | 3,024,964 | 3,082,617 | 3,143,429 |
| Additional Firm | 2,074,887 | 2,081,619 | 2,088,963 | 2,096,186 | 2,101,203 | 2,111,939 | 2,112,515 | 2,119,494 | 2,118,995 | 2,125,092 |
| **System Sales** | 16,910,836 | 17,111,622 | 17,324,626 | 17,552,664 | 17,706,401 | 17,920,807 | 18,101,346 | 18,427,795 | 18,619,341 | 18,884,751 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 16,910,836 | 17,111,622 | 17,324,626 | 17,552,664 | 17,706,401 | 17,920,807 | 18,101,346 | 18,427,795 | 18,619,341 | 18,884,751 |
| Loss | 1,607,831 | 1,627,748 | 1,649,127 | 1,672,210 | 1,687,095 | 1,708,185 | 1,726,396 | 1,760,025 | 1,779,484 | 1,806,546 |
| **Required Generation** | 18,518,667 | 18,739,370 | 18,973,754 | 19,224,874 | 19,393,496 | 19,628,991 | 19,827,743 | 20,187,820 | 20,398,825 | 20,691,297 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 692 | 704 | 717 | 727 | 734 | 743 | 749 | 766 | 774 | 786 |
| Commercial | 491 | 496 | 502 | 508 | 515 | 523 | 531 | 541 | 550 | 561 |
| Irrigation | 203 | 203 | 204 | 204 | 205 | 206 | 206 | 205 | 207 | 207 |
| Industrial | 308 | 312 | 317 | 321 | 327 | 333 | 339 | 344 | 352 | 359 |
| Additional Firm | 237 | 238 | 238 | 239 | 240 | 241 | 241 | 241 | 242 | 243 |
| Loss | 184 | 186 | 188 | 190 | 193 | 195 | 197 | 200 | 203 | 206 |
| **System Load** | 2,114 | 2,139 | 2,166 | 2,189 | 2,214 | 2,241 | 2,263 | 2,298 | 2,329 | 2,362 |
| Light Load | 1,923 | 1,946 | 1,970 | 1,991 | 2,014 | 2,038 | 2,059 | 2,091 | 2,118 | 2,149 |
| Heavy Load | 2,264 | 2,291 | 2,320 | 2,343 | 2,371 | 2,400 | 2,424 | 2,462 | 2,494 | 2,529 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,114 | 2,139 | 2,166 | 2,189 | 2,214 | 2,241 | 2,263 | 2,298 | 2,329 | 2,362 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 4,229 | 4,296 | 4,367 | 4,435 | 4,501 | 4,571 | 4,635 | 4,718 | 4,792 | 4,870 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 4,229 | 4,296 | 4,367 | 4,435 | 4,501 | 4,571 | 4,635 | 4,718 | 4,792 | 4,870 |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 835 | 713 | 593 | 499 | 465 | 512 | 656 | 625 | 502 | 490 | 611 | 837 |
| Commercial | 482 | 440 | 408 | 391 | 403 | 436 | 509 | 490 | 435 | 403 | 421 | 498 |
| Irrigation | 2 | 1 | 1 | 75 | 339 | 572 | 633 | 517 | 336 | 57 | 1 | 1 |
| Industrial | 261 | 261 | 253 | 244 | 250 | 271 | 269 | 270 | 266 | 268 | 265 | 271 |
| Additional Firm | 136 | 155 | 172 | 181 | 176 | 153 | 146 | 154 | 170 | 175 | 180 | 185 |
| Loss | 169 | 152 | 136 | 131 | 158 | 193 | 222 | 205 | 166 | 131 | 140 | 174 |
| **System Load** | 1,885 | 1,722 | 1,563 | 1,521 | 1,790 | 2,137 | 2,434 | 2,262 | 1,876 | 1,525 | 1,619 | 1,965 |
| Light Load | 1,736 | 1,590 | 1,438 | 1,384 | 1,608 | 1,921 | 2,202 | 2,007 | 1,707 | 1,380 | 1,487 | 1,827 |
| Heavy Load | 2,013 | 1,821 | 1,653 | 1,621 | 1,947 | 2,295 | 2,634 | 2,446 | 2,011 | 1,639 | 1,724 | 2,074 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,885 | 1,722 | 1,563 | 1,521 | 1,790 | 2,137 | 2,434 | 2,262 | 1,876 | 1,525 | 1,619 | 1,965 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,553 | 2,440 | 2,147 | 1,901 | 2,863 | 3,377 | 3,515 | 3,185 | 3,019 | 2,068 | 2,231 | 2,815 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,553 | 2,440 | 2,147 | 1,901 | 2,863 | 3,377 | 3,515 | 3,185 | 3,019 | 2,068 | 2,231 | 2,815 |
| | **1/2012** | **2/2012** | **3/2012** | **4/2012** | **5/2012** | **6/2012** | **7/2012** | **8/2012** | **9/2012** | **10/2012** | **11/2012** | **12/2012** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 832 | 708 | 589 | 496 | 463 | 513 | 660 | 629 | 504 | 489 | 610 | 837 |
| Commercial | 488 | 445 | 413 | 396 | 409 | 444 | 518 | 498 | 442 | 409 | 427 | 505 |
| Irrigation | 1 | 1 | 1 | 75 | 340 | 574 | 636 | 520 | 338 | 57 | 0 | 1 |
| Industrial | 266 | 257 | 259 | 250 | 256 | 277 | 275 | 276 | 272 | 275 | 271 | 276 |
| Additional Firm | 199 | 195 | 194 | 189 | 185 | 162 | 154 | 163 | 182 | 193 | 200 | 206 |
| Loss | 172 | 153 | 137 | 132 | 159 | 194 | 225 | 207 | 168 | 133 | 142 | 176 |
| **System Load** | 1,959 | 1,760 | 1,592 | 1,538 | 1,812 | 2,165 | 2,468 | 2,293 | 1,905 | 1,556 | 1,650 | 2,000 |
| Light Load | 1,804 | 1,625 | 1,465 | 1,399 | 1,628 | 1,946 | 2,232 | 2,035 | 1,733 | 1,408 | 1,515 | 1,860 |
| Heavy Load | 2,092 | 1,859 | 1,684 | 1,649 | 1,958 | 2,325 | 2,670 | 2,480 | 2,055 | 1,663 | 1,757 | 2,121 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,959 | 1,760 | 1,592 | 1,538 | 1,812 | 2,165 | 2,468 | 2,293 | 1,905 | 1,556 | 1,650 | 2,000 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,551 | 2,433 | 2,143 | 1,880 | 2,906 | 3,430 | 3,577 | 3,219 | 3,071 | 2,099 | 2,245 | 2,800 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,551 | 2,433 | 2,143 | 1,880 | 2,906 | 3,430 | 3,577 | 3,219 | 3,071 | 2,099 | 2,245 | 2,800 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 833 | 708 | 589 | 495 | 464 | 517 | 668 | 637 | 508 | 491 | 612 | 851 |
| Commercial | 494 | 449 | 418 | 400 | 415 | 451 | 526 | 506 | 449 | 414 | 432 | 512 |
| Irrigation | 1 | 1 | 1 | 75 | 339 | 574 | 635 | 519 | 337 | 57 | 0 | 1 |
| Industrial | 271 | 271 | 264 | 255 | 261 | 283 | 281 | 282 | 277 | 280 | 276 | 280 |
| Additional Firm | 213 | 211 | 207 | 202 | 198 | 193 | 202 | 200 | 201 | 206 | 213 | 219 |
| Loss | 174 | 155 | 138 | 133 | 161 | 197 | 229 | 211 | 170 | 135 | 143 | 179 |
| **System Load** | 1,986 | 1,795 | 1,617 | 1,561 | 1,838 | 2,214 | 2,541 | 2,354 | 1,943 | 1,584 | 1,677 | 2,042 |
| Light Load | 1,829 | 1,658 | 1,487 | 1,420 | 1,652 | 1,990 | 2,299 | 2,088 | 1,768 | 1,433 | 1,541 | 1,899 |
| Heavy Load | 2,110 | 1,898 | 1,718 | 1,664 | 1,986 | 2,394 | 2,732 | 2,546 | 2,096 | 1,692 | 1,787 | 2,165 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,986 | 1,795 | 1,617 | 1,561 | 1,838 | 2,214 | 2,541 | 2,354 | 1,943 | 1,584 | 1,677 | 2,042 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,561 | 2,441 | 2,157 | 1,879 | 2,955 | 3,533 | 3,684 | 3,312 | 3,146 | 2,127 | 2,264 | 2,817 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,561 | 2,441 | 2,157 | 1,879 | 2,955 | 3,533 | 3,684 | 3,312 | 3,146 | 2,127 | 2,264 | 2,817 |
| | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 853 | 723 | 602 | 506 | 475 | 533 | 692 | 660 | 525 | 505 | 627 | 870 |
| Commercial | 500 | 453 | 423 | 405 | 421 | 458 | 535 | 514 | 456 | 420 | 438 | 519 |
| Irrigation | 1 | 1 | 1 | 75 | 340 | 574 | 635 | 519 | 337 | 57 | 0 | 1 |
| Industrial | 276 | 276 | 269 | 259 | 266 | 288 | 286 | 287 | 282 | 285 | 281 | 285 |
| Additional Firm | 224 | 223 | 219 | 214 | 209 | 204 | 214 | 211 | 213 | 218 | 225 | 231 |
| Loss | 177 | 158 | 141 | 136 | 163 | 201 | 233 | 215 | 174 | 137 | 146 | 182 |
| **System Load** | 2,032 | 1,834 | 1,654 | 1,596 | 1,875 | 2,258 | 2,594 | 2,406 | 1,986 | 1,622 | 1,718 | 2,087 |
| Light Load | 1,872 | 1,694 | 1,521 | 1,452 | 1,685 | 2,030 | 2,347 | 2,134 | 1,807 | 1,468 | 1,578 | 1,941 |
| Heavy Load | 2,159 | 1,940 | 1,758 | 1,701 | 2,026 | 2,441 | 2,789 | 2,619 | 2,129 | 1,734 | 1,841 | 2,203 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,032 | 1,834 | 1,654 | 1,596 | 1,875 | 2,258 | 2,594 | 2,406 | 1,986 | 1,622 | 1,718 | 2,087 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,620 | 2,485 | 2,203 | 1,928 | 3,011 | 3,611 | 3,770 | 3,398 | 3,213 | 2,167 | 2,314 | 2,895 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,620 | 2,485 | 2,203 | 1,928 | 3,011 | 3,611 | 3,770 | 3,398 | 3,213 | 2,167 | 2,314 | 2,895 |
| | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 868 | 735 | 611 | 514 | 484 | 546 | 711 | 679 | 538 | 515 | 639 | 885 |
| Commercial | 506 | 458 | 428 | 410 | 427 | 466 | 543 | 521 | 463 | 425 | 443 | 525 |
| Irrigation | 2 | 1 | 1 | 76 | 342 | 577 | 639 | 523 | 340 | 58 | 1 | 1 |
| Industrial | 280 | 280 | 273 | 263 | 270 | 293 | 290 | 291 | 287 | 290 | 286 | 289 |
| Additional Firm | 236 | 234 | 230 | 225 | 221 | 216 | 225 | 223 | 224 | 229 | 237 | 243 |
| Loss | 180 | 161 | 143 | 138 | 166 | 204 | 237 | 219 | 177 | 140 | 149 | 185 |
| **System Load** | 2,072 | 1,868 | 1,686 | 1,627 | 1,910 | 2,301 | 2,646 | 2,455 | 2,028 | 1,657 | 1,754 | 2,127 |
| Light Load | 1,908 | 1,725 | 1,551 | 1,480 | 1,716 | 2,068 | 2,394 | 2,179 | 1,845 | 1,500 | 1,611 | 1,978 |
| Heavy Load | 2,201 | 1,975 | 1,792 | 1,734 | 2,077 | 2,471 | 2,845 | 2,674 | 2,174 | 1,771 | 1,879 | 2,244 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,072 | 1,868 | 1,686 | 1,627 | 1,910 | 2,301 | 2,646 | 2,455 | 2,028 | 1,657 | 1,754 | 2,127 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,661 | 2,517 | 2,236 | 1,958 | 3,067 | 3,685 | 3,854 | 3,474 | 3,277 | 2,203 | 2,352 | 2,948 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,661 | 2,517 | 2,236 | 1,958 | 3,067 | 3,685 | 3,854 | 3,474 | 3,277 | 2,203 | 2,352 | 2,948 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 879 | 742 | 617 | 520 | 490 | 556 | 728 | 695 | 549 | 523 | 648 | 899 |
| Commercial | 510 | 461 | 432 | 414 | 432 | 472 | 550 | 527 | 468 | 429 | 447 | 530 |
| Irrigation | 2 | 2 | 1 | 76 | 343 | 580 | 642 | 525 | 341 | 58 | 1 | 1 |
| Industrial | 284 | 274 | 277 | 267 | 274 | 297 | 295 | 295 | 291 | 295 | 290 | 293 |
| Additional Firm | 248 | 244 | 241 | 235 | 230 | 224 | 232 | 229 | 229 | 233 | 240 | 245 |
| Loss | 183 | 162 | 145 | 140 | 168 | 206 | 241 | 222 | 179 | 142 | 151 | 188 |
| **System Load** | 2,106 | 1,885 | 1,713 | 1,652 | 1,938 | 2,334 | 2,687 | 2,493 | 2,057 | 1,681 | 1,777 | 2,156 |
| Light Load | 1,939 | 1,741 | 1,576 | 1,503 | 1,741 | 2,098 | 2,431 | 2,212 | 1,872 | 1,521 | 1,632 | 2,005 |
| Heavy Load | 2,249 | 1,991 | 1,812 | 1,760 | 2,107 | 2,507 | 2,907 | 2,697 | 2,205 | 1,806 | 1,893 | 2,275 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,106 | 1,885 | 1,713 | 1,652 | 1,938 | 2,334 | 2,687 | 2,493 | 2,057 | 1,681 | 1,777 | 2,156 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,691 | 2,543 | 2,261 | 1,975 | 3,116 | 3,750 | 3,925 | 3,535 | 3,331 | 2,226 | 2,374 | 2,978 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,691 | 2,543 | 2,261 | 1,975 | 3,116 | 3,750 | 3,925 | 3,535 | 3,331 | 2,226 | 2,374 | 2,978 |
| | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 893 | 752 | 626 | 527 | 499 | 569 | 747 | 714 | 562 | 534 | 660 | 914 |
| Commercial | 515 | 464 | 436 | 417 | 437 | 478 | 557 | 534 | 474 | 434 | 451 | 535 |
| Irrigation | 2 | 2 | 1 | 76 | 344 | 581 | 643 | 526 | 342 | 58 | 1 | 1 |
| Industrial | 288 | 288 | 281 | 271 | 279 | 302 | 299 | 300 | 295 | 299 | 294 | 297 |
| Additional Firm | 248 | 246 | 241 | 235 | 230 | 223 | 232 | 229 | 229 | 233 | 240 | 244 |
| Loss | 185 | 164 | 147 | 141 | 170 | 209 | 244 | 225 | 182 | 144 | 153 | 190 |
| **System Load** | 2,131 | 1,915 | 1,731 | 1,668 | 1,957 | 2,361 | 2,723 | 2,527 | 2,083 | 1,701 | 1,798 | 2,182 |
| Light Load | 1,963 | 1,769 | 1,592 | 1,517 | 1,758 | 2,122 | 2,463 | 2,242 | 1,896 | 1,540 | 1,652 | 2,029 |
| Heavy Load | 2,276 | 2,025 | 1,831 | 1,788 | 2,114 | 2,536 | 2,946 | 2,733 | 2,233 | 1,828 | 1,916 | 2,313 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,131 | 1,915 | 1,731 | 1,668 | 1,957 | 2,361 | 2,723 | 2,527 | 2,083 | 1,701 | 1,798 | 2,182 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,716 | 2,556 | 2,280 | 1,991 | 3,156 | 3,809 | 3,991 | 3,595 | 3,382 | 2,247 | 2,397 | 3,017 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,716 | 2,556 | 2,280 | 1,991 | 3,156 | 3,809 | 3,991 | 3,595 | 3,382 | 2,247 | 2,397 | 3,017 |
| | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 905 | 760 | 633 | 532 | 505 | 579 | 764 | 731 | 573 | 542 | 669 | 929 |
| Commercial | 519 | 467 | 439 | 421 | 442 | 484 | 564 | 540 | 479 | 438 | 455 | 540 |
| Irrigation | 2 | 2 | 1 | 77 | 345 | 583 | 646 | 528 | 343 | 59 | 1 | 1 |
| Industrial | 292 | 291 | 284 | 275 | 282 | 306 | 303 | 304 | 299 | 303 | 298 | 301 |
| Additional Firm | 249 | 246 | 241 | 235 | 230 | 224 | 233 | 229 | 230 | 234 | 240 | 245 |
| Loss | 187 | 166 | 148 | 142 | 171 | 211 | 247 | 228 | 184 | 145 | 155 | 193 |
| **System Load** | 2,153 | 1,932 | 1,747 | 1,683 | 1,976 | 2,387 | 2,757 | 2,560 | 2,108 | 1,720 | 1,818 | 2,209 |
| Light Load | 1,983 | 1,784 | 1,607 | 1,531 | 1,775 | 2,145 | 2,494 | 2,271 | 1,919 | 1,557 | 1,670 | 2,054 |
| Heavy Load | 2,287 | 2,042 | 1,847 | 1,804 | 2,134 | 2,563 | 2,983 | 2,768 | 2,274 | 1,838 | 1,937 | 2,342 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,153 | 1,932 | 1,747 | 1,683 | 1,976 | 2,387 | 2,757 | 2,560 | 2,108 | 1,720 | 1,818 | 2,209 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,733 | 2,567 | 2,293 | 1,997 | 3,195 | 3,865 | 4,056 | 3,650 | 3,431 | 2,266 | 2,416 | 3,046 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,733 | 2,567 | 2,293 | 1,997 | 3,195 | 3,865 | 4,056 | 3,650 | 3,431 | 2,266 | 2,416 | 3,046 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 919 | 771 | 642 | 540 | 514 | 592 | 785 | 751 | 587 | 553 | 681 | 945 |
| Commercial | 523 | 469 | 443 | 424 | 447 | 490 | 571 | 546 | 485 | 442 | 459 | 546 |
| Irrigation | 2 | 2 | 1 | 77 | 345 | 584 | 647 | 529 | 344 | 59 | 1 | 1 |
| Industrial | 295 | 295 | 288 | 279 | 287 | 310 | 308 | 308 | 304 | 308 | 303 | 305 |
| Additional Firm | 249 | 247 | 242 | 236 | 231 | 224 | 233 | 230 | 230 | 234 | 241 | 245 |
| Loss | 189 | 167 | 150 | 144 | 173 | 214 | 251 | 231 | 186 | 147 | 157 | 195 |
| **System Load** | 2,178 | 1,951 | 1,765 | 1,700 | 1,996 | 2,415 | 2,794 | 2,595 | 2,136 | 1,742 | 1,841 | 2,237 |
| Light Load | 2,006 | 1,802 | 1,624 | 1,546 | 1,793 | 2,170 | 2,528 | 2,302 | 1,943 | 1,577 | 1,691 | 2,081 |
| Heavy Load | 2,314 | 2,063 | 1,877 | 1,812 | 2,156 | 2,610 | 3,004 | 2,806 | 2,304 | 1,861 | 1,961 | 2,372 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,178 | 1,951 | 1,765 | 1,700 | 1,996 | 2,415 | 2,794 | 2,595 | 2,136 | 1,742 | 1,841 | 2,237 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,759 | 2,584 | 2,312 | 2,013 | 3,236 | 3,924 | 4,123 | 3,711 | 3,482 | 2,288 | 2,440 | 3,086 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,759 | 2,584 | 2,312 | 2,013 | 3,236 | 3,924 | 4,123 | 3,711 | 3,482 | 2,288 | 2,440 | 3,086 |
| | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 933 | 780 | 650 | 546 | 522 | 605 | 804 | 770 | 600 | 562 | 692 | 959 |
| Commercial | 527 | 473 | 446 | 428 | 451 | 495 | 578 | 552 | 490 | 446 | 463 | 550 |
| Irrigation | 2 | 2 | 1 | 77 | 346 | 586 | 649 | 531 | 345 | 59 | 1 | 1 |
| Industrial | 299 | 289 | 292 | 283 | 291 | 315 | 312 | 312 | 308 | 312 | 307 | 309 |
| Additional Firm | 248 | 243 | 241 | 235 | 230 | 224 | 233 | 230 | 230 | 234 | 240 | 245 |
| Loss | 191 | 168 | 151 | 145 | 175 | 216 | 254 | 234 | 189 | 149 | 158 | 197 |
| **System Load** | 2,200 | 1,956 | 1,781 | 1,714 | 2,015 | 2,441 | 2,829 | 2,629 | 2,161 | 1,761 | 1,861 | 2,261 |
| Light Load | 2,026 | 1,806 | 1,639 | 1,560 | 1,810 | 2,194 | 2,560 | 2,332 | 1,967 | 1,594 | 1,709 | 2,103 |
| Heavy Load | 2,338 | 2,066 | 1,894 | 1,827 | 2,191 | 2,621 | 3,042 | 2,863 | 2,317 | 1,882 | 1,994 | 2,386 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,200 | 1,956 | 1,781 | 1,714 | 2,015 | 2,441 | 2,829 | 2,629 | 2,161 | 1,761 | 1,861 | 2,261 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,781 | 2,595 | 2,328 | 2,026 | 3,276 | 3,983 | 4,190 | 3,770 | 3,532 | 2,307 | 2,462 | 3,121 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,781 | 2,595 | 2,328 | 2,026 | 3,276 | 3,983 | 4,190 | 3,770 | 3,532 | 2,307 | 2,462 | 3,121 |
| | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 943 | 787 | 656 | 551 | 528 | 615 | 822 | 787 | 612 | 570 | 701 | 973 |
| Commercial | 531 | 475 | 450 | 431 | 456 | 502 | 585 | 558 | 496 | 450 | 467 | 556 |
| Irrigation | 2 | 2 | 1 | 77 | 347 | 587 | 650 | 532 | 346 | 59 | 1 | 1 |
| Industrial | 303 | 303 | 296 | 287 | 295 | 319 | 316 | 317 | 312 | 316 | 311 | 313 |
| Additional Firm | 249 | 246 | 242 | 236 | 231 | 225 | 234 | 230 | 230 | 234 | 241 | 245 |
| Loss | 193 | 170 | 152 | 146 | 176 | 219 | 257 | 238 | 191 | 151 | 160 | 200 |
| **System Load** | 2,222 | 1,984 | 1,797 | 1,729 | 2,033 | 2,467 | 2,864 | 2,662 | 2,187 | 1,781 | 1,881 | 2,288 |
| Light Load | 2,046 | 1,832 | 1,653 | 1,573 | 1,827 | 2,217 | 2,591 | 2,361 | 1,990 | 1,612 | 1,727 | 2,128 |
| Heavy Load | 2,373 | 2,098 | 1,901 | 1,843 | 2,211 | 2,649 | 3,079 | 2,898 | 2,344 | 1,914 | 2,003 | 2,415 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,222 | 1,984 | 1,797 | 1,729 | 2,033 | 2,467 | 2,864 | 2,662 | 2,187 | 1,781 | 1,881 | 2,288 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,797 | 2,609 | 2,341 | 2,033 | 3,316 | 4,040 | 4,254 | 3,826 | 3,582 | 2,327 | 2,481 | 3,152 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,797 | 2,609 | 2,341 | 2,033 | 3,316 | 4,040 | 4,254 | 3,826 | 3,582 | 2,327 | 2,481 | 3,152 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 956 | 796 | 663 | 558 | 536 | 628 | 842 | 806 | 625 | 580 | 712 | 989 |
| Commercial | 536 | 479 | 454 | 436 | 462 | 508 | 592 | 565 | 502 | 455 | 471 | 561 |
| Irrigation | 2 | 2 | 1 | 77 | 348 | 588 | 652 | 533 | 346 | 59 | 1 | 1 |
| Industrial | 308 | 308 | 301 | 291 | 299 | 324 | 321 | 322 | 317 | 321 | 316 | 317 |
| Additional Firm | 249 | 247 | 242 | 237 | 232 | 225 | 235 | 231 | 231 | 235 | 241 | 246 |
| Loss | 196 | 172 | 154 | 148 | 178 | 221 | 261 | 241 | 194 | 153 | 162 | 203 |
| **System Load** | 2,248 | 2,004 | 1,816 | 1,747 | 2,054 | 2,495 | 2,902 | 2,698 | 2,215 | 1,803 | 1,904 | 2,318 |
| Light Load | 2,070 | 1,851 | 1,671 | 1,589 | 1,845 | 2,243 | 2,625 | 2,394 | 2,016 | 1,632 | 1,749 | 2,155 |
| Heavy Load | 2,400 | 2,119 | 1,921 | 1,862 | 2,234 | 2,680 | 3,140 | 2,918 | 2,375 | 1,938 | 2,028 | 2,446 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,248 | 2,004 | 1,816 | 1,747 | 2,054 | 2,495 | 2,902 | 2,698 | 2,215 | 1,803 | 1,904 | 2,318 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,823 | 2,626 | 2,360 | 2,049 | 3,357 | 4,100 | 4,323 | 3,889 | 3,635 | 2,349 | 2,505 | 3,193 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,823 | 2,626 | 2,360 | 2,049 | 3,357 | 4,100 | 4,323 | 3,889 | 3,635 | 2,349 | 2,505 | 3,193 |
| | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 971 | 806 | 672 | 565 | 544 | 641 | 863 | 827 | 639 | 591 | 723 | 1,004 |
| Commercial | 541 | 483 | 459 | 440 | 467 | 516 | 600 | 573 | 509 | 460 | 476 | 567 |
| Irrigation | 2 | 2 | 1 | 77 | 348 | 590 | 653 | 535 | 347 | 59 | 1 | 1 |
| Industrial | 313 | 312 | 305 | 295 | 304 | 329 | 326 | 326 | 322 | 326 | 321 | 322 |
| Additional Firm | 250 | 248 | 243 | 238 | 233 | 226 | 235 | 232 | 232 | 236 | 242 | 247 |
| Loss | 198 | 174 | 156 | 150 | 180 | 224 | 265 | 245 | 196 | 155 | 165 | 205 |
| **System Load** | 2,275 | 2,025 | 1,836 | 1,765 | 2,076 | 2,526 | 2,942 | 2,737 | 2,246 | 1,827 | 1,928 | 2,347 |
| Light Load | 2,095 | 1,871 | 1,689 | 1,606 | 1,865 | 2,270 | 2,662 | 2,428 | 2,043 | 1,653 | 1,771 | 2,182 |
| Heavy Load | 2,430 | 2,142 | 1,942 | 1,893 | 2,243 | 2,712 | 3,184 | 2,960 | 2,407 | 1,963 | 2,054 | 2,489 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,275 | 2,025 | 1,836 | 1,765 | 2,076 | 2,526 | 2,942 | 2,737 | 2,246 | 1,827 | 1,928 | 2,347 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,855 | 2,647 | 2,383 | 2,072 | 3,400 | 4,163 | 4,393 | 3,956 | 3,690 | 2,373 | 2,533 | 3,243 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,855 | 2,647 | 2,383 | 2,072 | 3,400 | 4,163 | 4,393 | 3,956 | 3,690 | 2,373 | 2,533 | 3,243 |
| | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 982 | 814 | 678 | 570 | 551 | 653 | 882 | 845 | 651 | 599 | 733 | 1,015 |
| Commercial | 546 | 489 | 464 | 445 | 473 | 523 | 609 | 581 | 517 | 466 | 482 | 574 |
| Irrigation | 2 | 2 | 1 | 78 | 349 | 592 | 656 | 536 | 348 | 59 | 1 | 1 |
| Industrial | 317 | 306 | 310 | 299 | 308 | 334 | 331 | 331 | 326 | 331 | 325 | 327 |
| Additional Firm | 250 | 246 | 243 | 238 | 233 | 227 | 236 | 232 | 232 | 236 | 242 | 247 |
| Loss | 200 | 175 | 158 | 151 | 182 | 227 | 268 | 248 | 199 | 157 | 167 | 208 |
| **System Load** | 2,299 | 2,031 | 1,854 | 1,782 | 2,097 | 2,554 | 2,981 | 2,774 | 2,274 | 1,848 | 1,950 | 2,373 |
| Light Load | 2,117 | 1,876 | 1,705 | 1,621 | 1,884 | 2,296 | 2,696 | 2,461 | 2,069 | 1,673 | 1,791 | 2,206 |
| Heavy Load | 2,442 | 2,146 | 1,971 | 1,899 | 2,265 | 2,761 | 3,205 | 3,000 | 2,453 | 1,975 | 2,077 | 2,516 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,299 | 2,031 | 1,854 | 1,782 | 2,097 | 2,554 | 2,981 | 2,774 | 2,274 | 1,848 | 1,950 | 2,373 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,877 | 2,660 | 2,400 | 2,086 | 3,442 | 4,224 | 4,462 | 4,017 | 3,745 | 2,394 | 2,555 | 3,280 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,877 | 2,660 | 2,400 | 2,086 | 3,442 | 4,224 | 4,462 | 4,017 | 3,745 | 2,394 | 2,555 | 3,280 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 989 | 818 | 682 | 573 | 555 | 662 | 897 | 860 | 661 | 606 | 739 | 1,026 |
| Commercial | 553 | 493 | 470 | 451 | 480 | 532 | 618 | 589 | 525 | 472 | 488 | 582 |
| Irrigation | 2 | 2 | 1 | 78 | 350 | 593 | 657 | 538 | 349 | 60 | 1 | 1 |
| Industrial | 323 | 323 | 315 | 305 | 313 | 339 | 336 | 337 | 332 | 336 | 331 | 333 |
| Additional Firm | 251 | 249 | 244 | 239 | 234 | 228 | 237 | 233 | 234 | 237 | 243 | 248 |
| Loss | 202 | 177 | 159 | 153 | 184 | 229 | 271 | 251 | 202 | 159 | 168 | 210 |
| **System Load** | 2,321 | 2,061 | 1,871 | 1,798 | 2,117 | 2,582 | 3,017 | 2,809 | 2,302 | 1,869 | 1,971 | 2,401 |
| Light Load | 2,138 | 1,904 | 1,721 | 1,636 | 1,901 | 2,321 | 2,729 | 2,492 | 2,095 | 1,692 | 1,810 | 2,232 |
| Heavy Load | 2,466 | 2,180 | 1,989 | 1,917 | 2,286 | 2,791 | 3,244 | 3,058 | 2,468 | 1,998 | 2,112 | 2,533 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,321 | 2,061 | 1,871 | 1,798 | 2,117 | 2,582 | 3,017 | 2,809 | 2,302 | 1,869 | 1,971 | 2,401 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,892 | 2,674 | 2,413 | 2,092 | 3,483 | 4,283 | 4,528 | 4,075 | 3,799 | 2,415 | 2,574 | 3,309 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,892 | 2,674 | 2,413 | 2,092 | 3,483 | 4,283 | 4,528 | 4,075 | 3,799 | 2,415 | 2,574 | 3,309 |
| | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 999 | 824 | 687 | 578 | 561 | 672 | 915 | 878 | 673 | 614 | 748 | 1,035 |
| Commercial | 560 | 499 | 476 | 457 | 488 | 541 | 628 | 599 | 534 | 480 | 495 | 590 |
| Irrigation | 2 | 2 | 1 | 78 | 351 | 594 | 658 | 539 | 350 | 60 | 1 | 1 |
| Industrial | 329 | 329 | 321 | 310 | 319 | 345 | 342 | 343 | 338 | 342 | 337 | 339 |
| Additional Firm | 253 | 250 | 246 | 240 | 235 | 229 | 238 | 235 | 235 | 238 | 245 | 249 |
| Loss | 205 | 179 | 161 | 154 | 186 | 232 | 275 | 255 | 204 | 161 | 171 | 213 |
| **System Load** | 2,348 | 2,083 | 1,892 | 1,818 | 2,139 | 2,613 | 3,057 | 2,848 | 2,334 | 1,894 | 1,996 | 2,427 |
| Light Load | 2,163 | 1,924 | 1,740 | 1,654 | 1,922 | 2,349 | 2,766 | 2,526 | 2,123 | 1,714 | 1,833 | 2,257 |
| Heavy Load | 2,495 | 2,203 | 2,011 | 1,937 | 2,326 | 2,806 | 3,287 | 3,101 | 2,502 | 2,024 | 2,138 | 2,561 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,348 | 2,083 | 1,892 | 1,818 | 2,139 | 2,613 | 3,057 | 2,848 | 2,334 | 1,894 | 1,996 | 2,427 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,916 | 2,691 | 2,431 | 2,106 | 3,527 | 4,346 | 4,599 | 4,137 | 3,856 | 2,440 | 2,598 | 3,345 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,916 | 2,691 | 2,431 | 2,106 | 3,527 | 4,346 | 4,599 | 4,137 | 3,856 | 2,440 | 2,598 | 3,345 |
| | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,003 | 825 | 688 | 578 | 564 | 679 | 928 | 890 | 680 | 618 | 752 | 1,051 |
| Commercial | 568 | 505 | 483 | 464 | 496 | 551 | 639 | 609 | 544 | 488 | 502 | 599 |
| Irrigation | 2 | 2 | 1 | 78 | 351 | 595 | 660 | 540 | 350 | 60 | 1 | 1 |
| Industrial | 336 | 335 | 327 | 316 | 324 | 351 | 348 | 349 | 344 | 348 | 343 | 346 |
| Additional Firm | 252 | 250 | 246 | 240 | 236 | 229 | 239 | 235 | 235 | 239 | 245 | 249 |
| Loss | 207 | 180 | 162 | 156 | 188 | 234 | 278 | 258 | 207 | 163 | 172 | 216 |
| **System Load** | 2,367 | 2,098 | 1,907 | 1,833 | 2,158 | 2,640 | 3,092 | 2,881 | 2,360 | 1,914 | 2,015 | 2,461 |
| Light Load | 2,180 | 1,938 | 1,754 | 1,667 | 1,938 | 2,372 | 2,797 | 2,556 | 2,148 | 1,733 | 1,851 | 2,289 |
| Heavy Load | 2,528 | 2,219 | 2,017 | 1,953 | 2,346 | 2,835 | 3,324 | 3,137 | 2,530 | 2,058 | 2,146 | 2,598 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,367 | 2,098 | 1,907 | 1,833 | 2,158 | 2,640 | 3,092 | 2,881 | 2,360 | 1,914 | 2,015 | 2,461 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,920 | 2,696 | 2,438 | 2,101 | 3,568 | 4,403 | 4,664 | 4,188 | 3,910 | 2,460 | 2,611 | 3,361 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,920 | 2,696 | 2,438 | 2,101 | 3,568 | 4,403 | 4,664 | 4,188 | 3,910 | 2,460 | 2,611 | 3,361 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,023 | 840 | 700 | 589 | 575 | 697 | 956 | 918 | 699 | 633 | 768 | 1,066 |
| Commercial | 576 | 514 | 491 | 472 | 504 | 562 | 651 | 621 | 555 | 497 | 511 | 609 |
| Irrigation | 2 | 2 | 1 | 78 | 351 | 595 | 659 | 540 | 350 | 60 | 1 | 1 |
| Industrial | 343 | 331 | 333 | 322 | 330 | 357 | 354 | 356 | 350 | 354 | 349 | 352 |
| Additional Firm | 252 | 248 | 246 | 241 | 236 | 230 | 239 | 236 | 236 | 239 | 245 | 249 |
| Loss | 210 | 183 | 165 | 158 | 190 | 238 | 283 | 263 | 211 | 166 | 176 | 219 |
| **System Load** | 2,407 | 2,117 | 1,936 | 1,860 | 2,188 | 2,679 | 3,144 | 2,932 | 2,401 | 1,948 | 2,049 | 2,497 |
| Light Load | 2,217 | 1,955 | 1,781 | 1,692 | 1,965 | 2,408 | 2,844 | 2,601 | 2,185 | 1,763 | 1,882 | 2,322 |
| Heavy Load | 2,570 | 2,237 | 2,048 | 1,994 | 2,363 | 2,877 | 3,401 | 3,171 | 2,574 | 2,093 | 2,183 | 2,647 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,407 | 2,117 | 1,936 | 1,860 | 2,188 | 2,679 | 3,144 | 2,932 | 2,401 | 1,948 | 2,049 | 2,497 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,974 | 2,721 | 2,476 | 2,144 | 3,618 | 4,476 | 4,747 | 4,273 | 3,972 | 2,494 | 2,655 | 3,434 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,974 | 2,721 | 2,476 | 2,144 | 3,618 | 4,476 | 4,747 | 4,273 | 3,972 | 2,494 | 2,655 | 3,434 |
| | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,031 | 844 | 704 | 592 | 580 | 707 | 972 | 934 | 710 | 639 | 775 | 1,079 |
| Commercial | 586 | 521 | 499 | 481 | 514 | 574 | 664 | 633 | 567 | 506 | 519 | 619 |
| Irrigation | 2 | 2 | 1 | 78 | 353 | 598 | 663 | 542 | 352 | 60 | 1 | 1 |
| Industrial | 350 | 350 | 340 | 328 | 336 | 364 | 361 | 362 | 357 | 360 | 356 | 359 |
| Additional Firm | 252 | 250 | 246 | 241 | 237 | 230 | 240 | 237 | 236 | 239 | 245 | 249 |
| Loss | 213 | 185 | 167 | 160 | 193 | 241 | 287 | 267 | 214 | 168 | 178 | 222 |
| **System Load** | 2,433 | 2,152 | 1,957 | 1,880 | 2,212 | 2,713 | 3,187 | 2,974 | 2,435 | 1,973 | 2,074 | 2,530 |
| Light Load | 2,241 | 1,987 | 1,800 | 1,710 | 1,987 | 2,439 | 2,883 | 2,639 | 2,216 | 1,786 | 1,905 | 2,353 |
| Heavy Load | 2,585 | 2,275 | 2,070 | 2,016 | 2,389 | 2,914 | 3,449 | 3,217 | 2,627 | 2,109 | 2,210 | 2,683 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,433 | 2,152 | 1,957 | 1,880 | 2,212 | 2,713 | 3,187 | 2,974 | 2,435 | 1,973 | 2,074 | 2,530 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 2,991 | 2,748 | 2,491 | 2,151 | 3,665 | 4,541 | 4,822 | 4,335 | 4,031 | 2,520 | 2,677 | 3,463 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 2,991 | 2,748 | 2,491 | 2,151 | 3,665 | 4,541 | 4,822 | 4,335 | 4,031 | 2,520 | 2,677 | 3,463 |
| | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,043 | 852 | 710 | 597 | 587 | 719 | 994 | 955 | 724 | 649 | 786 | 1,095 |
| Commercial | 596 | 530 | 508 | 490 | 524 | 586 | 677 | 646 | 580 | 517 | 529 | 631 |
| Irrigation | 2 | 2 | 1 | 78 | 353 | 598 | 663 | 543 | 352 | 60 | 1 | 1 |
| Industrial | 357 | 357 | 347 | 335 | 342 | 370 | 368 | 369 | 364 | 367 | 362 | 367 |
| Additional Firm | 252 | 250 | 246 | 242 | 238 | 231 | 241 | 238 | 237 | 240 | 246 | 250 |
| Loss | 216 | 188 | 169 | 162 | 195 | 245 | 292 | 271 | 217 | 171 | 181 | 226 |
| **System Load** | 2,466 | 2,179 | 1,982 | 1,904 | 2,239 | 2,750 | 3,235 | 3,021 | 2,474 | 2,004 | 2,104 | 2,570 |
| Light Load | 2,271 | 2,012 | 1,823 | 1,733 | 2,011 | 2,472 | 2,927 | 2,680 | 2,251 | 1,813 | 1,933 | 2,389 |
| Heavy Load | 2,620 | 2,304 | 2,107 | 2,030 | 2,418 | 2,972 | 3,478 | 3,267 | 2,668 | 2,141 | 2,242 | 2,725 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,466 | 2,179 | 1,982 | 1,904 | 2,239 | 2,750 | 3,235 | 3,021 | 2,474 | 2,004 | 2,104 | 2,570 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,023 | 2,772 | 2,516 | 2,172 | 3,713 | 4,609 | 4,900 | 4,406 | 4,092 | 2,550 | 2,708 | 3,509 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 3,023 | 2,772 | 2,516 | 2,172 | 3,713 | 4,609 | 4,900 | 4,406 | 4,092 | 2,550 | 2,708 | 3,509 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,357,421 | 5,350,025 | 5,374,565 | 5,521,030 | 5,634,806 | 5,723,417 | 5,833,019 | 5,924,726 | 6,040,115 | 6,145,352 |
| Commercial | 3,880,072 | 3,934,333 | 3,989,337 | 4,044,412 | 4,097,916 | 4,140,627 | 4,182,801 | 4,224,463 | 4,265,773 | 4,306,283 |
| Irrigation | 1,861,930 | 1,869,427 | 1,866,437 | 1,867,696 | 1,880,558 | 1,888,961 | 1,894,245 | 1,900,506 | 1,904,290 | 1,909,550 |
| Industrial | 2,294,027 | 2,346,083 | 2,391,684 | 2,434,390 | 2,472,828 | 2,509,361 | 2,545,600 | 2,580,387 | 2,616,525 | 2,653,140 |
| Additional Firm | 1,449,272 | 1,627,180 | 1,798,947 | 1,901,753 | 2,002,406 | 2,070,809 | 2,065,176 | 2,069,629 | 2,074,558 | 2,073,248 |
| **System Sales** | 14,842,722 | 15,127,047 | 15,420,970 | 15,769,281 | 16,088,513 | 16,333,175 | 16,520,841 | 16,699,711 | 16,901,261 | 17,087,573 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 14,842,722 | 15,127,047 | 15,420,970 | 15,769,281 | 16,088,513 | 16,333,175 | 16,520,841 | 16,699,711 | 16,901,261 | 17,087,573 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,356,552 | 5,368,321 | 5,384,199 | 5,528,413 | 5,640,457 | 5,748,305 | 5,838,861 | 5,932,173 | 6,046,857 | 6,169,719 |
| Commercial | 3,884,105 | 3,949,205 | 3,993,381 | 4,048,367 | 4,101,300 | 4,155,506 | 4,186,117 | 4,227,754 | 4,269,015 | 4,321,445 |
| Irrigation | 1,861,934 | 1,869,472 | 1,866,438 | 1,867,700 | 1,880,561 | 1,889,009 | 1,894,248 | 1,900,508 | 1,904,292 | 1,909,598 |
| Industrial | 2,299,135 | 2,350,458 | 2,395,812 | 2,438,153 | 2,476,427 | 2,512,935 | 2,549,050 | 2,583,953 | 2,620,131 | 2,656,639 |
| Additional Firm | 1,449,272 | 1,627,180 | 1,798,947 | 1,901,753 | 2,002,406 | 2,070,809 | 2,065,176 | 2,069,629 | 2,074,558 | 2,073,248 |
| **System Sales** | 14,850,998 | 15,164,636 | 15,438,777 | 15,784,386 | 16,101,150 | 16,376,563 | 16,533,451 | 16,714,015 | 16,914,853 | 17,130,649 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 14,850,998 | 15,164,636 | 15,438,777 | 15,784,386 | 16,101,150 | 16,376,563 | 16,533,451 | 16,714,015 | 16,914,853 | 17,130,649 |
| Loss | 1,444,182 | 1,463,763 | 1,479,931 | 1,508,228 | 1,533,705 | 1,557,212 | 1,573,206 | 1,591,131 | 1,611,191 | 1,633,386 |
| **Required Generation** | 16,295,180 | 16,628,399 | 16,918,708 | 17,292,614 | 17,634,855 | 17,933,775 | 18,106,657 | 18,305,146 | 18,526,044 | 18,764,035 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 611 | 611 | 615 | 631 | 644 | 654 | 667 | 677 | 690 | 702 |
| Commercial | 443 | 450 | 456 | 462 | 468 | 473 | 478 | 483 | 487 | 492 |
| Irrigation | 213 | 213 | 213 | 213 | 215 | 215 | 216 | 217 | 217 | 217 |
| Industrial | 262 | 268 | 273 | 278 | 283 | 286 | 291 | 295 | 299 | 302 |
| Additional Firm | 165 | 185 | 205 | 217 | 229 | 236 | 236 | 236 | 237 | 236 |
| Loss | 165 | 167 | 169 | 172 | 175 | 177 | 180 | 182 | 184 | 186 |
| **System Load** | 1,860 | 1,893 | 1,931 | 1,974 | 2,013 | 2,042 | 2,067 | 2,090 | 2,115 | 2,136 |
| Light Load | 1,692 | 1,722 | 1,757 | 1,796 | 1,831 | 1,857 | 1,880 | 1,901 | 1,924 | 1,943 |
| Heavy Load | 1,992 | 2,028 | 2,068 | 2,114 | 2,156 | 2,186 | 2,214 | 2,238 | 2,264 | 2,287 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,860 | 1,893 | 1,931 | 1,974 | 2,013 | 2,042 | 2,067 | 2,090 | 2,115 | 2,136 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,515 | 3,577 | 3,684 | 3,770 | 3,854 | 3,925 | 3,991 | 4,056 | 4,123 | 4,190 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 3,515 | 3,577 | 3,684 | 3,770 | 3,854 | 3,925 | 3,991 | 4,056 | 4,123 | 4,190 |

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,234,625 | 6,340,476 | 6,456,861 | 6,550,687 | 6,619,355 | 6,706,622 | 6,753,472 | 6,910,560 | 6,983,002 | 7,087,720 |
| Commercial | 4,349,042 | 4,396,651 | 4,448,515 | 4,503,254 | 4,565,023 | 4,634,525 | 4,708,162 | 4,792,331 | 4,879,416 | 4,975,065 |
| Irrigation | 1,914,466 | 1,917,913 | 1,922,878 | 1,929,306 | 1,933,757 | 1,936,501 | 1,940,279 | 1,939,931 | 1,949,092 | 1,950,483 |
| Industrial | 2,690,609 | 2,732,262 | 2,771,129 | 2,811,827 | 2,859,873 | 2,911,643 | 2,964,041 | 3,021,185 | 3,078,753 | 3,139,413 |
| Additional Firm | 2,074,887 | 2,081,619 | 2,088,963 | 2,096,186 | 2,101,203 | 2,111,939 | 2,112,515 | 2,119,494 | 2,118,995 | 2,125,092 |
| **System Sales** | 17,263,629 | 17,468,921 | 17,688,347 | 17,891,260 | 18,079,212 | 18,301,230 | 18,478,470 | 18,783,502 | 19,009,257 | 19,277,774 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 17,263,629 | 17,468,921 | 17,688,347 | 17,891,260 | 18,079,212 | 18,301,230 | 18,478,470 | 18,783,502 | 19,009,257 | 19,277,774 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,241,386 | 6,347,940 | 6,462,780 | 6,574,419 | 6,624,811 | 6,709,331 | 6,763,635 | 6,935,136 | 6,989,597 | 7,095,612 |
| Commercial | 4,352,048 | 4,399,576 | 4,451,288 | 4,518,688 | 4,567,958 | 4,637,373 | 4,711,254 | 4,808,349 | 4,882,499 | 4,978,134 |
| Irrigation | 1,914,468 | 1,917,915 | 1,922,881 | 1,929,355 | 1,933,758 | 1,936,503 | 1,940,279 | 1,939,982 | 1,949,093 | 1,950,485 |
| Industrial | 2,694,287 | 2,735,521 | 2,774,365 | 2,815,511 | 2,863,696 | 2,915,340 | 2,967,964 | 3,024,964 | 3,082,617 | 3,143,429 |
| Additional Firm | 2,074,887 | 2,081,619 | 2,088,963 | 2,096,186 | 2,101,203 | 2,111,939 | 2,112,515 | 2,119,494 | 2,118,995 | 2,125,092 |
| **System Sales** | 17,277,075 | 17,482,570 | 17,700,277 | 17,934,159 | 18,091,427 | 18,310,486 | 18,495,648 | 18,827,925 | 19,022,801 | 19,292,751 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Sales** | 17,277,075 | 17,482,570 | 17,700,277 | 17,934,159 | 18,091,427 | 18,310,486 | 18,495,648 | 18,827,925 | 19,022,801 | 19,292,751 |
| Loss | 1,647,751 | 1,668,181 | 1,690,073 | 1,713,793 | 1,729,063 | 1,750,660 | 1,769,375 | 1,803,639 | 1,823,461 | 1,851,018 |
| **Required Generation** | 18,924,826 | 19,150,752 | 19,390,350 | 19,647,952 | 19,820,490 | 20,061,146 | 20,265,023 | 20,631,564 | 20,846,262 | 21,143,769 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 712 | 725 | 738 | 748 | 756 | 766 | 772 | 790 | 798 | 810 |
| Commercial | 497 | 502 | 508 | 514 | 521 | 529 | 538 | 547 | 557 | 568 |
| Irrigation | 219 | 219 | 220 | 220 | 221 | 221 | 221 | 221 | 222 | 223 |
| Industrial | 308 | 312 | 317 | 321 | 327 | 333 | 339 | 344 | 352 | 359 |
| Additional Firm | 237 | 238 | 238 | 239 | 240 | 241 | 241 | 241 | 242 | 243 |
| Loss | 188 | 190 | 193 | 195 | 197 | 200 | 202 | 205 | 208 | 211 |
| **System Load** | 2,160 | 2,186 | 2,214 | 2,237 | 2,263 | 2,290 | 2,313 | 2,349 | 2,380 | 2,414 |
| Light Load | 1,965 | 1,989 | 2,014 | 2,035 | 2,058 | 2,083 | 2,104 | 2,137 | 2,165 | 2,196 |
| Heavy Load | 2,314 | 2,341 | 2,371 | 2,395 | 2,423 | 2,452 | 2,478 | 2,516 | 2,548 | 2,584 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 2,160 | 2,186 | 2,214 | 2,237 | 2,263 | 2,290 | 2,313 | 2,349 | 2,380 | 2,414 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 4,254 | 4,323 | 4,393 | 4,462 | 4,528 | 4,599 | 4,664 | 4,747 | 4,822 | 4,900 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Peak Load** | 4,254 | 4,323 | 4,393 | 4,462 | 4,528 | 4,599 | 4,664 | 4,747 | 4,822 | 4,900 |

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 14 | 13 | 13 | 14 | 16 | 17 | 17 | 17 | 15 | 14 | 13 | 13 |
| Load Forecast (70th% w/DSM) | (1,885) | (1,722) | (1,563) | (1,521) | (1,790) | (2,137) | (2,434) | (2,262) | (1,876) | (1,525) | (1,619) | (1,965) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 933 | 933 | 863 | 669 | 646 | 914 | 932 | 932 | 932 | 931 | 932 | 932 |
| **Gas (Langley Gulch)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro (70th%)—HCC | 571 | 700 | 590 | 668 | 823 | 714 | 499 | 364 | 410 | 435 | 364 | 473 |
| Hydro (70th%)—Other | 217 | 253 | 245 | 240 | 334 | 346 | 278 | 235 | 229 | 224 | 198 | 211 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 953 | 836 | 908 | 1,156 | 1,060 | 849 | 599 | 639 | 658 | 562 | 684 |
| **CSPP (PURPA)** | 93 | 97 | 129 | 151 | 185 | 193 | 207 | 210 | 211 | 187 | 163 | 168 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 48 | 45 | 48 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 42 | 42 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 49 | 49 | 31 | 34 | 50 | 106 | 144 | 140 | 43 | 26 | 25 | 58 |
| **Firm Pacific NW Import Capability** | 133 | 32 | 0 | 0 | 320 | 254 | 126 | 186 | 197 | 0 | 115 | 325 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,219 | 2,065 | 1,859 | 1,762 | 2,357 | 2,767 | 2,482 | 2,309 | 2,021 | 1,802 | 1,798 | 2,400 |
| **Monthly Surplus/Deficit** | 334 | 343 | 296 | 241 | 566 | 630 | 47 | 47 | 146 | 277 | 179 | 435 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| Residential | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 0 |
| **Total New DSM (aMW)** | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| **Monthly Surplus/Deficit** | 336 | 345 | 299 | 244 | 569 | 634 | 51 | 50 | 148 | 279 | 182 | 437 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 336 | 345 | 299 | 244 | 569 | 634 | 51 | 50 | 148 | 279 | 182 | 437 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2012 | 2/2012 | 3/2012 | 4/2012 | 5/2012 | 6/2012 | 7/2012 | 8/2012 | 9/2012 | 10/2012 | 11/2012 | 12/2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 27 | 26 | 26 | 28 | 31 | 34 | 34 | 33 | 30 | 27 | 27 | 27 |
| Load Forecast (70th% w/DSM) | (1,959) | (1,760) | (1,592) | (1,538) | (1,812) | (2,165) | (2,468) | (2,293) | (1,905) | (1,556) | (1,650) | (2,000) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 932 | 932 | 886 | 776 | 735 | 851 | 931 | 931 | 931 | 930 | 931 | 931 |
| **Gas (Langley Gulch)** | 0 | 0 | 0 | 0 | 0 | 0 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 571 | 698 | 590 | 666 | 823 | 713 | 499 | 363 | 410 | 433 | 364 | 471 |
| Hydro (70th%)—Other | 216 | 252 | 246 | 240 | 333 | 346 | 278 | 235 | 229 | 223 | 198 | 211 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 950 | 835 | 906 | 1,156 | 1,059 | 848 | 598 | 639 | 656 | 562 | 682 |
| **CSPP (PURPA)** | 155 | 162 | 179 | 199 | 228 | 229 | 217 | 210 | 211 | 187 | 163 | 170 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 48 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 49 | 49 | 31 | 34 | 50 | 58 | 102 | 98 | 43 | 46 | 45 | 78 |
| **Firm Pacific NW Import Capability** | 122 | 30 | 0 | 0 | 444 | 360 | 233 | 294 | 304 | 0 | 129 | 322 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,269 | 2,124 | 1,932 | 1,915 | 2,612 | 2,798 | 2,806 | 2,624 | 2,378 | 2,070 | 2,082 | 2,657 |
| **Monthly Surplus/Deficit** | 310 | 364 | 339 | 377 | 799 | 633 | 338 | 331 | 474 | 514 | 433 | 657 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Residential | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 1 | 1 | 1 | 1 |
| **Total New DSM (aMW)** | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 7 | 5 | 5 | 5 | 5 |
| **Monthly Surplus/Deficit** | 315 | 369 | 344 | 382 | 804 | 640 | 345 | 337 | 479 | 519 | 438 | 662 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 315 | 369 | 344 | 382 | 804 | 640 | 345 | 337 | 479 | 519 | 438 | 662 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 39 | 39 | 39 | 41 | 46 | 49 | 50 | 48 | 44 | 40 | 39 | 40 |
| Load Forecast (70th% w/DSM) | (1,986) | (1,795) | (1,617) | (1,561) | (1,838) | (2,214) | (2,541) | (2,354) | (1,943) | (1,584) | (1,677) | (2,042) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 931 | 931 | 852 | 558 | 612 | 931 | 931 | 931 | 931 | 930 | 931 | 931 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 572 | 695 | 589 | 666 | 823 | 713 | 499 | 363 | 411 | 431 | 364 | 471 |
| Hydro (70th%)—Other | 216 | 252 | 244 | 239 | 332 | 345 | 278 | 235 | 229 | 223 | 198 | 211 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 947 | 834 | 905 | 1,155 | 1,058 | 848 | 597 | 639 | 654 | 562 | 681 |
| **CSPP (PURPA)** | 161 | 169 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 69 | 69 | 51 | 54 | 70 | 78 | 77 | 70 | 63 | 46 | 45 | 78 |
| **Firm Pacific NW Import Capability** | 131 | 37 | 0 | 0 | 443 | 357 | 229 | 291 | 302 | 0 | 148 | 319 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,564 | 2,404 | 2,177 | 1,977 | 2,769 | 3,146 | 2,794 | 2,600 | 2,405 | 2,078 | 2,110 | 2,662 |
| **Monthly Surplus/Deficit** | 577 | 609 | 561 | 416 | 930 | 932 | 253 | 246 | 462 | 494 | 433 | 620 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Residential | 1 | 1 | 1 | 1 | 1 | 4 | 4 | 4 | 1 | 1 | 1 | 1 |
| **Total New DSM (aMW)** | 8 | 8 | 8 | 8 | 8 | 10 | 10 | 10 | 8 | 8 | 8 | 8 |
| **Monthly Surplus/Deficit** | 585 | 617 | 569 | 424 | 938 | 942 | 264 | 257 | 470 | 502 | 440 | 628 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 585 | 617 | 569 | 424 | 938 | 942 | 264 | 257 | 470 | 502 | 440 | 628 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 52 | 52 | 52 | 54 | 60 | 65 | 65 | 63 | 57 | 53 | 52 | 52 |
| Load Forecast (70th% w/DSM) | (2,032) | (1,835) | (1,654) | (1,596) | (1,875) | (2,258) | (2,594) | (2,406) | (1,986) | (1,623) | (1,718) | (2,087) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 931 | 931 | 880 | 584 | 722 | 921 | 931 | 931 | 931 | 930 | 931 | 931 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 574 | 682 | 587 | 663 | 823 | 710 | 497 | 362 | 405 | 428 | 365 | 467 |
| Hydro (70th%)—Other | 214 | 246 | 241 | 226 | 331 | 345 | 277 | 234 | 228 | 222 | 197 | 209 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 928 | 828 | 889 | 1,154 | 1,055 | 845 | 595 | 632 | 650 | 561 | 676 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 69 | 69 | 51 | 54 | 70 | 78 | 77 | 70 | 63 | 46 | 45 | 78 |
| **Firm Pacific NW Import Capability** | 190 | 81 | 0 | 0 | 441 | 353 | 225 | 288 | 301 | 0 | 198 | 318 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,625 | 2,432 | 2,200 | 1,987 | 2,875 | 3,128 | 2,787 | 2,585 | 2,397 | 2,073 | 2,159 | 2,664 |
| **Monthly Surplus/Deficit** | 593 | 598 | 546 | 391 | 1,000 | 870 | 193 | 180 | 411 | 450 | 441 | 577 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Commercial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Residential | 2 | 2 | 2 | 2 | 2 | 6 | 6 | 6 | 2 | 2 | 2 | 2 |
| **Total New DSM (aMW)** | 10 | 10 | 10 | 10 | 10 | 14 | 14 | 14 | 10 | 10 | 10 | 10 |
| **Monthly Surplus/Deficit** | 603 | 608 | 556 | 401 | 1,010 | 884 | 207 | 194 | 421 | 460 | 451 | 587 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 603 | 608 | 556 | 401 | 1,010 | 884 | 207 | 194 | 421 | 460 | 451 | 587 |

# *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 64 | 64 | 64 | 66 | 74 | 79 | 79 | 77 | 70 | 65 | 64 | 64 |
| Load Forecast (70th% w/DSM) | (2,072) | (1,868) | (1,686) | (1,627) | (1,910) | (2,301) | (2,646) | (2,456) | (2,028) | (1,657) | (1,754) | (2,127) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 931 | 931 | 834 | 634 | 715 | 814 | 931 | 931 | 931 | 930 | 931 | 931 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 576 | 671 | 586 | 659 | 822 | 708 | 495 | 360 | 406 | 421 | 364 | 464 |
| Hydro (70th%)—Other | 212 | 236 | 237 | 223 | 331 | 344 | 276 | 233 | 227 | 221 | 195 | 207 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 907 | 823 | 882 | 1,153 | 1,052 | 843 | 592 | 632 | 642 | 560 | 682 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 69 | 69 | 51 | 54 | 70 | 78 | 77 | 70 | 63 | 46 | 45 | 78 |
| **Firm Pacific NW Import Capability** | 231 | 113 | 0 | 0 | 440 | 350 | 222 | 286 | 299 | 0 | 237 | 316 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,666 | 2,443 | 2,149 | 2,030 | 2,865 | 3,025 | 2,782 | 2,581 | 2,395 | 2,065 | 2,197 | 2,669 |
| **Monthly Surplus/Deficit** | 594 | 575 | 463 | 403 | 955 | 724 | 135 | 125 | 367 | 408 | 442 | 542 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Commercial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Residential | 3 | 3 | 3 | 3 | 3 | 8 | 8 | 8 | 3 | 3 | 3 | 3 |
| **Total New DSM (aMW)** | 12 | 12 | 12 | 12 | 12 | 17 | 17 | 17 | 12 | 12 | 12 | 12 |
| **Monthly Surplus/Deficit** | 606 | 587 | 475 | 415 | 967 | 741 | 152 | 142 | 379 | 420 | 454 | 554 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 48 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 45 | 48 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 606 | 587 | 475 | 415 | 967 | 741 | 197 | 190 | 379 | 420 | 454 | 554 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 77 | 76 | 76 | 79 | 88 | 93 | 93 | 91 | 83 | 78 | 76 | 76 |
| Load Forecast (70th% w/DSM) | (2,106) | (1,885) | (1,713) | (1,652) | (1,938) | (2,334) | (2,687) | (2,493) | (2,057) | (1,681) | (1,777) | (2,156) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 931 | 931 | 898 | 823 | 715 | 888 | 937 | 937 | 937 | 936 | 937 | 937 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 578 | 668 | 585 | 656 | 821 | 705 | 494 | 358 | 410 | 420 | 365 | 468 |
| Hydro (70th%)—Other | 210 | 255 | 240 | 232 | 330 | 343 | 275 | 232 | 227 | 221 | 195 | 205 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 957 | 840 | 888 | 1,166 | 1,067 | 771 | 590 | 636 | 641 | 560 | 684 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 254 | 105 | 0 | 0 | 437 | 346 | 218 | 283 | 297 | 0 | 258 | 314 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,682 | 2,479 | 2,243 | 2,237 | 2,866 | 3,099 | 2,693 | 2,584 | 2,399 | 2,089 | 2,241 | 2,671 |
| **Monthly Surplus/Deficit** | 576 | 594 | 530 | 585 | 929 | 764 | 6 | 90 | 342 | 408 | 464 | 515 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 8 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 |
| Commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Residential | 3 | 3 | 3 | 3 | 3 | 10 | 10 | 10 | 3 | 3 | 3 | 3 |
| **Total New DSM (aMW)** | 14 | 14 | 14 | 14 | 14 | 20 | 20 | 20 | 14 | 14 | 14 | 14 |
| **Monthly Surplus/Deficit** | 590 | 608 | 544 | 599 | 942 | 785 | 26 | 111 | 355 | 422 | 478 | 529 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 287 | 232 | 196 | 123 | 110 | 128 | 123 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 287 | 232 | 196 | 123 | 110 | 128 | 123 |
| **Monthly Surplus/Deficit** | 590 | 608 | 544 | 599 | 942 | 1,071 | 258 | 307 | 478 | 531 | 606 | 652 |

# *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 88 | 88 | 88 | 92 | 101 | 107 | 108 | 105 | 96 | 90 | 88 | 89 |
| Load Forecast (70th% w/DSM) | (2,131) | (1,915) | (1,731) | (1,668) | (1,957) | (2,361) | (2,723) | (2,527) | (2,083) | (1,701) | (1,798) | (2,182) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 937 | 937 | 904 | 840 | 705 | 916 | 943 | 943 | 943 | 942 | 943 | 943 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 580 | 660 | 583 | 651 | 817 | 702 | 492 | 356 | 404 | 415 | 364 | 465 |
| Hydro (70th%)—Other | 208 | 246 | 237 | 220 | 329 | 342 | 274 | 227 | 226 | 220 | 194 | 204 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 941 | 835 | 871 | 1,162 | 1,063 | 768 | 584 | 630 | 635 | 558 | 681 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 280 | 117 | 0 | 0 | 435 | 343 | 214 | 281 | 295 | 0 | 281 | 311 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,714 | 2,482 | 2,244 | 2,237 | 2,850 | 3,120 | 2,692 | 2,582 | 2,397 | 2,088 | 2,268 | 2,661 |
| **Monthly Surplus/Deficit** | 583 | 566 | 514 | 569 | 892 | 758 | (30) | 54 | 313 | 387 | 470 | 479 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Residential | 4 | 4 | 4 | 4 | 4 | 12 | 12 | 12 | 4 | 4 | 4 | 4 |
| **Total New DSM (aMW)** | 16 | 16 | 16 | 16 | 16 | 24 | 24 | 24 | 16 | 16 | 16 | 16 |
| **Monthly Surplus/Deficit** | 598 | 582 | 529 | 584 | 908 | 782 | (7) | 78 | 329 | 403 | 485 | 495 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 95 | 8 | 46 | 136 | 247 | 290 | 235 | 192 | 135 | 114 | 128 | 152 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 95 | 8 | 46 | 136 | 247 | 290 | 235 | 192 | 135 | 114 | 128 | 152 |
| **Monthly Surplus/Deficit** | 693 | 590 | 575 | 720 | 1,154 | 1,072 | 228 | 270 | 464 | 517 | 613 | 646 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 100 | 100 | 100 | 104 | 114 | 121 | 122 | 119 | 109 | 101 | 100 | 101 |
| Load Forecast (70th% w/DSM) | (2,153) | (1,932) | (1,747) | (1,683) | (1,976) | (2,387) | (2,757) | (2,560) | (2,108) | (1,720) | (1,818) | (2,209) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 943 | 947 | 943 | 841 | 726 | 900 | 944 | 944 | 944 | 943 | 944 | 944 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 582 | 649 | 580 | 649 | 813 | 700 | 490 | 355 | 411 | 399 | 364 | 461 |
| Hydro (70th%)—Other | 206 | 240 | 235 | 218 | 328 | 341 | 273 | 226 | 221 | 219 | 193 | 203 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 925 | 830 | 867 | 1,156 | 1,060 | 766 | 582 | 632 | 618 | 557 | 675 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 296 | 128 | 0 | 0 | 433 | 339 | 209 | 278 | 293 | 0 | 300 | 309 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,745 | 2,486 | 2,278 | 2,234 | 2,864 | 3,096 | 2,686 | 2,577 | 2,398 | 2,073 | 2,287 | 2,654 |
| **Monthly Surplus/Deficit** | 592 | 554 | 531 | 551 | 888 | 709 | (71) | 17 | 289 | 353 | 469 | 445 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Commercial | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 4 | 4 | 4 | 4 | 4 |
| Residential | 5 | 5 | 5 | 5 | 5 | 15 | 15 | 15 | 5 | 5 | 5 | 5 |
| **Total New DSM (aMW)** | 17 | 17 | 17 | 17 | 17 | 27 | 27 | 27 | 17 | 17 | 17 | 17 |
| **Monthly Surplus/Deficit** | 609 | 572 | 549 | 569 | 906 | 736 | (44) | 45 | 307 | 370 | 486 | 463 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 89 | 7 | 41 | 89 | 230 | 275 | 262 | 211 | 127 | 108 | 171 | 158 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 89 | 7 | 41 | 89 | 230 | 275 | 262 | 211 | 127 | 108 | 171 | 158 |
| **Monthly Surplus/Deficit** | 699 | 578 | 590 | 658 | 1,135 | 1,011 | 218 | 256 | 434 | 478 | 657 | 621 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 112 | 112 | 112 | 116 | 127 | 135 | 136 | 133 | 123 | 114 | 112 | 113 |
| Load Forecast (70th% w/DSM) | (2,178) | (1,951) | (1,765) | (1,700) | (1,996) | (2,415) | (2,794) | (2,595) | (2,136) | (1,742) | (1,841) | (2,237) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 944 | 944 | 944 | 843 | 728 | 901 | 950 | 950 | 950 | 949 | 950 | 950 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 583 | 638 | 579 | 646 | 810 | 697 | 489 | 354 | 411 | 394 | 364 | 459 |
| Hydro (70th%)—Other | 205 | 228 | 232 | 217 | 328 | 340 | 273 | 225 | 220 | 218 | 192 | 202 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 902 | 827 | 864 | 1,153 | 1,056 | 764 | 580 | 632 | 612 | 556 | 673 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 100 | 145 | 0 | 0 | 432 | 335 | 205 | 275 | 291 | 0 | 324 | 307 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,550 | 2,478 | 2,276 | 2,231 | 2,860 | 3,081 | 2,695 | 2,578 | 2,402 | 2,073 | 2,316 | 2,656 |
| **Monthly Surplus/Deficit** | 372 | 526 | 511 | 532 | 864 | 666 | (99) | (17) | 266 | 331 | 475 | 418 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 9 | 9 | 9 | 9 |
| Commercial | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Residential | 6 | 6 | 6 | 6 | 6 | 17 | 17 | 17 | 6 | 6 | 6 | 6 |
| **Total New DSM (aMW)** | 19 | 19 | 19 | 19 | 19 | 31 | 31 | 31 | 19 | 19 | 19 | 19 |
| **Monthly Surplus/Deficit** | 391 | 546 | 530 | 551 | 884 | 697 | (68) | 14 | 285 | 351 | 495 | 438 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 88 | 8 | 28 | 40 | 214 | 291 | 280 | 151 | 119 | 118 | 154 | 149 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 88 | 8 | 28 | 40 | 214 | 291 | 280 | 151 | 119 | 118 | 154 | 149 |
| **Monthly Surplus/Deficit** | 479 | 553 | 558 | 591 | 1,097 | 988 | 212 | 165 | 404 | 469 | 649 | 587 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 125 | 124 | 125 | 128 | 141 | 149 | 150 | 147 | 134 | 126 | 125 | 125 |
| Load Forecast (70th% w/DSM) | (2,200) | (1,956) | (1,781) | (1,714) | (2,015) | (2,441) | (2,830) | (2,629) | (2,161) | (1,761) | (1,861) | (2,261) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 944 | 946 | 944 | 838 | 730 | 896 | 954 | 955 | 949 | 956 | 951 | 959 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 584 | 630 | 579 | 645 | 808 | 696 | 489 | 353 | 411 | 391 | 365 | 457 |
| Hydro (70th%)—Other | 204 | 221 | 230 | 213 | 327 | 340 | 272 | 225 | 220 | 218 | 191 | 201 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 885 | 824 | 858 | 1,150 | 1,054 | 763 | 578 | 631 | 609 | 556 | 670 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 100 | 157 | 0 | 0 | 430 | 333 | 201 | 272 | 289 | 0 | 346 | 305 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,550 | 2,474 | 2,273 | 2,221 | 2,858 | 3,081 | 2,694 | 2,570 | 2,397 | 2,077 | 2,338 | 2,669 |
| **Monthly Surplus/Deficit** | 349 | 519 | 491 | 507 | 843 | 640 | (136) | (59) | 236 | 316 | 478 | 408 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 5 | 5 | 5 | 5 |
| Residential | 7 | 7 | 7 | 7 | 7 | 20 | 20 | 19 | 7 | 7 | 7 | 7 |
| **Total New DSM (aMW)** | 21 | 21 | 21 | 21 | 21 | 34 | 34 | 34 | 21 | 21 | 21 | 21 |
| **Monthly Surplus/Deficit** | 371 | 540 | 512 | 528 | 865 | 674 | (101) | (25) | 257 | 337 | 499 | 429 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| **Monthly Surplus/Deficit** | 468 | 551 | 544 | 623 | 1,094 | 956 | 179 | 146 | 393 | 475 | 645 | 562 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 136 | 134 | 135 | 139 | 154 | 162 | 163 | 159 | 146 | 137 | 135 | 135 |
| Load Forecast (70th% w/DSM) | (2,222) | (1,984) | (1,797) | (1,729) | (2,033) | (2,467) | (2,864) | (2,662) | (2,187) | (1,781) | (1,881) | (2,288) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 881 | 889 | 788 | 728 | 841 | 899 | 900 | 893 | 901 | 895 | 904 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 622 | 578 | 637 | 807 | 695 | 488 | 352 | 411 | 390 | 364 | 457 |
| Hydro (70th%)—Other | 203 | 219 | 227 | 213 | 327 | 339 | 272 | 224 | 219 | 217 | 191 | 201 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 876 | 820 | 850 | 1,149 | 1,053 | 762 | 577 | 630 | 607 | 555 | 669 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 90 | 170 | 0 | 0 | 489 | 389 | 257 | 328 | 347 | 0 | 365 | 364 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 242 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,476 | 2,413 | 2,213 | 2,163 | 2,914 | 3,080 | 2,702 | 2,569 | 2,399 | 2,020 | 2,301 | 2,672 |
| **Monthly Surplus/Deficit** | 254 | 429 | 416 | 434 | 881 | 613 | (162) | (92) | 212 | 239 | 420 | 383 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Residential | 8 | 8 | 8 | 8 | 7 | 22 | 22 | 22 | 8 | 8 | 8 | 8 |
| **Total New DSM (aMW)** | 23 | 23 | 23 | 23 | 23 | 38 | 38 | 38 | 23 | 23 | 23 | 23 |
| **Monthly Surplus/Deficit** | 277 | 452 | 439 | 457 | 904 | 651 | (124) | (55) | 235 | 262 | 443 | 406 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 149 | 64 | 84 | 147 | 282 | 334 | 332 | 223 | 188 | 190 | 198 | 184 |
| **Monthly Surplus/Deficit** | 426 | 515 | 523 | 604 | 1,186 | 985 | 208 | 169 | 423 | 452 | 642 | 591 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 146 | 144 | 144 | 149 | 165 | 173 | 174 | 170 | 157 | 147 | 145 | 144 |
| Load Forecast (70th% w/DSM) | (2,248) | (2,004) | (1,816) | (1,747) | (2,054) | (2,495) | (2,902) | (2,698) | (2,215) | (1,803) | (1,904) | (2,318) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 887 | 891 | 887 | 791 | 724 | 844 | 889 | 889 | 889 | 887 | 889 | 889 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 620 | 577 | 636 | 806 | 694 | 487 | 352 | 410 | 389 | 365 | 455 |
| Hydro (70th%)—Other | 202 | 218 | 224 | 212 | 327 | 339 | 272 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 873 | 816 | 848 | 1,147 | 1,051 | 761 | 577 | 630 | 606 | 555 | 667 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 116 | 187 | 0 | 0 | 487 | 386 | 254 | 326 | 346 | 0 | 389 | 361 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 242 |
| **Existing Resource Subtotal** | 2,500 | 2,438 | 2,208 | 2,164 | 2,907 | 3,079 | 2,671 | 2,565 | 2,393 | 2,005 | 2,318 | 2,661 |
| **Monthly Surplus/Deficit** | 252 | 434 | 392 | 418 | 853 | 584 | (231) | (133) | 177 | 202 | 415 | 343 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Residential | 8 | 8 | 8 | 8 | 8 | 25 | 24 | 25 | 8 | 8 | 8 | 8 |
| **Total New DSM (aMW)** | 25 | 25 | 25 | 25 | 25 | 41 | 41 | 41 | 25 | 25 | 25 | 25 |
| **Monthly Surplus/Deficit** | 277 | 458 | 417 | 443 | 878 | 625 | (190) | (92) | 202 | 227 | 439 | 368 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 149 | 64 | 84 | 147 | 282 | 432 | 424 | 322 | 188 | 190 | 198 | 184 |
| **Monthly Surplus/Deficit** | 426 | 522 | 501 | 590 | 1,159 | 1,057 | 233 | 230 | 390 | 417 | 638 | 552 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 153 | 152 | 153 | 159 | 173 | 183 | 184 | 180 | 166 | 156 | 153 | 154 |
| Load Forecast (70th% w/DSM) | (2,275) | (2,025) | (1,837) | (1,765) | (2,076) | (2,526) | (2,943) | (2,737) | (2,246) | (1,827) | (1,928) | (2,347) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 889 | 889 | 793 | 726 | 845 | 895 | 895 | 895 | 893 | 895 | 895 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 148 | 208 | 0 | 0 | 485 | 382 | 250 | 323 | 344 | 0 | 410 | 359 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,543 | 2,455 | 2,208 | 2,166 | 2,906 | 3,076 | 2,672 | 2,568 | 2,397 | 2,010 | 2,346 | 2,646 |
| **Monthly Surplus/Deficit** | 267 | 430 | 371 | 400 | 830 | 551 | (270) | (169) | 151 | 184 | 418 | 299 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Residential | 9 | 9 | 9 | 9 | 9 | 27 | 27 | 27 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 26 | 27 | 27 | 26 | 26 | 45 | 44 | 45 | 26 | 26 | 26 | 26 |
| **Monthly Surplus/Deficit** | 294 | 456 | 398 | 427 | 856 | 595 | (226) | (125) | 177 | 210 | 444 | 326 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 149 | 64 | 84 | 147 | 282 | 432 | 424 | 322 | 188 | 190 | 198 | 184 |
| **Monthly Surplus/Deficit** | 443 | 520 | 481 | 574 | 1,138 | 1,027 | 198 | 197 | 365 | 400 | 643 | 510 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 161 | 160 | 161 | 165 | 181 | 192 | 193 | 188 | 174 | 162 | 161 | 162 |
| Load Forecast (70th% w/DSM) | (2,299) | (2,031) | (1,854) | (1,782) | (2,097) | (2,554) | (2,981) | (2,774) | (2,274) | (1,848) | (1,950) | (2,373) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 889 | 889 | 788 | 728 | 841 | 899 | 900 | 893 | 901 | 895 | 904 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 871 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 170 | 222 | 5 | 2 | 484 | 378 | 246 | 320 | 342 | 0 | 407 | 357 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,565 | 2,468 | 2,213 | 2,163 | 2,907 | 3,058 | 2,681 | 2,570 | 2,393 | 2,018 | 2,343 | 2,653 |
| **Monthly Surplus/Deficit** | 266 | 437 | 359 | 381 | 810 | 504 | (299) | (204) | 119 | 170 | 394 | 281 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 10 | 10 | 10 | 10 | 10 | 30 | 30 | 30 | 10 | 10 | 10 | 10 |
| **Total New DSM (aMW)** | 28 | 28 | 28 | 28 | 28 | 47 | 48 | 48 | 28 | 28 | 28 | 28 |
| **Monthly Surplus/Deficit** | 294 | 465 | 387 | 409 | 838 | 552 | (252) | (156) | 147 | 198 | 422 | 309 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 152 | 71 | 94 | 160 | 299 | 452 | 453 | 347 | 208 | 203 | 205 | 186 |
| **Monthly Surplus/Deficit** | 446 | 535 | 481 | 569 | 1,138 | 1,003 | 201 | 190 | 355 | 400 | 626 | 494 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 167 | 166 | 167 | 172 | 187 | 199 | 200 | 195 | 180 | 168 | 168 | 167 |
| Load Forecast (70th% w/DSM) | (2,321) | (2,061) | (1,871) | (1,798) | (2,117) | (2,582) | (3,017) | (2,809) | (2,302) | (1,870) | (1,971) | (2,401) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 881 | 889 | 788 | 728 | 841 | 899 | 900 | 893 | 901 | 895 | 904 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 185 | 235 | 18 | 18 | 482 | 375 | 243 | 318 | 340 | 0 | 405 | 355 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 231 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,580 | 2,474 | 2,226 | 2,179 | 2,905 | 3,055 | 2,678 | 2,559 | 2,391 | 2,018 | 2,341 | 2,660 |
| **Monthly Surplus/Deficit** | 258 | 413 | 355 | 381 | 788 | 473 | (339) | (250) | 89 | 148 | 371 | 260 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 12 | 13 | 13 | 13 | 12 | 12 | 12 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 11 | 11 | 11 | 11 | 11 | 32 | 32 | 32 | 11 | 11 | 11 | 11 |
| **Total New DSM (aMW)** | 29 | 29 | 29 | 29 | 29 | 51 | 51 | 51 | 29 | 29 | 29 | 29 |
| **Monthly Surplus/Deficit** | 288 | 442 | 384 | 411 | 818 | 524 | (288) | (199) | 118 | 178 | 400 | 289 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 152 | 71 | 94 | 160 | 299 | 703 | 704 | 598 | 459 | 454 | 456 | 437 |
| **Monthly Surplus/Deficit** | 440 | 513 | 478 | 570 | 1,117 | 1,227 | 416 | 398 | 577 | 632 | 856 | 726 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 172 | 170 | 172 | 177 | 194 | 204 | 206 | 201 | 184 | 173 | 173 | 172 |
| Load Forecast (70th% w/DSM) | (2,348) | (2,083) | (1,892) | (1,818) | (2,139) | (2,613) | (3,057) | (2,848) | (2,334) | (1,894) | (1,996) | (2,427) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 887 | 891 | 887 | 791 | 724 | 844 | 889 | 889 | 889 | 887 | 889 | 889 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 209 | 252 | 36 | 38 | 480 | 371 | 238 | 315 | 339 | 4 | 404 | 353 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 233 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,602 | 2,502 | 2,242 | 2,202 | 2,900 | 3,064 | 2,663 | 2,545 | 2,386 | 2,008 | 2,334 | 2,643 |
| **Monthly Surplus/Deficit** | 254 | 418 | 350 | 385 | 760 | 451 | (394) | (303) | 52 | 114 | 338 | 216 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 13 | 13 | 13 | 13 | 12 | 12 | 13 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 12 | 12 | 12 | 12 | 12 | 35 | 35 | 35 | 12 | 12 | 12 | 12 |
| **Total New DSM (aMW)** | 31 | 31 | 31 | 31 | 31 | 54 | 54 | 54 | 31 | 31 | 31 | 31 |
| **Monthly Surplus/Deficit** | 285 | 449 | 381 | 415 | 791 | 504 | (340) | (250) | 83 | 145 | 369 | 247 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 403 | 322 | 345 | 411 | 550 | 703 | 704 | 598 | 459 | 454 | 456 | 437 |
| **Monthly Surplus/Deficit** | 688 | 771 | 726 | 826 | 1,341 | 1,207 | 364 | 348 | 542 | 599 | 825 | 684 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 176 | 174 | 174 | 180 | 198 | 209 | 210 | 205 | 189 | 178 | 175 | 175 |
| Load Forecast (70th% w/DSM) | (2,367) | (2,098) | (1,907) | (1,833) | (2,158) | (2,640) | (3,092) | (2,881) | (2,360) | (1,914) | (2,015) | (2,461) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 889 | 889 | 793 | 726 | 845 | 895 | 895 | 895 | 893 | 895 | 895 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 164 | 172 | 189 | 209 | 238 | 239 | 225 | 218 | 219 | 196 | 173 | 178 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 213 | 257 | 43 | 53 | 478 | 368 | 234 | 313 | 335 | 24 | 401 | 349 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 242 | 233 | 0 | 0 | 0 | 233 |
| **Existing Resource Subtotal** | 2,599 | 2,504 | 2,251 | 2,219 | 2,899 | 3,062 | 2,674 | 2,549 | 2,388 | 2,034 | 2,337 | 2,645 |
| **Monthly Surplus/Deficit** | 231 | 406 | 344 | 386 | 741 | 423 | (417) | (333) | 27 | 120 | 322 | 184 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 13 | 13 | 13 | 13 | 13 | 38 | 38 | 38 | 13 | 13 | 13 | 13 |
| **Total New DSM (aMW)** | 32 | 32 | 32 | 32 | 32 | 57 | 57 | 57 | 32 | 32 | 32 | 32 |
| **Monthly Surplus/Deficit** | 263 | 438 | 376 | 418 | 773 | 479 | (361) | (276) | 59 | 152 | 354 | 216 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 403 | 322 | 345 | 411 | 550 | 703 | 704 | 598 | 459 | 454 | 456 | 437 |
| **Monthly Surplus/Deficit** | 666 | 759 | 721 | 829 | 1,323 | 1,182 | 343 | 322 | 518 | 606 | 810 | 652 |

## *Monthly Average Energy Load and Resource Balance (continued)*

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 178 | 176 | 176 | 183 | 200 | 212 | 213 | 208 | 191 | 180 | 177 | 178 |
| Load Forecast (70th% w/DSM) | (2,407) | (2,117) | (1,936) | (1,860) | (2,188) | (2,679) | (3,144) | (2,932) | (2,401) | (1,948) | (2,049) | (2,497) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 889 | 889 | 788 | 728 | 841 | 899 | 900 | 893 | 901 | 895 | 904 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 871 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 203 | 263 | 231 | 233 | 218 | 219 | 196 | 167 | 184 | 164 | 160 | 189 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 267 | 68 | 81 | 80 | 477 | 364 | 231 | 310 | 333 | 58 | 399 | 348 |
| **Gas Peakers** | 224 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,691 | 2,405 | 2,331 | 2,265 | 2,880 | 3,034 | 2,628 | 2,509 | 2,348 | 2,044 | 2,323 | 2,656 |
| **Monthly Surplus/Deficit** | 284 | 288 | 394 | 405 | 693 | 355 | (515) | (423) | (53) | 96 | 274 | 159 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 14 | 14 | 14 | 14 | 14 | 40 | 40 | 40 | 14 | 14 | 14 | 14 |
| **Total New DSM (aMW)** | 33 | 33 | 33 | 33 | 33 | 60 | 59 | 60 | 33 | 33 | 33 | 33 |
| **Monthly Surplus/Deficit** | 317 | 321 | 428 | 438 | 726 | 415 | (456) | (364) | (20) | 129 | 307 | 192 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 403 | 322 | 345 | 419 | 590 | 750 | 756 | 646 | 496 | 466 | 456 | 437 |
| **Monthly Surplus/Deficit** | 720 | 643 | 772 | 857 | 1,316 | 1,164 | 299 | 282 | 476 | 595 | 763 | 629 |

## *Monthly Average Energy Load and Resource Balance (continued)*

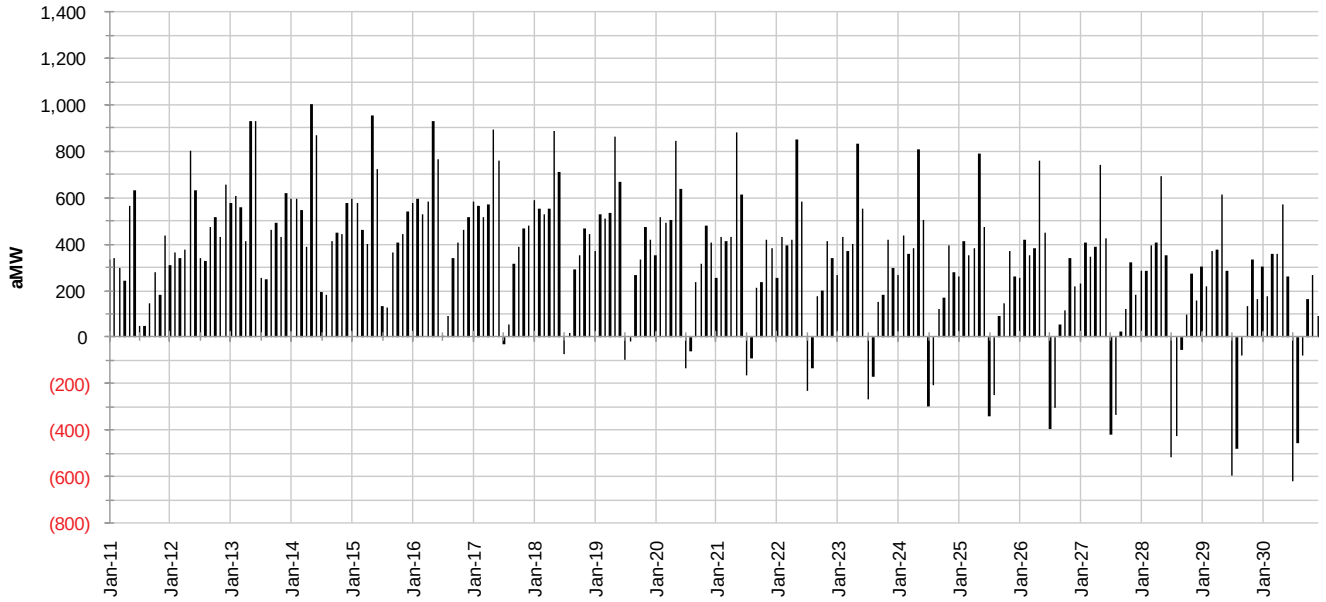
| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 179 | 177 | 178 | 185 | 201 | 213 | 214 | 209 | 194 | 180 | 179 | 180 |
| Load Forecast (70th% w/DSM) | (2,433) | (2,152) | (1,957) | (1,880) | (2,212) | (2,713) | (3,187) | (2,974) | (2,435) | (1,973) | (2,074) | (2,530) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 889 | 881 | 889 | 788 | 728 | 841 | 899 | 900 | 893 | 901 | 895 | 904 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 225 | 241 | 212 | 203 | 167 | 184 | 164 | 155 | 196 | 203 | 246 | 231 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 284 | 59 | 97 | 100 | 476 | 362 | 227 | 308 | 331 | 84 | 397 | 346 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,740 | 2,368 | 2,328 | 2,255 | 2,829 | 2,996 | 2,592 | 2,495 | 2,358 | 2,108 | 2,406 | 2,696 |
| **Monthly Surplus/Deficit** | 307 | 216 | 371 | 375 | 617 | 283 | (595) | (480) | (77) | 135 | 332 | 166 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 15 | 15 | 15 | 15 | 15 | 43 | 43 | 43 | 15 | 15 | 15 | 15 |
| **Total New DSM (aMW)** | 34 | 34 | 34 | 34 | 34 | 62 | 62 | 62 | 34 | 34 | 34 | 34 |
| **Monthly Surplus/Deficit** | 341 | 250 | 405 | 409 | 651 | 345 | (533) | (417) | (43) | 169 | 366 | 200 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 403 | 322 | 345 | 419 | 590 | 848 | 847 | 744 | 496 | 466 | 456 | 437 |
| **Monthly Surplus/Deficit** | 744 | 571 | 750 | 828 | 1,240 | 1,193 | 314 | 327 | 453 | 635 | 822 | 636 |

# Monthly Average Energy Load and Resource Balance (continued)

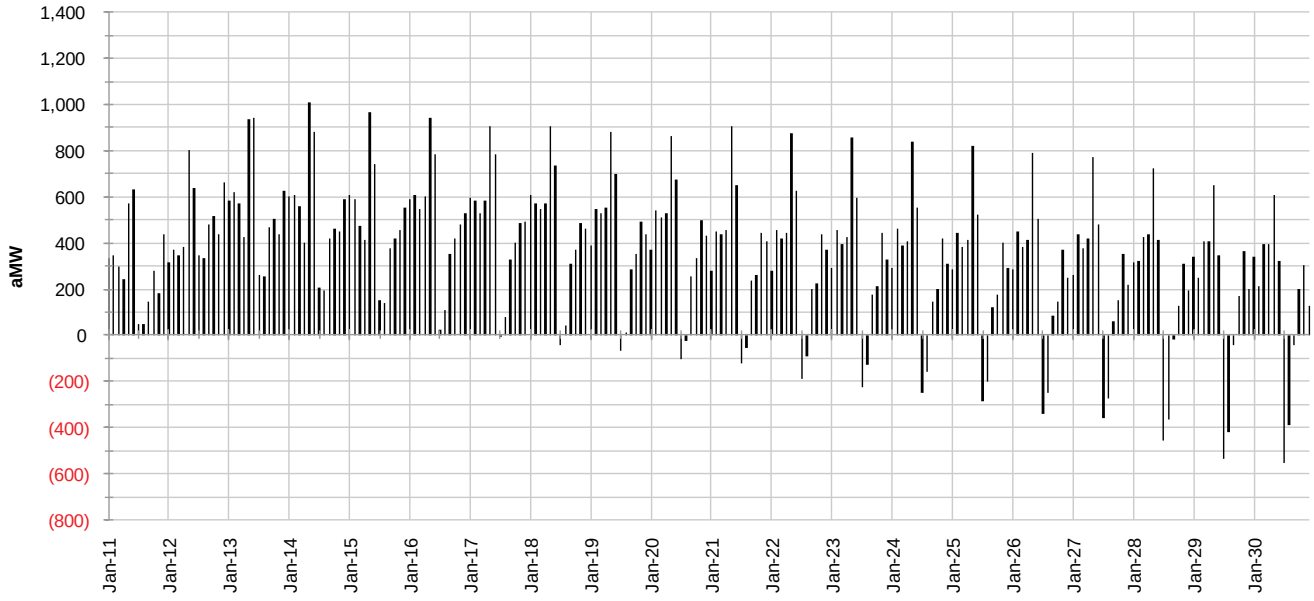
| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast DSM | 179 | 177 | 179 | 184 | 201 | 213 | 214 | 209 | 194 | 180 | 179 | 180 |
| Load Forecast (70th% w/DSM) | (2,466) | (2,179) | (1,982) | (1,904) | (2,239) | (2,750) | (3,235) | (3,021) | (2,474) | (2,004) | (2,104) | (2,570) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 887 | 891 | 887 | 791 | 724 | 844 | 889 | 889 | 889 | 887 | 889 | 889 |
| **Gas (Langley Gulch)** | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| Hydro (70th%)—HCC | 585 | 619 | 577 | 636 | 806 | 693 | 487 | 352 | 410 | 388 | 365 | 454 |
| Hydro (70th%)—Other | 202 | 217 | 222 | 212 | 327 | 339 | 271 | 224 | 219 | 217 | 190 | 200 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 794 | 872 | 814 | 848 | 1,147 | 1,051 | 761 | 577 | 629 | 605 | 556 | 666 |
| **CSPP (PURPA)** | 196 | 185 | 178 | 170 | 155 | 196 | 203 | 238 | 239 | 225 | 225 | 212 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 34 | 33 | 34 | 35 | 30 | 37 | 37 | 33 | 29 | 35 | 32 | 44 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 64 | 63 | 64 | 65 | 60 | 67 | 67 | 63 | 59 | 65 | 62 | 74 |
| **Firm Pacific NW Import Capability** | 344 | 94 | 147 | 138 | 475 | 359 | 224 | 306 | 330 | 134 | 388 | 344 |
| **Gas Peakers** | 233 | 0 | 0 | 0 | 0 | 240 | 224 | 242 | 0 | 0 | 0 | 224 |
| **Existing Resource Subtotal** | 2,769 | 2,357 | 2,342 | 2,263 | 2,812 | 3,008 | 2,618 | 2,564 | 2,396 | 2,167 | 2,371 | 2,660 |
| **Monthly Surplus/Deficit** | 303 | 178 | 359 | 358 | 573 | 258 | (617) | (457) | (77) | 164 | 267 | 90 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 15 | 16 | 15 | 16 | 15 | 45 | 45 | 45 | 15 | 16 | 15 | 15 |
| **Total New DSM (aMW)** | 35 | 35 | 35 | 35 | 35 | 65 | 65 | 65 | 35 | 35 | 35 | 35 |
| **Monthly Surplus/Deficit** | 338 | 213 | 394 | 393 | 608 | 323 | (552) | (392) | (42) | 199 | 302 | 125 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 97 | 12 | 32 | 95 | 230 | 282 | 280 | 171 | 136 | 138 | 146 | 132 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 3 | 7 | 10 | 13 | 17 | 20 | 29 | 25 | 20 | 13 | 6 | 1 |
| 2025 CCCT | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 | 251 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 98 | 92 | 99 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 403 | 322 | 345 | 419 | 590 | 848 | 847 | 744 | 496 | 466 | 456 | 437 |
| **Monthly Surplus/Deficit** | 741 | 534 | 739 | 812 | 1,198 | 1,170 | 295 | 353 | 453 | 664 | 757 | 562 |

# Monthly Average Energy Surplus/Deficit Charts

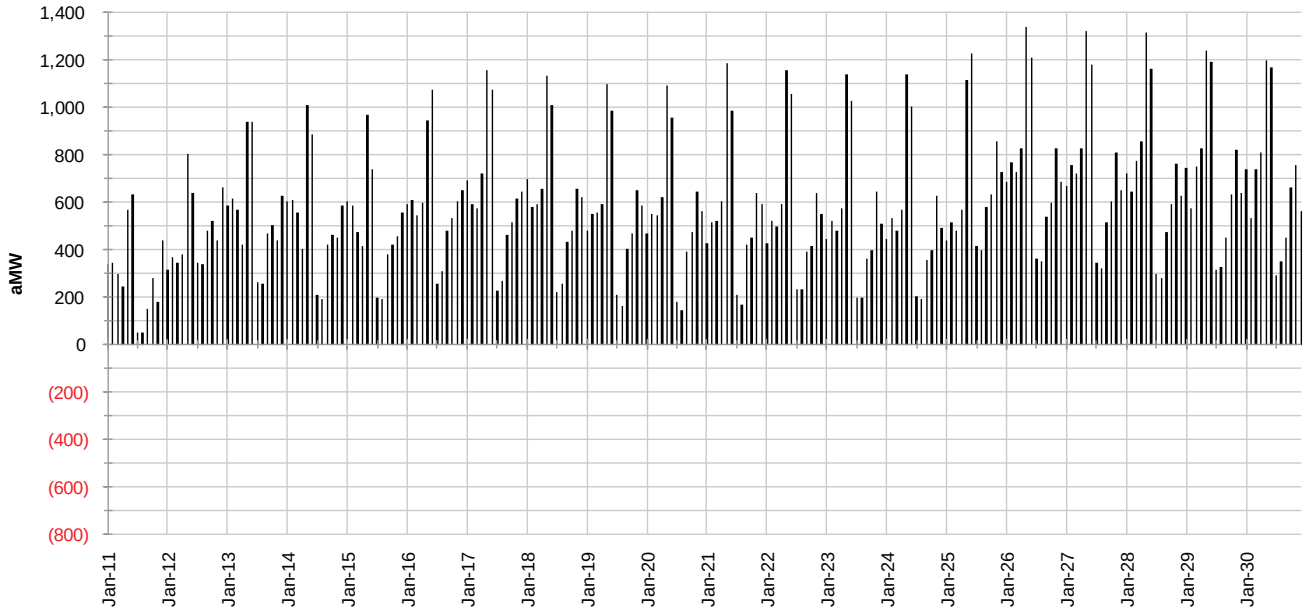
**Average energy monthly surpluses and deficits with existing DSM and resources**




**Average energy monthly surpluses and deficits with existing resources and new DSM**



**Average energy monthly surpluses and deficits with existing resources, new DSM, and IRP resources**



# Peak-Hour Load and Resource Balance

| | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,553) | (2,440) | (2,147) | (1,901) | (2,863) | (3,377) | (3,515) | (3,185) | (3,019) | (2,068) | (2,231) | (2,815) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 330 | 330 | 255 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,553) | (2,440) | (2,147) | (1,901) | (2,863) | (3,047) | (3,185) | (2,930) | (3,019) | (2,068) | (2,231) | (2,815) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 200 | 202 | 192 | 193 | 299 | 307 | 263 | 216 | 210 | 209 | 191 | 200 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 47 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,300 | 1,202 | 1,262 | 1,313 | 1,449 | 1,337 | 1,330 | 1,206 | 1,190 | 1,089 | 1,101 | 1,230 |
| **CSPP (PURPA)** | 47 | 48 | 54 | 81 | 129 | 143 | 160 | 152 | 136 | 97 | 67 | 63 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 83 | 83 | 83 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 75 | 75 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 19 | 19 | 9 | 6 | 21 | 105 | 179 | 177 | 18 | 6 | 2 | 18 |
| **Firm Pacific NW Import Capability** | 180 | 35 | 0 | 0 | 320 | 254 | 126 | 186 | 197 | 0 | 115 | 325 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,924 | 2,683 | 2,705 | 2,779 | 3,298 | 3,219 | 3,173 | 3,100 | 2,919 | 2,571 | 2,665 | 3,015 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (12) | 0 | (100) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| Residential | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 0 |
| **Total New DSM Peak Reduction** | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (8) | 0 | (98) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (8) | 0 | (98) | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 373 | 246 | 561 | 880 | 437 | 175 | (8) | 174 | (98) | 506 | 436 | 203 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2012 | 2/2012 | 3/2012 | 4/2012 | 5/2012 | 6/2012 | 7/2012 | 8/2012 | 9/2012 | 10/2012 | 11/2012 | 12/2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,551) | (2,433) | (2,143) | (1,880) | (2,906) | (3,430) | (3,577) | (3,220) | (3,071) | (2,099) | (2,245) | (2,800) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 310 | 310 | 243 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,551) | (2,433) | (2,143) | (1,880) | (2,906) | (3,120) | (3,267) | (2,977) | (3,071) | (2,099) | (2,245) | (2,800) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 0 | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 199 | 201 | 192 | 192 | 299 | 307 | 262 | 216 | 209 | 209 | 191 | 200 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,299 | 1,201 | 1,262 | 1,312 | 1,449 | 1,337 | 1,330 | 1,206 | 1,189 | 1,089 | 1,101 | 1,230 |
| **CSPP (PURPA)** | 59 | 61 | 65 | 92 | 141 | 150 | 161 | 152 | 136 | 98 | 68 | 64 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 83 | 83 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 19 | 19 | 9 | 6 | 21 | 22 | 104 | 102 | 18 | 26 | 22 | 38 |
| **Firm Pacific NW Import Capability** | 122 | 30 | 0 | 0 | 444 | 360 | 233 | 294 | 304 | 0 | 129 | 322 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,878 | 2,690 | 2,715 | 2,789 | 3,433 | 3,248 | 3,507 | 3,433 | 3,326 | 2,892 | 2,999 | 3,333 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Residential | 1 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 1 | 1 | 1 | 1 |
| **Total New DSM Peak Reduction** | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 7 | 5 | 5 | 5 | 5 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 332 | 262 | 577 | 914 | 532 | 134 | 247 | 463 | 259 | 798 | 759 | 538 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,561) | (2,441) | (2,157) | (1,879) | (2,955) | (3,533) | (3,684) | (3,312) | (3,146) | (2,127) | (2,264) | (2,817) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 315 | 315 | 248 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,561) | (2,441) | (2,157) | (1,879) | (2,955) | (3,218) | (3,370) | (3,065) | (3,146) | (2,127) | (2,264) | (2,817) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 199 | 201 | 192 | 192 | 298 | 307 | 262 | 216 | 209 | 209 | 191 | 199 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,299 | 1,201 | 1,262 | 1,312 | 1,448 | 1,337 | 1,330 | 1,206 | 1,189 | 1,089 | 1,101 | 1,229 |
| **CSPP (PURPA)** | 63 | 65 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 39 | 29 | 26 | 41 | 42 | 41 | 39 | 38 | 26 | 22 | 38 |
| **Firm Pacific NW Import Capability** | 131 | 51 | 0 | 0 | 383 | 357 | 229 | 291 | 302 | 0 | 148 | 319 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,210 | 3,035 | 3,040 | 3,113 | 3,696 | 3,569 | 3,444 | 3,371 | 3,348 | 2,895 | 3,022 | 3,332 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Commercial | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Residential | 1 | 1 | 1 | 1 | 1 | 4 | 4 | 4 | 1 | 1 | 1 | 1 |
| **Total New DSM Peak Reduction** | 8 | 8 | 8 | 8 | 8 | 10 | 10 | 10 | 8 | 8 | 8 | 8 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 658 | 601 | 890 | 1,242 | 750 | 361 | 85 | 317 | 209 | 775 | 765 | 523 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,620) | (2,485) | (2,203) | (1,928) | (3,011) | (3,611) | (3,770) | (3,398) | (3,213) | (2,167) | (2,314) | (2,895) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 315 | 315 | 248 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,620) | (2,485) | (2,203) | (1,928) | (3,011) | (3,296) | (3,455) | (3,150) | (3,213) | (2,167) | (2,314) | (2,895) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 197 | 198 | 191 | 191 | 297 | 305 | 261 | 214 | 208 | 207 | 190 | 197 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,297 | 1,198 | 1,261 | 1,311 | 1,447 | 1,335 | 1,329 | 1,204 | 1,188 | 1,087 | 1,100 | 1,227 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 39 | 29 | 26 | 41 | 42 | 41 | 39 | 38 | 26 | 22 | 38 |
| **Firm Pacific NW Import Capability** | 190 | 86 | 0 | 12 | 439 | 353 | 225 | 288 | 301 | 0 | 198 | 318 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,268 | 3,068 | 3,039 | 3,124 | 3,751 | 3,563 | 3,440 | 3,367 | 3,346 | 2,894 | 3,071 | 3,329 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (15) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Commercial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Residential | 2 | 2 | 2 | 2 | 2 | 6 | 6 | 6 | 2 | 2 | 2 | 2 |
| **Total New DSM Peak Reduction** | 10 | 10 | 10 | 10 | 10 | 14 | 14 | 14 | 10 | 10 | 10 | 10 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (1) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (1) | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 658 | 593 | 846 | 1,206 | 750 | 281 | (1) | 231 | 143 | 737 | 767 | 444 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,661) | (2,517) | (2,236) | (1,958) | (3,067) | (3,685) | (3,854) | (3,474) | (3,277) | (2,203) | (2,353) | (2,948) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 321 | 321 | 252 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,661) | (2,517) | (2,236) | (1,958) | (3,067) | (3,364) | (3,533) | (3,222) | (3,277) | (2,203) | (2,353) | (2,948) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 195 | 196 | 190 | 190 | 296 | 304 | 260 | 213 | 207 | 206 | 189 | 195 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,295 | 1,196 | 1,260 | 1,310 | 1,446 | 1,334 | 1,328 | 1,203 | 1,187 | 1,086 | 1,099 | 1,237 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 39 | 29 | 26 | 41 | 42 | 41 | 39 | 38 | 26 | 22 | 38 |
| **Firm Pacific NW Import Capability** | 231 | 114 | 0 | 38 | 440 | 350 | 222 | 286 | 299 | 14 | 237 | 316 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,307 | 3,094 | 3,037 | 3,149 | 3,751 | 3,559 | 3,436 | 3,364 | 3,342 | 2,906 | 3,109 | 3,337 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (97) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Commercial | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Residential | 3 | 3 | 3 | 3 | 3 | 8 | 8 | 8 | 3 | 3 | 3 | 3 |
| **Total New DSM Peak Reduction** | 12 | 12 | 12 | 12 | 12 | 17 | 17 | 17 | 12 | 12 | 12 | 12 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (80) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 83 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 83 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 658 | 590 | 813 | 1,203 | 696 | 212 | 3 | 159 | 78 | 715 | 768 | 401 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,691) | (2,543) | (2,261) | (1,975) | (3,116) | (3,750) | (3,925) | (3,535) | (3,331) | (2,226) | (2,374) | (2,978) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,691) | (2,543) | (2,261) | (1,975) | (3,116) | (3,399) | (3,574) | (3,262) | (3,331) | (2,226) | (2,374) | (2,978) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 193 | 195 | 189 | 189 | 295 | 303 | 260 | 211 | 207 | 206 | 188 | 194 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,300 | 1,229 | 1,275 | 1,309 | 1,460 | 1,352 | 1,282 | 1,202 | 1,187 | 1,086 | 1,098 | 1,236 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 37 | 139 | 0 | 57 | 437 | 346 | 218 | 283 | 297 | 49 | 258 | 314 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,114 | 3,148 | 3,058 | 3,176 | 3,756 | 3,566 | 3,379 | 3,355 | 3,338 | 2,951 | 3,142 | 3,331 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (196) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 8 | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 |
| Commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Residential | 3 | 3 | 3 | 3 | 3 | 10 | 10 | 10 | 3 | 3 | 3 | 3 |
| **Total New DSM Peak Reduction** | 14 | 14 | 14 | 14 | 14 | 20 | 20 | 20 | 14 | 14 | 14 | 14 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (175) | 0 | 0 | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 437 | 619 | 810 | 1,215 | 654 | 637 | 275 | 563 | 470 | 1,188 | 1,232 | 817 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,717) | (2,556) | (2,280) | (1,991) | (3,156) | (3,809) | (3,991) | (3,595) | (3,382) | (2,247) | (2,397) | (3,017) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,717) | (2,556) | (2,280) | (1,991) | (3,156) | (3,458) | (3,641) | (3,322) | (3,382) | (2,247) | (2,397) | (3,017) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 192 | 193 | 188 | 188 | 291 | 299 | 259 | 210 | 206 | 205 | 187 | 192 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,299 | 1,228 | 1,274 | 1,308 | 1,456 | 1,348 | 1,281 | 1,201 | 1,186 | 1,085 | 1,097 | 1,234 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 36 | 157 | 14 | 85 | 435 | 343 | 214 | 281 | 295 | 71 | 281 | 311 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,112 | 3,165 | 3,071 | 3,203 | 3,750 | 3,559 | 3,374 | 3,352 | 3,335 | 2,971 | 3,164 | 3,326 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (267) | 0 | (47) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Residential | 4 | 4 | 4 | 4 | 4 | 12 | 12 | 12 | 4 | 4 | 4 | 4 |
| **Total New DSM Peak Reduction** | 16 | 16 | 16 | 16 | 16 | 24 | 24 | 24 | 16 | 16 | 16 | 16 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (243) | 0 | (32) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 861 | 1,074 | 1,257 | 1,678 | 1,059 | 575 | 207 | 504 | 418 | 1,190 | 1,232 | 774 |

## *Peak-Hour Load and Resource Balance (continued)*

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,733) | (2,567) | (2,293) | (1,997) | (3,195) | (3,865) | (4,056) | (3,650) | (3,431) | (2,266) | (2,416) | (3,046) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,733) | (2,567) | (2,293) | (1,997) | (3,195) | (3,514) | (3,705) | (3,377) | (3,431) | (2,266) | (2,416) | (3,046) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 191 | 191 | 187 | 187 | 286 | 295 | 258 | 209 | 205 | 204 | 186 | 190 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,298 | 1,226 | 1,272 | 1,307 | 1,451 | 1,343 | 1,280 | 1,200 | 1,185 | 1,084 | 1,096 | 1,232 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 41 | 175 | 30 | 101 | 433 | 339 | 209 | 278 | 293 | 81 | 300 | 309 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,116 | 3,181 | 3,085 | 3,218 | 3,743 | 3,550 | 3,368 | 3,348 | 3,331 | 2,980 | 3,182 | 3,322 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (337) | (29) | (100) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Commercial | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 4 | 4 | 4 | 4 | 4 |
| Residential | 5 | 5 | 5 | 5 | 5 | 15 | 15 | 15 | 5 | 5 | 5 | 5 |
| **Total New DSM Peak Reduction** | 17 | 17 | 17 | 17 | 17 | 27 | 27 | 27 | 17 | 17 | 17 | 17 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (310) | (2) | (82) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 851 | 1,082 | 1,260 | 1,688 | 1,015 | 513 | 140 | 448 | 368 | 1,182 | 1,233 | 743 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,759) | (2,584) | (2,312) | (2,013) | (3,236) | (3,924) | (4,123) | (3,711) | (3,482) | (2,288) | (2,440) | (3,086) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,759) | (2,584) | (2,312) | (2,013) | (3,236) | (3,574) | (3,772) | (3,438) | (3,482) | (2,288) | (2,440) | (3,086) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 190 | 190 | 185 | 186 | 283 | 291 | 257 | 208 | 204 | 203 | 186 | 189 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,297 | 1,225 | 1,271 | 1,306 | 1,448 | 1,339 | 1,279 | 1,199 | 1,184 | 1,083 | 1,096 | 1,230 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 59 | 195 | 60 | 109 | 432 | 335 | 205 | 275 | 291 | 104 | 117 | 307 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,133 | 3,200 | 3,114 | 3,225 | 3,738 | 3,542 | 3,363 | 3,344 | 3,329 | 3,002 | 2,998 | 3,318 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (31) | (409) | (94) | (153) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 9 | 9 | 9 | 9 |
| Commercial | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Residential | 6 | 6 | 6 | 6 | 6 | 17 | 17 | 17 | 6 | 6 | 6 | 6 |
| **Total New DSM Peak Reduction** | 19 | 19 | 19 | 19 | 19 | 31 | 31 | 31 | 19 | 19 | 19 | 19 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (1) | (378) | (63) | (134) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 843 | 1,086 | 1,272 | 1,681 | 972 | 449 | 72 | 387 | 316 | 1,184 | 1,027 | 702 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,781) | (2,595) | (2,328) | (2,026) | (3,276) | (3,983) | (4,190) | (3,770) | (3,532) | (2,307) | (2,462) | (3,121) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,781) | (2,595) | (2,328) | (2,026) | (3,276) | (3,632) | (3,839) | (3,498) | (3,532) | (2,307) | (2,462) | (3,121) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 | 963 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 190 | 189 | 185 | 185 | 280 | 288 | 256 | 207 | 204 | 203 | 185 | 188 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,297 | 1,223 | 1,270 | 1,305 | 1,445 | 1,336 | 1,278 | 1,198 | 1,184 | 1,083 | 1,095 | 1,230 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 81 | 198 | 77 | 124 | 430 | 333 | 201 | 272 | 289 | 125 | 106 | 305 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,155 | 3,201 | 3,131 | 3,239 | 3,734 | 3,538 | 3,358 | 3,341 | 3,326 | 3,023 | 2,986 | 3,316 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (94) | (480) | (157) | (205) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 5 | 5 | 5 | 5 |
| Residential | 7 | 7 | 7 | 7 | 7 | 20 | 20 | 19 | 7 | 7 | 7 | 7 |
| **Total New DSM Peak Reduction** | 21 | 21 | 21 | 21 | 21 | 34 | 34 | 34 | 21 | 21 | 21 | 21 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (60) | (446) | (123) | (184) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 845 | 1,077 | 1,274 | 1,685 | 929 | 390 | 4 | 327 | 266 | 1,187 | 996 | 666 |

## *Peak-Hour Load and Resource Balance (continued)*

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,797) | (2,609) | (2,341) | (2,034) | (3,316) | (4,040) | (4,254) | (3,826) | (3,582) | (2,327) | (2,481) | (3,152) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,797) | (2,609) | (2,341) | (2,034) | (3,316) | (3,689) | (3,904) | (3,554) | (3,582) | (2,327) | (2,481) | (3,152) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 189 | 184 | 185 | 278 | 286 | 256 | 207 | 203 | 202 | 184 | 188 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,443 | 1,335 | 1,278 | 1,198 | 1,184 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 138 | 20 | 144 | 200 | 489 | 389 | 257 | 328 | 347 | 0 | 95 | 364 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,156 | 2,969 | 3,142 | 3,260 | 3,736 | 3,537 | 3,359 | 3,341 | 3,329 | 2,843 | 2,920 | 3,319 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (152) | (545) | (212) | (254) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Residential | 8 | 8 | 8 | 8 | 7 | 22 | 22 | 22 | 8 | 8 | 8 | 8 |
| **Total New DSM Peak Reduction** | 23 | 23 | 23 | 23 | 23 | 38 | 38 | 38 | 23 | 23 | 23 | 23 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (114) | (507) | (175) | (230) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 502 | 502 | 502 | 502 | 502 | 502 | 502 | 502 | 502 | 502 | 502 | 502 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (5) | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 884 | 885 | 1,326 | 1,752 | 946 | 388 | (5) | 327 | 272 | 1,041 | 964 | 692 |

## *Peak-Hour Load and Resource Balance (continued)*

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,823) | (2,626) | (2,360) | (2,050) | (3,357) | (4,100) | (4,323) | (3,889) | (3,635) | (2,349) | (2,505) | (3,193) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,823) | (2,626) | (2,360) | (2,050) | (3,357) | (3,749) | (3,972) | (3,616) | (3,635) | (2,349) | (2,505) | (3,193) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 285 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 166 | 41 | 164 | 0 | 487 | 386 | 254 | 326 | 346 | 0 | 119 | 361 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,184 | 2,989 | 3,162 | 3,060 | 3,733 | 3,532 | 3,356 | 3,339 | 3,328 | 2,842 | 2,943 | 3,316 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (217) | (616) | (277) | (307) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Commercial | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Residential | 8 | 8 | 8 | 8 | 8 | 25 | 24 | 25 | 8 | 8 | 8 | 8 |
| **Total New DSM Peak Reduction** | 25 | 25 | 25 | 25 | 25 | 41 | 41 | 41 | 25 | 25 | 25 | 25 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (176) | (575) | (235) | (283) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 502 | 502 | 502 | 502 | 502 | 672 | 672 | 672 | 502 | 502 | 502 | 502 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 888 | 891 | 1,329 | 1,537 | 902 | 496 | 97 | 437 | 219 | 1,020 | 965 | 650 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,855) | (2,647) | (2,383) | (2,072) | (3,400) | (4,163) | (4,394) | (3,956) | (3,690) | (2,373) | (2,533) | (3,243) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,855) | (2,647) | (2,383) | (2,072) | (3,400) | (3,812) | (4,043) | (3,683) | (3,690) | (2,373) | (2,533) | (3,243) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 195 | 64 | 185 | 0 | 485 | 382 | 250 | 323 | 344 | 0 | 147 | 359 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,213 | 3,012 | 3,183 | 3,060 | 3,730 | 3,528 | 3,352 | 3,336 | 3,326 | 2,842 | 2,971 | 3,314 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (284) | (691) | (347) | (365) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Residential | 9 | 9 | 9 | 9 | 9 | 27 | 27 | 27 | 9 | 9 | 9 | 9 |
| **Total New DSM Peak Reduction** | 26 | 27 | 27 | 26 | 26 | 45 | 44 | 45 | 26 | 26 | 26 | 26 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (240) | (647) | (302) | (338) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 502 | 502 | 502 | 502 | 502 | 672 | 672 | 672 | 502 | 502 | 502 | 502 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 886 | 894 | 1,329 | 1,516 | 859 | 432 | 25 | 370 | 164 | 998 | 967 | 600 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,877) | (2,660) | (2,400) | (2,086) | (3,442) | (4,224) | (4,462) | (4,017) | (3,745) | (2,394) | (2,555) | (3,280) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,877) | (2,660) | (2,400) | (2,086) | (3,442) | (3,873) | (4,111) | (3,745) | (3,745) | (2,394) | (2,555) | (3,280) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,222 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 207 | 68 | (0) | 0 | 484 | 378 | 246 | 320 | 342 | 8 | 169 | 357 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,225 | 3,015 | 2,997 | 3,060 | 3,729 | 3,524 | 3,348 | 3,333 | 3,324 | 2,850 | 2,993 | 3,312 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (349) | (764) | (412) | (421) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 10 | 10 | 10 | 10 | 10 | 30 | 30 | 30 | 10 | 10 | 10 | 10 |
| **Total New DSM Peak Reduction** | 28 | 28 | 28 | 28 | 28 | 47 | 48 | 48 | 28 | 28 | 28 | 28 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (302) | (716) | (364) | (393) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 510 | 517 | 522 | 527 | 533 | 708 | 716 | 713 | 538 | 527 | 517 | 506 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 886 | 900 | 1,148 | 1,529 | 848 | 406 | 0 | 349 | 145 | 1,011 | 983 | 566 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,892) | (2,674) | (2,413) | (2,092) | (3,483) | (4,283) | (4,529) | (4,075) | (3,799) | (2,415) | (2,574) | (3,309) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,892) | (2,674) | (2,413) | (2,092) | (3,483) | (3,932) | (4,178) | (3,802) | (3,799) | (2,415) | (2,574) | (3,309) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 231 | 102 | (0) | 4 | 482 | 375 | 243 | 318 | 340 | 31 | 188 | 355 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,249 | 3,050 | 2,997 | 3,064 | 3,727 | 3,521 | 3,345 | 3,331 | 3,322 | 2,873 | 3,012 | 3,310 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (411) | (833) | (471) | (477) | 0 | 0 | 0 |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 12 | 13 | 13 | 13 | 12 | 12 | 12 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 11 | 11 | 11 | 11 | 11 | 32 | 32 | 32 | 11 | 11 | 11 | 11 |
| **Total New DSM Peak Reduction** | 29 | 29 | 29 | 29 | 29 | 51 | 51 | 51 | 29 | 29 | 29 | 29 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (361) | (782) | (420) | (448) | 0 | 0 | 0 |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 510 | 517 | 522 | 527 | 533 | 1,008 | 1,016 | 1,013 | 838 | 827 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 896 | 923 | 1,136 | 1,528 | 806 | 647 | 234 | 592 | 390 | 1,314 | 1,285 | 836 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,916) | (2,691) | (2,431) | (2,106) | (3,527) | (4,346) | (4,599) | (4,137) | (3,856) | (2,440) | (2,598) | (3,345) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,916) | (2,691) | (2,431) | (2,106) | (3,527) | (3,995) | (4,248) | (3,865) | (3,856) | (2,440) | (2,598) | (3,345) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 260 | 125 | (0) | 24 | 480 | 371 | 238 | 315 | 339 | 57 | 212 | 353 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,278 | 3,073 | 2,997 | 3,084 | 3,725 | 3,517 | 3,340 | 3,328 | 3,321 | 2,899 | 3,036 | 3,308 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (478) | (908) | (537) | (535) | 0 | 0 | (37) |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 12 | 12 | 12 | 12 | 13 | 13 | 13 | 13 | 12 | 12 | 13 | 12 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Residential | 12 | 12 | 12 | 12 | 12 | 35 | 35 | 35 | 12 | 12 | 12 | 12 |
| **Total New DSM Peak Reduction** | 31 | 31 | 31 | 31 | 31 | 54 | 54 | 54 | 31 | 31 | 31 | 31 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (424) | (855) | (483) | (504) | 0 | 0 | (7) |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 810 | 817 | 822 | 827 | 833 | 1,008 | 1,016 | 1,013 | 838 | 827 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 1,203 | 1,230 | 1,419 | 1,835 | 1,062 | 583 | 162 | 529 | 333 | 1,316 | 1,286 | 799 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,920) | (2,696) | (2,438) | (2,101) | (3,568) | (4,403) | (4,664) | (4,188) | (3,910) | (2,460) | (2,611) | (3,361) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,920) | (2,696) | (2,438) | (2,101) | (3,568) | (4,052) | (4,313) | (3,915) | (3,910) | (2,460) | (2,611) | (3,361) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 63 | 66 | 69 | 96 | 145 | 154 | 166 | 157 | 140 | 101 | 72 | 67 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 293 | 141 | (0) | 40 | 478 | 368 | 234 | 313 | 335 | 91 | 225 | 349 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,311 | 3,089 | 2,997 | 3,100 | 3,723 | 3,514 | 3,336 | 3,326 | 3,317 | 2,933 | 3,049 | 3,304 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (538) | (977) | (589) | (593) | 0 | 0 | (57) |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 13 | 13 | 13 | 13 | 13 | 38 | 38 | 38 | 13 | 13 | 13 | 13 |
| **Total New DSM Peak Reduction** | 32 | 32 | 32 | 32 | 32 | 57 | 57 | 57 | 32 | 32 | 32 | 32 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (481) | (921) | (533) | (561) | 0 | 0 | (25) |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 810 | 817 | 822 | 827 | 833 | 1,008 | 1,016 | 1,013 | 838 | 827 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 1,233 | 1,242 | 1,414 | 1,858 | 1,020 | 527 | 96 | 480 | 277 | 1,331 | 1,287 | 781 |

## Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,974) | (2,721) | (2,476) | (2,144) | (3,618) | (4,476) | (4,747) | (4,273) | (3,972) | (2,494) | (2,655) | (3,434) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,974) | (2,721) | (2,476) | (2,144) | (3,618) | (4,126) | (4,396) | (4,000) | (3,972) | (2,494) | (2,655) | (3,434) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 34 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,222 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 94 | 158 | 150 | 171 | 157 | 139 | 101 | 70 | 68 | 63 | 63 | 69 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 335 | 159 | 21 | 81 | 477 | 364 | 231 | 310 | 333 | 126 | 269 | 348 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,383 | 3,198 | 3,100 | 3,215 | 3,735 | 3,496 | 3,268 | 3,236 | 3,243 | 2,930 | 3,085 | 3,306 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (630) | (1,128) | (764) | (729) | 0 | 0 | (129) |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 14 | 14 | 14 | 14 | 14 | 40 | 40 | 40 | 14 | 14 | 14 | 14 |
| **Total New DSM Peak Reduction** | 33 | 33 | 33 | 33 | 33 | 60 | 59 | 60 | 33 | 33 | 33 | 33 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (570) | (1,069) | (704) | (696) | 0 | 0 | (96) |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 810 | 817 | 822 | 835 | 872 | 1,054 | 1,068 | 1,060 | 875 | 839 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (1) | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 1,253 | 1,327 | 1,479 | 1,939 | 1,021 | 484 | (1) | 356 | 178 | 1,307 | 1,280 | 710 |

## Peak-Hour Load and Resource Balance (continued)

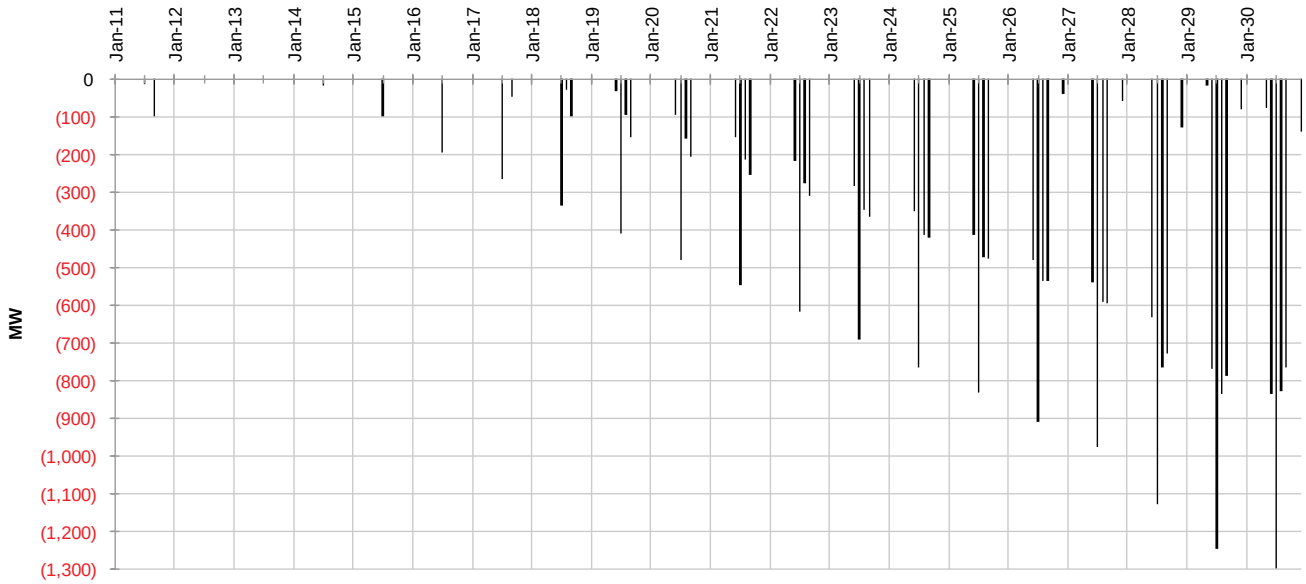
| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (2,991) | (2,748) | (2,492) | (2,151) | (3,665) | (4,541) | (4,822) | (4,335) | (4,031) | (2,520) | (2,677) | (3,463) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (2,991) | (2,748) | (2,492) | (2,151) | (3,665) | (4,190) | (4,471) | (4,062) | (4,031) | (2,520) | (2,677) | (3,463) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 166 | 171 | 136 | 104 | 70 | 68 | 63 | 61 | 71 | 94 | 149 | 150 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 350 | 197 | 43 | 103 | 476 | 362 | 227 | 308 | 331 | 142 | 291 | 346 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,470 | 3,251 | 3,108 | 3,171 | 3,647 | 3,422 | 3,226 | 3,226 | 3,244 | 2,976 | 3,193 | 3,384 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | (18) | (768) | (1,245) | (836) | (787) | 0 | 0 | (78) |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 15 | 15 | 15 | 15 | 15 | 43 | 43 | 43 | 15 | 15 | 15 | 15 |
| **Total New DSM Peak Reduction** | 34 | 34 | 34 | 34 | 34 | 62 | 62 | 62 | 34 | 34 | 34 | 34 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (705) | (1,183) | (774) | (753) | 0 | 0 | (44) |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 810 | 817 | 822 | 835 | 872 | 1,224 | 1,238 | 1,230 | 875 | 839 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 1,324 | 1,354 | 1,473 | 1,888 | 888 | 519 | 55 | 456 | 122 | 1,329 | 1,367 | 762 |

## Peak-Hour Load and Resource Balance (continued)

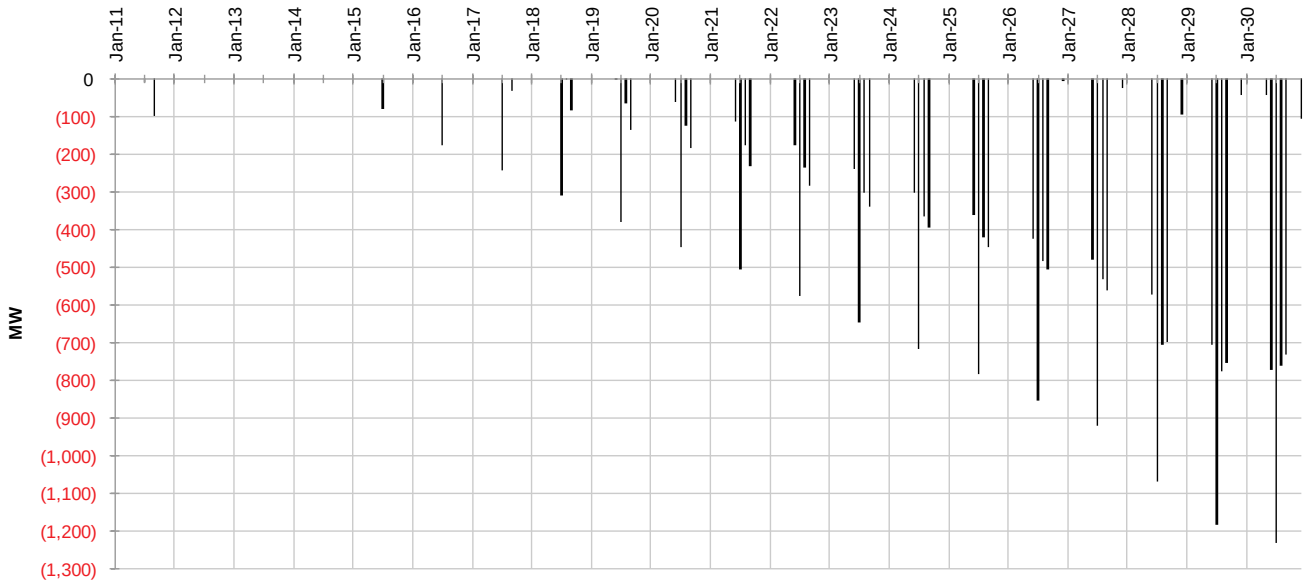
| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/EE)** | (3,023) | (2,772) | (2,516) | (2,172) | (3,713) | (4,609) | (4,901) | (4,406) | (4,092) | (2,550) | (2,708) | (3,509) |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 351 | 351 | 273 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DR** | (3,023) | (2,772) | (2,516) | (2,172) | (3,713) | (4,258) | (4,550) | (4,133) | (4,092) | (2,550) | (2,708) | (3,509) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 | 908 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 1,100 | 1,000 | 1,070 | 1,120 | 1,150 | 1,030 | 1,020 | 990 | 980 | 880 | 910 | 1,030 |
| Hydro (90th%)—Other | 189 | 188 | 184 | 185 | 277 | 284 | 256 | 207 | 203 | 202 | 184 | 187 |
| Shoshone Falls Upgrade | 7 | 35 | 16 | 0 | 15 | 19 | 2 | 1 | 0 | 0 | 0 | 12 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,296 | 1,224 | 1,270 | 1,305 | 1,442 | 1,333 | 1,278 | 1,198 | 1,183 | 1,082 | 1,094 | 1,229 |
| **CSPP (PURPA)** | 101 | 75 | 67 | 64 | 62 | 70 | 93 | 144 | 154 | 166 | 162 | 136 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Neal Hot Springs Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PPL Montana–Jefferson (83 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Eastside Purchase (50 MW) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mead Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| **Firm Pacific NW Import Capability** | 370 | 243 | 85 | 143 | 475 | 359 | 224 | 306 | 330 | 184 | 345 | 344 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,426 | 3,201 | 3,080 | 3,171 | 3,637 | 3,422 | 3,253 | 3,307 | 3,326 | 3,091 | 3,259 | 3,368 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | (76) | (837) | (1,296) | (826) | (766) | 0 | 0 | (141) |
| **2011 IRP DSM** | | | | | | | | | | | | |
| Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Commercial | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| Residential | 15 | 16 | 15 | 16 | 15 | 45 | 45 | 45 | 15 | 16 | 15 | 15 |
| **Total New DSM Peak Reduction** | 35 | 35 | 35 | 35 | 35 | 65 | 65 | 65 | 35 | 35 | 35 | 35 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | (41) | (772) | (1,232) | (761) | (731) | 0 | 0 | (106) |
| **2011 IRP Resources** | | | | | | | | | | | | |
| 2015 Eastside Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2016 Boardman to Hemingway | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| 2021 Geothermal | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| 2022 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| 2024 Solar Power Tower | 8 | 15 | 20 | 25 | 31 | 36 | 44 | 41 | 36 | 25 | 15 | 4 |
| 2025 CCCT | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2028 Small Hydro | 0 | 0 | 0 | 8 | 40 | 47 | 52 | 48 | 37 | 12 | 0 | 0 |
| 2029 SCCT Frame | 0 | 0 | 0 | 0 | 0 | 170 | 170 | 170 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 810 | 817 | 822 | 835 | 872 | 1,224 | 1,238 | 1,230 | 875 | 839 | 817 | 806 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 1,248 | 1,280 | 1,421 | 1,869 | 831 | 452 | 6 | 469 | 143 | 1,414 | 1,403 | 700 |

# Peak-Hour Surplus/Deficit Charts

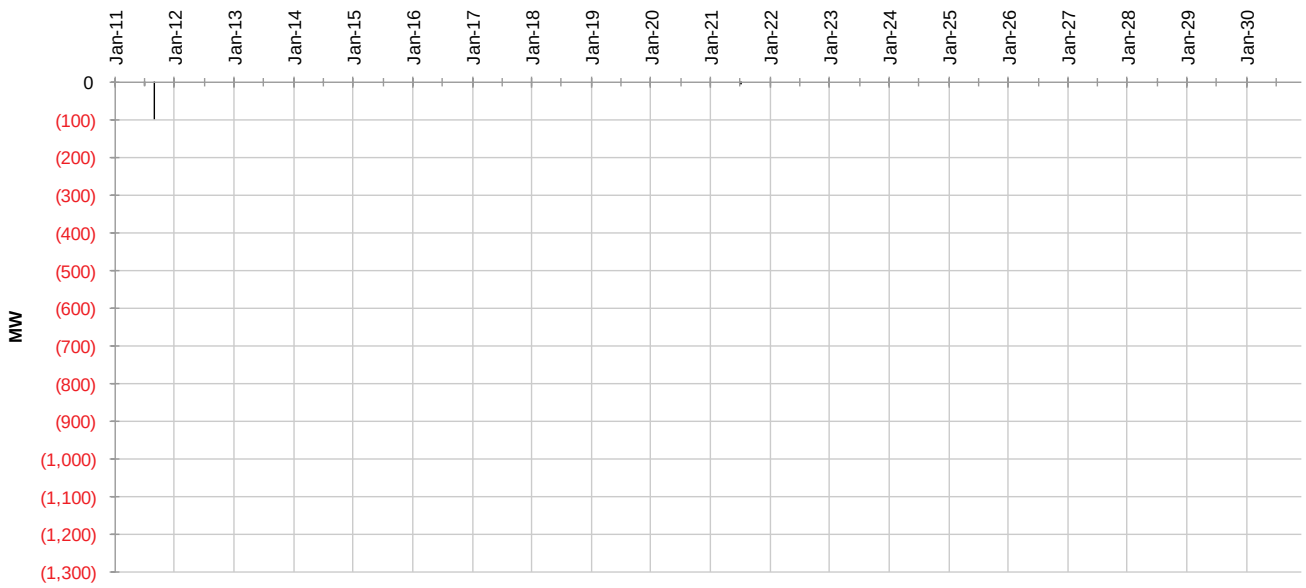
**Peak-hour monthly deficits with existing DSM and resources**




**Peak-hour monthly deficits with existing resources and new DSM**



**Peak-hour monthly deficits with existing resources, new DSM, and IRP resources**



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

The majority of Idaho Power's energy efficiency programs are preliminarily identified through the integrated resource planning process. Similar to the 2009 IRP, a majority of the anticipated new energy efficiency future commitments for the 2011 IRP come through additional measures added to existing programs and existing program expansion as opposed to new program offerings.

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power primarily uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant.

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. For the 2011 IRP, program administration costs were derived from actual 2010 program performance. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from engineering estimates or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process including the financial assumptions along with the forecasted value of avoided costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. Demand response program B/C ratios for the residential A/C Cool Credit, Irrigation Peak Rewards, and the commercial and industrial FlexPeak Management program are calculated over a 20-year period which allows for a better comparison with supply-side resource costs. In all cases, whether cost-effectiveness is looked at from the point of view of one measure, as a program, or a 20-year life, for a program to be considered cost-effective the program must have B/C ratios greater than one for both the TRC and UC tests.

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

When developing energy efficiency and demand response resources including program design, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost,

savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

The financial assumptions used in the analysis are consistent with the 2011 IRP, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative cost, which is the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward market prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

## Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AURORA model. The preferred portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward electric market prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing throughout each year of the planning period. The resulting categories are:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June–August
- Summer Off-Peak (SOFP)—Average of light load prices from June–August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January–May and September–December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January–May and September–December

The SONP is treated differently than the other four pricing periods. During the SONP, additional purchases from the regional power market are not an option due to currently existing transmission constraints. The marginal resource Idaho Power is trying to avoid with DSM efforts for SONP hours is the construction of SCCT. The estimated levelized capacity cost of building a new SCCT is approximately $94 per kW over a 30-year expected plant life. For demand response or direct load

control DSM programs operating during the summer peak, the $94 per kW becomes the cost threshold for program cost-effectiveness.

The avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 depending on the calendar year. Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward energy prices over the 20-year planning period that were used to screen new energy efficiency and demand response programs for cost-effectiveness along with the forecast of operation and maintenance (O&M) costs, including fuel for peak summer hours (SONP). The forward energy prices for measures that have a life longer than 20 years, which is typical for weatherization and building shell measures, are escalated at 3 percent annually as needed.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 through DSM-7 show the 20-year forecasted impact of energy efficiency by customer class for existing programs, along with the corresponding forecasted UC, and the TRC.

Table DSM-8 outlines the 20-year flow of avoided generation and the benefits attributed to the existing energy efficiency portfolio of programs.

Table DSM-9 summarizes the cost-effectiveness analysis for the existing energy efficiency portfolio of programs through the 20-year IRP planning period.

Table DSM-10 shows the 20-year annual forecasted impact of energy efficiency by customer class for new program measures and existing program expansions.

Table DSM-11 shows the 20-year annual forecast of UC or the costs to administer new program measures and existing program expansions.

Table DSM-12 shows the 20-year flow of resource costs that combines the program participant costs with the costs to administer the program for new program measures and existing program expansions.

Table DSM-13 outlines the 20-year flow of avoided generation and the benefits attributed to new program measures and existing program expansions.

Table DSM-14 summarizes the cost-effectiveness analysis for new program measures and existing program expansions through the 20-year IRP planning period.

Table DSM-15 shows the 20 year annual forecasted operational targets from all existing and new energy efficiency programs.

Tables DSM-16 through DSM-19 show the 20-year flow of demand reduction targets, UC, TRC, and the value of avoided generation for demand response programs, similar to those presented for energy efficiency programs.

Table DSM-20 summarizes the cost-effectiveness for demand response programs and the forecasted impact of the demand response operational targets through the IRP planning horizon.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided Capacity Costs** | |
| SCCT | $94/kW |
| **Financial Assumptions** | |
| Weighted average cost of capital (2008 year ending after tax) | 7.00% |
| Financial escalation factor | 3.00% |
| **Transmission Losses** | |
| Non-summer secondary losses | 10.90% |
| Summer peak loss | 13.00% |

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak* (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2011 | $60.89 | $54.42 | $36.25 | $55.21 | $38.22 |
| 2012 | $69.32 | $60.74 | $40.77 | $61.61 | $42.87 |
| 2013 | $76.15 | $65.06 | $44.41 | $64.89 | $45.74 |
| 2014 | $81.13 | $70.10 | $48.16 | $69.41 | $48.81 |
| 2015 | $102.02 | $83.09 | $63.18 | $82.13 | $61.71 |
| 2016 | $107.46 | $87.44 | $66.55 | $85.69 | $64.88 |
| 2017 | $112.71 | $92.77 | $71.14 | $90.50 | $69.13 |
| 2018 | $117.79 | $96.80 | $75.64 | $95.88 | $73.50 |
| 2019 | $122.76 | $102.71 | $80.62 | $101.44 | $78.51 |
| 2020 | $128.32 | $109.45 | $86.52 | $107.53 | $84.34 |
| 2021 | $134.04 | $114.80 | $90.59 | $113.45 | $89.30 |
| 2022 | $137.67 | $119.64 | $94.79 | $117.74 | $92.35 |
| 2023 | $142.80 | $130.75 | $102.71 | $128.30 | $100.59 |
| 2024 | $148.73 | $134.44 | $104.67 | $133.70 | $105.39 |
| 2025 | $155.25 | $143.49 | $109.80 | $140.64 | $109.95 |
| 2026 | $161.87 | $149.37 | $113.29 | $147.30 | $114.66 |
| 2027 | $168.70 | $154.60 | $111.26 | $153.26 | $118.05 |
| 2028 | $176.12 | $160.39 | $119.72 | $158.69 | $124.71 |
| 2029 | $183.85 | $166.21 | $125.48 | $165.50 | $131.51 |
| 2030 | $191.80 | $171.20 | $129.24 | $170.46 | $135.45 |

* Estimated variable operations and management costs of a 170 MW capacity SCCT.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. Cumulative existing energy efficiency portfolio forecast 2011-2030**
*(aMW w/transmission losses)*

| Year | Industrial | Irrigation | Commercial | Residential | Total |
|---|---|---|---|---|---|
| 2011 | 5 | 1 | 6 | 2 | 15 |
| 2012 | 10 | 2 | 12 | 5 | 29 |
| 2013 | 15 | 3 | 18 | 7 | 43 |
| 2014 | 19 | 4 | 24 | 10 | 57 |
| 2015 | 23 | 5 | 30 | 11 | 69 |
| 2016 | 28 | 6 | 36 | 13 | 82 |
| 2017 | 32 | 6 | 42 | 15 | 95 |
| 2018 | 37 | 7 | 48 | 16 | 108 |
| 2019 | 41 | 8 | 54 | 18 | 121 |
| 2020 | 46 | 8 | 60 | 20 | 133 |
| 2021 | 50 | 9 | 65 | 22 | 145 |
| 2022 | 53 | 9 | 70 | 23 | 155 |
| 2023 | 56 | 10 | 74 | 24 | 164 |
| 2024 | 59 | 10 | 77 | 25 | 172 |
| 2025 | 61 | 11 | 80 | 26 | 178 |
| 2026 | 63 | 11 | 83 | 27 | 183 |
| 2027 | 64 | 11 | 85 | 27 | 187 |
| 2028 | 65 | 11 | 86 | 28 | 190 |
| 2029 | 66 | 11 | 86 | 28 | 191 |
| 2030 | 66 | 11 | 86 | 28 | 191 |

**Table DSM-6. Existing energy efficiency portfolio UC 2011-2030**

| Year | Industrial | Irrigation | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|---|
| 2011 | $5,305,131 | $2,066,694 | $5,428,863 | $6,086,795 | $18,887,483 |
| 2012 | $5,008,928 | $1,915,825 | $5,709,427 | $6,116,523 | $18,750,703 |
| 2013 | $4,690,178 | $1,754,044 | $5,956,945 | $6,071,831 | $18,472,998 |
| 2014 | $4,830,883 | $1,580,832 | $6,135,653 | $6,269,750 | $18,817,119 |
| 2015 | $4,975,810 | $1,209,563 | $6,319,723 | $5,958,083 | $18,463,179 |
| 2016 | $5,125,084 | $1,245,849 | $6,509,314 | $6,154,123 | $19,034,371 |
| 2017 | $5,278,837 | $1,283,225 | $6,704,594 | $6,356,866 | $19,623,522 |
| 2018 | $5,437,202 | $1,321,722 | $6,905,732 | $6,566,552 | $20,231,207 |
| 2019 | $5,600,318 | $1,361,373 | $7,112,904 | $6,763,617 | $20,838,212 |
| 2020 | $5,768,327 | $1,402,215 | $7,326,291 | $6,966,526 | $21,463,358 |
| 2021 | $5,347,239 | $1,299,853 | $6,791,471 | $6,457,969 | $19,896,533 |
| 2022 | $4,895,695 | $1,190,088 | $6,217,969 | $5,912,630 | $18,216,381 |
| 2023 | $4,412,245 | $1,072,566 | $5,603,945 | $5,328,757 | $16,417,514 |
| 2024 | $3,895,382 | $946,923 | $4,947,483 | $4,704,532 | $14,494,319 |
| 2025 | $3,343,536 | $812,775 | $4,246,589 | $4,038,056 | $12,440,957 |
| 2026 | $2,755,074 | $669,727 | $3,499,190 | $3,327,358 | $10,251,349 |
| 2027 | $2,128,295 | $517,364 | $2,703,124 | $2,570,384 | $7,919,167 |
| 2028 | $1,461,429 | $355,257 | $1,856,145 | $1,764,997 | $5,437,828 |
| 2029 | $752,636 | $182,957 | $955,915 | $908,974 | $2,800,481 |
| 2030 | $0 | $0 | $0 | $0 | $0 |
| **20-Year NPV** | **49398585.63** | **14229457.72** | **60885631.38** | **60023977.7** | **184537652.4** |

**Table DSM-7. Existing energy efficiency portfolio TRC 2011-2030**

| Year | Industrial | Irrigation | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|---|
| 2011 | $10,378,144 | $5,613,834 | $10,688,073 | $10,369,974 | $37,050,025 |
| 2012 | $9,798,697 | $5,204,024 | $11,235,421 | $10,391,021 | $36,629,164 |
| 2013 | $9,175,144 | $4,764,573 | $11,739,780 | $10,478,055 | $36,157,552 |
| 2014 | $9,450,398 | $4,294,071 | $12,091,974 | $10,811,816 | $36,648,259 |
| 2015 | $9,733,910 | $3,285,578 | $12,454,733 | $10,335,755 | $35,809,976 |
| 2016 | $10,025,928 | $3,384,145 | $12,828,375 | $10,667,137 | $36,905,585 |
| 2017 | $10,326,705 | $3,485,670 | $13,213,226 | $11,009,472 | $38,035,073 |
| 2018 | $10,636,507 | $3,590,240 | $13,609,623 | $11,363,138 | $39,199,507 |
| 2019 | $10,955,602 | $3,697,947 | $14,017,912 | $11,704,116 | $40,375,577 |
| 2020 | $11,284,270 | $3,808,885 | $14,438,449 | $12,055,240 | $41,586,844 |
| 2021 | $10,460,518 | $3,530,837 | $13,384,442 | $11,175,207 | $38,551,004 |
| 2022 | $9,577,185 | $3,232,677 | $12,254,200 | $10,231,523 | $35,295,586 |
| 2023 | $8,631,438 | $2,913,450 | $11,044,098 | $9,221,160 | $31,810,147 |
| 2024 | $7,620,327 | $2,572,160 | $9,750,361 | $8,140,967 | $28,083,816 |
| 2025 | $6,540,781 | $2,207,771 | $8,369,060 | $6,987,663 | $24,105,275 |
| 2026 | $5,389,603 | $1,819,203 | $6,896,105 | $5,757,835 | $19,862,747 |
| 2027 | $4,163,469 | $1,405,335 | $5,327,241 | $4,447,927 | $15,343,972 |
| 2028 | $2,858,915 | $964,996 | $3,658,039 | $3,054,243 | $10,536,194 |
| 2029 | $1,472,341 | $496,973 | $1,883,890 | $1,572,935 | $5,426,140 |
| 2030 | $0 | $0 | $0 | $0 | $0 |
| **20-Year NPV** | **$96,635,806** | **$38,651,984** | **$119,966,128** | **$103,519,281** | **$358,773,200** |

**Table DSM-8. Existing energy efficiency portfolio avoided energy costs 2011-2030**

| Year | Industrial | Irrigation | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|---|
| 2011 | $32,844,311 | $7,358,378 | $35,697,627 | $21,464,719 | $97,365,035 |
| 2012 | $30,107,285 | $6,622,540 | $36,479,634 | $21,068,162 | $94,277,622 |
| 2013 | $27,370,259 | $5,886,702 | $36,870,638 | $20,711,920 | $90,839,519 |
| 2014 | $27,370,259 | $5,150,864 | $36,870,638 | $20,735,849 | $90,127,610 |
| 2015 | $27,370,259 | $3,826,356 | $36,870,638 | $19,035,142 | $87,102,396 |
| 2016 | $27,370,259 | $3,826,356 | $36,870,638 | $19,059,891 | $87,127,145 |
| 2017 | $27,370,259 | $3,826,356 | $36,870,638 | $19,085,062 | $87,152,315 |
| 2018 | $27,370,259 | $3,826,356 | $36,870,638 | $19,110,660 | $87,177,913 |
| 2019 | $27,370,259 | $3,826,356 | $36,870,638 | $19,110,749 | $87,178,003 |
| 2020 | $27,370,259 | $3,826,356 | $36,870,638 | $19,110,749 | $87,178,003 |
| 2021 | $24,633,233 | $3,443,721 | $33,183,574 | $17,199,674 | $78,460,202 |
| 2022 | $21,896,207 | $3,061,085 | $29,496,510 | $15,288,599 | $69,742,402 |
| 2023 | $19,159,182 | $2,678,449 | $25,809,447 | $13,377,524 | $61,024,602 |
| 2024 | $16,422,156 | $2,295,814 | $22,122,383 | $11,466,449 | $52,306,802 |
| 2025 | $13,685,130 | $1,913,178 | $18,435,319 | $9,555,375 | $43,589,001 |
| 2026 | $10,948,104 | $1,530,543 | $14,748,255 | $7,644,300 | $34,871,201 |
| 2027 | $8,211,078 | $1,147,907 | $11,061,191 | $5,733,225 | $26,153,401 |
| 2028 | $5,474,052 | $765,271 | $7,374,128 | $3,822,150 | $17,435,601 |
| 2029 | $2,737,026 | $382,636 | $3,687,064 | $1,911,075 | $8,717,800 |
| 2030 | $0 | $0 | $0 | $0 | $0 |
| **20-Year NPV** | $257,704,824 | $43,667,373 | $335,208,357 | $181,086,911 | $817,667,465 |

**Table DSM-9. Existing energy efficiency portfolio cost-effectiveness summary**

| | Impact | 20-Year NPV Costs | | | UC | | TRC | |
|---|---|---|---|---|---|---|---|---|
| | 2030 Load (aMW) | Utility | Resource | Avoided Energy | B/C Ratio | Levelized ($/kWh) | B/C Ratio | Levelized Costs ($/kWh) |
| Industrial | 66 | $49,398,586 | $96,635,806 | $257,704,824 | 5.2 | $0.015 | 2.7 | $0.028 |
| Irrigation | 11 | $14,229,458 | $38,651,984 | $43,667,373 | 3.1 | $0.023 | 1.1 | $0.061 |
| Commercial | 86 | $60,885,631 | $119,966,128 | $335,208,357 | 5.5 | $0.014 | 2.8 | $0.027 |
| Residential | 28 | $60,023,978 | $103,519,281 | $181,086,911 | 3.0 | $0.040 | 1.7 | $0.069 |
| **Total** | 191 | $184,537,652 | $358,773,200 | $817,667,465 | 4.4 | $0.019 | 2.3 | $0.036 |

**Table DSM-10. Cumulative new energy efficiency portfolio forecast 2011-2030**

*(aMW w/transmission losses)*

| Year | Industrial | Commercial | Residential | Total |
|---|---|---|---|---|
| 2011 | 2 | 1 | 1 | 3 |
| 2012 | 3 | 1 | 1 | 5 |
| 2013 | 5 | 1 | 2 | 8 |
| 2014 | 6 | 2 | 3 | 11 |
| 2015 | 7 | 2 | 4 | 13 |
| 2016 | 8 | 3 | 5 | 15 |
| 2017 | 8 | 3 | 6 | 18 |
| 2018 | 9 | 4 | 7 | 20 |
| 2019 | 9 | 4 | 9 | 22 |
| 2020 | 10 | 5 | 10 | 25 |
| 2021 | 11 | 5 | 11 | 27 |
| 2022 | 11 | 5 | 13 | 29 |
| 2023 | 12 | 6 | 14 | 31 |
| 2024 | 12 | 6 | 15 | 33 |
| 2025 | 12 | 6 | 16 | 35 |
| 2026 | 13 | 6 | 18 | 37 |
| 2027 | 13 | 6 | 19 | 38 |
| 2028 | 13 | 7 | 20 | 40 |
| 2029 | 13 | 7 | 22 | 41 |
| 2030 | 13 | 7 | 23 | 42 |

**Table DSM-11. New energy efficiency UC 2011-2030**

| Year | Industrial | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $1,642,064 | $479,932 | $1,622,645 | $3,744,641 |
| 2012 | $1,496,173 | $453,136 | $1,873,579 | $3,822,888 |
| 2013 | $2,010,076 | $424,300 | $2,112,145 | $4,546,521 |
| 2014 | $1,380,252 | $437,029 | $2,666,461 | $4,483,742 |
| 2015 | $710,830 | $450,140 | $2,909,628 | $4,070,597 |
| 2016 | $732,155 | $463,644 | $3,173,904 | $4,369,702 |
| 2017 | $754,120 | $477,553 | $3,404,458 | $4,636,130 |
| 2018 | $776,743 | $491,880 | $3,554,156 | $4,822,778 |
| 2019 | $800,045 | $506,636 | $3,706,560 | $5,013,242 |
| 2020 | $824,047 | $521,835 | $3,889,291 | $5,235,173 |
| 2021 | $763,891 | $483,741 | $4,017,933 | $5,265,565 |
| 2022 | $699,385 | $442,892 | $4,076,109 | $5,218,385 |
| 2023 | $630,321 | $399,156 | $4,134,669 | $5,164,146 |
| 2024 | $556,483 | $352,398 | $4,193,613 | $5,102,494 |
| 2025 | $477,648 | $302,475 | $4,252,937 | $5,033,060 |
| 2026 | $393,582 | $249,239 | $4,312,642 | $4,955,463 |
| 2027 | $304,042 | $192,537 | $4,372,729 | $4,869,308 |
| 2028 | $208,776 | $132,209 | $4,433,200 | $4,774,184 |
| 2029 | $107,519 | $68,088 | $4,417,298 | $4,592,905 |
| 2030 | $0 | $0 | $4,396,453 | $4,396,453 |
| **20-Year NPV** | $10,293,124 | $4,468,872 | $35,582,870 | $50,344,865 |

**Table DSM-12. New energy efficiency TRC 2011-2030**

| Year | Industrial | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $3,212,283 | $924,431 | $2,671,501 | $6,808,215 |
| 2012 | $2,926,884 | $872,817 | $3,190,869 | $6,990,570 |
| 2013 | $3,932,205 | $817,274 | $3,694,416 | $8,443,895 |
| 2014 | $2,700,114 | $841,792 | $4,903,200 | $8,445,106 |
| 2015 | $1,390,559 | $867,046 | $5,415,211 | $7,672,816 |
| 2016 | $1,432,275 | $893,058 | $5,973,476 | $8,298,809 |
| 2017 | $1,475,244 | $919,849 | $6,455,345 | $8,850,437 |
| 2018 | $1,519,501 | $947,445 | $6,755,376 | $9,222,322 |
| 2019 | $1,565,086 | $975,868 | $7,060,418 | $9,601,373 |
| 2020 | $1,612,039 | $1,005,144 | $7,432,207 | $10,049,389 |
| 2021 | $1,494,360 | $931,769 | $7,812,294 | $10,238,423 |
| 2022 | $1,368,169 | $853,086 | $8,041,475 | $10,262,731 |
| 2023 | $1,233,063 | $768,844 | $8,278,518 | $10,280,425 |
| 2024 | $1,088,618 | $678,779 | $8,523,748 | $10,291,146 |
| 2025 | $934,397 | $582,619 | $8,777,506 | $10,294,522 |
| 2026 | $769,943 | $480,078 | $9,040,150 | $10,290,171 |
| 2027 | $594,781 | $370,860 | $9,312,055 | $10,277,696 |
| 2028 | $408,416 | $254,657 | $9,593,615 | $10,256,689 |
| 2029 | $210,334 | $131,149 | $9,713,579 | $10,055,061 |
| 2030 | $0 | $0 | $9,832,105 | $9,832,105 |
| **20-Year NPV** | $20,135,886 | $8,607,815 | $69,027,549 | $97,771,250 |

**Table DSM-13. New energy efficiency avoided energy costs 2011-2030**

| Year | Industrial | Commercial | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $10,166,096 | $3,284,431 | $9,688,235 | $23,138,763 |
| 2012 | $8,993,085 | $3,010,729 | $11,886,107 | $23,889,920 |
| 2013 | $11,730,111 | $2,737,026 | $13,741,375 | $28,208,512 |
| 2014 | $7,820,074 | $2,737,026 | $18,590,724 | $29,147,824 |
| 2015 | $3,910,037 | $2,737,026 | $20,155,510 | $26,802,573 |
| 2016 | $3,910,037 | $2,737,026 | $21,803,334 | $28,450,397 |
| 2017 | $3,910,037 | $2,737,026 | $23,026,680 | $29,673,743 |
| 2018 | $3,910,037 | $2,737,026 | $23,444,101 | $30,091,164 |
| 2019 | $3,910,037 | $2,737,026 | $23,834,165 | $30,481,227 |
| 2020 | $3,910,037 | $2,737,026 | $24,425,904 | $31,072,967 |
| 2021 | $3,519,033 | $2,463,323 | $25,296,694 | $31,279,050 |
| 2022 | $3,128,030 | $2,189,621 | $25,585,141 | $30,902,792 |
| 2023 | $2,737,026 | $1,915,918 | $25,877,455 | $30,530,399 |
| 2024 | $2,346,022 | $1,642,216 | $26,173,719 | $30,161,956 |
| 2025 | $1,955,019 | $1,368,513 | $26,474,018 | $29,797,549 |
| 2026 | $1,564,015 | $1,094,810 | $26,778,442 | $29,437,267 |
| 2027 | $1,173,011 | $821,108 | $27,087,083 | $29,081,202 |
| 2028 | $782,007 | $547,405 | $27,400,039 | $28,729,452 |
| 2029 | $391,004 | $273,703 | $27,230,745 | $27,895,451 |
| 2030 | $0 | $0 | $27,061,451 | $27,061,451 |
| **20-Year NPV** | $56,034,905 | $25,770,482 | $228,851,046 | $310,656,434 |

**Table DSM-14. New energy efficiency cost-effectiveness summary 2011-2030**

| | Impact | 20-Year NPV Costs | | | UC | | TRC | |
|---|---|---|---|---|---|---|---|---|
| | 2030 Load (aMW) | Utility | Resource | Avoided Energy | B/C Ratio | Levelized ($/kWh) | B/C Ratio | Levelized Costs ($/kWh) |
| Industrial | 13 | $10,293,124 | $20,135,886 | $56,034,905 | 5.4 | $0.013 | 2.8 | $0.026 |
| Commercial | 7 | $4,468,872 | $8,607,815 | $25,770,482 | 5.8 | $0.013 | 3.0 | $0.025 |
| Residential | 23 | $35,582,870 | $69,027,549 | $228,851,046 | 6.4 | $0.045 | 3.3 | $0.086 |
| **Total** | 42 | $50,344,865 | $97,771,250 | $310,656,434 | 6.2 | $0.026 | 3.2 | $0.051 |

**Table DSM-15. Total energy efficiency portfolio forecasted impact existing and new 2011-2030**
*(aMW w/transmission losses)*

| Year | Industrial | Irrigation | Commercial | Residential | Total |
|---|---|---|---|---|---|
| 2011 | 7 | 1 | 6 | 3 | 18 |
| 2012 | 13 | 2 | 13 | 6 | 34 |
| 2013 | 20 | 3 | 19 | 9 | 51 |
| 2014 | 25 | 4 | 26 | 12 | 68 |
| 2015 | 30 | 5 | 32 | 15 | 83 |
| 2016 | 35 | 6 | 38 | 18 | 98 |
| 2017 | 41 | 6 | 45 | 21 | 113 |
| 2018 | 46 | 7 | 51 | 24 | 128 |
| 2019 | 51 | 8 | 58 | 27 | 143 |
| 2020 | 56 | 8 | 64 | 30 | 158 |
| 2021 | 60 | 9 | 70 | 33 | 172 |
| 2022 | 64 | 9 | 75 | 35 | 184 |
| 2023 | 68 | 10 | 79 | 38 | 195 |
| 2024 | 71 | 10 | 83 | 40 | 205 |
| 2025 | 73 | 11 | 87 | 42 | 213 |
| 2026 | 75 | 11 | 89 | 45 | 220 |
| 2027 | 77 | 11 | 91 | 46 | 225 |
| 2028 | 78 | 11 | 92 | 48 | 229 |
| 2029 | 78 | 11 | 93 | 50 | 232 |
| 2030 | 78 | 11 | 93 | 51 | 233 |

**Table DSM-16. Demand response portfolio forecasted impact 2011-2030**
*(MW w/transmission losses)*

| Year | Commercial/Industrial | Irrigation | Residential | Total |
|---|---|---|---|---|
| 2011 | 35 | 250 | 45 | 330 |
| 2012 | 35 | 224 | 51 | 310 |
| 2013 | 40 | 224 | 51 | 315 |
| 2014 | 40 | 224 | 51 | 315 |
| 2015 | 40 | 230 | 51 | 321 |
| 2016 | 40 | 260 | 51 | 351 |
| 2017 | 40 | 260 | 51 | 351 |
| 2018 | 40 | 260 | 51 | 351 |
| 2019 | 40 | 260 | 51 | 351 |
| 2020 | 40 | 260 | 51 | 351 |
| 2021 | 40 | 260 | 51 | 351 |
| 2022 | 40 | 260 | 51 | 351 |
| 2023 | 40 | 260 | 51 | 351 |
| 2024 | 40 | 260 | 51 | 351 |
| 2025 | 40 | 260 | 51 | 351 |
| 2026 | 40 | 260 | 51 | 351 |
| 2027 | 40 | 260 | 51 | 351 |
| 2028 | 40 | 260 | 51 | 351 |
| 2029 | 40 | 260 | 51 | 351 |
| 2030 | 40 | 260 | 51 | 351 |

**Table DSM-17. Demand response portfolio UC 2011-2030**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $2,247,361 | $11,295,980 | $2,836,308 | $16,379,648 |
| 2012 | $2,257,055 | $10,142,226 | $1,973,958 | $14,373,239 |
| 2013 | $2,554,314 | $9,960,104 | $2,007,751 | $14,522,170 |
| 2014 | $2,561,526 | $9,990,770 | $2,042,659 | $14,594,955 |
| 2015 | $2,568,688 | $10,262,003 | $2,078,732 | $14,909,422 |
| 2016 | $2,576,064 | $10,303,688 | $2,116,026 | $14,995,779 |
| 2017 | $2,583,662 | $10,331,152 | $2,153,998 | $15,068,812 |
| 2018 | $2,591,487 | $10,421,500 | $2,193,073 | $15,206,060 |
| 2019 | $2,599,548 | $10,404,669 | $2,233,853 | $15,238,070 |
| 2020 | $2,607,850 | $10,423,523 | $2,275,028 | $15,306,401 |
| 2021 | $2,616,401 | $10,457,730 | $2,317,860 | $15,391,991 |
| 2022 | $2,625,209 | $10,510,168 | $2,362,467 | $15,497,844 |
| 2023 | $2,634,281 | $10,550,924 | $2,408,035 | $15,593,240 |
| 2024 | $2,643,626 | $10,582,001 | $2,454,658 | $15,680,285 |
| 2025 | $2,653,250 | $10,631,069 | $2,503,167 | $15,787,487 |
| 2026 | $2,663,164 | $10,675,465 | $2,552,956 | $15,891,585 |
| 2027 | $2,673,374 | $10,707,573 | $2,603,851 | $15,984,798 |
| 2028 | $2,683,891 | $10,851,976 | $2,657,019 | $16,192,886 |
| 2029 | $2,694,724 | $10,828,235 | $2,711,791 | $16,234,750 |
| 2030 | $2,705,882 | $10,891,789 | $2,768,217 | $16,365,887 |
| **20-Year NPV** | $29,797,258 | $122,250,426 | $25,242,292 | $177,289,977 |

**Table DSM-18. Demand response portfolio TRC 2011-2030**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $2,247,361 | $11,295,980 | $2,836,308 | $16,379,648 |
| 2012 | $2,257,055 | $10,142,226 | $1,973,958 | $14,373,239 |
| 2013 | $2,554,314 | $9,960,104 | $2,007,751 | $14,522,170 |
| 2014 | $2,561,526 | $9,990,770 | $2,042,659 | $14,594,955 |
| 2015 | $2,568,688 | $10,262,003 | $2,078,732 | $14,909,422 |
| 2016 | $2,576,064 | $10,303,688 | $2,116,026 | $14,995,779 |
| 2017 | $2,583,662 | $10,331,152 | $2,153,998 | $15,068,812 |
| 2018 | $2,591,487 | $10,421,500 | $2,193,073 | $15,206,060 |
| 2019 | $2,599,548 | $10,404,669 | $2,233,853 | $15,238,070 |
| 2020 | $2,607,850 | $10,423,523 | $2,275,028 | $15,306,401 |
| 2021 | $2,616,401 | $10,457,730 | $2,317,860 | $15,391,991 |
| 2022 | $2,625,209 | $10,510,168 | $2,362,467 | $15,497,844 |
| 2023 | $2,634,281 | $10,550,924 | $2,408,035 | $15,593,240 |
| 2024 | $2,643,626 | $10,582,001 | $2,454,658 | $15,680,285 |
| 2025 | $2,653,250 | $10,631,069 | $2,503,167 | $15,787,487 |
| 2026 | $2,663,164 | $10,675,465 | $2,552,956 | $15,891,585 |
| 2027 | $2,673,374 | $10,707,573 | $2,603,851 | $15,984,798 |
| 2028 | $2,683,891 | $10,851,976 | $2,657,019 | $16,192,886 |
| 2029 | $2,694,724 | $10,828,235 | $2,711,791 | $16,234,750 |
| 2030 | $2,705,882 | $10,891,789 | $2,768,217 | $16,365,887 |
| **20-Year NPV** | $29,797,258 | $122,250,426 | $25,242,292 | $177,289,977 |

**Table DSM-19. Demand response avoided capacity costs 2011-2030**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2011 | $3,450,064 | $21,808,244 | $4,304,426 | $29,562,735 |
| 2012 | $3,467,767 | $19,640,451 | $4,847,528 | $27,955,745 |
| 2013 | $3,979,560 | $19,721,715 | $4,851,697 | $28,552,973 |
| 2014 | $3,991,512 | $19,780,945 | $4,854,736 | $28,627,192 |
| 2015 | $4,041,649 | $20,029,412 | $4,867,483 | $28,938,545 |
| 2016 | $4,054,703 | $20,094,105 | $4,870,802 | $29,019,610 |
| 2017 | $4,067,303 | $20,156,544 | $4,874,005 | $29,097,853 |
| 2018 | $4,079,498 | $20,216,981 | $4,877,106 | $29,173,585 |
| 2019 | $4,091,417 | $20,276,049 | $4,880,136 | $29,247,603 |
| 2020 | $4,104,769 | $20,342,220 | $4,883,531 | $29,330,520 |
| 2021 | $4,118,497 | $20,410,249 | $4,887,021 | $29,415,767 |
| 2022 | $4,127,211 | $20,453,436 | $4,889,237 | $29,469,884 |
| 2023 | $4,139,508 | $20,514,376 | $4,892,364 | $29,546,248 |
| 2024 | $4,153,749 | $20,584,950 | $4,895,984 | $29,634,684 |
| 2025 | $4,169,405 | $20,662,540 | $4,899,965 | $29,731,910 |
| 2026 | $4,185,278 | $20,741,199 | $4,904,001 | $29,830,477 |
| 2027 | $4,201,677 | $20,822,471 | $4,908,170 | $29,932,318 |
| 2028 | $4,219,495 | $20,910,773 | $4,912,700 | $30,042,968 |
| 2029 | $4,238,051 | $21,002,731 | $4,917,418 | $30,158,200 |
| 2030 | $4,257,124 | $21,097,253 | $4,922,268 | $30,276,645 |
| **20-Year NPV** | $46,640,850 | $238,224,468 | $52,905,340 | $337,770,658 |

**Table DSM-20. Demand response cost-effectiveness summary**

| | | 20-Year NPV Costs | | TRC | |
|---|---|---|---|---|---|
| | 2030 Load Impact(MW) | Resource | Avoided Energy | B/C Ratio | Levelized Costs ($/kWh) |
| Commercial/Industrial | 40 | $29,797,258 | $46,640,850 | 1.6 | $65 |
| Irrigation | 260 | $122,250,426 | $238,224,468 | 2.0 | $45 |
| Residential | 51 | $25,242,292 | $52,905,340 | 2.1 | $46 |
| **Total** | 351 | $177,289,977 | $337,770,659 | 1.9 | $48 |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.73% |
| Preferred | 0.00% |
| Common | 49.27% |
| Total | 100.00% |
| **Cost** | |
| Debt | 5.93% |
| Preferred | 0.00% |
| Common | 10.50% |
| Average Weighted Cost | 8.18% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | 30 Years |
| Discount rate (AKA WACC) | 7.00% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 3.00% |
| Emissions adder escalation rate | 2.50% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.00% |
| Production tax credits escalation rate | 3.00% |

| Tax Credits (2011$) | |
|---|---|
| Wind and geothermal | $21/MWh first 10 Years of Operation |
| Hydro and in-stream generation | $10/MWh first 10 Years of Operation |
| Solar investment tax credit (ITC) | 30% of depreciable investment |

| Emissions Adder Rates | |
|---|---|
| Carbon Dioxide ($CO_2$) | $20 per ton (2015 $) |
| Nitrogen Oxide ($NO_x$) | $2,600 per ton (2015 $) |
| Mercury (Hg) | $1,443 per ounce (2015 $) |
| Sulfur Oxide ($SO_2$) | $1.75 per ton (2011 $) |

| Emissions Limits (lbs per MWh by technology, adders brought into the analysis beginning in 2015) | | | | |
|---|---|---|---|---|
| | $CO_2$ | $NO_x$ | HG | $SO_2$ |
| Small aeroderivative SCCT | 1,115 | 1.07052 | N/A | 0.0096 |
| Large aeroderivative SCCT | 1,047 | 1.00540 | N/A | 0.0090 |
| Large frame SCCT | 1,413 | 1.35615 | N/A | 0.0122 |
| CCCT 1x1 | 809 | 0.77690 | N/A | 0.0070 |
| CCCT 2x1 | 809 | 0.77690 | N/A | 0.0070 |
| Combined heat and power (CHP) | 1,047 | 1.00540 | N/A | 0.0090 |
| Distributed generation–gas fired | 1,115 | 1.07052 | N/A | 0.0096 |
| Pulverized coal | 1,901 | 3.38192 | 0.000050 | 8.5339 |
| IGCC | 2,279 | 0.21036 | 0.000006 | 0.1490 |
| IGCC w/carbon sequestration | 421 | 0.25874 | 0.000006 | 0.1833 |

| Fuel Forecast Base Case (Nominal, $ per MMBtu) | | | |
|---|---|---|---|
| Year | Gas | Generic Coal | Nuclear |
| 2011 | $5.00 | $2.26 | $0.66 |
| 2012 | $5.79 | $2.38 | $0.66 |
| 2013 | $6.42 | $2.43 | $0.67 |
| 2014 | $6.87 | $2.54 | $0.67 |
| 2015 | $7.27 | $2.50 | $0.67 |
| 2016 | $7.68 | $2.53 | $0.68 |
| 2017 | $8.08 | $2.63 | $0.68 |
| 2018 | $8.45 | $2.67 | $0.69 |
| 2019 | $8.80 | $2.69 | $0.69 |
| 2020 | $9.21 | $2.81 | $0.69 |
| 2021 | $9.62 | $2.90 | $0.70 |
| 2022 | $9.83 | $2.99 | $0.70 |
| 2023 | $10.18 | $3.08 | $0.71 |
| 2024 | $10.59 | $3.18 | $0.71 |
| 2025 | $11.06 | $3.28 | $0.72 |
| 2026 | $11.53 | $3.39 | $0.72 |
| 2027 | $12.01 | $3.49 | $0.72 |
| 2028 | $12.54 | $3.61 | $0.73 |
| 2029 | $13.09 | $3.72 | $0.73 |
| 2030 | $13.66 | $3.84 | $0.74 |
| 2031 | $13.74 | $3.86 | $0.74 |
| 2032 | $13.82 | $3.89 | $0.75 |
| 2033 | $13.91 | $3.91 | $0.75 |
| 2034 | $13.99 | $3.93 | $0.75 |
| 2035 | $14.07 | $3.96 | $0.76 |
| 2036 | $14.16 | $3.98 | $0.76 |
| 2037 | $14.24 | $4.00 | $0.77 |
| 2038 | $14.33 | $4.03 | $0.78 |
| 2039 | $14.41 | $4.05 | $0.78 |
| 2040 | $14.50 | $4.08 | $0.79 |

# Cost Inputs and Operating Assumptions

(All costs in 2011 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Tranmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Varibale O&M $/kW | Emissions $/MWh | Heat Rate Btu/kWh |
|---|---|---|---|---|---|---|---|---|---|
| Wind | 100 | $1,450 | $283 | $1,733 | $1,840 | $35 | $1 | $0 | NA |
| Wind Magic Valley | 100 | $1,450 | $298 | $1,748 | $1,856 | $35 | $1 | $0 | NA |
| Wind Eastern Oregon | 100 | $1,450 | $672 | $2,122 | $2,253 | $35 | $1 | $0 | NA |
| Geothermal Nevada | 26 | $6,250 | $231 | $6,481 | $7,115 | $136 | $5 | $0 | NA |
| Geothermal Oregon | 26 | $6,250 | $135 | $6,385 | $7,010 | $136 | $5 | $0 | NA |
| Geothermal Idaho | 26 | $6,250 | $665 | $6,915 | $7,592 | $136 | $5 | $0 | NA |
| Solar–Parabolic Trough | 150 | $2,115 | $258 | $2,373 | $2,737 | $122 | $0 | $0 | NA |
| Solar–Parabolic Trough, 12 hrs energy storage | 150 | $3,562 | $258 | $3,820 | $4,407 | $79 | $0 | $0 | NA |
| Solar–Molten Salt Power Tower, 6.9 hrs energy storage | 100 | $3,220 | $258 | $3,478 | $4,012 | $55 | $0 | $0 | NA |
| Solar–Flat Plate PV (Distributed) | 1 | $3,750 | $0 | $3,750 | $3,816 | $25 | $0 | $0 | NA |
| Solar–Concentrating PV | 5 | $6,171 | $50 | $6,221 | $6,443 | $12 | $0 | $0 | NA |
| Low Drop/Small Hydro New | 10 | $4,000 | $50 | $4,050 | $4,672 | $14 | $3 | $0 | NA |
| Pumped Storage | 25 | $5,000 | $0 | $5,000 | $5,768 | $10 | $6 | $0 | NA |
| SCCT–Small Aeroderivative | 47 | $1,050 | $13 | $1,063 | $1,126 | $13 | $4 | $15 | 9,370 |
| SCCT–Large Aeroderivative | 100 | $1,130 | $111 | $1,241 | $1,314 | $8 | $5 | $11 | 8,800 |
| SCCT–Industrial Frame | 170 | $610 | $136 | $746 | $790 | $4 | $2 | $19 | 11,870 |
| CCCT (1x1) F Class | 270 | $1,120 | $96 | $1,216 | $1,380 | $7 | $2 | $11 | 6,800 |
| CCCT (2x1) F Class | 540 | $1,050 | $78 | $1,128 | $1,280 | $12 | $2 | $11 | 6,800 |
| CHP/Co-Generation | 100 | $1,860 | $28 | $1,888 | $2,008 | $8 | $5 | $0 | 9,200 |
| Reciprocating Engines | 25 | $1,150 | $134 | $1,284 | $1,354 | $13 | $10 | $13 | 9,700 |
| Distributed Generation (Option # 1) Load shed | 10 | $0 | $0 | $0 | $0 | $60 | $0 | $0 | 9,050 |
| Distributed Generation (Option # 2) Grid synchronized | 15 | $0 | $160 | $160 | $160 | $60 | $0 | $0 | 9,050 |
| Conventional Scrubbed Coal | 600 | $2,223 | $730 | $2,953 | $3,499 | $5 | $28 | $34 | 9,200 |
| IGCC | 550 | $2,569 | $730 | $3,299 | $4,026 | $3 | $40 | $34 | 8,765 |
| IGCC w/carbon sequestration | 380 | $3,776 | $730 | $4,506 | $5,498 | $5 | $47 | $7 | 10,781 |
| Advanced Nuclear | 250 | $3,820 | $283 | $4,103 | $5,965 | $1 | $92 | $0 | 10,488 |
| Boardman to Hemingway | 450 | $0 | $510 | $510 | $580 | $1 | $0 | $0 | NA |
| Solar–Flat Plate PV (Utility) | 1 | $3,750 | $0 | $3,750 | $3,816 | $25 | $0 | $0 | NA |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

# Levelized Cost of Production

**30-Year Levelized Cost of Production (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Emission Adders | Total Cost per MWh[1] | Capacity Factor |
|---|---|---|---|---|---|---|---|
| Advanced Nuclear (380 MW) | $85 | $137 | $8 | $0 | $0 | $229 | 85% |
| CCCT 1x1 (270 MW) | $26 | $6 | $65 | $0 | $11 | $108 | 65% |
| CCCT 2x1 (540 MW) | $24 | $7 | $65 | $0 | $11 | $107 | 65% |
| CHP (100 MW) | $26 | $10 | $74 | $0 | $0 | $111 | 93% |
| Distributed Generation–Grid Sync (15 MW) | $1,690 | $8,478 | $0 | $0 | $0 | $10,168 | 0% |
| Distributed Generation–Load Shed (10 MW) | $0 | $8,478 | $0 | $0 | $0 | $8,478 | 0% |
| Geothermal Idaho (26 MW) | $99 | $25 | $0 | $0 | $0 | $124 | 92% |
| Geothermal Nevada (26 MW) | $93 | $24 | $0 | $0 | $0 | $117 | 92% |
| Geothermal Oregon (26 MW) | $92 | $24 | $0 | $0 | $0 | $116 | 92% |
| IGCC (550 MW) | $57 | $61 | $27 | $0 | $34 | $179 | 85% |
| IGCC w/Carbon Sequestration (380 MW) | $78 | $74 | $33 | $0 | $7 | $191 | 85% |
| Low Drop/Small Hydro New (10 MW) | $125 | $19 | $0 | $0 | $0 | $144 | 45% |
| Pulverized Coal (750 MW) | $48 | $44 | $28 | $0 | $34 | $154 | 88% |
| Pumped Storage (25 MW) | $134 | $21 | $0 | $0 | $0 | $155 | 52% |
| Reciprocating Engines (25 MW) | $272 | $70 | $93 | $0 | $13 | $449 | 6% |
| SCCT–Industrial Frame (170 MW) | $159 | $25 | $114 | $0 | $19 | $316 | 6% |
| SCCT–Large Aero (100 MW) | $158 | $32 | $85 | $0 | $11 | $286 | 10% |
| SCCT–Small Aero (47 MW) | $170 | $45 | $90 | $0 | $15 | $319 | 8% |
| Solar–Concentrating PV (1 MW) | $135 | $36 | $0 | $0 | $0 | $171 | 22% |
| Solar–Flat Plate PV (1 MW) | $105 | $46 | $0 | $0 | $0 | $150 | 17% |
| Solar–Parabolic Trough No Storage (150 MW) | $56 | $122 | $0 | $0 | $0 | $177 | 18% |
| Solar–Parabolic Trough, with Energy Storage (150 MW) | $70 | $60 | $0 | $0 | $0 | $130 | 28% |
| Solar–Salt Power Tower (100 MW) | $64 | $45 | $0 | $0 | $0 | $109 | 28% |
| Transmission–Boardman to Hemingway (450 MW) | $19 | $1 | $0 | $64 | $0 | $83 | 32% |
| Wind (100 MW) | $69 | $20 | $0 | $0 | $0 | $89 | 32% |
| Wind Eastern Oregon (100 MW) | $85 | $21 | $0 | $0 | $0 | $106 | 32% |
| Wind Magic Valley (100 MW) | $70 | $20 | $0 | $0 | $0 | $90 | 32% |

[1] Includes emissions costs.

| Supply-Side Resources | 30-Year Levelized Capacity (fixed) Cost per kW/Month<br>Cost of Capital | Non-Fuel O&M[1] | Fuel | Emission Adders | Total Cost per kW/Month |
|---|---|---|---|---|---|
| Advanced Nuclear (380 MW) | $52 | $4 | $0 | $0 | $57 |
| CCCT 1x1 (270 MW) | $12 | $2 | $0 | $0 | $14 |
| CCCT 2x1 (540 MW) | $11 | $2 | $0 | $0 | $14 |
| CHP (100 MW) | $18 | $2 | $0 | $0 | $20 |
| Distributed Generation–Grid Sync (15 MW) | $1 | $7 | $0 | $0 | $8 |
| Distributed Generation–Load Shed (10 MW) | $0 | $7 | $0 | $0 | $7 |
| Geothermal Idaho (26 MW) | $67 | $21 | $0 | $0 | $88 |
| Geothermal Nevada (26 MW) | $63 | $21 | $0 | $0 | $83 |
| Geothermal Oregon (26 MW) | $62 | $21 | $0 | $0 | $82 |
| IGCC (550 MW) | $35 | $3 | $0 | $0 | $38 |
| IGCC w/Carbon Sequestration (380 MW) | $48 | $4 | $0 | $0 | $53 |
| Low Drop/Small Hydro New (10 MW) | $41 | $5 | $0 | $0 | $46 |
| Pulverized Coal (750 MW) | $31 | $3 | $0 | $0 | $34 |
| Pumped Storage (25 MW) | $51 | $5 | $0 | $0 | $56 |
| Reciprocating Engines (25 MW) | $12 | $2 | $0 | $0 | $14 |
| SCCT–Industrial Frame (170 MW) | $7 | $1 | $0 | $0 | $8 |
| SCCT–Large Aero (100 MW) | $12 | $2 | $0 | $0 | $13 |
| SCCT–Small Aero (47 MW) | $10 | $2 | $0 | $0 | $12 |
| Solar–Concentrating PV (1 MW) | $57 | $6 | $0 | $0 | $62 |
| Solar–Flat Plate PV (1 MW) | $34 | $6 | $0 | $0 | $39 |
| Solar–Parabolic Trough No Storage (150 MW) | $24 | $16 | $0 | $0 | $40 |
| Solar–Parabolic Trough, with Energy Storage (150 MW) | $39 | $12 | $0 | $0 | $51 |
| Solar–Salt Power Tower (100 MW) | $35 | $9 | $0 | $0 | $45 |
| Transmission–Boardman to Hemingway (450 MW) | $4 | $0 | $0 | $0 | $5 |
| Wind (100 MW) | $16 | $5 | $0 | $0 | $22 |
| Wind Eastern Oregon (100 MW) | $20 | $6 | $0 | $0 | $25 |
| Wind Magic Valley (100 MW) | $16 | $5 | $0 | $0 | $22 |

# Resource Advantages and Disadvantages

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Geothermal** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk (once developed)<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• High exploration costs due to drilling risks<br>• Uncertainty surrounding future tax incentives |
| **Wind** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of good sites in southern Idaho<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Avian and aesthetic impacts<br>• Uncertainty surrounding future tax incentives |
| **Hydro** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of sites<br>• Future development is limited to small sites or at existing dams without power generation<br>• Fish and other environmental issues |

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Solar** (General) | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs<br>• Generation would match well with summer peak loads. | • More expensive than other resource options<br>• Poor generation during winter months<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Limited utility scale projects exist |
| Parabolic Trough | • Can be built with thermal storage | • Utility scale production is limited |
| Power Tower | • By using molten salt, thermal storage can be built integrally into the system | • Utility scale production is unproven<br>• Requires land slope of 1 percent of less |
| Parabolic Dish | • Off-grid electricity production in remote areas | • Not suitable for storage options<br>• Unproven technology |
| Photovoltaic | • Proven & reliable technology<br>• Suitable for distributed generation | • Cloud cover creates a rapid power drop-off<br>• Utility scale projects are only practical up to 10 MW |
| **Biomass** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• Uncertainty surrounding future tax incentives<br>• Fuel supply risk |
| **In-stream Generation** | • Renewable resource<br>• No harmful emissions<br>• No fuel cost | • Small size, many sites would be required<br>• Environmental impact and permitting<br>• High maintenance cost |
| **Distributed Generation** | • Utilize existing backup generators at customer sites<br>• Dispatchable resource<br>• Provides operating reserves | • More expensive than other resource options<br>• Limited number of sites<br>• Fuel price risk and volatility<br>• Existing air quality permits may need to be modified<br>• Small size, many sites would be required |
| **Natural Gas** | | |
| Combined-Cycle Combustion Turbines (CCCT) | • Proven and reliable technology<br>• Dispatchable resource<br>• Provides operating reserves necessary for integration of renewable generation<br>• More efficient than a SCCT<br>• Greater than 50% reduction in $CO_2$ emissions per MWh of output compared to conventional pulverized coal technology | • Fuel price risk and volatility<br>• Potential fuel supply and transportation issues |
| Simple-Cycle Combustion Turbines (SCCT) | • Dispatchable resource<br>• Proven, reliable resource<br>• Low capital cost<br>• Short construction lead times<br>• Ideal for peaking service | • High variable operating cost<br>• Fuel price risk and volatility<br>• Less efficient than a CCCT |

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Coal** | | |
| Pulverized | • Abundant, low cost fuel<br>• Less price volatility than natural gas<br>• Proven and reliable technology<br>• Dispatchable resource<br>• Well suited for baseload operations | • Potential lack of public acceptance<br>• Significant particulate and gas emissions, particularly $CO_2$<br>• Significant capital investment<br>• Long construction lead times<br>• Lengthy environmental permitting and siting processes |
| Advanced Technology | • Abundant, low cost fuel<br>• Potentially lower greenhouse gas emissions if $CO_2$ is sequestered<br>• Potential for financial incentives<br>• Dispatchable resource | • New, unproven technologies<br>• Higher capital costs than pulverized coal<br>• Long construction lead times |
| **Nuclear** | • Forecasted low fuel costs<br>• Forecasted adequate fuel availability<br>• Lack of greenhouse gas emissions<br>• Potential low cost of production<br>• Proven technology (existing reactor types) | • Lack of public acceptance<br>• Safety concerns<br>• Waste disposal<br>• Construction cost uncertainties and the potential for construction cost overruns<br>• Security concerns |

## Camp Process

The Eastern Snake Plain Aquifer (ESPA) serves nearly one million acres of ground water irrigated land, cities, industries, and thousands of domestic wells. Above American Falls, the ESPA supports spring discharge that provides natural flow for irrigated lands in the Magic Valley. The ESPA has experienced serious declines that began in the late 1970s and appear to be ongoing. Those declines have impacted spring discharge to the Snake River, including springs that provide irrigation water and flows of cold water that support fish hatcheries from Twin Falls to Hagerman. Flow from the ESPA also provides a significant portion of the flow in the Snake River at King Hill and below.

Declining spring discharge has created numerous water shortages resulting in water calls pitting senior spring and surface water users against junior ground water appropriators. Many of those water calls are still pending or have been only partially resolved through orders from the director of the Idaho Department of Water Resources (IDWR). Continued declines in spring flows are likely to exacerbate these ongoing conflicts over water use on the Eastern Snake River Plain (ESRP).

The 2007 Idaho Legislature tasked the Idaho Water Resource Board (IWRB) with developing an ESPA Comprehensive Aquifer Management Plan (CAMP). The charge of the legislature was to "establish public policy as a settlement framework for future management of the ESPA." To meet legislative goals, the IWRB established a 15-member committee representing various water user groups and other parties interested in the management of the ESPA. The goal of the committee was to develop an aquifer management plan to "sustain the economic viability and social and environmental health of the eastern Snake Plain by adaptively managing a balance between water use and supplies."

**Table CAMP-1. Phase I Measures Included in the CAMP**

| Measure | Target (Acft) |
|---|---|
| Ground Water to Surface Water Conversions | 100,000 |
| Managed Aquifer Recharge | 100,000 |
| Demand Reduction | |
| Surface Water Conservation | 50,000 |
| Crop Mix Modification | 5,000 |
| Rotating Fallowing, Dry-Year Lease, CREP | 40,000 |
| Weather Modification | 50,000 |

The committee met monthly starting in May 2007 continuing through September 2008. The CAMP committee first established a goal of producing an annual 600,000 acre-feet adjustment in the water budget of the ESRP. This water balance adjustment was adopted as the long-term hydrologic target; however, committee members recognized this adjustment would be achieved only after many years of implementation. The committee adopted an interim plan called Phase I that targets an annual water budget change of 200,000–300,000 acre-feet/year. The committee's goal is to have Phase I fully implemented in 10 years. Table CAMP-1 shows the measures anticipated under Phase I. The Phase I plan includes the implementation of a variety of measures to change the overall water budget of the ESRP.

CAMP was submitted to the 2009 Idaho Legislature for approval. Upon legislative approval of the plan, the IWRB began a process of selecting an implementation committee. The charge of that committee will be to "assist the Board in the prioritization, development, implementation, and monitoring and evaluation of management actions." The implementation committee will also develop a mechanism to fund measures implemented under CAMP. The successful implementation of any CAMP-recommended measure is dependent upon securing a long-term funding source. As such, the specific practices, their extent or location is unknown at this time. Additionally, some practices are likely to change as the feasibility and impact of specific practices is evaluated over the next five years. The legislative approval of CAMP was only the first step in implementing management practices on the ESPA.

Idaho Power recognizes the potential for declining spring flow below Milner Dam to impact generation capabilities. Idaho Power also recognizes the potential for management practices recommended and implemented through CAMP to impact generation capabilities. Those impacts could be either positive or negative. As such, Idaho Power has been an active member of the CAMP committee. Idaho Power was represented at every CAMP committee meeting, and the company representatives participated in several sub-committees. Idaho Power also developed the appropriate modeling techniques to assess the potential impacts of CAMP on river flows and spring discharge. The results of the modeling was provided to the CAMP committee and used during the decision-making process. Idaho Power has also suggested management alternatives and has agreed to provide technical and material support for a pilot weather modification program in the upper Snake River basin.

CAMP committee members recognize that the failure of proposed management practices to increase aquifer levels or improve spring discharge to the Snake River could result in continued legal action against junior ground water appropriators. Implementation of CAMP was not to supplant the need for litigation but to manage the aquifer such that water calls would be lessened. Ground water appropriators could be subjected to increased mitigation requirements or potential curtailment if CAMP fails to produce desired results.

## Potential Impact of CAMP Implementation on Idaho Power

The implementation of CAMP practices impact hydropower generation in three different ways.

1) Managed recharge can increase spring discharge below Milner Dam, but those increases can occur only if water is diverted above Milner Dam and directed onto the ESRP and recharged to the aquifer. Conversions of ground water supplied irrigated land to surface supplied can also improve spring flow, but would require diversions of water from the Snake River above Milner Dam as well. Diversion for managed recharge and conversion projects have the potential to reduce the volume of water passing through numerous Idaho Power projects. Those diversions may have a negative impact to hydropower production on those facilities located between Milner Dam and King Hill. Additionally, while most of the water diverted for these projects comes back to the river as spring discharge, up to 10% of the water remains in the aquifer as long-term storage. These practices essentially shift water from one compartment, surface water, to another compartment, ground water. The net effect on the overall water budget is zero, but the diversions from the Snake River can have negative impacts to hydropower production.

2) Weather modification and practices that reduce consumptive use of ground water can increase water flowing through those generation facilities located on the Snake River above King Hill. These measures actually change the water budget by reducing consumptive demand or by increasing water supply in the basin. They can increase spring flow or tributary flow into the Snake River, but, unlike managed recharge or conversion projects, they require no diversions from the Snake River. These projects increase flows in the Snake River and could potentially benefit power generation.

3) Practices described in 1) and 2) are likely to be implemented in some combination. The relative extent of those practices will ultimately determine whether the impact is positive or negative for hydropower production. Diversions and increases in spring discharge may eventually balance, but the first five to ten years of implementation may produce a net negative effect on hydropower production.

The actual impact to hydropower production resulting from the implementation of the CAMP plan is uncertain. The availability of funding could drastically alter the implementation of the CAMP Phase I plan and long-standing water calls may eventually trump any plan proffered. Changing economic conditions may also alter decisions made by agriculture producers and their participation in current mitigation plans and other programs, such as the Conservation Reserve Enhancement Program (CREP). In evaluating the potential impacts of CAMP on hydropower production, the Phase I targets provide a basis for modeling and evaluation.

## Modeled CAMP Scenario

Idaho Power developed modeling capabilities to help determine the potential impacts of CAMP on spring discharge and flows in the Snake River. Idaho Power modeled several different scenarios for the CAMP committee. The modeling incorporates the Enhanced Snake Plain Aquifer Model (ESPAM) and the Snake River Planning Modeling (SRPM). The modeling also incorporates information on canal capacities and sets limits for managed recharge, system conversions, and demand reduction activities. The modeling also includes estimates on increased water from weather-modification activities.

The scenario modeled for the IRP was the Phase I implementation plan proposed in CAMP. The parameters entered into the model were done to try and match the goals of the Phase I plan. Table CAMP-2 compares the results of the Phase I CAMP with the modeled results. The modeled scenario provides close approximation of the planned Phase I and allows for the examination of the impacts of CAMP on spring discharge and flows in the Snake River.

**Table CAMP-2. CAMP Phase I Goals and Results of Modeling**

| Action | CAMP Goal (Average thousand acre-feet/year) | Modeled (Average thousand acre-feet/year) |
|---|---|---|
| Ground to Surface Water Conversions | 100 | 81 |
| Managed Recharge | 100 | 140** |
| Demand Reduction | 95* | 45 |
| Weather Modification | 50 | 50 |

*Some demand reduction includes the purchase of subordination agreements from spring owners that cannot be modeled, but would have no impact on spring flows or Snake River Flows.

**This recharge also includes approximately 20 KAF/yr recharge on the Wood River system.

The SRPM uses a variety of data inputs to determine water availability for irrigation diversions as well as providing information on reservoir storage and river flows. The model allows for present conditioning of historic data. In other words, it applies today's level of development (irrigation diversions and storage), reach gains, and diversions to historic water availability. The model is currently calibrated to run from 1928 through 2005. This mode of operation allows for the comparison of a base case scenario to a variety of management scenarios. This provides a perspective on the degree to which different management scenarios may impact reservoir storage and river flows.

**Table CAMP-3. Average Difference Between the CAMP Scenario and the Base Case Scenario for Flow at King Hill**

| July (acre-feet) | December (acre-feet) | Yearly (acre-feet) |
|---|---|---|
| 7,700 | 10,900 | 66,600 |

A comparison was made for the months of July and December and total yearly flows for the base case scenario and the CAMP scenario. July and December were selected because they are critical months for power generation. The comparison of modeled data was for the King Hill gage on the Snake River (Table CAMP-3). The average flows for July increased 7,670 acre-feet/month, and December flows increased 10,880 acre-feet/month. The yearly average flows increased by 66,580 acre-feet/year, which is about 1 percent of the yearly average flow at the King Hill gage. These small increases reflect the nature of changes in the water budget for the upper Snake Basin as proposed through CAMP. The CAMP Phase I plan contains only 95,000 acft in new or additional water to the system. CAMP may increase spring discharge tributary to the Snake River, but those increases are dependent upon large diversion from the Snake River for managed recharge or system conversions. The overall increase in Snake River flow is dependent upon a reduction in consumptive use of water or increases related to water modification activities.

# Brownlee Reservoir Inflow Record

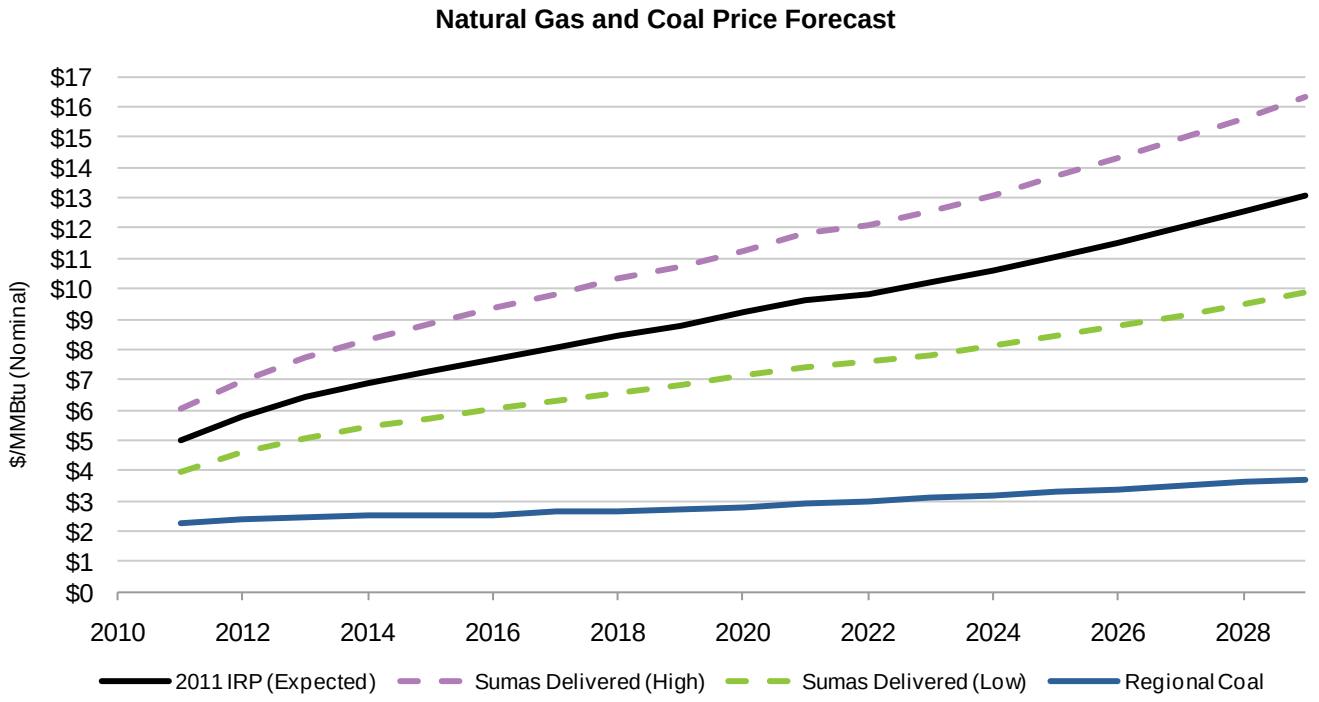
| Record used for 2011 IRP Modeling of Idaho Power Hydropower System (Million Acre-Feet [MAF]) | | | | | |
|---|---|---|---|---|---|
| CY | Brownlee April–July Inflow Volume (MAF) | Brownlee Annual Inflow Volume (MAF) | CY | Brownlee April–July Inflow Volume (MAF) | Brownlee Annual Inflow Volume (MAF) |
| 1928 | 6.8 | 14.8 | 1969 | 6.9 | 15.3 |
| 1929 | 3.5 | 9.1 | 1970 | 6.3 | 14.9 |
| 1930 | 2.8 | 8.3 | 1971 | 10.3 | 22.8 |
| 1931 | 2.3 | 7.2 | 1972 | 7.9 | 20.2 |
| 1932 | 4.8 | 10.2 | 1973 | 4.0 | 11.4 |
| 1933 | 4.3 | 9.4 | 1974 | 9.8 | 20.1 |
| 1934 | 2.3 | 7.4 | 1975 | 8.1 | 17.6 |
| 1935 | 3.1 | 8.0 | 1976 | 7.3 | 16.5 |
| 1936 | 5.1 | 10.4 | 1977 | 2.2 | 7.8 |
| 1937 | 3.0 | 8.5 | 1978 | 5.3 | 12.0 |
| 1938 | 7.1 | 13.7 | 1979 | 4.0 | 10.7 |
| 1939 | 3.9 | 10.0 | 1980 | 6.1 | 13.3 |
| 1940 | 4.3 | 10.7 | 1981 | 4.4 | 11.5 |
| 1941 | 3.9 | 10.2 | 1982 | 9.3 | 21.2 |
| 1942 | 5.0 | 11.2 | 1983 | 10.0 | 23.5 |
| 1943 | 9.4 | 18.9 | 1984 | 11.5 | 24.3 |
| 1944 | 3.4 | 9.6 | 1985 | 5.5 | 13.5 |
| 1945 | 4.9 | 11.7 | 1986 | 8.6 | 20.7 |
| 1946 | 6.9 | 15.4 | 1987 | 3.0 | 9.3 |
| 1947 | 5.4 | 12.6 | 1988 | 2.7 | 7.9 |
| 1948 | 5.9 | 12.5 | 1989 | 4.4 | 10.7 |
| 1949 | 5.5 | 12.5 | 1990 | 3.2 | 8.7 |
| 1950 | 6.6 | 14.7 | 1991 | 2.9 | 8.2 |
| 1951 | 6.7 | 16.2 | 1992 | 2.0 | 6.8 |
| 1952 | 10.4 | 19.3 | 1993 | 6.3 | 13.0 |
| 1953 | 6.1 | 13.6 | 1994 | 2.8 | 8.5 |
| 1954 | 5.7 | 12.7 | 1995 | 6.9 | 14.1 |
| 1955 | 3.6 | 9.8 | 1996 | 8.3 | 19.0 |
| 1956 | 8.0 | 17.7 | 1997 | 10.5 | 24.0 |
| 1957 | 7.9 | 16.2 | 1998 | 8.6 | 17.7 |
| 1958 | 7.6 | 15.0 | 1999 | 7.9 | 17.8 |
| 1959 | 4.0 | 10.5 | 2000 | 4.7 | 12.1 |
| 1960 | 4.4 | 10.8 | 2001 | 2.6 | 7.8 |
| 1961 | 3.2 | 8.7 | 2002 | 3.5 | 8.8 |
| 1962 | 4.9 | 11.1 | 2003 | 3.7 | 9.2 |
| 1963 | 4.7 | 11.5 | 2004 | 3.3 | 8.8 |
| 1964 | 5.8 | 13.2 | 2005 | 3.8 | 8.9 |
| 1965 | 8.6 | 19.9 | 2006 | 8.8 | 16.8 |
| 1966 | 3.6 | 10.0 | 2007 | 2.8 | 8.5 |
| 1967 | 5.0 | 11.4 | 2008 | 4.5 | 10.0 |
| 1968 | 3.5 | 10.7 | 2009 | 5.6 | 11.3 |

Note: Based on normalized historical flows for 1928–2009 using the Snake River Planning Model.

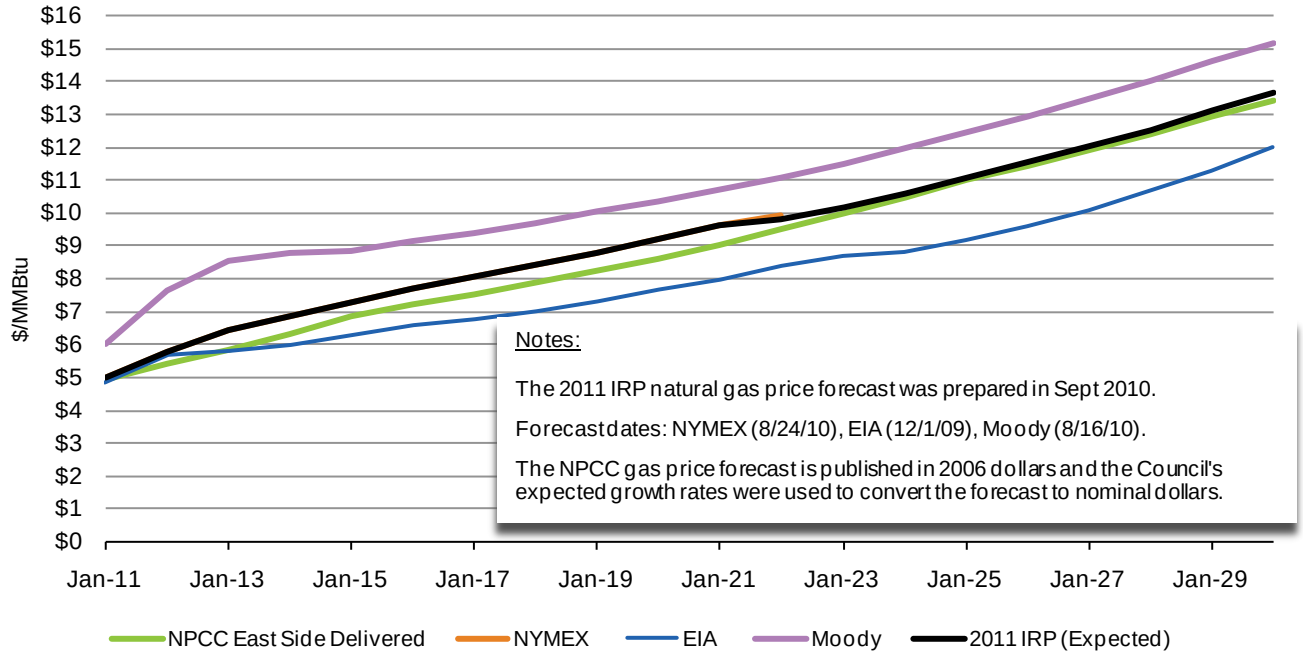
# FUEL DATA

## Natural Gas and Coal Price Forecast

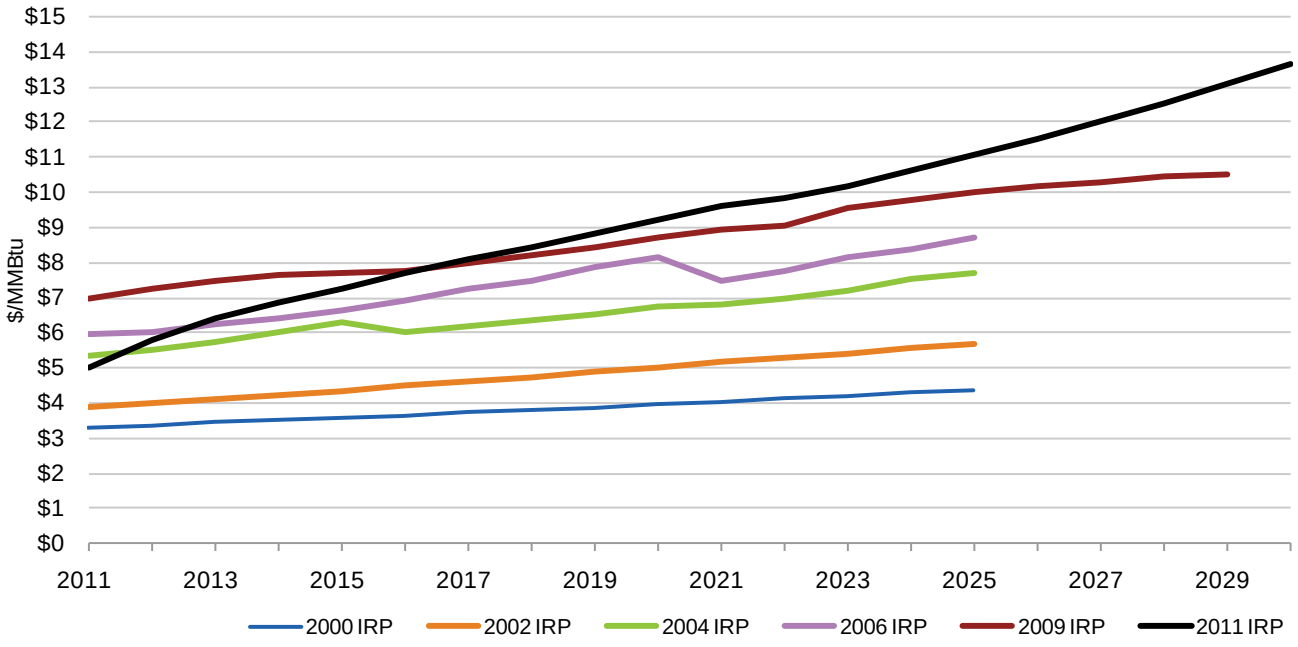
| Year | Sumas | Sumas Delivered (Expected) | Sumas Delivered (High) | Sumas Delivered (Low) | Regional Coal |
|---|---|---|---|---|---|
| 2011 | $4.51 | $5.00 | $6.02 | $3.99 | $2.26 |
| 2012 | $5.28 | $5.79 | $6.97 | $4.60 | $2.38 |
| 2013 | $5.90 | $6.42 | $7.75 | $5.09 | $2.43 |
| 2014 | $6.34 | $6.87 | $8.31 | $5.43 | $2.54 |
| 2015 | $6.73 | $7.27 | $8.81 | $5.72 | $2.50 |
| 2016 | $7.14 | $7.68 | $9.34 | $6.03 | $2.53 |
| 2017 | $7.52 | $8.08 | $9.83 | $6.32 | $2.63 |
| 2018 | $7.89 | $8.45 | $10.30 | $6.59 | $2.67 |
| 2019 | $8.24 | $8.80 | $10.76 | $6.84 | $2.69 |
| 2020 | $8.64 | $9.21 | $11.28 | $7.14 | $2.81 |
| 2021 | $9.04 | $9.62 | $11.81 | $7.43 | $2.90 |
| 2022 | $9.25 | $9.83 | $12.09 | $7.57 | $2.99 |
| 2023 | $9.59 | $10.18 | $12.54 | $7.81 | $3.08 |
| 2024 | $10.00 | $10.59 | $13.08 | $8.10 | $3.18 |
| 2025 | $10.46 | $11.06 | $13.69 | $8.43 | $3.28 |
| 2026 | $10.92 | $11.53 | $14.30 | $8.76 | $3.39 |
| 2027 | $11.39 | $12.01 | $14.92 | $9.10 | $3.49 |
| 2028 | $11.91 | $12.54 | $15.62 | $9.47 | $3.61 |
| 2029 | $12.45 | $13.09 | $16.34 | $9.85 | $3.72 |
| 2030 | $13.01 | $13.66 | $17.07 | $10.24 | $3.84 |



**Natural Gas Price Forecast $/MMBtu (Nominal)**




**Natural Gas Price Forecast Comparison (expected case delivered)**



# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 108,850 |
| Bliss | 86,250 | 75,000 | 75,000 | 76,470 |
| Brownlee | 650,444 | 585,400 | 585,400 | 746,570 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,800 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 90,720 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,420 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 444,830 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 64,340 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 16,520 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,540 |
| Milner | 62,890 | 59,448 | 59,448 | 61,090 |
| Oxbow | 211,112 | 190,000 | 190,000 | 221,410 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 14,040 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800 | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 53,060 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,930 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 17,510 |
| **Total Hydro** | **1,897,046** | **1,709,045** | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC)[6,7] kW | Net Dependable Capability (NDC)[6,7] Summer kW | Net Dependable Capability (NDC)[6,7] Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,501 | | 706,000 | 706,000 |
| Boardman (Idaho Power share) | 67,600 | 64,200 | | 58,600 | 59,100 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 258,250 | 239,000 |
| **Total Thermal** | **1,193,653** | **1,118,201** | | 1,022,850 | 1,004,100 |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit 1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit 2 | 51,000 | 45,900 | 45,236 | | |
| Evander Andrews Unit 3 | 51,000 | 45,900 | 45,236 | | |
| **Total Natural Gas** | **493,000** | **443,700** | **425,586** | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,590,579** | **3,275,946** | | | |

[1] A power factor rating of 0.8 is assumed on four units (Clear Lake, unit 2 at Shoshone Falls, and units 1 and 2 at Thousand Springs) with a total kVA rating of 6,127 kVA on which there is no nameplate kW rating.

[2] The two smaller units, 1 and 2, both having nameplate ratings of 1.25 MVA and 1 MW, have been taken out of service due to reduced flows from the springs and penstock integrity.

[3] The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

[4] Normal Rating is defined as the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

[5] Emergency Rating is defined as the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

[6] Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

[7] NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Projects under contract at time 2011 Forecast was prepared.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Lowline Canal | 2.50 | May-1985 | Apr-2005 |
| Birch Creek | 0.05 | Nov-1984 | Oct-2019 | Magic Reservoir | 9.07 | Jun-1989 | May-2024 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Malad River | 0.62 | May-1984 | Apr-2019 |
| Blind Canyon | 1.50 | Dec-1994 | Dec-2014 | Marco Ranches | 1.20 | Aug-1985 | Jul-2020 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Mile 28 | 1.50 | Jun-1994 | May-2029 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Mitchell Butte | 2.09 | May-1989 | May-2024 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mora Drop | 1.90 | Oct-2006 | Sep-2026 |
| Canyon Springs | 0.13 | Oct-1984 | Non firm | Mud Creek S&S | 0.52 | Feb-1982 | Feb-2017 |
| Cedar Draw | 1.55 | Jun-1984 | May-2019 | Mud Creek White | 0.21 | Jan-1986 | Jan-2021 |
| Clear Springs Trout | 0.52 | Nov-1983 | Oct-2018 | Owyhee Dam CSPP | 5.00 | Aug-1985 | Aug-2015 |
| Crystal Springs | 2.44 | Apr-1986 | Mar-2021 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Pristine Springs | 0.13 | May-2005 | Apr-2015 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pristine Springs #3 | 0.20 | May-2005 | Apr-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Rim View | 0.20 | Nov-2000 | Non firm |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Fisheries Development Co | 0.26 | Jul-1990 | Non firm | Rock Creek #2 | 1.90 | Apr-1989 | Mar-2024 |
| Geo Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sagebrush | 0.43 | Sep-1985 | Aug-2020 |
| Hailey CSPP | 0.06 | Jun-1985 | Jun-2020 | Sahko Hydro | 0.50 | Jun-2006 | Feb-2021 |
| Hazelton A | 7.70 | Jun-1990 | Jun-2010 | Schaffner | 0.53 | Aug-1986 | Jul-2021 |
| Hazelton B | 7.60 | May-1993 | Apr-2028 | Shingle Creek | 0.22 | Aug-1983 | Jul-2018 |
| Horseshoe Bend Hydroelectric | 9.50 | Sep-1995 | Sep-2030 | Shoshone #2 | 0.58 | May-1996 | Apr-2031 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Shoshone CSPP | 0.37 | Jun-1982 | Jun-2017 |
| Kasel and Witherspoon | 0.90 | Mar-1984 | Feb-2019 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Mar-2019 | Snedigar | 0.54 | Jan-1985 | Dec-2019 |
| Lateral # 10 | 2.06 | May-1985 | Apr-2020 | Tiber Dam | 7.50 | Jun-2004 | May-2024 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | Trout—Co | 0.24 | Dec-1986 | Nov-2021 |
| Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 | Tunnel #1 | 7.00 | Jun-1993 | May-2028 |
| Littlewood–Arkoosh | 0.87 | Aug-1986 | Jul-2021 | White Water Ranch | 0.16 | Aug-1985 | Jul-2020 |
| Lowline Midway Hydro | 7.97 | Aug-2007 | Aug-2027 | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 141.0 MW** | | | | | | | |
| **Thermal Projects** | | | | | | | |
| Magic Valley Natural Gas | 10.00 | Nov-1996 | Nov-2016 | TASCO—Nampa Natural Gas | 2.00 | Sep-2003 | Auto Renewal |
| Magic West Natural Gas | 10.00 | Dec-1996 | Nov-2016 | TASCO—Twin Falls Natural Gas | 2.00 | Aug-2001 | Auto Renewal |
| Simplot Pocatello Cogen | 12.00 | Mar-2006 | Feb-2016 | | | | |
| **Total Thermal Nameplate Rating 37.0 MW** | | | | | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2009 | Aug-2019 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Bettencourt Dry Creek | 2.25 | Aug-2008 | Aug-2018 | Rock Creek Dairy | 4.00 | May-2012 | Estimated |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | Swager Farms | 2.00 | Oct-2011 | Estimated |
| Double B Dairy | 2.00 | Dec-2012 | Estimated | Tamarack CSPP | 5.00 | Jun-1983 | May-2018 |
| Hidden Hollow Landfill Gas | 3.20 | Oct-2006 | Jan-2027 | | | | |
| **Total Biomass Nameplate Rating 22.69 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Notch Butte Wind | 18.00 | Aug-2011 | Estimated |
| Burley Butte Wind | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind | 10.50 | Jan-2011 | Jan-2031 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Rockland Wind Project | 80.00 | Dec-2011 | Estimated |
| Golden Valley Wind | 12.00 | Feb-2011 | Feb-2031 | Salmon Falls Wind | 22.00 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind Park | 9.00 | Feb-2006 | Feb-2026 | Sawtooth Wind Project | 21.00 | Dec-2012 | Estimated |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Thousand Springs Wind | 12.00 | Jan-2011 | Jan-2031 |
| Lava Beds Wind | 18.00 | Aug-2011 | Estimated | Tuana Gulch Wind | 10.50 | Jan-2011 | Jan-2031 |
| Magic Wind Park | 19.50 | Aug-2011 | Estimated | Tuana Springs Expansion | 35.70 | May-2010 | Jun-2030 |
| Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| **Total Wind Nameplate Rating 450.42 MW** | | | | | | | |
| **Solar Projects** | | | | | | | |
| Grand View Solar | 20.00 | Dec-2012 | Estimated | | | | |
| **Total Solar Nameplate Rating 20.00 MW** | | | | | | | |
| **Total Nameplate Rating 671.11 MW** | | | | | | | |

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of September 2010. In the case of CSPP projects, nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce. The application of this information to the portfolio of CSPP projects resulted in the average annual MW from CSPP projects being 167 MW in 2011.

# Power Purchase Agreement Data

**Idaho Power Company Power Purchase Agreements Status as of April 1, 2011**

| Project | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | September 2012 | September 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

# Hydro Modeling Results (PDR580)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 269.4 | 434.9 | 343.4 | 413.6 | 386.3 | 386.2 | 244.8 | 186.0 | 209.3 | 193.7 | 152.8 | 252.3 | 289.4 |
| Oxbow | HCC | 111.8 | 181.3 | 154.9 | 180.0 | 158.6 | 157.2 | 103.9 | 81.7 | 95.4 | 88.5 | 69.3 | 106.3 | 124.1 |
| Hells Canyon | HCC | 222.1 | 359.4 | 312.3 | 369.3 | 327.9 | 318.2 | 206.0 | 160.7 | 187.2 | 174.7 | 138.1 | 210.7 | 248.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.9 | 25.9 | 56.9 | 84.6 | 101.1 | 82.4 | 68.0 | 40.7 | 18.1 | 0.0 | 16.9 | 45.7 |
| Bliss | ROR | 49.7 | 52.3 | 45.9 | 51.3 | 49.3 | 48.6 | 36.3 | 37.7 | 37.8 | 40.4 | 38.2 | 46.9 | 44.5 |
| C.J. Strike | ROR | 66.4 | 69.5 | 60.5 | 68.4 | 62.5 | 61.1 | 39.4 | 42.3 | 45.3 | 51.5 | 50.2 | 61.2 | 56.5 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 36.2 | 37.2 | 30.6 | 35.9 | 34.3 | 34.9 | 23.6 | 24.4 | 23.9 | 26.2 | 24.5 | 32.5 | 30.4 |
| Milner | ROR | 42.4 | 45.5 | 27.1 | 40.5 | 35.5 | 36.7 | 6.7 | 6.7 | 0.0 | 0.0 | 1.9 | 30.0 | 22.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.4 | 11.2 | 12.0 | 12.0 | 11.6 |
| Swan Falls | ROR | 21.3 | 22.3 | 20.0 | 22.0 | 20.1 | 19.6 | 13.6 | 14.1 | 14.8 | 16.4 | 16.3 | 19.7 | 18.4 |
| Twin Falls | ROR | 42.4 | 44.5 | 28.3 | 40.4 | 36.2 | 38.2 | 11.5 | 11.8 | 3.8 | 7.3 | 8.2 | 31.5 | 25.3 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.7 | 19.1 | 19.1 | 19.1 | 14.5 | 15.4 | 14.7 | 16.3 | 15.0 | 19.2 | 17.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.7 | 13.6 | 14.3 | 13.8 | 15.1 | 14.0 | 17.7 | 16.0 |
| **HCC Total** | | **603.3** | **975.6** | **810.6** | **962.9** | **872.8** | **861.6** | **554.7** | **428.4** | **491.8** | **456.9** | **360.2** | **569.3** | **662.3** |
| **ROR Total** | | **359.8** | **375.9** | **311.4** | **396.1** | **405.9** | **427.5** | **286.4** | **283.4** | **239.6** | **232.8** | **206.5** | **314.9** | **320.0** |
| **Total** | | **963.1** | **1351.5** | **1122.0** | **1359.0** | **1278.7** | **1289.1** | **841.1** | **711.8** | **731.3** | **689.7** | **566.7** | **884.2** | **982.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

**aMW 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2012 | 2/2012 | 3/2012 | 4/2012 | 5/2012 | 6/2012 | 7/2012 | 8/2012 | 9/2012 | 10/2012 | 11/2012 | 12/2012 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 269.2 | 434.7 | 343.2 | 413.2 | 386.5 | 386.0 | 244.7 | 185.9 | 208.9 | 193.9 | 152.6 | 251.9 | 289.2 |
| Oxbow | HCC | 111.7 | 181.2 | 154.9 | 179.8 | 158.6 | 157.1 | 103.8 | 81.7 | 95.2 | 88.6 | 69.3 | 106.1 | 124.0 |
| Hells Canyon | HCC | 221.9 | 359.2 | 312.1 | 368.9 | 328.1 | 318.0 | 205.9 | 160.6 | 186.8 | 174.8 | 138.0 | 210.3 | 248.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.8 | 25.9 | 56.9 | 84.6 | 101.1 | 82.4 | 68.0 | 40.8 | 18.2 | 0.0 | 16.8 | 45.7 |
| Bliss | ROR | 51.2 | 52.2 | 45.8 | 51.2 | 49.3 | 48.6 | 36.2 | 37.7 | 37.8 | 40.4 | 38.2 | 46.8 | 44.6 |
| C.J. Strike | ROR | 66.3 | 69.4 | 60.4 | 68.3 | 62.5 | 61.0 | 39.3 | 42.2 | 45.2 | 51.4 | 50.2 | 61.0 | 56.4 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 36.2 | 37.1 | 30.6 | 35.8 | 34.2 | 34.8 | 23.5 | 24.4 | 23.9 | 26.2 | 24.4 | 32.3 | 30.3 |
| Milner | ROR | 42.4 | 45.4 | 27.1 | 40.4 | 35.5 | 36.7 | 6.7 | 6.7 | 0.0 | 0.0 | 1.9 | 29.7 | 22.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 12.0 | 12.0 | 11.5 |
| Swan Falls | ROR | 21.3 | 22.3 | 19.9 | 21.9 | 20.1 | 19.6 | 13.5 | 14.2 | 14.8 | 16.4 | 16.3 | 19.6 | 18.3 |
| Twin Falls | ROR | 42.3 | 44.4 | 28.3 | 40.3 | 36.2 | 38.2 | 11.5 | 11.7 | 3.8 | 7.3 | 8.0 | 31.2 | 25.3 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 14.5 | 15.3 | 14.6 | 16.3 | 14.9 | 19.2 | 17.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.6 | 14.3 | 13.7 | 15.1 | 14.0 | 17.7 | 16.1 |
| **HCC Total** | | **602.8** | **975.1** | **810.2** | **961.9** | **873.1** | **861.1** | **554.4** | **428.2** | **490.8** | **457.3** | **359.9** | **568.3** | **661.9** |
| **ROR Total** | | **361.1** | **375.6** | **317.8** | **396.4** | **404.7** | **425.8** | **286.0** | **283.2** | **239.3** | **232.8** | **206.1** | **313.6** | **320.2** |
| **Total** | | **963.9** | **1350.7** | **1128.0** | **1358.3** | **1277.8** | **1286.9** | **840.4** | **711.4** | **730.1** | **690.1** | **566.0** | **881.9** | **982.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 268.9 | 434.3 | 343.1 | 413.0 | 386.3 | 385.7 | 244.6 | 185.7 | 208.5 | 193.8 | 152.9 | 251.4 | 289.0 |
| Oxbow | HCC | 111.6 | 181.1 | 154.8 | 179.8 | 158.5 | 157.0 | 103.8 | 81.6 | 95.0 | 88.5 | 69.4 | 105.9 | 123.9 |
| Hells Canyon | HCC | 221.7 | 359.0 | 312.0 | 368.7 | 328.0 | 317.8 | 205.8 | 160.5 | 186.4 | 174.6 | 138.2 | 210.0 | 248.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.7 | 25.9 | 56.9 | 84.6 | 101.1 | 82.5 | 68.0 | 40.8 | 18.2 | 0.0 | 16.6 | 45.6 |
| Bliss | ROR | 51.1 | 52.1 | 45.8 | 51.2 | 49.2 | 48.6 | 36.2 | 37.7 | 37.8 | 40.3 | 38.1 | 46.6 | 44.6 |
| C.J. Strike | ROR | 66.3 | 69.3 | 60.4 | 68.2 | 62.4 | 61.0 | 39.3 | 42.2 | 45.1 | 51.4 | 50.1 | 60.8 | 56.4 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 36.1 | 37.1 | 30.5 | 35.8 | 34.2 | 34.8 | 23.5 | 24.4 | 23.8 | 26.1 | 24.4 | 32.2 | 30.2 |
| Milner | ROR | 42.3 | 45.2 | 27.0 | 40.3 | 35.5 | 36.6 | 6.7 | 6.7 | 0.0 | 0.0 | 1.9 | 29.4 | 22.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 12.0 | 12.0 | 11.5 |
| Swan Falls | ROR | 21.3 | 22.2 | 19.9 | 21.9 | 20.1 | 19.5 | 13.5 | 14.2 | 14.7 | 16.4 | 16.3 | 19.6 | 18.3 |
| Twin Falls | ROR | 42.3 | 44.2 | 28.2 | 40.3 | 36.2 | 38.2 | 11.5 | 11.7 | 3.8 | 7.3 | 8.0 | 30.9 | 25.2 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 14.4 | 15.3 | 14.6 | 16.2 | 14.9 | 19.2 | 17.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.5 | 14.3 | 13.7 | 15.1 | 13.9 | 17.7 | 16.1 |
| **HCC Total** | | **602.2** | **974.4** | **809.9** | **961.5** | **872.7** | **860.5** | **554.2** | **427.8** | **489.9** | **456.9** | **360.5** | **567.3** | **661.5** |
| **ROR Total** | | **360.8** | **374.8** | **317.5** | **396.2** | **404.5** | **425.6** | **285.9** | **283.2** | **239.0** | **232.5** | **205.8** | **312.3** | **319.8** |
| **Total** | | **963.0** | **1349.2** | **1127.4** | **1357.7** | **1277.2** | **1286.1** | **840.1** | **711.0** | **728.8** | **689.4** | **566.3** | **879.6** | **981.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 267.8 | 433.1 | 341.9 | 412.3 | 385.7 | 384.5 | 243.8 | 185.0 | 206.3 | 193.9 | 153.0 | 249.6 | 288.1 |
| Oxbow | HCC | 111.1 | 180.6 | 154.3 | 179.4 | 158.3 | 156.6 | 103.4 | 81.3 | 93.8 | 88.4 | 69.3 | 105.1 | 123.5 |
| Hells Canyon | HCC | 220.8 | 358.0 | 311.0 | 368.0 | 327.5 | 316.9 | 205.2 | 159.9 | 184.2 | 174.4 | 138.1 | 208.4 | 247.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.6 | 25.9 | 56.9 | 84.8 | 101.1 | 82.6 | 68.1 | 40.8 | 18.3 | 0.0 | 15.8 | 45.6 |
| Bliss | ROR | 50.9 | 51.5 | 45.5 | 50.8 | 49.0 | 48.3 | 36.0 | 37.5 | 37.6 | 40.1 | 37.9 | 45.8 | 44.2 |
| C.J. Strike | ROR | 65.9 | 68.6 | 60.1 | 67.8 | 62.5 | 60.7 | 39.0 | 41.9 | 44.9 | 51.1 | 49.9 | 59.7 | 56.0 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 35.9 | 36.4 | 30.3 | 35.5 | 34.0 | 34.5 | 23.3 | 24.2 | 23.7 | 26.0 | 24.2 | 31.4 | 30.0 |
| Milner | ROR | 42.0 | 44.8 | 26.7 | 40.3 | 35.4 | 36.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 27.8 | 22.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 11.8 | 12.0 | 11.5 |
| Swan Falls | ROR | 21.2 | 22.1 | 19.8 | 21.8 | 20.0 | 19.5 | 13.4 | 14.1 | 14.7 | 16.4 | 16.2 | 19.3 | 18.2 |
| Twin Falls | ROR | 42.0 | 43.9 | 27.9 | 40.0 | 36.1 | 38.1 | 11.4 | 11.7 | 3.8 | 7.2 | 7.8 | 29.4 | 24.9 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 14.3 | 15.2 | 14.5 | 16.1 | 14.8 | 19.2 | 17.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.4 | 14.2 | 13.6 | 15.0 | 13.8 | 17.7 | 16.0 |
| **HCC Total** | | **599.7** | **971.7** | **807.2** | **959.7** | **871.5** | **858.0** | **552.4** | **426.2** | **484.3** | **456.7** | **360.4** | **563.1** | **659.2** |
| **ROR Total** | | **359.3** | **371.9** | **316.0** | **394.7** | **404.0** | **424.5** | **284.9** | **282.3** | **238.3** | **231.7** | **204.4** | **305.4** | **318.1** |
| **Total** | | **959.0** | **1343.6** | **1123.2** | **1354.4** | **1275.5** | **1282.5** | **837.3** | **708.5** | **722.6** | **688.4** | **564.8** | **868.5** | **977.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 266.5 | 431.6 | 341.4 | 410.0 | 387.2 | 383.3 | 243.1 | 184.3 | 204.2 | 194.3 | 153.0 | 247.8 | 287.2 |
| Oxbow | HCC | 110.6 | 180.0 | 154.0 | 186.2 | 158.9 | 156.1 | 103.1 | 81.0 | 92.7 | 88.4 | 69.3 | 104.3 | 123.7 |
| Hells Canyon | HCC | 219.8 | 356.8 | 310.5 | 376.1 | 328.6 | 316.0 | 204.5 | 159.3 | 182.0 | 174.5 | 138.1 | 206.9 | 247.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.6 | 25.9 | 56.8 | 84.9 | 101.2 | 82.7 | 68.2 | 40.9 | 18.4 | 0.0 | 14.9 | 45.6 |
| Bliss | ROR | 50.6 | 51.2 | 45.2 | 50.5 | 48.8 | 48.0 | 35.8 | 37.3 | 37.4 | 39.9 | 37.6 | 44.9 | 43.9 |
| C.J. Strike | ROR | 65.5 | 67.9 | 59.7 | 67.4 | 62.1 | 60.5 | 38.8 | 41.7 | 44.6 | 50.9 | 49.6 | 58.5 | 55.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 35.6 | 36.0 | 30.0 | 35.3 | 33.8 | 34.3 | 23.2 | 24.0 | 23.5 | 25.8 | 24.0 | 30.6 | 29.7 |
| Milner | ROR | 41.7 | 44.5 | 26.4 | 40.0 | 35.4 | 36.4 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 25.9 | 22.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.2 | 11.1 | 11.3 | 12.0 | 11.5 |
| Swan Falls | ROR | 21.1 | 21.8 | 19.7 | 21.7 | 19.9 | 19.4 | 13.4 | 14.0 | 14.6 | 16.3 | 16.1 | 18.9 | 18.1 |
| Twin Falls | ROR | 41.8 | 43.6 | 27.6 | 39.7 | 36.0 | 38.0 | 11.4 | 11.7 | 3.7 | 7.2 | 7.3 | 27.7 | 24.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 14.2 | 15.1 | 14.4 | 16.0 | 14.6 | 19.2 | 17.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.3 | 14.1 | 13.5 | 14.9 | 13.7 | 17.7 | 16.0 |
| **HCC Total** | | **596.9** | **968.4** | **805.9** | **972.3** | **874.6** | **855.4** | **550.7** | **424.6** | **478.8** | **457.2** | **360.4** | **559.0** | **658.7** |
| **ROR Total** | | **357.7** | **369.6** | **314.3** | **393.0** | **403.1** | **423.6** | **284.3** | **281.5** | **237.1** | **230.8** | **202.2** | **297.6** | **316.2** |
| **Total** | | **954.6** | **1338.0** | **1120.2** | **1365.3** | **1277.7** | **1279.0** | **835.0** | **706.1** | **715.9** | **688.0** | **562.6** | **856.6** | **974.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 265.4 | 430.4 | 340.3 | 411.1 | 383.6 | 382.1 | 242.3 | 163.9 | 205.0 | 194.1 | 152.9 | 250.7 | 285.2 |
| Oxbow | HCC | 110.2 | 179.5 | 153.5 | 187.0 | 157.5 | 155.6 | 102.8 | 74.9 | 93.2 | 88.5 | 69.3 | 105.6 | 123.1 |
| Hells Canyon | HCC | 218.9 | 355.8 | 309.5 | 377.6 | 325.8 | 315.0 | 203.9 | 147.3 | 183.0 | 174.6 | 138.1 | 209.4 | 246.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 28.1 | 25.9 | 56.7 | 85.1 | 101.3 | 82.8 | 64.2 | 41.7 | 18.8 | 0.0 | 19.2 | 45.8 |
| Bliss | ROR | 50.3 | 51.5 | 45.0 | 50.2 | 48.6 | 47.7 | 35.6 | 33.6 | 37.2 | 39.8 | 38.0 | 47.2 | 43.7 |
| C.J. Strike | ROR | 65.1 | 68.2 | 59.4 | 67.1 | 61.4 | 60.1 | 38.5 | 36.8 | 44.5 | 50.8 | 49.8 | 61.8 | 55.3 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 35.4 | 36.4 | 29.7 | 35.0 | 33.7 | 34.2 | 23.0 | 20.9 | 23.4 | 25.7 | 24.0 | 32.7 | 29.5 |
| Milner | ROR | 41.5 | 44.9 | 26.3 | 39.6 | 35.3 | 36.4 | 6.7 | 0.0 | 0.0 | 0.0 | 3.1 | 32.7 | 22.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 13.5 |
| Swan Falls | ROR | 21.0 | 21.9 | 19.6 | 21.6 | 19.8 | 19.3 | 13.3 | 12.5 | 14.6 | 16.2 | 16.2 | 19.9 | 18.0 |
| Twin Falls | ROR | 41.5 | 43.8 | 27.5 | 39.4 | 36.0 | 37.9 | 11.4 | 3.7 | 3.7 | 7.2 | 8.2 | 33.8 | 24.5 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 14.0 | 12.6 | 14.2 | 15.9 | 14.6 | 19.2 | 17.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.2 | 12.0 | 13.4 | 14.8 | 13.7 | 17.7 | 15.8 |
| **HCC Total** | | **594.5** | **965.7** | **803.3** | **975.7** | **866.9** | **852.7** | **549.0** | **386.1** | **481.2** | **457.2** | **360.3** | **565.7** | **654.9** |
| **ROR Total** | | **356.2** | **371.8** | **313.2** | **391.2** | **402.1** | **422.7** | **283.3** | **240.1** | **237.3** | **230.6** | **205.8** | **351.5** | **317.2** |
| **Total** | | **950.7** | **1337.5** | **1116.5** | **1366.9** | **1269.0** | **1275.4** | **832.3** | **626.2** | **718.5** | **687.8** | **566.1** | **917.2** | **972.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 264.2 | 429.3 | 339.2 | 409.0 | 385.4 | 380.9 | 241.6 | 163.2 | 203.1 | 194.2 | 152.9 | 249.7 | 284.4 |
| Oxbow | HCC | 109.7 | 179.0 | 153.0 | 185.7 | 158.2 | 155.1 | 102.5 | 74.6 | 92.2 | 88.4 | 69.3 | 105.1 | 122.7 |
| Hells Canyon | HCC | 217.9 | 354.9 | 308.4 | 375.1 | 327.2 | 314.1 | 203.3 | 146.7 | 181.1 | 174.4 | 138.0 | 208.5 | 245.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 28.1 | 25.9 | 56.6 | 85.2 | 101.5 | 82.9 | 64.3 | 41.8 | 18.9 | 0.0 | 18.3 | 45.7 |
| Bliss | ROR | 50.0 | 51.3 | 44.7 | 49.9 | 48.3 | 47.5 | 35.4 | 33.4 | 37.0 | 39.6 | 37.6 | 46.3 | 43.4 |
| C.J. Strike | ROR | 64.7 | 67.8 | 59.1 | 66.7 | 61.3 | 59.8 | 38.3 | 36.6 | 44.3 | 50.5 | 49.5 | 60.6 | 54.9 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 35.1 | 36.2 | 29.5 | 34.7 | 33.4 | 34.0 | 22.8 | 20.7 | 23.2 | 25.5 | 23.8 | 31.9 | 29.2 |
| Milner | ROR | 41.2 | 44.6 | 26.0 | 39.1 | 35.3 | 36.4 | 6.7 | 0.0 | 0.0 | 0.0 | 3.0 | 30.9 | 21.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.9 | 21.8 | 19.5 | 21.5 | 19.7 | 19.2 | 13.2 | 12.5 | 14.5 | 16.2 | 16.1 | 19.5 | 17.9 |
| Twin Falls | ROR | 41.3 | 43.6 | 27.2 | 39.0 | 35.9 | 37.9 | 11.3 | 3.6 | 3.7 | 7.1 | 8.1 | 32.2 | 24.2 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.1 | 13.9 | 12.5 | 14.1 | 15.7 | 14.5 | 19.2 | 16.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.1 | 11.9 | 13.3 | 14.7 | 13.6 | 17.7 | 15.8 |
| **HCC Total** | | **591.8** | **963.2** | **800.6** | **969.8** | **870.7** | **850.1** | **547.4** | **384.5** | **476.3** | **457.0** | **360.2** | **563.3** | **652.9** |
| **ROR Total** | | **397.6** | **416.4** | **334.7** | **428.1** | **437.3** | **460.1** | **286.4** | **239.3** | **236.4** | **229.6** | **204.4** | **343.9** | **334.3** |
| **Total** | | **989.4** | **1379.6** | **1135.3** | **1397.9** | **1308.0** | **1310.2** | **833.8** | **623.8** | **712.7** | **686.6** | **564.6** | **907.2** | **987.2** |

*HCC=Hells Canyon Complex,**ROR=Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 263.0 | 427.8 | 338.6 | 408.1 | 384.5 | 379.7 | 240.8 | 162.5 | 200.2 | 194.8 | 153.1 | 247.9 | 283.4 |
| Oxbow | HCC | 109.2 | 178.4 | 152.7 | 185.3 | 157.8 | 154.7 | 102.2 | 74.3 | 90.6 | 88.4 | 69.3 | 104.3 | 122.3 |
| Hells Canyon | HCC | 216.9 | 353.7 | 307.9 | 374.3 | 326.4 | 313.2 | 202.7 | 146.1 | 178.0 | 174.4 | 138.0 | 207.0 | 244.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.7 | 25.9 | 56.4 | 85.3 | 101.6 | 83.1 | 64.4 | 41.8 | 19.0 | 0.0 | 17.3 | 45.7 |
| Bliss | ROR | 49.8 | 50.8 | 44.4 | 49.7 | 48.0 | 47.4 | 35.2 | 33.3 | 36.8 | 39.4 | 37.3 | 45.4 | 43.1 |
| C.J. Strike | ROR | 64.3 | 67.4 | 58.7 | 66.3 | 61.0 | 59.4 | 38.0 | 36.4 | 43.9 | 50.3 | 49.2 | 59.4 | 54.5 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.9 | 35.9 | 29.2 | 34.4 | 33.2 | 33.8 | 22.7 | 20.5 | 23.0 | 25.3 | 23.6 | 31.1 | 29.0 |
| Milner | ROR | 40.9 | 43.7 | 25.6 | 38.7 | 35.2 | 36.4 | 6.7 | 0.0 | 0.0 | 0.0 | 2.3 | 29.2 | 21.6 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.8 | 21.7 | 19.4 | 21.4 | 19.6 | 19.1 | 13.1 | 12.4 | 14.4 | 16.1 | 16.0 | 19.2 | 17.8 |
| Twin Falls | ROR | 41.0 | 42.9 | 26.8 | 38.6 | 35.8 | 37.8 | 11.3 | 0.0 | 3.6 | 7.1 | 8.0 | 30.6 | 23.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.1 | 19.1 | 17.6 | 19.1 | 13.8 | 12.3 | 14.0 | 15.6 | 14.3 | 19.2 | 16.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.5 | 17.7 | 17.7 | 16.2 | 13.0 | 11.7 | 13.2 | 14.6 | 13.5 | 17.7 | 15.7 |
| **HCC Total** | | **589.1** | **959.9** | **799.2** | **967.7** | **868.7** | **847.6** | **545.7** | **382.9** | **468.7** | **457.6** | **360.4** | **559.2** | **650.6** |
| **ROR Total** | | **396.1** | **413.1** | **332.5** | **426.1** | **436.3** | **459.3** | **285.7** | **234.8** | **235.3** | **228.8** | **202.4** | **336.4** | **332.0** |
| **Total** | | **985.2** | **1373.0** | **1131.7** | **1393.8** | **1305.0** | **1306.9** | **831.4** | **617.7** | **704.0** | **686.4** | **562.8** | **895.6** | **982.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 262.1 | 425.8 | 339.2 | 407.8 | 383.8 | 378.8 | 240.2 | 162.1 | 197.9 | 195.0 | 153.1 | 246.6 | 282.7 |
| Oxbow | HCC | 108.8 | 177.5 | 152.8 | 185.1 | 157.5 | 154.3 | 101.9 | 74.0 | 89.4 | 88.3 | 69.2 | 103.8 | 121.9 |
| Hells Canyon | HCC | 216.2 | 351.9 | 308.1 | 374.0 | 325.9 | 312.5 | 202.2 | 145.7 | 175.6 | 174.2 | 137.9 | 205.9 | 244.2 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.6 | 25.8 | 56.3 | 85.4 | 101.7 | 83.2 | 64.4 | 41.9 | 19.1 | 0.0 | 16.6 | 45.6 |
| Bliss | ROR | 49.6 | 50.6 | 44.2 | 49.4 | 47.7 | 47.2 | 35.1 | 33.1 | 36.7 | 39.3 | 37.1 | 44.7 | 42.9 |
| C.J. Strike | ROR | 64.0 | 66.8 | 58.5 | 66.0 | 60.6 | 59.1 | 37.8 | 36.2 | 43.7 | 50.1 | 48.7 | 58.5 | 54.2 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.7 | 35.5 | 29.0 | 34.2 | 33.1 | 33.7 | 22.6 | 20.4 | 22.9 | 25.2 | 23.4 | 30.5 | 28.8 |
| Milner | ROR | 40.7 | 43.5 | 25.4 | 38.4 | 35.2 | 36.3 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 27.8 | 21.3 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.4 | 21.5 | 19.3 | 21.3 | 19.5 | 19.0 | 13.1 | 12.3 | 14.3 | 16.1 | 15.9 | 18.9 | 17.6 |
| Twin Falls | ROR | 40.8 | 42.7 | 26.6 | 38.3 | 35.8 | 37.7 | 11.3 | 0.0 | 0.0 | 7.1 | 7.9 | 29.3 | 23.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.9 | 19.1 | 17.6 | 19.1 | 13.7 | 12.2 | 13.9 | 15.5 | 14.2 | 19.2 | 16.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.4 | 17.7 | 17.7 | 16.2 | 12.9 | 11.7 | 13.1 | 14.5 | 13.3 | 17.7 | 15.6 |
| **HCC Total** | | **587.1** | **955.2** | **800.1** | **966.9** | **867.2** | **845.6** | **544.3** | **381.8** | **462.9** | **457.5** | **360.2** | **556.3** | **648.8** |
| **ROR Total** | | **394.6** | **411.2** | **331.0** | **424.5** | **435.5** | **458.5** | **285.2** | **234.1** | **231.0** | **228.3** | **200.5** | **330.5** | **330.2** |
| **Total** | | **981.7** | **1366.4** | **1131.1** | **1391.4** | **1302.7** | **1304.1** | **829.5** | **615.9** | **693.9** | **685.8** | **560.7** | **886.8** | **979.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 261.4 | 425.2 | 338.7 | 407.3 | 383.3 | 378.1 | 239.8 | 161.7 | 196.5 | 195.1 | 153.6 | 245.1 | 282.2 |
| Oxbow | HCC | 108.5 | 177.2 | 152.6 | 184.9 | 157.3 | 154.0 | 101.7 | 73.9 | 88.6 | 88.3 | 69.4 | 103.1 | 121.6 |
| Hells Canyon | HCC | 215.7 | 351.4 | 307.7 | 373.6 | 325.5 | 312.0 | 201.9 | 145.4 | 174.2 | 174.1 | 138.3 | 204.7 | 243.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.6 | 25.8 | 56.2 | 85.4 | 101.8 | 83.2 | 64.5 | 41.9 | 19.1 | 0.0 | 16.0 | 45.6 |
| Bliss | ROR | 49.4 | 50.5 | 44.0 | 49.3 | 47.4 | 47.1 | 35.0 | 33.0 | 36.6 | 39.2 | 36.9 | 44.2 | 42.7 |
| C.J. Strike | ROR | 63.8 | 66.3 | 58.3 | 65.8 | 60.4 | 58.9 | 37.7 | 36.0 | 43.6 | 49.9 | 48.6 | 57.9 | 53.9 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.5 | 35.3 | 28.9 | 34.0 | 33.0 | 33.5 | 22.5 | 20.3 | 22.8 | 25.1 | 23.3 | 30.0 | 28.6 |
| Milner | ROR | 40.6 | 43.3 | 25.2 | 38.2 | 35.1 | 36.3 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 26.7 | 21.2 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.4 | 21.4 | 19.2 | 21.3 | 19.4 | 18.9 | 13.0 | 12.3 | 14.3 | 16.0 | 15.9 | 18.7 | 17.6 |
| Twin Falls | ROR | 40.7 | 42.6 | 26.5 | 38.1 | 35.7 | 37.7 | 11.2 | 0.0 | 0.0 | 7.0 | 7.6 | 28.2 | 22.9 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.8 | 19.1 | 17.6 | 19.1 | 13.6 | 12.2 | 13.8 | 15.4 | 14.1 | 19.2 | 16.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.3 | 17.7 | 17.7 | 16.2 | 12.9 | 11.6 | 13.0 | 14.4 | 13.3 | 17.7 | 15.6 |
| **HCC Total** | | **585.6** | **953.8** | **799.0** | **965.8** | **866.1** | **844.1** | **543.4** | **381.0** | **459.3** | **457.5** | **361.3** | **552.9** | **647.5** |
| **ROR Total** | | **393.8** | **410.0** | **329.9** | **423.5** | **434.7** | **458.0** | **284.6** | **233.7** | **230.5** | **227.5** | **199.7** | **325.9** | **329.1** |
| **Total** | | **979.4** | **1363.8** | **1128.9** | **1389.3** | **1300.8** | **1302.1** | **828.0** | **614.7** | **689.8** | **685.0** | **561.0** | **878.8** | **976.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 261.0 | 424.8 | 338.2 | 407.4 | 383.0 | 377.7 | 239.5 | 161.5 | 195.8 | 195.3 | 153.4 | 244.6 | 281.8 |
| Oxbow | HCC | 108.4 | 177.1 | 152.3 | 184.9 | 157.2 | 153.9 | 101.6 | 73.8 | 88.3 | 88.3 | 69.3 | 102.9 | 121.5 |
| Hells Canyon | HCC | 215.3 | 351.1 | 307.2 | 373.6 | 325.3 | 311.7 | 201.6 | 145.1 | 173.4 | 174.1 | 138.0 | 204.2 | 243.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.4 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.7 | 45.6 |
| Bliss | ROR | 49.3 | 50.4 | 43.9 | 49.2 | 47.3 | 47.0 | 34.9 | 32.9 | 36.5 | 39.1 | 36.8 | 43.9 | 42.6 |
| C.J. Strike | ROR | 63.6 | 66.2 | 58.1 | 65.6 | 60.2 | 58.7 | 37.6 | 35.9 | 43.5 | 49.7 | 48.5 | 57.4 | 53.8 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 35.1 | 28.8 | 33.9 | 32.9 | 33.5 | 22.4 | 20.3 | 22.7 | 25.1 | 23.3 | 29.7 | 28.5 |
| Milner | ROR | 40.5 | 42.9 | 25.1 | 38.0 | 35.1 | 36.3 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 26.0 | 21.0 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.4 | 19.1 | 21.2 | 19.4 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.6 | 17.5 |
| Twin Falls | ROR | 40.6 | 42.2 | 26.4 | 38.0 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.6 | 22.8 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.6 | 12.1 | 13.8 | 15.4 | 14.1 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.6 | 13.0 | 14.4 | 13.2 | 17.6 | 15.6 |
| **HCC Total** | | **584.7** | **953.0** | **797.7** | **965.9** | **865.5** | **843.3** | **542.7** | **380.4** | **457.4** | **457.7** | **360.7** | **551.7** | **646.7** |
| **ROR Total** | | **393.1** | **408.6** | **329.0** | **422.8** | **434.4** | **457.6** | **284.3** | **233.3** | **230.1** | **227.2** | **199.0** | **323.0** | **328.3** |
| **Total** | | **977.8** | **1361.6** | **1126.7** | **1388.7** | **1299.9** | **1300.9** | **827.0** | **613.7** | **687.5** | **684.9** | **559.7** | **874.7** | **975.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 260.7 | 424.5 | 337.4 | 407.5 | 383.5 | 377.4 | 239.3 | 161.3 | 195.3 | 195.2 | 153.5 | 244.0 | 281.6 |
| Oxbow | HCC | 108.2 | 176.9 | 151.9 | 184.8 | 157.4 | 153.8 | 101.5 | 73.7 | 88.0 | 88.2 | 69.3 | 102.7 | 121.4 |
| Hells Canyon | HCC | 215.1 | 350.8 | 306.3 | 373.4 | 325.6 | 311.4 | 201.5 | 145.0 | 173.0 | 173.9 | 138.1 | 203.7 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.2 | 25.8 | 56.3 | 85.5 | 101.9 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.4 | 45.5 |
| Bliss | ROR | 49.2 | 50.3 | 43.9 | 49.1 | 47.2 | 47.0 | 34.9 | 32.9 | 36.5 | 39.1 | 36.8 | 43.6 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.1 | 57.9 | 65.5 | 60.0 | 58.6 | 37.5 | 35.9 | 43.4 | 49.7 | 48.4 | 57.1 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.9 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.5 | 28.4 |
| Milner | ROR | 40.4 | 42.7 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.4 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.1 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.9 | 26.3 | 37.9 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.2 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.6 | 12.1 | 13.7 | 15.4 | 14.0 | 19.0 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 13.0 | 14.3 | 13.2 | 17.5 | 15.5 |
| **HCC Total** | | **584.0** | **952.2** | **795.6** | **965.7** | **866.4** | **842.6** | **542.3** | **380.0** | **456.3** | **457.3** | **360.9** | **550.4** | **646.1** |
| **ROR Total** | | **392.7** | **407.4** | **328.5** | **422.3** | **434.0** | **457.4** | **284.2** | **233.1** | **230.0** | **227.0** | **198.7** | **320.5** | **327.8** |
| **Total** | | **976.7** | **1359.6** | **1124.1** | **1388.0** | **1300.4** | **1300.0** | **826.5** | **613.1** | **686.2** | **684.3** | **559.6** | **870.9** | **973.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 50th Percentile Water, 50th Percentile Load

| Resource | Type | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 260.6 | 424.3 | 337.2 | 407.4 | 383.4 | 377.3 | 239.3 | 161.2 | 195.0 | 195.4 | 153.5 | 243.8 | 281.5 |
| Oxbow | HCC | 108.2 | 176.9 | 151.8 | 184.8 | 157.4 | 153.7 | 101.5 | 73.7 | 87.9 | 88.3 | 69.3 | 102.6 | 121.3 |
| Hells Canyon | HCC | 215.0 | 350.7 | 306.2 | 373.3 | 325.5 | 311.3 | 201.4 | 144.9 | 172.7 | 174.1 | 138.1 | 203.5 | 243.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 25.4 | 27.1 | 25.8 | 56.3 | 85.5 | 101.8 | 83.3 | 64.5 | 41.9 | 19.2 | 0.0 | 15.3 | 45.5 |
| Bliss | ROR | 49.2 | 50.2 | 43.8 | 49.1 | 47.1 | 46.9 | 34.9 | 32.9 | 36.5 | 39.0 | 36.8 | 43.5 | 42.5 |
| C.J. Strike | ROR | 63.5 | 66.0 | 57.8 | 65.5 | 59.9 | 58.6 | 37.5 | 35.9 | 43.4 | 49.6 | 48.4 | 57.0 | 53.6 |
| Cascade | ROR | 1.5 | 2.6 | 4.6 | 7.5 | 7.3 | 11.9 | 6.9 | 10.1 | 9.1 | 2.7 | 2.2 | 1.5 | 5.7 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 34.4 | 34.9 | 28.7 | 33.8 | 32.8 | 33.4 | 22.4 | 20.2 | 22.7 | 25.0 | 23.2 | 29.4 | 28.4 |
| Milner | ROR | 40.3 | 42.6 | 25.0 | 37.9 | 35.1 | 36.2 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 25.2 | 20.9 |
| Shoshone Falls | ROR | 55.0 | 58.0 | 35.0 | 51.0 | 48.0 | 50.0 | 16.0 | 7.1 | 7.2 | 11.1 | 12.0 | 40.0 | 32.4 |
| Swan Falls | ROR | 20.3 | 21.3 | 19.0 | 21.2 | 19.3 | 18.9 | 13.0 | 12.2 | 14.2 | 15.9 | 15.8 | 18.5 | 17.5 |
| Twin Falls | ROR | 40.5 | 41.8 | 26.2 | 37.8 | 35.7 | 37.6 | 11.2 | 0.0 | 0.0 | 7.0 | 7.3 | 27.0 | 22.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.7 | 19.1 | 17.6 | 19.1 | 13.5 | 12.1 | 13.7 | 15.4 | 14.0 | 18.9 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.2 | 17.7 | 17.7 | 16.2 | 12.8 | 11.5 | 12.9 | 14.3 | 13.2 | 17.4 | 15.5 |
| **HCC Total** | | **583.8** | **951.9** | **795.2** | **965.5** | **866.2** | **842.3** | **542.2** | **379.8** | **455.5** | **457.8** | **360.9** | **549.9** | **645.9** |
| **ROR Total** | | **392.6** | **406.9** | **328.1** | **422.2** | **433.6** | **457.2** | **284.1** | **233.1** | **229.9** | **226.8** | **198.7** | **319.5** | **327.5** |
| **Total** | | **976.4** | **1358.8** | **1123.3** | **1387.7** | **1299.8** | **1299.5** | **826.3** | **612.9** | **685.3** | **684.6** | **559.6** | **869.4** | **973.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2011** | **2/2011** | **3/2011** | **4/2011** | **5/2011** | **6/2011** | **7/2011** | **8/2011** | **9/2011** | **10/2011** | **11/2011** | **12/2011** | **aMW** |
| Brownlee | HCC* | 253.3 | 311.8 | 252.9 | 295.1 | 370.0 | 322.8 | 221.1 | 166.7 | 177.0 | 187.7 | 156.4 | 210.3 | 243.8 |
| Oxbow | HCC | 106.5 | 130.5 | 111.0 | 123.0 | 149.1 | 129.5 | 93.5 | 76.2 | 78.7 | 83.1 | 69.6 | 88.0 | 103.2 |
| Hells Canyon | HCC | 210.8 | 257.4 | 226.4 | 249.8 | 303.7 | 261.2 | 184.7 | 149.4 | 154.5 | 163.9 | 138.1 | 174.4 | 206.2 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.4 | 15.1 | 36.5 | 72.9 | 87.6 | 77.8 | 62.0 | 33.8 | 13.9 | 0.0 | 0.0 | 34.1 |
| Bliss | ROR | 38.6 | 40.7 | 39.7 | 37.3 | 42.0 | 41.3 | 35.7 | 37.4 | 37.0 | 39.3 | 37.2 | 38.0 | 38.7 |
| C.J. Strike | ROR | 50.0 | 52.6 | 53.5 | 50.1 | 53.7 | 49.1 | 38.2 | 41.2 | 44.2 | 50.3 | 48.4 | 49.9 | 48.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 24.2 | 26.6 | 24.8 | 22.6 | 28.4 | 28.7 | 23.2 | 24.0 | 23.5 | 25.6 | 23.9 | 24.1 | 25.0 |
| Milner | ROR | 8.6 | 16.5 | 11.5 | 3.7 | 17.9 | 18.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 6.1 | 8.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 11.3 | 12.0 | 11.5 |
| Swan Falls | ROR | 16.1 | 17.3 | 17.6 | 16.9 | 17.5 | 16.3 | 13.2 | 13.8 | 14.4 | 16.0 | 15.8 | 16.2 | 15.9 |
| Twin Falls | ROR | 11.9 | 19.2 | 14.5 | 8.1 | 21.0 | 22.7 | 11.5 | 11.7 | 3.8 | 7.3 | 7.4 | 9.8 | 12.4 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.9 | 16.9 | 13.8 | 14.0 | 18.4 | 18.5 | 14.2 | 15.0 | 14.3 | 15.8 | 14.5 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 13.9 | 15.6 | 14.5 | 13.2 | 17.0 | 17.0 | 13.3 | 14.1 | 13.5 | 14.7 | 13.6 | 13.8 | 14.5 |
| **HCC Total** | | **570.6** | **699.7** | **590.3** | **667.9** | **822.8** | **713.5** | **499.3** | **392.3** | **410.2** | **434.7** | **364.1** | **472.7** | **553.2** |
| **ROR Total** | | **217.4** | **253.9** | **245.9** | **241.4** | **333.2** | **346.2** | **278.6** | **274.6** | **229.0** | **223.9** | **199.3** | **211.9** | **254.6** |
| **Total** | | **788.0** | **953.6** | **836.2** | **909.3** | **1156.0** | **1059.7** | **777.9** | **666.9** | **639.2** | **658.6** | **563.4** | **684.6** | **807.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2012** | **2/2012** | **3/2012** | **4/2012** | **5/2012** | **6/2012** | **7/2012** | **8/2012** | **9/2012** | **10/2012** | **11/2012** | **12/2012** | **aMW** |
| Brownlee | HCC* | 253.4 | 310.8 | 252.7 | 294.4 | 370.3 | 322.6 | 221.0 | 166.5 | 177.1 | 186.9 | 156.6 | 209.5 | 243.5 |
| Oxbow | HCC | 106.6 | 130.1 | 110.9 | 122.7 | 149.2 | 129.4 | 93.5 | 76.1 | 78.7 | 82.8 | 69.6 | 87.7 | 103.1 |
| Hells Canyon | HCC | 211.0 | 256.6 | 226.2 | 249.2 | 303.9 | 261.1 | 184.6 | 149.2 | 154.6 | 163.2 | 138.2 | 173.8 | 206.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.4 | 14.8 | 36.5 | 72.9 | 87.7 | 77.8 | 62.0 | 33.7 | 13.9 | 0.0 | 0.0 | 34.1 |
| Bliss | ROR | 38.5 | 40.6 | 39.6 | 37.2 | 41.9 | 41.3 | 35.6 | 37.3 | 37.0 | 39.2 | 37.1 | 37.9 | 38.6 |
| C.J. Strike | ROR | 49.9 | 52.5 | 53.5 | 50.0 | 53.6 | 49.0 | 38.1 | 41.2 | 44.1 | 50.2 | 48.4 | 49.8 | 48.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 24.2 | 26.5 | 24.6 | 22.6 | 28.4 | 28.7 | 23.1 | 24.0 | 23.5 | 25.5 | 23.9 | 24.1 | 24.9 |
| Milner | ROR | 8.6 | 16.2 | 11.2 | 3.7 | 17.9 | 18.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 6.0 | 8.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 11.3 | 12.0 | 11.5 |
| Swan Falls | ROR | 16.0 | 17.3 | 17.6 | 16.9 | 17.4 | 16.3 | 13.1 | 13.8 | 14.4 | 15.9 | 15.8 | 16.2 | 15.9 |
| Twin Falls | ROR | 11.8 | 19.1 | 14.1 | 8.0 | 21.0 | 22.7 | 11.5 | 11.7 | 3.8 | 7.3 | 7.4 | 9.8 | 12.4 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.9 | 16.8 | 15.4 | 13.9 | 17.7 | 18.5 | 14.1 | 15.0 | 14.3 | 15.8 | 14.5 | 14.7 | 15.5 |
| Upper Salmon 3&4 | ROR | 13.9 | 15.6 | 14.4 | 13.1 | 17.0 | 16.2 | 13.3 | 14.0 | 13.5 | 14.7 | 13.6 | 13.8 | 14.4 |
| **HCC Total** | | **571.0** | **697.5** | **589.8** | **666.3** | **823.3** | **713.1** | **499.1** | **391.8** | **410.4** | **432.9** | **364.4** | **471.0** | **552.5** |
| **ROR Total** | | **217.0** | **253.1** | **246.1** | **240.9** | **332.2** | **345.4** | **278.1** | **274.4** | **228.9** | **223.5** | **199.2** | **211.5** | **254.2** |
| **Total** | | **788.0** | **950.6** | **835.9** | **907.2** | **1155.5** | **1058.5** | **777.2** | **666.2** | **639.2** | **656.4** | **563.6** | **682.5** | **806.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 253.6 | 309.6 | 252.5 | 294.2 | 370.1 | 322.4 | 220.9 | 166.4 | 177.1 | 186.2 | 156.4 | 209.4 | 243.2 |
| Oxbow | HCC | 106.7 | 129.7 | 110.8 | 122.6 | 149.2 | 129.3 | 93.4 | 76.0 | 78.8 | 82.5 | 69.5 | 87.6 | 103.0 |
| Hells Canyon | HCC | 211.2 | 255.8 | 226.0 | 249.0 | 303.7 | 260.9 | 184.4 | 149.1 | 154.7 | 162.6 | 138.0 | 173.7 | 205.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.4 | 14.5 | 36.6 | 73.0 | 87.7 | 77.8 | 62.1 | 33.8 | 13.9 | 0.0 | 0.0 | 34.1 |
| Bliss | ROR | 38.4 | 40.4 | 39.6 | 37.0 | 41.9 | 41.3 | 35.6 | 37.3 | 37.0 | 39.2 | 37.1 | 37.8 | 38.6 |
| C.J. Strike | ROR | 49.8 | 52.4 | 53.4 | 49.9 | 53.5 | 48.9 | 38.1 | 41.1 | 44.1 | 50.2 | 48.3 | 49.7 | 48.3 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 24.1 | 26.5 | 24.4 | 22.5 | 28.3 | 28.7 | 23.1 | 23.9 | 23.4 | 25.5 | 23.8 | 24.0 | 24.9 |
| Milner | ROR | 8.5 | 16.0 | 10.9 | 3.6 | 17.9 | 18.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 6.0 | 8.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 11.9 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.2 | 11.3 | 12.0 | 11.5 |
| Swan Falls | ROR | 16.0 | 17.3 | 17.5 | 16.8 | 17.4 | 16.3 | 13.1 | 13.8 | 14.4 | 15.9 | 15.8 | 16.1 | 15.9 |
| Twin Falls | ROR | 11.8 | 18.9 | 14.0 | 7.9 | 21.0 | 22.7 | 11.5 | 11.7 | 3.8 | 7.2 | 7.4 | 9.8 | 12.3 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.8 | 16.8 | 15.3 | 13.8 | 17.7 | 18.4 | 14.1 | 15.0 | 14.3 | 15.7 | 14.5 | 14.7 | 15.4 |
| Upper Salmon 3&4 | ROR | 13.9 | 15.6 | 14.3 | 13.0 | 16.9 | 16.2 | 13.3 | 14.0 | 13.4 | 14.7 | 13.6 | 13.8 | 14.4 |
| **HCC Total** | | **571.5** | **695.1** | **589.3** | **665.8** | **822.9** | **712.6** | **498.7** | **391.5** | **410.6** | **431.3** | **363.9** | **470.7** | **552.0** |
| **ROR Total** | | **216.5** | **252.4** | **244.8** | **240.0** | **332.0** | **345.2** | **278.1** | **274.3** | **228.7** | **223.3** | **199.0** | **211.1** | **253.8** |
| **Total** | | **788.0** | **947.5** | **834.1** | **905.8** | **1154.9** | **1057.8** | **776.8** | **665.8** | **639.3** | **654.6** | **562.9** | **681.8** | **805.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 254.3 | 303.2 | 251.6 | 292.9 | 370.1 | 321.3 | 220.1 | 165.8 | 172.7 | 184.8 | 156.8 | 207.8 | 241.8 |
| Oxbow | HCC | 107.2 | 127.2 | 110.3 | 122.0 | 149.1 | 128.9 | 93.1 | 75.7 | 78.4 | 81.8 | 69.6 | 86.9 | 102.5 |
| Hells Canyon | HCC | 212.1 | 251.1 | 225.2 | 247.8 | 303.8 | 260.1 | 183.8 | 148.6 | 153.8 | 161.2 | 138.2 | 172.4 | 204.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.0 | 14.4 | 35.6 | 73.1 | 87.8 | 77.9 | 62.1 | 33.8 | 14.0 | 0.0 | 0.0 | 34.0 |
| Bliss | ROR | 38.0 | 39.6 | 39.3 | 36.2 | 41.7 | 41.1 | 35.4 | 37.1 | 36.8 | 39.0 | 36.9 | 37.5 | 38.2 |
| C.J. Strike | ROR | 49.4 | 51.6 | 53.0 | 49.1 | 53.1 | 48.6 | 37.8 | 40.8 | 43.8 | 49.9 | 48.1 | 49.3 | 47.9 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 23.8 | 25.9 | 23.9 | 22.0 | 28.2 | 28.5 | 22.9 | 23.8 | 23.2 | 25.3 | 23.6 | 23.8 | 24.6 |
| Milner | ROR | 8.2 | 15.0 | 10.5 | 0.0 | 17.9 | 18.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 5.7 | 7.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 8.9 | 12.0 | 12.0 | 12.0 | 12.0 | 7.3 | 11.1 | 11.3 | 12.0 | 11.2 |
| Swan Falls | ROR | 15.9 | 17.1 | 17.4 | 16.7 | 17.3 | 16.2 | 13.0 | 13.7 | 14.3 | 15.9 | 15.7 | 16.0 | 15.8 |
| Twin Falls | ROR | 11.5 | 17.9 | 13.6 | 5.3 | 20.9 | 22.7 | 11.4 | 11.7 | 3.7 | 7.2 | 7.4 | 9.6 | 11.9 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.6 | 16.4 | 14.9 | 13.5 | 17.7 | 18.3 | 14.0 | 14.8 | 14.2 | 15.6 | 14.3 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 13.7 | 15.2 | 14.0 | 12.7 | 16.8 | 16.2 | 13.2 | 13.9 | 13.3 | 14.6 | 13.4 | 13.6 | 14.2 |
| **HCC Total** | | **573.6** | **681.5** | **587.1** | **662.7** | **823.0** | **710.3** | **497.0** | **390.1** | **404.9** | **427.8** | **364.6** | **467.1** | **549.1** |
| **ROR Total** | | **214.3** | **246.8** | **241.9** | **227.0** | **331.1** | **344.4** | **277.1** | **273.3** | **227.7** | **222.4** | **197.9** | **209.2** | **251.1** |
| **Total** | | **787.9** | **928.3** | **829.0** | **889.7** | **1154.1** | **1054.7** | **774.1** | **663.4** | **632.5** | **650.2** | **562.5** | **676.3** | **800.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 255.1 | 298.3 | 251.2 | 291.2 | 369.7 | 320.1 | 219.4 | 165.0 | 173.1 | 181.8 | 156.7 | 206.3 | 240.7 |
| Oxbow | HCC | 107.6 | 125.3 | 110.1 | 121.3 | 149.0 | 128.4 | 92.8 | 75.4 | 78.6 | 80.4 | 69.6 | 86.3 | 102.1 |
| Hells Canyon | HCC | 213.0 | 247.4 | 224.7 | 246.4 | 303.4 | 259.2 | 183.2 | 147.9 | 154.2 | 158.7 | 138.1 | 171.1 | 203.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 7.7 | 14.0 | 35.6 | 73.2 | 87.9 | 78.0 | 62.2 | 33.9 | 14.1 | 0.0 | 0.0 | 33.9 |
| Bliss | ROR | 37.7 | 38.9 | 39.0 | 36.0 | 41.5 | 40.9 | 35.2 | 36.8 | 36.6 | 38.8 | 36.7 | 37.2 | 37.9 |
| C.J. Strike | ROR | 49.0 | 50.6 | 52.5 | 47.9 | 52.7 | 48.3 | 37.6 | 40.6 | 43.5 | 49.7 | 47.7 | 48.9 | 47.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 23.6 | 25.0 | 23.5 | 21.8 | 28.0 | 28.4 | 22.8 | 23.6 | 23.1 | 25.2 | 23.4 | 23.6 | 24.3 |
| Milner | ROR | 8.0 | 12.4 | 9.6 | 0.0 | 17.9 | 18.5 | 6.7 | 6.7 | 0.0 | 0.0 | 1.8 | 5.3 | 7.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 8.4 | 12.0 | 12.0 | 12.0 | 12.0 | 7.2 | 11.1 | 11.2 | 12.0 | 11.2 |
| Swan Falls | ROR | 15.8 | 16.8 | 17.3 | 16.4 | 17.2 | 16.1 | 13.0 | 13.7 | 14.2 | 15.8 | 15.6 | 15.9 | 15.7 |
| Twin Falls | ROR | 11.1 | 15.7 | 12.6 | 4.7 | 20.9 | 22.6 | 11.4 | 11.6 | 3.7 | 7.2 | 7.3 | 9.3 | 11.5 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.4 | 15.7 | 14.6 | 13.3 | 17.7 | 18.2 | 13.9 | 14.7 | 14.0 | 15.5 | 14.1 | 14.3 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.5 | 14.6 | 13.7 | 12.6 | 16.7 | 16.2 | 13.1 | 13.8 | 13.2 | 14.5 | 13.3 | 13.5 | 14.1 |
| **HCC Total** | | **575.7** | **671.0** | **586.0** | **658.9** | **822.1** | **707.7** | **495.4** | **388.3** | **405.8** | **420.9** | **364.4** | **463.7** | **546.7** |
| **ROR Total** | | **212.3** | **236.5** | **237.7** | **223.7** | **330.2** | **343.6** | **276.5** | **272.4** | **226.6** | **221.7** | **196.5** | **207.2** | **248.7** |
| **Total** | | **788.0** | **907.5** | **823.7** | **882.6** | **1152.3** | **1051.3** | **771.9** | **660.7** | **632.4** | **642.6** | **560.9** | **670.9** | **795.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 255.9 | 296.7 | 250.6 | 290.0 | 369.1 | 319.0 | 218.7 | 152.2 | 176.7 | 181.4 | 156.7 | 208.1 | 239.6 |
| Oxbow | HCC | 108.0 | 124.7 | 109.8 | 120.7 | 148.7 | 128.0 | 92.5 | 69.3 | 78.6 | 80.3 | 69.6 | 87.1 | 101.4 |
| Hells Canyon | HCC | 213.7 | 246.1 | 224.2 | 245.4 | 302.9 | 258.3 | 182.6 | 136.4 | 154.4 | 158.4 | 138.2 | 172.6 | 202.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 10.6 | 15.0 | 36.6 | 73.4 | 88.1 | 78.1 | 58.7 | 34.6 | 14.5 | 0.0 | 0.0 | 34.1 |
| Bliss | ROR | 37.4 | 40.2 | 38.7 | 36.1 | 41.4 | 40.7 | 35.0 | 33.3 | 36.5 | 38.7 | 36.6 | 36.9 | 37.6 |
| C.J. Strike | ROR | 48.6 | 52.3 | 52.2 | 49.0 | 52.4 | 48.0 | 37.3 | 35.9 | 43.3 | 49.4 | 47.8 | 48.5 | 47.1 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 23.3 | 26.5 | 23.8 | 21.8 | 27.9 | 28.2 | 22.6 | 20.4 | 22.9 | 25.0 | 23.4 | 23.3 | 24.1 |
| Milner | ROR | 7.7 | 17.4 | 10.6 | 2.6 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 7.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 10.9 | 12.0 | 12.0 | 12.0 | 7.1 | 7.2 | 11.1 | 11.2 | 23.9 | 12.0 |
| Swan Falls | ROR | 15.7 | 17.1 | 17.2 | 16.4 | 17.1 | 16.1 | 12.9 | 12.2 | 14.2 | 15.7 | 15.6 | 15.8 | 15.5 |
| Twin Falls | ROR | 10.8 | 20.2 | 13.4 | 7.0 | 20.9 | 22.6 | 11.3 | 3.6 | 3.7 | 7.1 | 7.3 | 9.1 | 11.4 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.2 | 16.8 | 14.9 | 13.3 | 17.7 | 18.1 | 13.7 | 12.3 | 13.9 | 15.4 | 14.1 | 14.2 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.4 | 15.6 | 13.9 | 12.6 | 16.6 | 16.2 | 13.0 | 11.7 | 13.1 | 14.3 | 13.3 | 13.3 | 13.9 |
| **HCC Total** | | **577.6** | **667.5** | **584.6** | **656.1** | **820.7** | **705.3** | **493.8** | **357.9** | **409.7** | **420.1** | **364.5** | **467.8** | **543.8** |
| **ROR Total** | | **210.3** | **255.8** | **240.6** | **233.3** | **329.7** | **343.0** | **275.4** | **231.9** | **226.7** | **221.0** | **196.5** | **217.2** | **248.5** |
| **Total** | | **787.9** | **923.3** | **825.2** | **889.4** | **1150.4** | **1048.3** | **769.2** | **589.8** | **636.3** | **641.1** | **561.0** | **685.0** | **792.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 256.7 | 293.3 | 249.8 | 287.9 | 367.6 | 317.7 | 218.0 | 151.5 | 172.4 | 179.2 | 156.7 | 206.9 | 238.1 |
| Oxbow | HCC | 108.4 | 123.4 | 109.5 | 119.8 | 148.1 | 127.4 | 92.2 | 69.0 | 78.3 | 79.3 | 69.5 | 86.5 | 101.0 |
| Hells Canyon | HCC | 214.5 | 243.6 | 223.5 | 243.6 | 301.7 | 257.3 | 182.0 | 135.8 | 153.6 | 156.4 | 138.0 | 171.6 | 201.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.5 | 14.6 | 35.7 | 73.6 | 88.2 | 78.2 | 58.8 | 34.7 | 14.5 | 0.0 | 0.0 | 34.0 |
| Bliss | ROR | 37.1 | 39.6 | 38.4 | 35.7 | 41.2 | 40.5 | 34.8 | 33.1 | 36.3 | 38.5 | 36.4 | 36.7 | 37.4 |
| C.J. Strike | ROR | 48.3 | 51.2 | 51.8 | 48.0 | 52.1 | 47.7 | 37.1 | 35.6 | 43.1 | 49.2 | 47.3 | 48.2 | 46.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 23.0 | 25.6 | 23.4 | 21.3 | 27.7 | 27.9 | 22.4 | 20.3 | 22.8 | 24.9 | 23.2 | 23.1 | 23.8 |
| Milner | ROR | 7.4 | 15.2 | 10.1 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.9 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.6 | 16.9 | 17.1 | 16.3 | 17.0 | 16.0 | 12.8 | 12.1 | 14.1 | 15.6 | 15.5 | 15.7 | 15.4 |
| Twin Falls | ROR | 10.5 | 18.3 | 13.0 | 4.1 | 20.9 | 22.5 | 11.3 | 0.0 | 3.7 | 7.1 | 7.2 | 9.1 | 10.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 14.0 | 16.1 | 14.5 | 13.0 | 17.7 | 17.8 | 13.6 | 12.1 | 13.8 | 15.2 | 14.0 | 14.0 | 14.7 |
| Upper Salmon 3&4 | ROR | 13.2 | 15.0 | 13.6 | 12.3 | 16.5 | 16.2 | 12.8 | 11.6 | 13.0 | 14.2 | 13.2 | 13.2 | 13.7 |
| **HCC Total** | | **579.6** | **660.3** | **582.8** | **651.3** | **817.4** | **702.4** | **492.2** | **356.3** | **404.3** | **414.9** | **364.2** | **465.0** | **540.9** |
| **ROR Total** | | **215.1** | **281.9** | **253.0** | **221.1** | **344.0** | **360.4** | **276.5** | **228.4** | **226.0** | **220.0** | **195.2** | **216.1** | **253.0** |
| **Total** | | **794.7** | **942.2** | **835.8** | **872.4** | **1161.4** | **1062.8** | **768.7** | **584.7** | **630.2** | **634.9** | **559.4** | **681.1** | **793.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 257.4 | 288.0 | 248.7 | 287.0 | 365.6 | 316.3 | 217.2 | 150.8 | 177.0 | 168.4 | 156.7 | 205.0 | 236.5 |
| Oxbow | HCC | 108.9 | 121.4 | 108.9 | 119.4 | 147.3 | 126.9 | 91.8 | 68.7 | 78.8 | 77.6 | 69.4 | 85.7 | 100.4 |
| Hells Canyon | HCC | 215.4 | 239.6 | 222.4 | 242.8 | 300.2 | 256.3 | 181.4 | 135.2 | 154.9 | 152.9 | 137.9 | 170.0 | 200.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.2 | 14.5 | 36.2 | 73.7 | 88.4 | 78.3 | 58.8 | 34.7 | 14.6 | 0.0 | 0.0 | 34.0 |
| Bliss | ROR | 36.9 | 38.9 | 38.1 | 35.5 | 41.0 | 40.3 | 34.6 | 32.9 | 36.1 | 38.3 | 36.2 | 36.5 | 37.1 |
| C.J. Strike | ROR | 47.9 | 50.3 | 51.4 | 47.2 | 51.7 | 47.5 | 36.8 | 35.3 | 42.8 | 48.9 | 47.1 | 48.0 | 46.2 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.8 | 25.1 | 23.2 | 21.1 | 27.5 | 27.7 | 22.3 | 20.1 | 22.6 | 24.7 | 23.0 | 22.9 | 23.6 |
| Milner | ROR | 7.1 | 14.3 | 9.7 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.8 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.4 | 16.7 | 17.0 | 16.1 | 17.0 | 15.9 | 12.8 | 12.0 | 14.1 | 15.6 | 15.4 | 15.6 | 15.3 |
| Twin Falls | ROR | 10.2 | 17.1 | 12.6 | 3.8 | 20.8 | 22.5 | 11.3 | 0.0 | 0.0 | 7.1 | 7.2 | 9.1 | 10.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.8 | 15.7 | 14.4 | 12.8 | 17.7 | 17.7 | 13.5 | 12.0 | 13.7 | 15.1 | 13.8 | 13.8 | 14.5 |
| Upper Salmon 3&4 | ROR | 13.0 | 14.7 | 13.5 | 12.1 | 16.4 | 16.2 | 12.7 | 11.5 | 12.9 | 14.1 | 13.0 | 13.0 | 13.6 |
| **HCC Total** | | **581.7** | **649.0** | **580.0** | **649.2** | **813.0** | **699.5** | **490.4** | **354.7** | **410.6** | **398.9** | **364.0** | **460.7** | **537.6** |
| **ROR Total** | | **213.1** | **276.5** | **250.9** | **219.5** | **343.1** | **359.8** | **275.8** | **227.4** | **221.4** | **219.2** | **194.1** | **215.0** | **251.2** |
| **Total** | | **794.8** | **925.5** | **830.9** | **868.7** | **1156.1** | **1059.3** | **766.2** | **582.1** | **632.0** | **618.1** | **558.1** | **675.7** | **788.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 70th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 257.8 | 283.1 | 248.4 | 285.6 | 364.2 | 315.2 | 216.7 | 150.4 | 177.2 | 166.4 | 156.8 | 204.3 | 235.5 |
| Oxbow | HCC | 109.1 | 119.4 | 108.8 | 118.8 | 146.7 | 126.5 | 91.6 | 68.5 | 79.0 | 76.7 | 69.5 | 85.4 | 100.0 |
| Hells Canyon | HCC | 216.0 | 235.9 | 222.2 | 241.7 | 299.0 | 255.4 | 181.0 | 134.8 | 155.2 | 151.1 | 138.0 | 169.4 | 200.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 7.5 | 14.2 | 36.8 | 73.8 | 88.4 | 78.3 | 58.8 | 34.7 | 14.7 | 0.0 | 0.0 | 33.9 |
| Bliss | ROR | 36.7 | 38.1 | 37.9 | 35.3 | 40.9 | 40.0 | 34.5 | 32.7 | 35.9 | 38.1 | 36.0 | 36.4 | 36.9 |
| C.J. Strike | ROR | 47.6 | 49.7 | 51.0 | 47.0 | 51.4 | 47.3 | 36.6 | 35.1 | 42.6 | 48.8 | 46.9 | 47.8 | 46.0 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.7 | 24.0 | 22.9 | 20.9 | 27.4 | 27.5 | 22.2 | 20.0 | 22.5 | 24.6 | 22.8 | 22.7 | 23.4 |
| Milner | ROR | 6.9 | 11.4 | 9.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.5 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.4 | 16.3 | 16.9 | 16.0 | 16.9 | 15.8 | 12.7 | 12.0 | 14.1 | 15.5 | 15.3 | 15.6 | 15.2 |
| Twin Falls | ROR | 10.1 | 14.2 | 12.1 | 3.7 | 20.8 | 22.5 | 11.2 | 0.0 | 0.0 | 7.0 | 7.2 | 9.0 | 9.8 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.7 | 14.9 | 14.2 | 12.6 | 17.7 | 17.5 | 13.4 | 11.9 | 13.6 | 15.0 | 13.7 | 13.7 | 14.3 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.9 | 13.3 | 12.0 | 16.3 | 16.2 | 12.7 | 11.4 | 12.8 | 14.0 | 12.9 | 12.9 | 13.4 |
| **HCC Total** | | **582.9** | **638.4** | **579.4** | **646.1** | **809.9** | **697.1** | **489.3** | **353.7** | **411.3** | **394.2** | **364.3** | **459.1** | **535.5** |
| **ROR Total** | | **212.0** | **264.5** | **248.3** | **219.0** | **342.5** | **358.8** | **275.1** | **226.7** | **220.7** | **218.5** | **193.2** | **214.2** | **249.3** |
| **Total** | | **794.9** | **902.9** | **827.7** | **865.1** | **1152.4** | **1055.9** | **764.4** | **580.4** | **631.9** | **612.7** | **557.5** | **673.3** | **784.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 70th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.2 | 279.4 | 248.1 | 285.0 | 363.3 | 314.4 | 216.3 | 150.0 | 177.1 | 165.0 | 157.1 | 203.4 | 234.8 |
| Oxbow | HCC | 109.4 | 117.9 | 108.6 | 118.5 | 146.4 | 126.2 | 91.5 | 68.3 | 79.0 | 76.0 | 69.6 | 85.1 | 99.7 |
| Hells Canyon | HCC | 216.4 | 232.9 | 221.8 | 241.1 | 298.4 | 254.9 | 180.7 | 134.5 | 155.2 | 149.9 | 138.2 | 168.8 | 199.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.9 | 14.0 | 36.9 | 73.8 | 88.4 | 78.3 | 58.8 | 34.8 | 14.7 | 0.0 | 0.0 | 33.8 |
| Bliss | ROR | 36.6 | 37.6 | 37.6 | 35.2 | 40.8 | 39.9 | 34.4 | 32.6 | 35.8 | 38.0 | 35.9 | 36.3 | 36.7 |
| C.J. Strike | ROR | 47.3 | 49.1 | 50.6 | 46.9 | 51.3 | 47.2 | 36.5 | 34.9 | 42.5 | 48.6 | 46.8 | 47.7 | 45.8 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.6 | 23.4 | 22.7 | 20.8 | 27.3 | 27.4 | 22.1 | 19.9 | 22.4 | 24.5 | 22.7 | 22.6 | 23.2 |
| Milner | ROR | 6.7 | 9.6 | 8.8 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.3 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.3 | 16.2 | 16.8 | 16.0 | 16.8 | 15.7 | 12.7 | 11.9 | 14.0 | 15.5 | 15.3 | 15.5 | 15.1 |
| Twin Falls | ROR | 9.9 | 12.6 | 11.6 | 0.0 | 20.8 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.3 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.6 | 14.4 | 14.0 | 12.5 | 17.6 | 17.4 | 13.3 | 11.8 | 13.5 | 14.9 | 13.6 | 13.6 | 14.2 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.5 | 13.2 | 11.9 | 16.3 | 16.1 | 12.6 | 11.3 | 12.7 | 14.0 | 12.8 | 12.8 | 13.3 |
| **HCC Total** | | **584.0** | **630.2** | **578.5** | **644.6** | **808.1** | **695.5** | **488.5** | **352.8** | **411.2** | **390.9** | **364.9** | **457.3** | **533.9** |
| **ROR Total** | | **210.9** | **256.8** | **245.8** | **214.9** | **342.0** | **358.1** | **274.6** | **226.0** | **220.2** | **218.0** | **192.6** | **213.6** | **247.6** |
| **Total** | | **794.9** | **887.0** | **824.3** | **859.5** | **1150.1** | **1053.6** | **763.1** | **578.8** | **631.4** | **608.9** | **557.5** | **670.9** | **781.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 258.4 | 270.2 | 247.7 | 276.1 | 363.0 | 314.0 | 216.0 | 149.7 | 176.9 | 164.5 | 156.9 | 203.1 | 233.0 |
| Oxbow | HCC | 109.5 | 117.5 | 108.4 | 118.2 | 146.3 | 126.0 | 91.3 | 68.2 | 78.9 | 75.8 | 69.5 | 84.9 | 99.5 |
| Hells Canyon | HCC | 216.6 | 233.9 | 221.5 | 242.3 | 298.1 | 254.5 | 180.4 | 134.3 | 154.9 | 149.3 | 137.9 | 168.5 | 199.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.7 | 13.9 | 36.9 | 73.8 | 88.5 | 78.3 | 58.7 | 34.7 | 14.7 | 0.0 | 0.0 | 33.8 |
| Bliss | ROR | 36.5 | 37.5 | 37.5 | 35.2 | 40.7 | 39.8 | 34.3 | 32.6 | 35.7 | 37.9 | 35.8 | 36.2 | 36.6 |
| C.J. Strike | ROR | 47.2 | 48.9 | 49.6 | 46.8 | 51.2 | 47.1 | 36.4 | 34.8 | 42.4 | 48.5 | 46.7 | 47.6 | 45.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.5 | 23.2 | 22.6 | 20.7 | 27.3 | 27.3 | 22.0 | 19.8 | 22.3 | 24.4 | 22.6 | 22.5 | 23.1 |
| Milner | ROR | 6.6 | 9.3 | 8.4 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.2 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.3 | 16.1 | 16.3 | 15.9 | 16.8 | 15.6 | 12.7 | 11.9 | 14.0 | 15.4 | 15.3 | 15.4 | 15.1 |
| Twin Falls | ROR | 9.9 | 12.3 | 11.3 | 0.0 | 20.8 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.3 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.6 | 14.3 | 13.9 | 12.5 | 17.5 | 17.4 | 13.3 | 11.8 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.4 | 13.1 | 11.9 | 16.2 | 16.1 | 12.6 | 11.3 | 12.7 | 13.9 | 12.8 | 12.8 | 13.3 |
| **HCC Total** | | **584.5** | **621.6** | **577.6** | **636.6** | **807.4** | **694.5** | **487.7** | **352.2** | **410.6** | **389.6** | **364.3** | **456.5** | **531.9** |
| **ROR Total** | | **210.4** | **255.2** | **243.1** | **214.6** | **341.7** | **357.8** | **274.3** | **225.7** | **219.7** | **217.5** | **192.2** | **213.1** | **247.0** |
| **Total** | | **794.9** | **876.8** | **820.7** | **851.2** | **1149.0** | **1052.3** | **762.0** | **577.9** | **630.3** | **607.1** | **556.5** | **669.6** | **778.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.4 | 247.5 | 275.7 | 362.3 | 313.6 | 215.8 | 149.6 | 176.7 | 164.1 | 157.0 | 202.4 | 232.7 |
| Oxbow | HCC | 109.6 | 117.2 | 108.4 | 118.0 | 146.0 | 125.9 | 91.3 | 68.1 | 78.8 | 75.6 | 69.5 | 84.6 | 99.4 |
| Hells Canyon | HCC | 216.8 | 233.3 | 221.3 | 242.0 | 297.6 | 254.2 | 180.3 | 134.1 | 154.7 | 148.9 | 138.0 | 167.9 | 199.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.6 | 13.6 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.8 |
| Bliss | ROR | 36.5 | 37.4 | 37.5 | 35.1 | 40.7 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.2 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.8 | 46.7 | 51.1 | 47.0 | 36.4 | 34.8 | 42.3 | 48.5 | 46.6 | 47.4 | 45.5 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 22.4 | 20.6 | 27.2 | 27.3 | 22.0 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.1 | 7.7 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.5 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 13.7 | 12.4 | 17.5 | 17.3 | 13.2 | 11.8 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 13.0 | 11.8 | 16.2 | 16.0 | 12.5 | 11.3 | 12.7 | 13.9 | 12.7 | 12.8 | 13.3 |
| **HCC Total** | | **585.0** | **619.9** | **577.2** | **635.7** | **805.8** | **693.7** | **487.4** | **351.8** | **410.1** | **388.6** | **364.5** | **454.9** | **531.2** |
| **ROR Total** | | **209.8** | **254.0** | **239.8** | **214.2** | **341.4** | **357.5** | **274.0** | **225.6** | **219.6** | **217.6** | **191.9** | **212.8** | **246.4** |
| **Total** | | **794.8** | **873.9** | **817.0** | **849.9** | **1147.2** | **1051.2** | **761.4** | **577.4** | **629.7** | **606.2** | **556.4** | **667.7** | **777.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 70th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 70th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.6 | 269.1 | 247.4 | 275.6 | 362.2 | 313.5 | 215.8 | 149.5 | 176.6 | 163.7 | 157.3 | 202.1 | 232.6 |
| Oxbow | HCC | 109.6 | 117.1 | 108.3 | 118.0 | 145.9 | 125.8 | 91.2 | 68.1 | 78.8 | 75.4 | 69.6 | 84.5 | 99.4 |
| Hells Canyon | HCC | 216.9 | 233.1 | 221.2 | 241.9 | 297.5 | 254.1 | 180.2 | 134.1 | 154.7 | 148.6 | 138.2 | 167.7 | 199.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.5 | 13.4 | 37.0 | 73.9 | 88.5 | 78.3 | 58.7 | 34.7 | 14.8 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 36.4 | 37.4 | 37.4 | 35.1 | 40.6 | 39.8 | 34.3 | 32.5 | 35.7 | 37.9 | 35.8 | 36.1 | 36.6 |
| C.J. Strike | ROR | 47.1 | 48.7 | 48.7 | 46.7 | 51.1 | 47.0 | 36.3 | 34.8 | 42.3 | 48.4 | 46.6 | 47.3 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.6 | 1.7 | 4.8 | 7.9 | 6.9 | 10.1 | 9.0 | 2.2 | 1.4 | 1.4 | 4.2 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.4 | 23.0 | 22.2 | 20.6 | 27.2 | 27.3 | 21.9 | 19.8 | 22.3 | 24.4 | 22.5 | 22.5 | 23.0 |
| Milner | ROR | 6.5 | 9.0 | 7.3 | 0.0 | 17.9 | 18.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 6.1 |
| Shoshone Falls | ROR | 18.8 | 47.4 | 27.6 | 7.8 | 27.0 | 30.6 | 14.1 | 8.2 | 7.2 | 11.0 | 11.3 | 23.9 | 19.4 |
| Swan Falls | ROR | 15.2 | 16.1 | 16.1 | 15.9 | 16.8 | 15.6 | 12.6 | 11.9 | 14.0 | 15.4 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 9.8 | 12.0 | 10.1 | 0.0 | 20.7 | 22.4 | 11.2 | 0.0 | 0.0 | 7.0 | 7.1 | 9.0 | 9.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.1 | 13.6 | 12.4 | 17.5 | 17.3 | 13.2 | 11.7 | 13.4 | 14.9 | 13.5 | 13.5 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.3 | 12.8 | 11.8 | 16.2 | 16.0 | 12.5 | 11.2 | 12.7 | 13.9 | 12.7 | 12.7 | 13.2 |
| **HCC Total** | | **585.1** | **619.3** | **576.9** | **635.5** | **805.5** | **693.4** | **487.2** | **351.7** | **410.0** | **387.7** | **365.1** | **454.3** | **531.0** |
| **ROR Total** | | **209.7** | **253.6** | **238.1** | **214.2** | **341.4** | **357.5** | **273.8** | **225.4** | **219.6** | **217.5** | **191.9** | **212.5** | **246.1** |
| **Total** | | **794.8** | **872.9** | **815.0** | **849.7** | **1146.9** | **1050.9** | **761.0** | **577.1** | **629.5** | **605.2** | **557.0** | **666.8** | **777.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2011 | 2/2011 | 3/2011 | 4/2011 | 5/2011 | 6/2011 | 7/2011 | 8/2011 | 9/2011 | 10/2011 | 11/2011 | 12/2011 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.2 | 159.9 | 202.7 | 242.6 | 273.2 | 222.4 | 205.5 | 155.3 | 165.0 | 148.7 | 158.7 | 195.0 | 198.9 |
| Oxbow | HCC | 110.9 | 72.6 | 85.3 | 99.9 | 112.8 | 91.6 | 86.5 | 70.8 | 75.1 | 67.8 | 69.8 | 81.2 | 85.4 |
| Hells Canyon | HCC | 218.5 | 144.8 | 173.9 | 203.2 | 231.5 | 184.2 | 170.1 | 138.7 | 147.1 | 134.0 | 138.2 | 160.6 | 170.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.4 | 78.6 | 69.6 | 50.5 | 25.8 | 9.4 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 35.6 | 36.0 | 34.6 | 33.1 | 38.9 | 38.4 | 34.7 | 36.3 | 35.9 | 38.2 | 36.2 | 36.2 | 36.2 |
| C.J. Strike | ROR | 45.2 | 45.2 | 44.9 | 41.3 | 44.9 | 40.8 | 34.9 | 38.4 | 42.2 | 47.6 | 45.7 | 45.6 | 43.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.7 | 23.3 | 21.2 | 20.4 | 26.3 | 26.5 | 22.5 | 23.4 | 22.7 | 24.8 | 23.0 | 23.1 | 23.3 |
| Milner | ROR | 6.1 | 6.5 | 2.0 | 0.0 | 13.9 | 14.4 | 6.7 | 6.2 | 0.0 | 0.0 | 1.8 | 5.1 | 5.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 4.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 9.7 | 11.2 | 12.0 | 10.6 |
| Swan Falls | ROR | 15.2 | 15.3 | 15.2 | 14.2 | 15.3 | 14.6 | 12.3 | 13.2 | 14.0 | 15.4 | 15.4 | 15.4 | 14.6 |
| Twin Falls | ROR | 9.6 | 9.5 | 6.4 | 0.0 | 17.4 | 18.9 | 10.8 | 11.2 | 0.0 | 5.9 | 7.3 | 9.1 | 8.8 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.7 | 14.3 | 12.8 | 12.2 | 16.8 | 16.7 | 13.6 | 14.6 | 13.7 | 15.2 | 13.8 | 14.0 | 14.3 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.4 | 12.2 | 11.7 | 15.6 | 15.5 | 12.9 | 13.7 | 13.0 | 14.2 | 13.0 | 13.2 | 13.5 |
| **HCC Total** | | **587.6** | **377.3** | **461.9** | **545.7** | **617.5** | **498.2** | **462.1** | **364.8** | **387.1** | **350.5** | **366.7** | **436.8** | **454.7** |
| **ROR Total** | | **200.2** | **202.5** | **192.9** | **193.7** | **298.7** | **307.2** | **262.9** | **255.9** | **209.7** | **209.5** | **192.7** | **200.9** | **227.2** |
| **Total** | | **787.8** | **579.8** | **654.8** | **739.4** | **916.1** | **805.4** | **725.0** | **620.7** | **596.8** | **560.0** | **559.4** | **637.7** | **681.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2012 | 2/2012 | 3/2012 | 4/2012 | 5/2012 | 6/2012 | 7/2012 | 8/2012 | 9/2012 | 10/2012 | 11/2012 | 12/2012 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.4 | 160.0 | 201.2 | 242.4 | 273.0 | 222.3 | 205.4 | 155.2 | 164.8 | 148.5 | 158.6 | 194.8 | 198.7 |
| Oxbow | HCC | 111.0 | 72.7 | 84.8 | 99.8 | 112.7 | 91.6 | 86.5 | 70.7 | 75.0 | 67.7 | 69.7 | 81.1 | 85.3 |
| Hells Canyon | HCC | 218.7 | 145.1 | 172.8 | 203.0 | 231.3 | 184.1 | 170.0 | 138.6 | 146.9 | 133.9 | 138.1 | 160.4 | 170.2 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.4 | 78.6 | 69.5 | 50.4 | 25.8 | 9.4 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 35.6 | 35.9 | 34.6 | 33.0 | 38.8 | 38.4 | 34.7 | 36.3 | 35.9 | 38.2 | 36.2 | 36.1 | 36.1 |
| C.J. Strike | ROR | 45.1 | 45.1 | 44.8 | 41.3 | 44.8 | 40.7 | 34.9 | 38.3 | 42.2 | 47.5 | 45.7 | 45.5 | 43.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.7 | 23.2 | 21.2 | 20.4 | 26.3 | 26.4 | 22.5 | 23.4 | 22.7 | 24.8 | 23.0 | 23.0 | 23.3 |
| Milner | ROR | 6.1 | 6.4 | 2.0 | 0.0 | 13.9 | 14.4 | 6.7 | 6.2 | 0.0 | 0.0 | 1.8 | 5.0 | 5.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 4.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 9.6 | 11.2 | 12.0 | 10.6 |
| Swan Falls | ROR | 15.2 | 15.3 | 15.2 | 14.2 | 15.2 | 14.6 | 12.3 | 13.2 | 13.9 | 15.4 | 15.3 | 15.4 | 14.6 |
| Twin Falls | ROR | 9.5 | 9.4 | 6.4 | 0.0 | 17.4 | 18.8 | 10.8 | 11.2 | 0.0 | 5.9 | 7.3 | 9.0 | 8.8 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.7 | 14.3 | 12.8 | 12.2 | 16.8 | 16.7 | 13.6 | 14.6 | 13.7 | 15.2 | 13.8 | 13.9 | 14.3 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.4 | 12.2 | 11.6 | 15.6 | 15.5 | 12.8 | 13.7 | 12.9 | 14.2 | 13.0 | 13.1 | 13.4 |
| **HCC Total** | | **588.1** | **377.8** | **458.8** | **545.2** | **617.0** | **498.0** | **461.9** | **364.5** | **386.7** | **350.1** | **366.4** | **436.3** | **454.2** |
| **ROR Total** | | **199.9** | **202.0** | **192.8** | **193.5** | **298.4** | **306.9** | **262.7** | **255.7** | **209.5** | **209.3** | **192.6** | **200.2** | **227.0** |
| **Total** | | **788.0** | **579.8** | **651.6** | **738.7** | **915.4** | **804.9** | **724.6** | **620.2** | **596.2** | **559.4** | **559.0** | **636.5** | **681.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 258.5 | 160.1 | 200.0 | 242.1 | 272.8 | 222.2 | 205.2 | 155.1 | 164.7 | 148.0 | 158.9 | 194.5 | 198.5 |
| Oxbow | HCC | 111.1 | 72.8 | 84.3 | 99.7 | 112.7 | 91.5 | 86.4 | 70.6 | 74.9 | 67.5 | 69.8 | 81.0 | 85.2 |
| Hells Canyon | HCC | 218.8 | 145.2 | 171.9 | 202.8 | 231.2 | 184.0 | 169.9 | 138.5 | 146.8 | 133.4 | 138.3 | 160.2 | 170.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.5 | 78.6 | 69.5 | 50.4 | 25.8 | 9.4 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 35.5 | 35.8 | 34.6 | 33.0 | 38.8 | 38.4 | 34.6 | 36.3 | 35.9 | 38.1 | 36.1 | 36.1 | 36.1 |
| C.J. Strike | ROR | 45.0 | 45.1 | 44.8 | 41.2 | 44.8 | 40.7 | 34.9 | 38.2 | 42.1 | 47.5 | 45.7 | 45.4 | 43.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.6 | 23.1 | 21.2 | 20.3 | 26.2 | 26.4 | 22.4 | 23.4 | 22.6 | 24.8 | 22.9 | 23.0 | 23.2 |
| Milner | ROR | 6.0 | 6.4 | 2.0 | 0.0 | 13.9 | 14.4 | 6.7 | 6.2 | 0.0 | 0.0 | 1.8 | 4.9 | 5.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 4.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 9.5 | 11.2 | 12.0 | 10.6 |
| Swan Falls | ROR | 15.2 | 15.2 | 15.2 | 14.1 | 15.2 | 14.5 | 12.3 | 13.1 | 13.9 | 15.3 | 15.3 | 15.3 | 14.6 |
| Twin Falls | ROR | 9.5 | 9.4 | 6.4 | 0.0 | 17.4 | 18.8 | 10.7 | 11.2 | 0.0 | 5.8 | 7.3 | 9.0 | 8.8 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.7 | 14.2 | 12.8 | 12.1 | 16.7 | 16.6 | 13.6 | 14.5 | 13.7 | 15.2 | 13.8 | 13.9 | 14.2 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.4 | 12.2 | 11.6 | 15.5 | 15.4 | 12.8 | 13.6 | 12.9 | 14.2 | 13.0 | 13.1 | 13.4 |
| **HCC Total** | | **588.4** | **378.1** | **456.2** | **544.6** | **616.6** | **497.7** | **461.5** | **364.2** | **386.4** | **348.9** | **367.0** | **435.7** | **453.8** |
| **ROR Total** | | **199.5** | **201.6** | **192.8** | **193.1** | **298.1** | **306.6** | **262.4** | **255.3** | **209.3** | **208.9** | **192.4** | **199.9** | **226.7** |
| **Total** | | **787.9** | **579.7** | **649.0** | **737.7** | **914.7** | **804.3** | **723.9** | **619.5** | **595.7** | **557.8** | **559.4** | **635.6** | **680.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 257.3 | 161.0 | 195.7 | 241.4 | 272.1 | 221.4 | 204.5 | 154.4 | 164.0 | 146.2 | 158.6 | 193.8 | 197.5 |
| Oxbow | HCC | 110.6 | 73.4 | 82.5 | 99.4 | 112.4 | 91.2 | 86.1 | 70.3 | 74.6 | 66.6 | 69.7 | 80.7 | 84.8 |
| Hells Canyon | HCC | 217.9 | 146.2 | 168.5 | 202.2 | 230.6 | 183.3 | 169.3 | 137.9 | 146.2 | 131.8 | 138.0 | 159.6 | 169.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.5 | 78.7 | 69.6 | 50.2 | 25.6 | 9.5 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 35.2 | 35.5 | 34.4 | 32.8 | 38.6 | 38.2 | 34.5 | 36.1 | 35.7 | 37.9 | 35.9 | 35.7 | 35.9 |
| C.J. Strike | ROR | 44.6 | 44.6 | 44.5 | 41.0 | 44.4 | 40.3 | 34.6 | 38.0 | 41.9 | 47.2 | 45.6 | 45.1 | 42.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.3 | 22.9 | 21.0 | 20.1 | 26.1 | 26.2 | 22.3 | 23.2 | 22.5 | 24.6 | 22.8 | 22.7 | 23.1 |
| Milner | ROR | 5.7 | 5.8 | 2.0 | 0.0 | 13.9 | 14.4 | 6.7 | 6.2 | 0.0 | 0.0 | 1.8 | 4.4 | 5.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 4.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.8 | 9.3 | 11.2 | 12.0 | 10.5 |
| Swan Falls | ROR | 15.1 | 15.1 | 15.1 | 14.2 | 15.1 | 14.2 | 12.2 | 13.1 | 13.8 | 15.3 | 15.3 | 15.2 | 14.5 |
| Twin Falls | ROR | 9.3 | 9.1 | 6.4 | 0.0 | 17.3 | 18.6 | 10.7 | 11.1 | 0.0 | 5.6 | 7.3 | 8.8 | 8.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.0 | 12.7 | 12.0 | 16.6 | 16.5 | 13.5 | 14.4 | 13.6 | 15.0 | 13.6 | 13.7 | 14.1 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.2 | 12.0 | 11.5 | 15.4 | 15.3 | 12.7 | 13.5 | 12.8 | 14.0 | 12.9 | 12.9 | 13.2 |
| **HCC Total** | | **585.8** | **380.6** | **446.7** | **543.0** | **615.1** | **495.9** | **459.9** | **362.6** | **384.8** | **344.6** | **366.3** | **434.1** | **451.6** |
| **ROR Total** | | **197.5** | **199.2** | **191.7** | **192.4** | **297.1** | **305.2** | **261.7** | **254.2** | **208.2** | **207.5** | **191.7** | **197.7** | **225.3** |
| **Total** | | **783.3** | **579.8** | **638.4** | **735.4** | **912.1** | **801.1** | **721.6** | **616.8** | **592.9** | **552.1** | **558.0** | **631.8** | **676.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 256.2 | 161.7 | 191.0 | 240.7 | 271.4 | 220.6 | 203.8 | 153.7 | 163.2 | 144.5 | 158.7 | 192.6 | 196.5 |
| Oxbow | HCC | 110.1 | 73.8 | 80.6 | 99.1 | 112.1 | 90.9 | 85.8 | 70.0 | 74.3 | 65.8 | 69.7 | 80.2 | 84.4 |
| Hells Canyon | HCC | 217.0 | 147.1 | 164.8 | 201.6 | 230.0 | 182.7 | 168.7 | 137.3 | 145.5 | 130.2 | 138.0 | 158.6 | 168.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.6 | 78.7 | 69.7 | 50.2 | 25.5 | 9.6 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 34.9 | 35.2 | 34.2 | 32.4 | 38.4 | 38.0 | 34.3 | 35.9 | 35.5 | 37.7 | 35.7 | 35.4 | 35.6 |
| C.J. Strike | ROR | 44.4 | 44.3 | 44.3 | 40.7 | 44.1 | 40.1 | 34.4 | 37.7 | 41.6 | 46.9 | 45.2 | 44.9 | 42.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 22.1 | 22.6 | 20.9 | 19.9 | 25.9 | 25.9 | 22.1 | 23.0 | 22.3 | 24.4 | 22.6 | 22.4 | 22.8 |
| Milner | ROR | 5.4 | 5.5 | 2.0 | 0.0 | 13.9 | 14.4 | 6.7 | 6.2 | 0.0 | 0.0 | 1.8 | 4.0 | 5.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.1 | 4.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 9.0 | 11.2 | 12.0 | 10.5 |
| Swan Falls | ROR | 15.0 | 15.0 | 15.0 | 14.1 | 15.0 | 14.1 | 12.1 | 13.0 | 13.8 | 15.4 | 15.2 | 15.1 | 14.4 |
| Twin Falls | ROR | 9.1 | 8.8 | 6.3 | 0.0 | 17.3 | 18.4 | 10.6 | 11.1 | 0.0 | 5.4 | 7.2 | 8.5 | 8.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.8 | 12.5 | 11.9 | 16.5 | 16.3 | 13.3 | 14.3 | 13.4 | 14.8 | 13.5 | 13.4 | 13.9 |
| Upper Salmon 3&4 | ROR | 12.5 | 13.0 | 11.9 | 11.4 | 15.3 | 15.1 | 12.6 | 13.4 | 12.7 | 13.9 | 12.8 | 12.7 | 13.1 |
| **HCC Total** | | **583.3** | **382.6** | **436.4** | **541.4** | **613.4** | **494.2** | **458.3** | **361.0** | **383.0** | **340.5** | **366.4** | **431.4** | **449.3** |
| **ROR Total** | | **195.8** | **197.2** | **190.6** | **191.1** | **296.2** | **303.8** | **260.7** | **253.2** | **207.0** | **206.2** | **190.5** | **195.6** | **224.0** |
| **Total** | | **779.1** | **579.8** | **627.0** | **732.5** | **909.5** | **798.0** | **719.0** | **614.2** | **590.0** | **546.7** | **556.9** | **627.0** | **673.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 255.1 | 162.2 | 189.8 | 239.5 | 270.6 | 219.9 | 203.1 | 140.7 | 162.9 | 143.0 | 158.8 | 191.9 | 194.8 |
| Oxbow | HCC | 109.6 | 74.1 | 80.2 | 98.6 | 111.7 | 90.6 | 85.5 | 63.9 | 74.1 | 65.0 | 69.7 | 79.9 | 83.6 |
| Hells Canyon | HCC | 216.0 | 147.6 | 163.9 | 200.7 | 229.4 | 182.2 | 168.1 | 125.7 | 145.2 | 128.7 | 138.0 | 158.0 | 167.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.2 | 68.7 | 78.9 | 69.8 | 48.1 | 26.5 | 9.8 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 34.6 | 35.0 | 34.0 | 32.3 | 38.2 | 37.8 | 34.1 | 32.3 | 35.3 | 37.5 | 35.5 | 35.2 | 35.2 |
| C.J. Strike | ROR | 44.0 | 43.9 | 44.0 | 40.5 | 43.9 | 39.8 | 34.1 | 33.1 | 41.4 | 46.8 | 45.1 | 44.6 | 41.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.8 | 22.4 | 20.7 | 19.8 | 25.7 | 25.8 | 21.9 | 19.8 | 22.1 | 24.3 | 22.4 | 22.3 | 22.4 |
| Milner | ROR | 5.1 | 5.7 | 2.0 | 0.0 | 13.5 | 14.3 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.9 | 4.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.1 | 4.8 | 12.0 | 12.0 | 12.0 | 6.8 | 6.9 | 9.4 | 11.1 | 12.0 | 10.1 |
| Swan Falls | ROR | 14.8 | 14.9 | 15.0 | 14.0 | 14.9 | 14.1 | 12.1 | 11.5 | 13.7 | 15.4 | 15.2 | 15.0 | 14.2 |
| Twin Falls | ROR | 9.0 | 8.8 | 6.3 | 0.0 | 17.2 | 18.3 | 10.6 | 0.0 | 0.0 | 5.7 | 7.2 | 8.3 | 7.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.6 | 12.4 | 11.7 | 16.4 | 16.2 | 13.2 | 11.8 | 13.3 | 14.8 | 13.4 | 13.3 | 13.6 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.8 | 11.8 | 11.2 | 15.2 | 15.0 | 12.5 | 11.3 | 12.6 | 13.8 | 12.7 | 12.6 | 12.8 |
| **HCC Total** | | **580.7** | **383.9** | **433.9** | **538.8** | **611.7** | **492.7** | **456.7** | **330.3** | **382.1** | **336.7** | **366.5** | **429.8** | **445.3** |
| **ROR Total** | | **193.9** | **196.1** | **189.7** | **190.1** | **294.9** | **303.0** | **259.9** | **211.1** | **207.3** | **206.6** | **189.7** | **194.4** | **219.7** |
| **Total** | | **774.6** | **580.0** | **623.6** | **728.9** | **906.5** | **795.7** | **716.6** | **541.4** | **589.4** | **543.3** | **556.2** | **624.2** | **665.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 253.9 | 163.1 | 179.0 | 238.4 | 269.9 | 219.1 | 202.3 | 140.1 | 158.6 | 141.7 | 158.9 | 190.7 | 193.0 |
| Oxbow | HCC | 109.1 | 74.6 | 78.7 | 98.2 | 111.4 | 90.3 | 85.2 | 63.6 | 73.8 | 64.4 | 69.7 | 79.4 | 83.2 |
| Hells Canyon | HCC | 215.0 | 148.6 | 160.6 | 199.7 | 228.8 | 181.5 | 167.5 | 125.2 | 144.4 | 127.5 | 138.0 | 157.0 | 166.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.7 | 78.6 | 70.0 | 47.9 | 26.2 | 9.9 | 0.0 | 0.0 | 28.0 |
| Bliss | ROR | 34.4 | 34.7 | 33.8 | 32.0 | 37.8 | 37.5 | 33.9 | 32.1 | 35.1 | 37.3 | 35.4 | 35.0 | 34.9 |
| C.J. Strike | ROR | 43.7 | 43.4 | 43.8 | 40.2 | 43.6 | 39.6 | 33.8 | 32.8 | 41.1 | 46.5 | 44.8 | 44.3 | 41.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.6 | 22.1 | 20.5 | 19.6 | 25.3 | 25.5 | 21.8 | 19.7 | 22.0 | 24.1 | 22.3 | 22.1 | 22.2 |
| Milner | ROR | 5.1 | 5.1 | 2.0 | 0.0 | 12.3 | 12.8 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.4 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.9 | 13.9 | 14.8 | 14.0 | 12.0 | 11.4 | 13.6 | 15.3 | 15.1 | 14.9 | 14.1 |
| Twin Falls | ROR | 8.9 | 8.5 | 6.2 | 0.0 | 16.0 | 17.5 | 10.5 | 0.0 | 0.0 | 5.6 | 7.1 | 8.0 | 7.4 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.4 | 12.3 | 11.6 | 16.0 | 15.9 | 13.1 | 11.7 | 13.2 | 14.6 | 13.3 | 13.2 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.7 | 11.7 | 11.1 | 14.9 | 14.8 | 12.4 | 11.2 | 12.5 | 13.7 | 12.5 | 12.5 | 12.7 |
| **HCC Total** | | **578.0** | **386.3** | **418.3** | **536.3** | **610.0** | **490.9** | **455.0** | **328.9** | **376.7** | **333.6** | **366.6** | **427.1** | **442.3** |
| **ROR Total** | | **192.7** | **193.6** | **188.6** | **189.0** | **298.5** | **309.0** | **261.1** | **210.0** | **206.1** | **205.3** | **188.7** | **192.6** | **219.6** |
| **Total** | | **770.7** | **579.9** | **606.9** | **725.3** | **908.5** | **799.9** | **716.1** | **538.9** | **582.7** | **538.9** | **555.3** | **619.7** | **661.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 252.8 | 163.7 | 174.1 | 238.1 | 269.1 | 218.4 | 201.6 | 139.4 | 157.8 | 140.0 | 159.0 | 189.9 | 192.0 |
| Oxbow | HCC | 108.6 | 75.0 | 76.6 | 98.0 | 111.1 | 90.0 | 84.9 | 63.3 | 73.4 | 63.6 | 69.7 | 79.0 | 82.8 |
| Hells Canyon | HCC | 214.0 | 149.2 | 156.6 | 199.5 | 228.2 | 181.0 | 166.9 | 124.6 | 143.7 | 126.0 | 138.0 | 156.4 | 165.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.3 | 68.7 | 78.4 | 70.1 | 48.0 | 26.1 | 9.9 | 0.0 | 0.0 | 28.0 |
| Bliss | ROR | 34.3 | 34.4 | 33.4 | 31.7 | 37.1 | 36.8 | 33.7 | 31.9 | 34.9 | 37.1 | 35.2 | 34.7 | 34.6 |
| C.J. Strike | ROR | 43.5 | 43.0 | 43.3 | 39.8 | 43.4 | 39.3 | 33.6 | 32.5 | 40.9 | 46.3 | 44.6 | 44.0 | 41.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.5 | 21.8 | 20.3 | 19.4 | 24.7 | 24.9 | 21.6 | 19.5 | 21.8 | 23.9 | 22.1 | 21.9 | 22.0 |
| Milner | ROR | 5.1 | 5.0 | 2.0 | 0.0 | 11.5 | 11.9 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.1 | 3.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.7 | 14.6 | 14.7 | 13.8 | 14.7 | 14.0 | 11.9 | 11.3 | 13.5 | 15.2 | 15.0 | 14.8 | 14.0 |
| Twin Falls | ROR | 8.7 | 8.4 | 6.2 | 0.0 | 14.7 | 16.3 | 10.5 | 0.0 | 0.0 | 5.3 | 7.1 | 7.6 | 7.1 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.8 | 13.2 | 12.2 | 11.5 | 15.5 | 15.5 | 13.0 | 11.5 | 13.0 | 14.5 | 13.1 | 13.1 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.5 | 11.6 | 11.0 | 14.5 | 14.5 | 12.3 | 11.1 | 12.4 | 13.6 | 12.4 | 12.4 | 12.5 |
| **HCC Total** | | **575.4** | **387.9** | **407.3** | **535.6** | **608.4** | **489.4** | **453.4** | **327.3** | **374.9** | **329.6** | **366.7** | **425.3** | **440.1** |
| **ROR Total** | | **191.8** | **191.9** | **187.1** | **187.8** | **294.0** | **304.4** | **260.3** | **209.0** | **205.0** | **204.1** | **187.7** | **190.8** | **217.8** |
| **Total** | | **767.2** | **579.8** | **594.4** | **723.4** | **902.3** | **793.8** | **713.7** | **536.3** | **579.9** | **533.7** | **554.4** | **616.1** | **657.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 251.9 | 164.1 | 171.9 | 237.5 | 268.6 | 217.8 | 201.0 | 138.9 | 157.3 | 138.9 | 159.3 | 189.2 | 191.4 |
| Oxbow | HCC | 108.3 | 75.2 | 75.6 | 97.8 | 110.9 | 89.8 | 84.6 | 63.0 | 73.1 | 63.0 | 69.8 | 78.7 | 82.5 |
| Hells Canyon | HCC | 213.4 | 149.7 | 154.9 | 199.0 | 227.8 | 180.5 | 166.4 | 124.1 | 143.2 | 124.9 | 138.2 | 155.7 | 164.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.4 | 68.8 | 78.3 | 70.2 | 48.0 | 26.2 | 10.0 | 0.0 | 0.0 | 28.0 |
| Bliss | ROR | 34.1 | 34.2 | 33.2 | 31.5 | 36.6 | 36.3 | 33.5 | 31.8 | 34.8 | 37.0 | 35.0 | 34.4 | 34.4 |
| C.J. Strike | ROR | 43.3 | 42.7 | 42.8 | 39.5 | 43.1 | 39.1 | 33.4 | 32.2 | 40.7 | 46.1 | 44.4 | 43.8 | 40.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.3 | 21.6 | 20.2 | 19.3 | 24.2 | 24.4 | 21.5 | 19.4 | 21.7 | 23.8 | 22.0 | 21.7 | 21.8 |
| Milner | ROR | 5.1 | 5.0 | 2.0 | 0.0 | 10.6 | 11.0 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.1 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.6 | 14.6 | 14.6 | 13.7 | 14.6 | 13.9 | 11.8 | 11.2 | 13.5 | 15.2 | 14.9 | 14.7 | 13.9 |
| Twin Falls | ROR | 8.6 | 8.3 | 6.1 | 0.0 | 13.8 | 15.3 | 10.5 | 0.0 | 0.0 | 5.3 | 7.1 | 7.5 | 6.9 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.7 | 13.0 | 12.0 | 11.4 | 15.2 | 15.1 | 12.9 | 11.4 | 13.0 | 14.4 | 13.0 | 12.9 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.0 | 12.4 | 11.5 | 10.9 | 14.2 | 14.1 | 12.2 | 11.0 | 12.3 | 13.5 | 12.4 | 12.3 | 12.4 |
| **HCC Total** | | **573.6** | **389.0** | **402.4** | **534.3** | **607.3** | **488.1** | **452.0** | **326.0** | **373.5** | **326.8** | **367.3** | **423.6** | **438.7** |
| **ROR Total** | | **190.8** | **190.8** | **185.8** | **187.0** | **290.2** | **300.3** | **259.6** | **208.2** | **204.6** | **203.6** | **187.0** | **189.6** | **216.5** |
| **Total** | | **764.4** | **579.8** | **588.2** | **721.3** | **897.5** | **788.4** | **711.6** | **534.2** | **578.1** | **530.4** | **554.3** | **613.2** | **655.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 251.3 | 164.5 | 170.3 | 237.0 | 268.1 | 217.4 | 200.6 | 138.6 | 156.9 | 138.2 | 159.3 | 188.7 | 190.9 |
| Oxbow | HCC | 108.0 | 75.4 | 74.9 | 97.6 | 110.7 | 89.6 | 84.5 | 62.9 | 73.0 | 62.7 | 69.8 | 78.5 | 82.3 |
| Hells Canyon | HCC | 212.8 | 150.1 | 153.6 | 198.6 | 227.5 | 180.2 | 166.1 | 123.8 | 142.9 | 124.3 | 138.2 | 155.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.4 | 68.8 | 78.2 | 70.1 | 48.1 | 26.2 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 34.0 | 34.1 | 33.1 | 31.4 | 36.2 | 35.9 | 33.4 | 31.7 | 34.7 | 36.9 | 34.9 | 34.2 | 34.2 |
| C.J. Strike | ROR | 43.2 | 42.5 | 42.6 | 39.3 | 42.8 | 39.0 | 33.2 | 32.1 | 40.6 | 45.9 | 44.2 | 43.7 | 40.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.2 | 21.5 | 20.1 | 19.2 | 23.9 | 24.1 | 21.4 | 19.3 | 21.6 | 23.7 | 21.9 | 21.7 | 21.6 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 10.0 | 10.4 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.6 | 14.5 | 14.6 | 13.7 | 14.6 | 13.7 | 11.6 | 11.2 | 13.4 | 15.1 | 14.9 | 14.7 | 13.9 |
| Twin Falls | ROR | 8.6 | 8.3 | 6.1 | 0.0 | 13.1 | 14.6 | 10.3 | 0.0 | 0.0 | 5.3 | 7.1 | 7.5 | 6.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 12.0 | 11.3 | 14.9 | 14.9 | 12.8 | 11.4 | 12.9 | 14.4 | 13.0 | 12.9 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.0 | 12.3 | 11.4 | 10.9 | 13.9 | 13.9 | 12.1 | 10.9 | 12.2 | 13.5 | 12.3 | 12.2 | 12.3 |
| **HCC Total** | | **572.1** | **390.0** | **398.8** | **533.2** | **606.3** | **487.2** | **451.2** | **325.3** | **372.7** | **325.2** | **367.3** | **422.6** | **437.7** |
| **ROR Total** | | **190.4** | **189.8** | **185.3** | **186.5** | **287.4** | **297.5** | **258.5** | **207.9** | **204.0** | **203.2** | **186.5** | **189.1** | **215.5** |
| **Total** | | **762.5** | **579.8** | **584.1** | **719.7** | **893.6** | **784.7** | **709.7** | **533.2** | **576.7** | **528.4** | **553.8** | **611.7** | **653.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 250.9 | 164.6 | 169.3 | 236.7 | 267.9 | 217.1 | 200.4 | 138.3 | 156.7 | 137.7 | 159.4 | 188.4 | 190.6 |
| Oxbow | HCC | 107.8 | 75.5 | 74.5 | 97.5 | 110.6 | 89.5 | 84.4 | 62.8 | 72.8 | 62.4 | 69.8 | 78.4 | 82.2 |
| Hells Canyon | HCC | 212.5 | 150.3 | 152.8 | 198.4 | 227.3 | 179.9 | 165.9 | 123.6 | 142.6 | 123.7 | 138.3 | 155.1 | 164.2 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.5 | 68.8 | 78.2 | 70.1 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 34.0 | 33.1 | 31.3 | 36.0 | 35.7 | 33.4 | 31.6 | 34.6 | 36.8 | 34.9 | 34.1 | 34.1 |
| C.J. Strike | ROR | 43.1 | 42.4 | 42.5 | 39.2 | 42.8 | 38.9 | 32.9 | 32.0 | 40.5 | 45.8 | 43.9 | 43.6 | 40.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 20.1 | 19.1 | 23.7 | 23.9 | 21.3 | 19.2 | 21.5 | 23.7 | 21.8 | 21.6 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.6 | 10.0 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.6 | 14.5 | 14.5 | 13.7 | 14.5 | 13.6 | 11.6 | 11.1 | 13.4 | 15.1 | 14.9 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.6 | 8.3 | 6.1 | 0.0 | 12.7 | 14.2 | 10.3 | 0.0 | 0.0 | 5.2 | 7.0 | 7.5 | 6.7 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.9 | 11.9 | 11.2 | 14.8 | 14.7 | 12.7 | 11.3 | 12.8 | 14.3 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.4 | 10.8 | 13.8 | 13.8 | 12.1 | 10.9 | 12.2 | 13.4 | 12.2 | 12.2 | 12.2 |
| **HCC Total** | | **571.2** | **390.4** | **396.6** | **532.6** | **605.8** | **486.5** | **450.7** | **324.7** | **372.1** | **323.8** | **367.5** | **421.9** | **437.0** |
| **ROR Total** | | **190.0** | **189.4** | **185.0** | **186.1** | **285.9** | **295.8** | **258.0** | **207.4** | **203.7** | **202.7** | **185.8** | **188.6** | **214.9** |
| **Total** | | **761.2** | **579.8** | **581.6** | **718.7** | **891.6** | **782.3** | **708.7** | **532.1** | **575.7** | **526.5** | **553.3** | **610.5** | **651.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 250.6 | 164.7 | 168.7 | 236.5 | 267.7 | 217.0 | 200.2 | 138.1 | 156.4 | 137.5 | 159.3 | 181.1 | 189.8 |
| Oxbow | HCC | 107.7 | 75.6 | 74.3 | 97.4 | 110.5 | 89.4 | 84.3 | 62.7 | 72.7 | 62.3 | 69.8 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.3 | 198.2 | 227.1 | 179.8 | 165.7 | 123.4 | 142.4 | 123.6 | 138.1 | 154.6 | 164.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.5 | 33.3 | 31.5 | 34.6 | 36.8 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.5 | 39.1 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.1 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.8 | 21.6 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.3 | 9.6 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.6 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.3 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.3 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.9 | 12.2 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.5** | **390.8** | **395.3** | **532.1** | **605.3** | **486.2** | **450.2** | **324.2** | **371.5** | **323.4** | **367.2** | **414.0** | **435.9** |
| **ROR Total** | | **189.6** | **189.1** | **184.8** | **186.0** | **284.5** | **294.4** | **257.9** | **207.2** | **203.6** | **202.5** | **185.4** | **188.3** | **214.4** |
| **Total** | | **760.1** | **579.9** | **580.1** | **718.1** | **889.7** | **780.6** | **708.1** | **531.4** | **575.1** | **525.9** | **552.6** | **602.3** | **650.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

aMW 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2028 | 2/2084 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

## Hydro Modeling Results (PDR 580) (continued)

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| aMW 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 250.5 | 164.8 | 168.4 | 236.4 | 267.6 | 216.9 | 200.1 | 138.1 | 156.4 | 137.4 | 159.1 | 181.0 | 189.7 |
| Oxbow | HCC | 107.7 | 75.6 | 74.2 | 97.4 | 110.5 | 89.4 | 84.2 | 62.7 | 72.7 | 62.3 | 69.7 | 78.3 | 82.1 |
| Hells Canyon | HCC | 212.2 | 150.5 | 152.1 | 198.2 | 227.0 | 179.7 | 165.6 | 123.4 | 142.4 | 123.5 | 138.0 | 154.5 | 163.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 5.7 | 29.6 | 68.9 | 78.3 | 70.2 | 48.1 | 26.3 | 10.1 | 0.0 | 0.0 | 28.1 |
| Bliss | ROR | 33.9 | 33.9 | 33.0 | 31.3 | 35.8 | 35.4 | 33.3 | 31.5 | 34.5 | 36.7 | 34.8 | 34.0 | 34.0 |
| C.J. Strike | ROR | 43.0 | 42.4 | 42.4 | 39.0 | 42.7 | 38.8 | 32.8 | 31.9 | 40.4 | 45.7 | 43.8 | 43.5 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.4 | 1.3 | 1.5 | 4.2 | 7.0 | 9.8 | 7.2 | 1.5 | 1.3 | 1.4 | 3.3 |
| Clear Lake | ROR | 1.7 | 1.7 | 1.7 | 1.4 | 1.6 | 1.4 | 1.4 | 1.6 | 1.6 | 1.7 | 1.6 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.4 | 11.5 | 12.1 | 11.7 | 12.9 | 11.9 | 11.8 | 12.1 | 13.0 | 12.9 | 10.6 | 11.5 | 12.0 |
| Lowe Salmon | ROR | 21.1 | 21.3 | 20.0 | 19.0 | 23.5 | 23.7 | 21.3 | 19.2 | 21.5 | 23.6 | 21.7 | 21.5 | 21.5 |
| Milner | ROR | 5.1 | 4.7 | 2.0 | 0.0 | 9.2 | 9.5 | 6.7 | 0.0 | 0.0 | 0.0 | 1.8 | 3.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 4.7 | 20.0 | 22.0 | 14.0 | 6.8 | 6.9 | 9.2 | 11.1 | 12.0 | 11.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.6 | 14.5 | 13.5 | 11.6 | 11.1 | 13.4 | 15.1 | 14.8 | 14.6 | 13.8 |
| Twin Falls | ROR | 8.5 | 8.3 | 6.1 | 0.0 | 12.2 | 13.8 | 10.3 | 0.0 | 0.0 | 5.2 | 6.9 | 7.5 | 6.6 |
| Upper Malad | ROR | 6.6 | 6.7 | 6.9 | 6.8 | 7.6 | 7.2 | 6.8 | 6.9 | 7.2 | 6.6 | 6.3 | 6.5 | 6.8 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.9 | 11.2 | 14.6 | 14.6 | 12.7 | 11.3 | 12.8 | 14.2 | 12.9 | 12.8 | 12.9 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.4 | 10.8 | 13.7 | 13.7 | 12.1 | 10.8 | 12.1 | 13.4 | 12.2 | 12.1 | 12.2 |
| **HCC Total** | | **570.4** | **390.9** | **394.7** | **532.0** | **605.1** | **486.0** | **449.9** | **324.2** | **371.4** | **323.2** | **366.8** | **413.8** | **435.7** |
| **ROR Total** | | **189.6** | **189.0** | **184.7** | **185.8** | **284.3** | **294.1** | **257.9** | **207.1** | **203.4** | **202.3** | **185.3** | **188.2** | **214.3** |
| **Total** | | **760.0** | **579.9** | **579.4** | **717.8** | **889.4** | **780.1** | **707.8** | **531.3** | **574.8** | **525.5** | **552.1** | **602.0** | **650.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

## Initial Resource Portfolios (2011–2020)

| 1-1 Sun & Steam | | 1-2 Solar | | 1-3 B2H | | 1-4 SCCT | | 1-5 CCCT | |
|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 2011 | | 2011 | | 2011 | | 2011 | |
| 2012 | Solar PV-1 | 2012 | | 2012 | | 2012 | | 2012 | |
| 2013 | Solar PV-5 | 2013 | | 2013 | | 2013 | | 2013 | |
| 2014 | CHP-75 | 2014 | Solar PV-5 | 2014 | | 2014 | | 2014 | |
| 2015 | Solar PV-30 | 2015 | Solar PT-100 | 2015 | Eastside Purchase | 2015 | SCCT Frame | 2015 | CCCT |
| 2016 | CHP-100 | 2016 | Solar PT-100 | 2016 | B2H-450 | 2016 | | 2016 | |
| 2017 | Geothermal-52 | 2017 | Solar PT-125 | 2017 | | 2017 | SCCT Frame | 2017 | |
| 2018 | Solar PT-125 | 2018 | Solar PV-50 | 2018 | | 2018 | | 2018 | |
| 2019 | Solar PV-30 | 2019 | Solar PT-100 | 2019 | | 2019 | SCCT S Aero-94 | 2019 | SCCT Frame |
| 2020 | Solar PT-75 | 2020 | Solar PV-50 | 2020 | | 2020 | | 2020 | |
| **MW** | **493** | **MW** | **530** | **MW** | **450** | **MW** | **434** | **MW** | **470** |

| 1-6 CHP | | 1-7 Balanced | | 1-8 Pumped Storage | | 1-9 Distributed Gen | |
|---|---|---|---|---|---|---|---|
| 2011 | | 2011 | | 2011 | | 2011 | |
| 2012 | | 2012 | | 2012 | | 2012 | Dist Gen-10 |
| 2013 | | 2013 | | 2013 | | 2013 | |
| 2014 | | 2014 | | 2014 | | 2014 | |
| 2015 | CHP-100 | 2015 | CHP-100 | 2015 | Pump St-80 | 2015 | SCCT Frame |
| 2016 | SCCT Frame | 2016 | SCCT Frame | 2016 | SCCT Frame | 2016 | |
| 2017 | | 2017 | Solar PV-10 | 2017 | | 2017 | SCCT Frame |
| 2018 | CHP-50 | 2018 | Solar PT-100 | 2018 | Pump St-80 | 2018 | |
| 2019 | CHP-50 | 2019 | Geothermal-26 | 2019 | SCCT S Aero-47 | 2019 | SCCT S Aero-94 |
| 2020 | SCCT S Aero-94 | 2020 | SCCT S Aero-47 | 2020 | Pump St-80 | 2020 | |
| **MW** | **464** | **MW** | **453** | **MW** | **457** | **MW** | **444** |

## Initial Resource Portfolios (2021–2030)

| 2-1 Nuclear | | 2-2 IGCC | | 2-3 SCCT/Wind | | 2-4 CCCT/Wind | | 2-5 Hydro/CHP | |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | Solar PT-100 | 2021 | Geothermal-52 | 2021 | SCCT S Aero-141 | 2021 | CCCT | 2021 | Hydro Sm-60 |
| 2022 | Pump St-50 | 2022 | SCCT Frame | 2022 | Wind-100 | 2022 | Wind-150 | 2022 | CHP-75 |
| 2023 | Solar PT-100 | 2023 | | 2023 | SCCT S Aero-141 | 2023 | | 2023 | Pump St-80 |
| 2024 | Nuclear | 2024 | CHP-50 | 2024 | Wind-100 | 2024 | | 2024 | CHP-100 |
| 2025 | | 2025 | Solar PT-75 | 2025 | SCCT S Aero-94 | 2025 | | 2025 | Hydro-40 |
| 2026 | | 2026 | IGCC w/CS | 2026 | Wind-100 | 2026 | CCCT | 2026 | Pump St-80 |
| 2027 | | 2027 | | 2027 | SCCT S Aero-141 | 2027 | | 2027 | Hydro Sm-100 |
| 2028 | Nuclear | 2028 | Solar PT-75 | 2028 | SCCT S Aero-141 | 2028 | Wind-150 | 2028 | SCCT S Aero-141 |
| 2029 | Pump St-50 | 2029 | | 2029 | SCCT S Aero-94 | 2029 | SCCT Frame | 2029 | Hydro Sm-80 |
| 2030 | | 2030 | | 2030 | | 2030 | | 2030 | Hydro Sm-60 |
| **MW** | **800** | **MW** | **802** | **MW** | **1,052** | **MW** | **1,070** | **MW** | **816** |

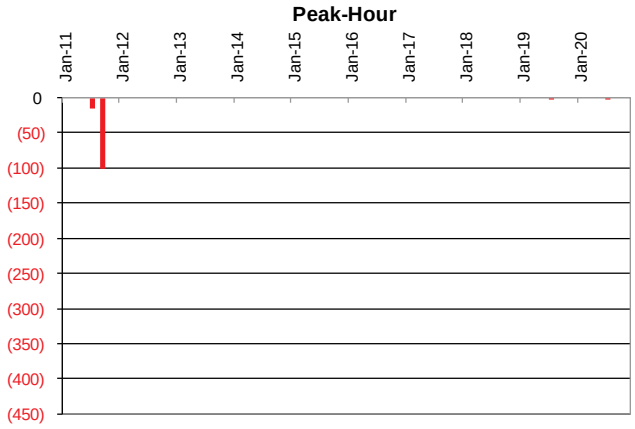
| 2-6 Balanced 1 | | 2-7 Balanced 2 | | 2-8 PNW Transmission | | 2-9 E/S Transmission | | 2-10 Renewable | |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | Geothermal-52 | 2021 | CHP-75 |
| 2022 | SCCT Frame | 2022 | CHP-75 | 2022 | PNW Purchase | 2022 | E/S Purchase | 2022 | Pump St-80 |
| 2023 | | 2023 | SCCT Frame | 2023 | | 2023 | | 2023 | Solar PT-150 |
| 2024 | Solar PT-50 | 2024 | | 2024 | | 2024 | | 2024 | |
| 2025 | CCCT | 2025 | Geothermal-52 | 2025 | | 2025 | | 2025 | CHP-75 |
| 2026 | | 2026 | CHP-75 | 2026 | | 2026 | | 2026 | Solar PT-150 |
| 2027 | | 2027 | Hydro Sm-60 | 2027 | Solar PV-20 | 2027 | Solar PV-20 | 2027 | Solar PV-150 |
| 2028 | Hydro Sm-60 | 2028 | CCCT | 2028 | Geothermal-52 | 2028 | Geothermal-52 | 2028 | Geothermal-52 |
| 2029 | SCCT Frame | 2029 | | 2029 | SCCT Frame | 2029 | SCCT Frame | 2029 | Hydro Sm-100 |
| 2030 | | 2030 | | 2030 | | 2030 | | 2030 | Solar PV-200 |
| **MW** | **802** | **MW** | **784** | **MW** | **794** | **MW** | **794** | **MW** | **1,032** |

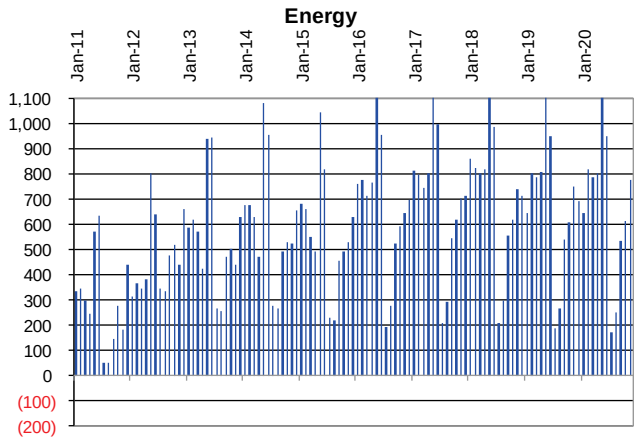
# Detailed Resource Portfolio Design Sheets

## *1-1 Sun and Steam*

| | | | | | | Cumm. | | | | | | | Capital Cost | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | E | P | Type | E | P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | $/kW | Total $ |
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | Solar PV-1 | 1 | 0 | 1 | R* | 0 | 1 | 26 | 69 | 0 | 70 | 44 | $3,750 | $3,750,000 |
| 2013 | Solar PV-5 | 5 | 1 | 3 | R | 1 | 3 | 27 | 70 | 1 | 71 | 43 | $3,750 | $18,750,000 |
| 2014 | CHP-75 | 75 | 70 | 75 | | 71 | 78 | 57 | 78 | 1 | 79 | 21 | $1,888 | $141,600,000 |
| 2015 | Solar PV-30 | 30 | 4 | 17 | R | 75 | 95 | 60 | 104 | 5 | 109 | 49 | $3,750 | $112,500,000 |
| 2016 | CHP-100 | 100 | 93 | 100 | | 168 | 195 | 62 | 104 | 5 | 109 | 48 | $1,888 | $188,800,000 |
| 2017 | Geothermal-52 | 52 | 48 | 52 | R | 216 | 247 | 95 | 113 | 53 | 166 | 71 | $6,385 | $332,020,000 |
| 2018 | Solar PT-125 | 125 | 35 | 114 | R | 251 | 361 | 97 | 119 | 88 | 207 | 109 | $3,220 | 402,500,000 |
| 2019 | Solar PV-30 | 30 | 4 | 17 | R | 255 | 377 | 133 | 128 | 92 | 220 | 87 | $3,750 | $112,500,000 |
| 2020 | Solar PT-75 | 75 | 21 | 68 | R | 276 | 445 | 136 | 129 | 113 | 242 | 106 | $3,220 | $241,500,000 |
| | **Total** | **193** | **276** | **445** | | | | | | | | | | **$1,553,920,000** |

* R=Renewable Resource

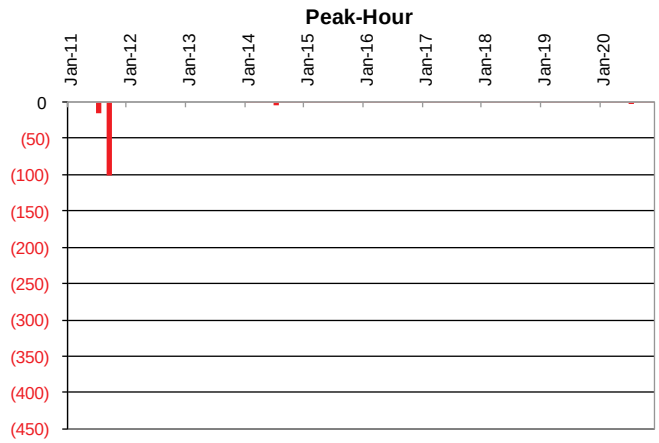


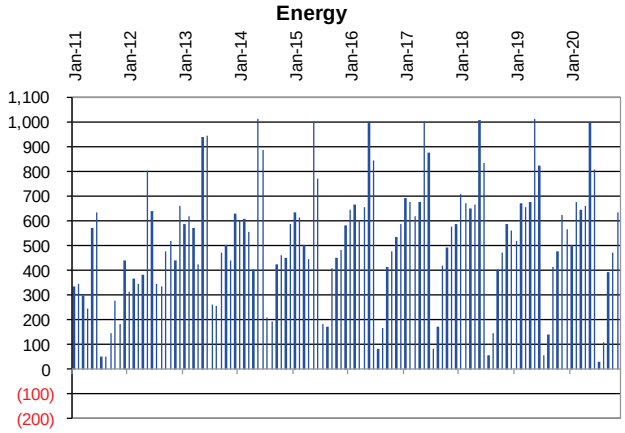



## 1-2 Solar

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | Solar PV-5 | 5 | 1 | 3 | R | 1 | 3 | 57 | 78 | 1 | 78 | 21 | $3,750 | $18,750,000 |
| 2015 | Solar PT-100 | 100 | 28 | 91 | R | 29 | 94 | 60 | 104 | 29 | 132 | 73 | $3,220 | $322,000,000 |
| 2016 | Solar PT-100 | 100 | 28 | 91 | R | 57 | 185 | 62 | 104 | 57 | 161 | 99 | $3,220 | $322,000,000 |
| 2017 | Solar PT-125 | 125 | 35 | 114 | R | 92 | 299 | 95 | 113 | 92 | 205 | 110 | $3,220 | $402,500,000 |
| 2018 | Solar PV-50 | 50 | 7 | 28 | R | 99 | 326 | 97 | 119 | 99 | 217 | 120 | $3,750 | $187,500,000 |
| 2019 | Solar PT-100 | 100 | 28 | 91 | R | 127 | 417 | 133 | 128 | 127 | 255 | 122 | $3,220 | $322,000,000 |
| 2020 | Solar PV-50 | 50 | 7 | 28 | R | 134 | 445 | 136 | 129 | 134 | 263 | 127 | $3,750 | $187,500,000 |
| | **Total** | **530** | **134** | **445** | | | | | | | | | | **$1,762,250,000** |

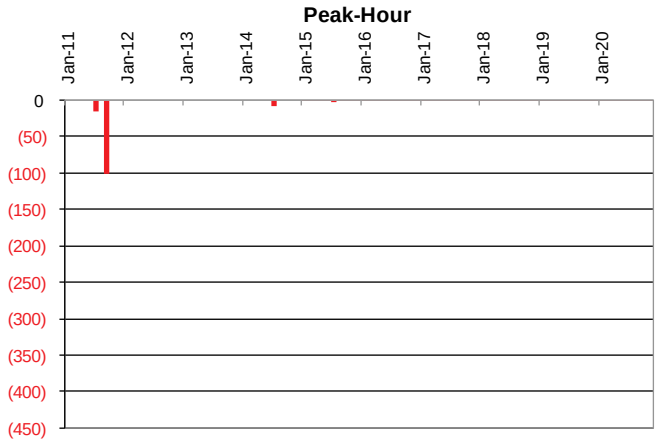
* R=Renewable Resource

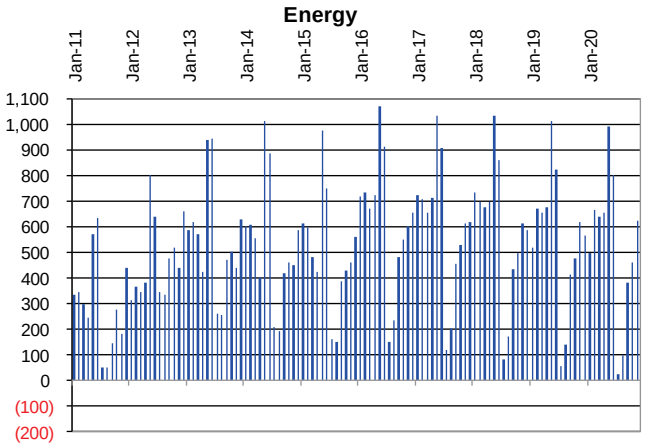


## 1-3 Boardman to Hemingway

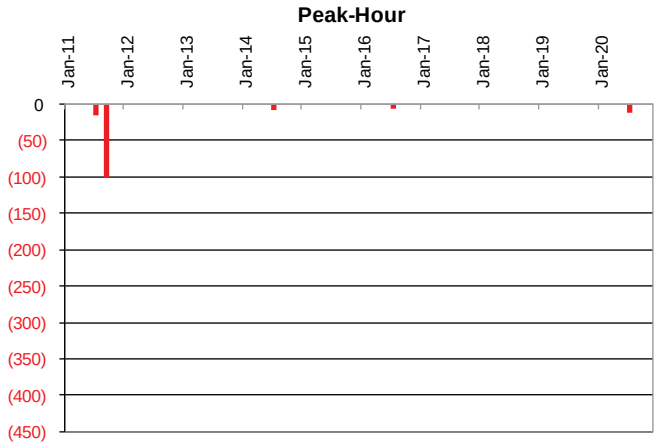
| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | Eastside Purchase | 83 | 8 | 83 | | 8 | 83 | 60 | 104 | 0 | 104 | 44 | $– | $– |
| 2016 | B2H-450 | 367 | 117 | 367 | | 126 | 450 | 62 | 104 | 0 | 104 | 43 | $381 | $247,214,209 |
| 2017 | | 0 | 0 | 0 | | 126 | 450 | 95 | 113 | 0 | 113 | 18 | | |
| 2018 | | 0 | 0 | 0 | | 126 | 450 | 97 | 119 | 0 | 119 | 21 | | |
| 2019 | | 0 | 0 | 0 | | 126 | 450 | 133 | 128 | 0 | 128 | (5) | | |
| 2020 | | 0 | 0 | 0 | | 126 | 450 | 136 | 129 | 0 | 129 | (7) | | |
| | **Total** | **450** | **126** | **450** | | | | | | | | | | **$247,214,209** |

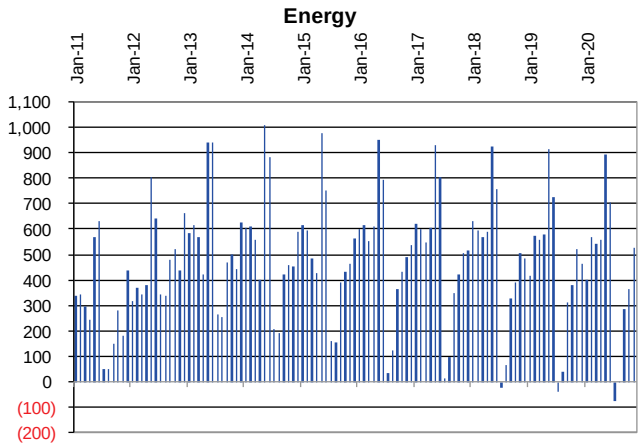


## 1-4 SCCT

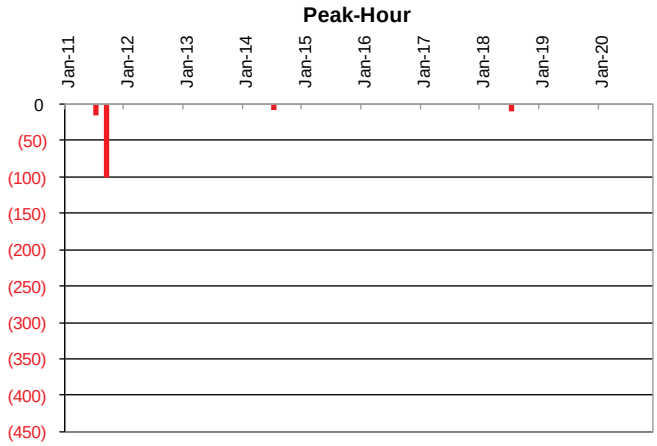
| | | | | | | Cumm. | | | | | | | Capital Cost | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | E | P | Type | E | P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | $/kW | Total $ |
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | SCCT Frame | 170 | 10 | 170 | | 10 | 170 | 60 | 104 | 0 | 104 | 44 | $746 | $126,820,000 |
| 2016 | | 0 | 0 | 0 | | 10 | 170 | 62 | 104 | 0 | 104 | 43 | | |
| 2017 | SCCT Frame | 170 | 10 | 170 | | 20 | 340 | 95 | 113 | 0 | 113 | 18 | $746 | $126,820,000 |
| 2018 | | 0 | 0 | 0 | | 20 | 340 | 97 | 119 | 0 | 119 | 21 | | |
| 2019 | SCCT S Aero-94 | 94 | 8 | 94 | | 28 | 434 | 133 | 128 | 0 | 128 | (5) | $1,063 | $99,922,000 |
| 2020 | | 0 | 0 | 0 | | 28 | 434 | 136 | 129 | 0 | 129 | (7) | | |
| | **Total** | **434** | **28** | **434** | | | | | | | | | | **$353,562,000** |

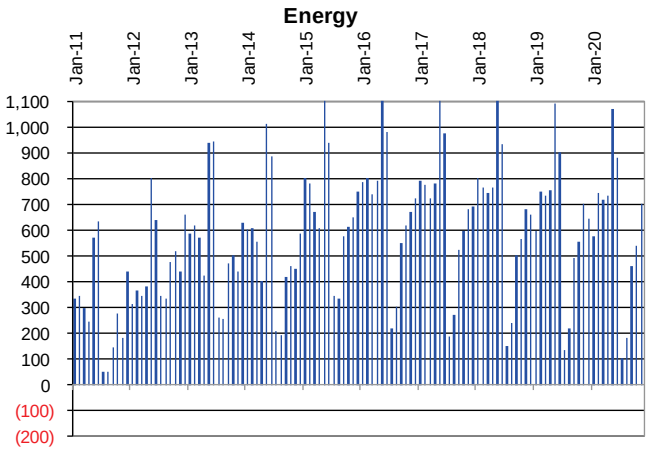


## 1-5 CCCT

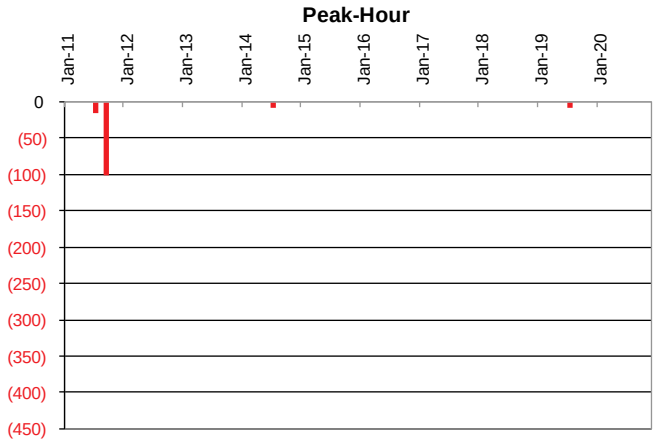
| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | CCCT | 300 | 195 | 300 | | 195 | 300 | 60 | 104 | 0 | 104 | 44 | $1,216 | $364,800,000 |
| 2016 | | 0 | 0 | 0 | | 195 | 300 | 62 | 104 | 0 | 104 | 43 | | |
| 2017 | | 0 | 0 | 0 | | 195 | 300 | 95 | 113 | 0 | 113 | 18 | | |
| 2018 | | 0 | 0 | 0 | | 195 | 300 | 97 | 119 | 0 | 119 | 21 | | |
| 2019 | SCCT Frame | 170 | 10 | 170 | | 205 | 470 | 133 | 128 | 0 | 128 | (5) | $746 | $126,820,000 |
| 2020 | | 0 | 0 | 0 | | 205 | 470 | 136 | 129 | 0 | 129 | (7) | | |
| | **Total** | **470** | **205** | **470** | | | | | | | | | | **$491,620,000** |

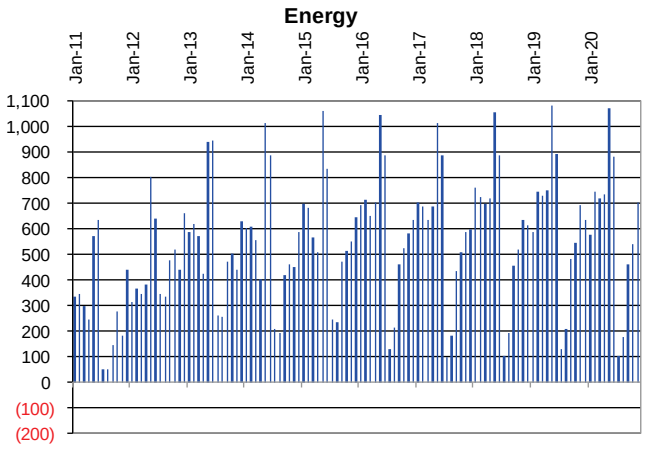


## 1-6 CHP

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | CHP-100 | 100 | 93 | 100 | | 93 | 100 | 60 | 104 | 0 | 104 | 44 | $1,888 | $188,800,000 |
| 2016 | SCCT Frame | 170 | 10 | 170 | | 103 | 270 | 62 | 104 | 0 | 104 | 43 | $746 | $126,820,000 |
| 2017 | | 0 | 0 | 0 | | 103 | 270 | 95 | 113 | 0 | 113 | 18 | | |
| 2018 | CHP-50 | 50 | 47 | 50 | | 150 | 320 | 97 | 119 | 0 | 119 | 21 | $1,888 | $94,400,000 |
| 2019 | CHP-50 | 50 | 47 | 50 | | 196 | 370 | 133 | 128 | 0 | 128 | (5) | $1,888 | $94,400,000 |
| 2020 | SCCT S Aero-94 | 94 | 8 | 94 | | 204 | 464 | 136 | 129 | 0 | 129 | (7) | $1,063 | $99,922,000 |
| | **Total** | **464** | **204** | **464** | | | | | | | | | | **$604,342,000** |

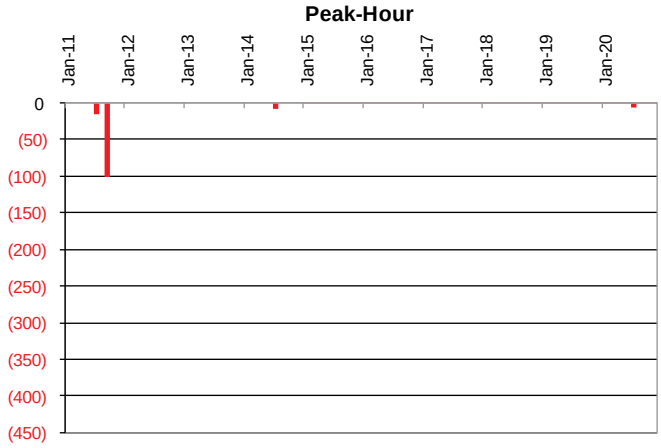


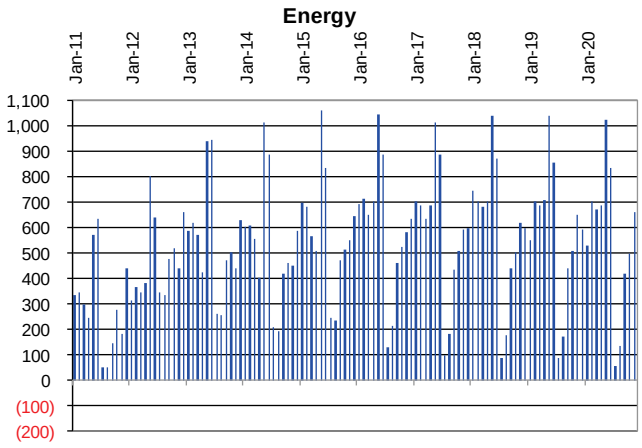



# 1-7 Balanced

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | CHP-100 | 100 | 93 | 100 | | 93 | 100 | 60 | 104 | 0 | 104 | 44 | $1,888 | $188,800,000 |
| 2016 | SCCT Frame | 170 | 10 | 170 | | 103 | 270 | 62 | 104 | 0 | 104 | 43 | $746 | $126,820,000 |
| 2017 | Solar PV-10 | 10 | 1 | 6 | R | 105 | 276 | 95 | 113 | 1 | 114 | 19 | $3,750 | $37,500,000 |
| 2018 | Solar PT-100 | 100 | 28 | 91 | R | 133 | 367 | 97 | 119 | 29 | 148 | 51 | $3,220 | $322,000,000 |
| 2019 | Geothermal-26 | 26 | 24 | 26 | R | 157 | 393 | 133 | 128 | 53 | 182 | 48 | $6,385 | $166,010,000 |
| 2020 | SCCT S Aero-47 | 47 | 4 | 47 | | 160 | 440 | 136 | 129 | 53 | 182 | 46 | $1,063 | $49,961,000 |
| | **Total** | **453** | **160** | **440** | | | | | | | | | | **$891,091,000** |

* R=Renewable Resource

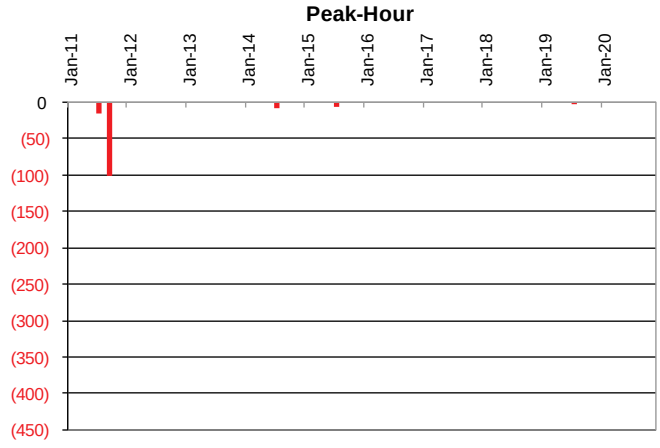


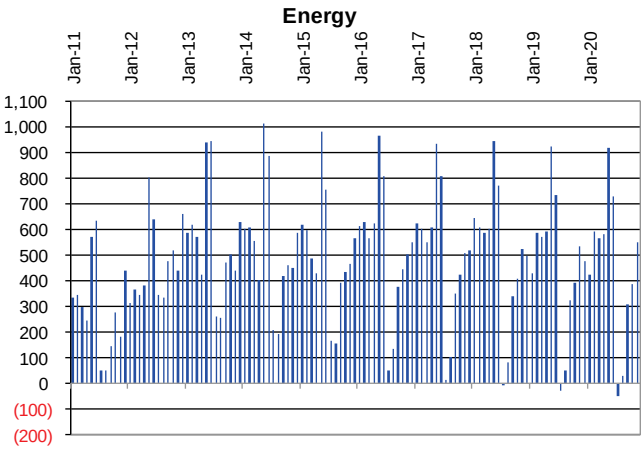



## 1-8 Pumped Storage

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | | 0 | 0 | 0 | | 0 | 0 | 26 | 69 | 0 | 69 | 43 | | |
| 2013 | | 0 | 0 | 0 | | 0 | 0 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 0 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | Pump St-80 | 80 | 13 | 80 | R | 13 | 80 | 60 | 104 | 13 | 116 | 57 | $5,000 | $400,000,000 |
| 2016 | SCCT Frame | 170 | 10 | 170 | | 23 | 250 | 62 | 104 | 13 | 117 | 55 | $746 | $126,820,000 |
| 2017 | | 0 | 0 | 0 | | 23 | 250 | 95 | 113 | 13 | 126 | 31 | | |
| 2018 | Pump St-80 | 80 | 13 | 80 | R | 36 | 330 | 97 | 119 | 26 | 144 | 47 | $5,000 | $400,000,000 |
| 2019 | SCCT S Aero-47 | 47 | 4 | 47 | | 40 | 377 | 133 | 128 | 26 | 154 | 21 | $1,063 | $49,961,000 |
| 2020 | Pump St-80 | 80 | 13 | 80 | R | 52 | 457 | 136 | 129 | 38 | 167 | 31 | $5,000 | $400,000,000 |
| | **Total** | **457** | **52** | **457** | | | | | | | | | | **$1,376,781,000** |

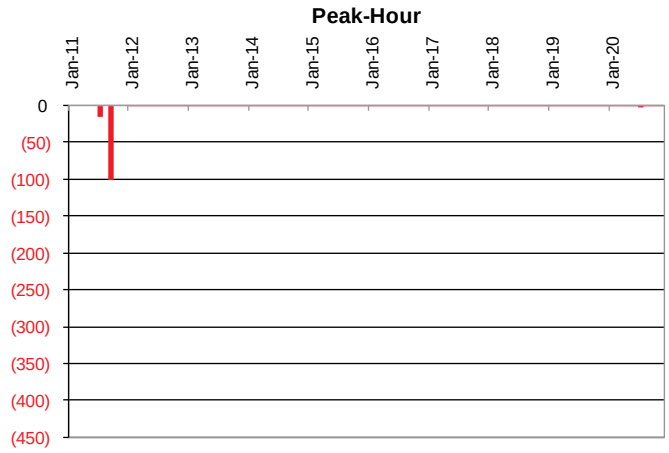
* R=Renewable Resource

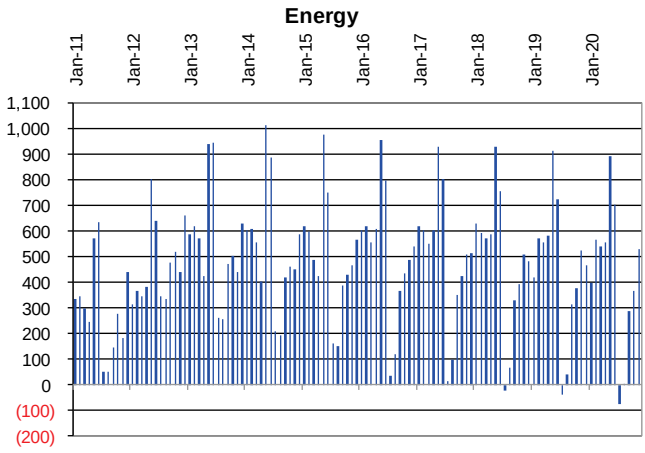


## 1-9 Distributed Generation

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | | 0 | 0 | 0 | | 0 | 0 | – | 44 | 0 | 44 | 44 | | |
| 2012 | Dist Gen-10 | 10 | 0 | 10 | | 0 | 10 | 26 | 69 | 0 | 69 | 43 | $– | $– |
| 2013 | | 0 | 0 | 0 | | 0 | 10 | 27 | 70 | 0 | 70 | 43 | | |
| 2014 | | 0 | 0 | 0 | | 0 | 10 | 57 | 78 | 0 | 78 | 21 | | |
| 2015 | SCCT Frame | 170 | 10 | 170 | | 10 | 180 | 60 | 104 | 0 | 104 | 44 | $746 | $126,820,000 |
| 2016 | | 0 | 0 | 0 | | 10 | 180 | 62 | 104 | 0 | 104 | 43 | | |
| 2017 | SCCT Frame | 170 | 10 | 170 | | 20 | 350 | 95 | 113 | 0 | 113 | 18 | $746 | $126,820,000 |
| 2018 | | 0 | 0 | 0 | | 20 | 350 | 97 | 119 | 0 | 119 | 21 | | |
| 2019 | SCCT S Aero-94 | 94 | 8 | 94 | | 28 | 444 | 133 | 128 | 0 | 128 | (5) | $1,063 | $99,922,000 |
| 2020 | | 0 | 0 | 0 | | 28 | 444 | 136 | 129 | 0 | 129 | (7) | | |
| | **Total** | **444** | **28** | **444** | | | | | | | | | | **$353,562,000** |

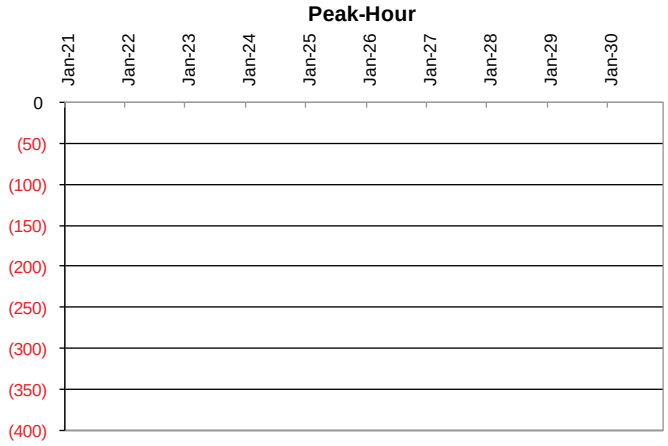


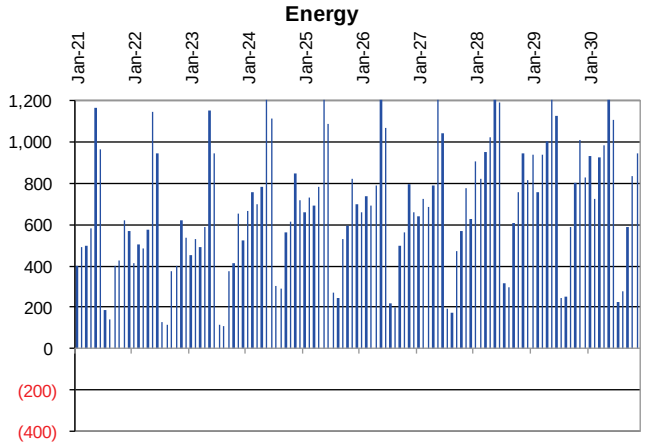



# 2-1 Nuclear

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Solar PT-100 | 100 | 28 | 91 | R | 28 | 91 | 174 | 139 | 28 | 167 | (7) | $3,220 | $322,000,000 |
| 2022 | Pump St-50 | 50 | 8 | 50 | R | 36 | 141 | 178 | 140 | 36 | 176 | (2) | $5,000 | $250,000,000 |
| 2023 | Solar PT-100 | 100 | 28 | 91 | R | 64 | 232 | 182 | 141 | 64 | 205 | 23 | $3,220 | $322,000,000 |
| 2024 | Nuclear | 250 | 213 | 250 | | 277 | 482 | 185 | 142 | 64 | 206 | 21 | $4,103 | $1,025,750,000 |
| 2025 | | 0 | 0 | 0 | | 277 | 482 | 189 | 143 | 64 | 207 | 18 | | |
| 2026 | | 0 | 0 | 0 | | 277 | 482 | 193 | 144 | 64 | 208 | 15 | | |
| 2027 | | 0 | 0 | 0 | | 277 | 482 | 196 | 145 | 64 | 209 | 13 | | |
| 2028 | Nuclear | 250 | 213 | 250 | | 489 | 732 | 202 | 113 | 64 | 177 | (25) | $4,103 | $1,025,750,000 |
| 2029 | Pump St-50 | 50 | 8 | 50 | R | 497 | 782 | 206 | 114 | 72 | 186 | (20) | $5,000 | $250,000,000 |
| 2030 | | 0 | 0 | 0 | | 497 | 782 | 211 | 115 | 72 | 187 | (24) | | |
| | **Total** | **800** | **497** | **782** | | | | | | | | | | **$3,195,500,000** |

* R=Renewable Resource

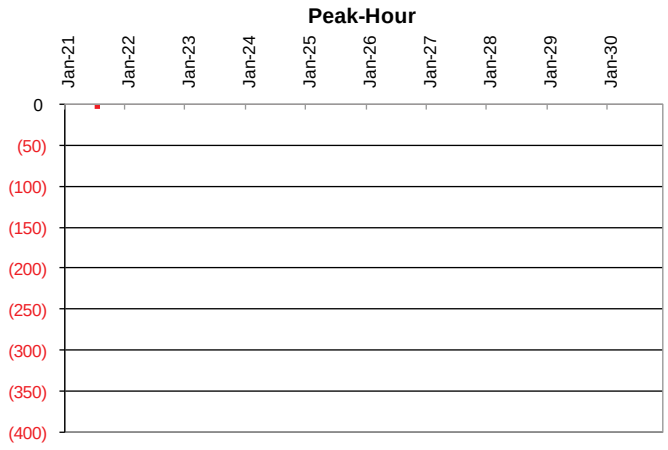


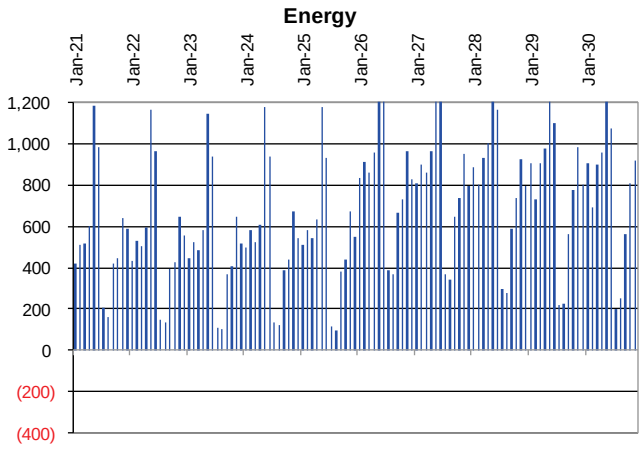



## 2-2 IGCC

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Geothermal-52 | 52 | 48 | 52 | R | 48 | 52 | 174 | 139 | 48 | 187 | 13 | $6,385 | $332,020,000 |
| 2022 | SCCT Frame | 170 | 10 | 170 | | 58 | 222 | 178 | 140 | 48 | 188 | 10 | $746 | $126,820,000 |
| 2023 | | 0 | 0 | 0 | | 58 | 222 | 182 | 141 | 48 | 189 | 7 | | |
| 2024 | CHP-50 | 50 | 47 | 50 | | 105 | 272 | 185 | 142 | 48 | 190 | 5 | $1,888 | $94,400,000 |
| 2025 | Solar PT-75 | 75 | 21 | 68 | R | 126 | 340 | 189 | 143 | 69 | 212 | 23 | $3,220 | $241,500,000 |
| 2026 | IGCC w/CS | 380 | 323 | 380 | | 449 | 720 | 193 | 144 | 69 | 213 | 20 | $4,506 | $1,712,280,000 |
| 2027 | | 0 | 0 | 0 | | 449 | 720 | 196 | 145 | 69 | 214 | 18 | | |
| 2028 | Solar PT-75 | 75 | 21 | 68 | R | 470 | 789 | 202 | 113 | 90 | 202 | 1 | $3,220 | $241,500,000 |
| 2029 | | 0 | 0 | 0 | | 470 | 789 | 206 | 114 | 90 | 204 | (3) | | |
| 2030 | | 0 | 0 | 0 | | 470 | 789 | 211 | 115 | 90 | 205 | (6) | | |
| | **Total** | **802** | **470** | **789** | | | | | | | | | | **$2,748,520,000** |

* R=Renewable Resource

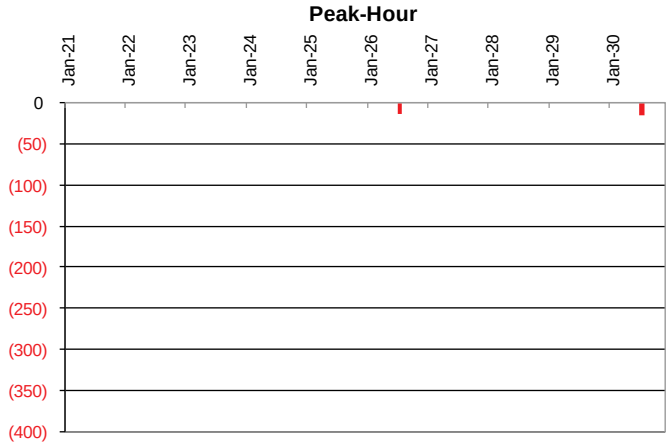


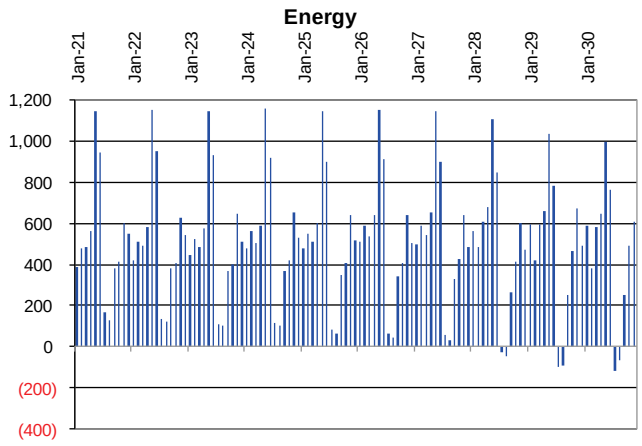



## 2-3 SCCT/Wind

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | SCCT S Aero-141 | 141 | 11 | 141 | | 11 | 141 | 174 | 139 | 0 | 139 | (35) | $1,063 | $149,883,000 |
| 2022 | Wind-100 | 100 | 32 | 5 | R | 43 | 146 | 178 | 140 | 32 | 172 | (6) | $1,733 | $173,300,000 |
| 2023 | SCCT S Aero-141 | 141 | 11 | 141 | | 55 | 287 | 182 | 141 | 32 | 173 | (9) | $1,063 | $149,883,000 |
| 2024 | Wind-100 | 100 | 32 | 5 | R | 87 | 292 | 185 | 142 | 64 | 206 | 21 | $1,733 | $173,300,000 |
| 2025 | SCCT S Aero-94 | 94 | 8 | 94 | | 94 | 386 | 189 | 143 | 64 | 207 | 18 | $1,063 | $99,922,000 |
| 2026 | Wind-100 | 100 | 32 | 5 | R | 126 | 391 | 193 | 144 | 96 | 240 | 47 | $1,733 | $173,300,000 |
| 2027 | SCCT S Aero-141 | 141 | 11 | 141 | | 137 | 532 | 196 | 145 | 96 | 241 | 45 | $1,063 | $149,883,000 |
| 2028 | SCCT S Aero-141 | 141 | 11 | 141 | | 149 | 673 | 202 | 113 | 96 | 209 | 7 | $1,063 | $149,883,000 |
| 2029 | SCCT S Aero-94 | 94 | 8 | 94 | | 156 | 767 | 206 | 114 | 96 | 210 | 4 | $1,063 | $99,922,000 |
| 2030 | | 0 | 0 | 0 | | 156 | 767 | 211 | 115 | 96 | 211 | (0) | | |
| | **Total** | **1,052** | **156** | **767** | | | | | | | | | | **$1,319,276,000** |

* R=Renewable Resource

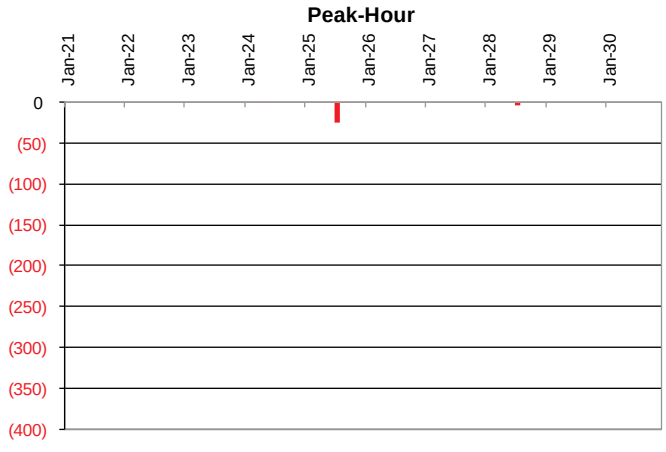


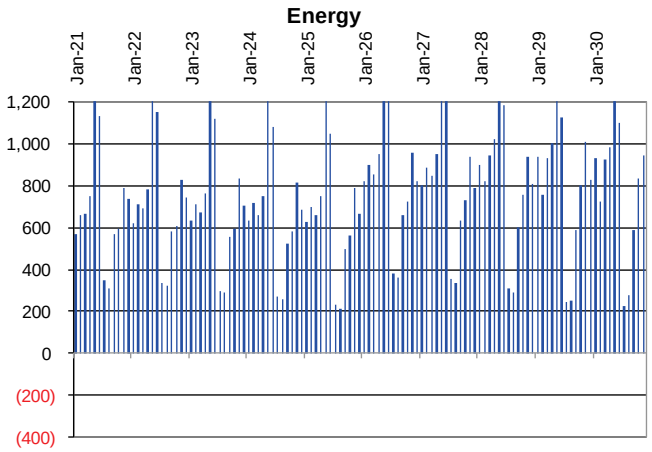



## 2-4 CCCT/Wind

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | CCCT | 300 | 195 | 300 | | 195 | 300 | 174 | 139 | 0 | 139 | (35) | $1,216 | $364,800,000 |
| 2022 | Wind-150 | 150 | 48 | 8 | R | 243 | 308 | 178 | 140 | 48 | 188 | 10 | $1,733 | $259,950,000 |
| 2023 | | 0 | 0 | 0 | | 243 | 308 | 182 | 141 | 48 | 189 | 7 | | |
| 2024 | | 0 | 0 | 0 | | 243 | 308 | 185 | 142 | 48 | 190 | 5 | | |
| 2025 | | 0 | 0 | 0 | | 243 | 308 | 189 | 143 | 48 | 191 | 2 | | |
| 2026 | CCCT | 300 | 195 | 300 | | 438 | 608 | 193 | 144 | 48 | 192 | (1) | $1,216 | $364,800,000 |
| 2027 | | 0 | 0 | 0 | | 438 | 608 | 196 | 145 | 48 | 193 | (3) | | |
| 2028 | Wind-150 | 150 | 48 | 8 | R | 486 | 615 | 202 | 113 | 96 | 209 | 7 | $1,733 | $259,950,000 |
| 2029 | SCCT Frame | 170 | 10 | 170 | | 496 | 785 | 206 | 114 | 96 | 210 | 4 | $746 | $126,820,000 |
| 2030 | | 0 | 0 | 0 | | 496 | 785 | 211 | 115 | 96 | 211 | (0) | | |
| | **Total** | **1,070** | **496** | **785** | | | | | | | | | | **$1,376,320,000** |

* R=Renewable Resource

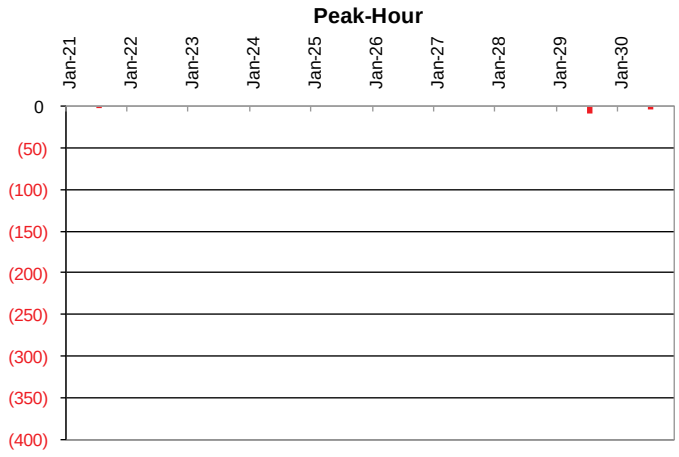


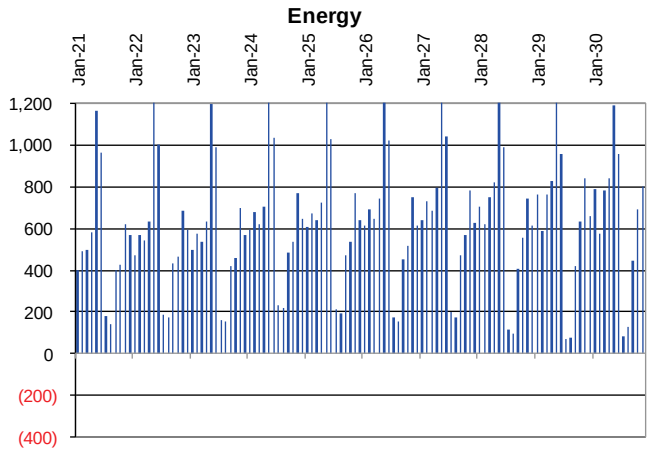



## 2-5 Hydro/CHP

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Hydro Sm-60 | 60 | 27 | 54 | R | 27 | 54 | 174 | 139 | 27 | 166 | (8) | $4,000 | $240,000,000 |
| 2022 | CHP-75 | 75 | 70 | 75 | | 97 | 129 | 178 | 140 | 27 | 167 | (11) | $1,888 | $141,600,000 |
| 2023 | Pump St-80 | 80 | 13 | 80 | R | 110 | 209 | 182 | 141 | 40 | 181 | (1) | $5,000 | $400,000,000 |
| 2024 | CHP-100 | 100 | 93 | 100 | | 203 | 309 | 185 | 142 | 40 | 182 | (3) | $1,888 | $188,800,000 |
| 2025 | Hydro-40 | 40 | 18 | 32 | R | 221 | 341 | 189 | 143 | 58 | 201 | 12 | $4,000 | $160,000,000 |
| 2026 | Pump St-80 | 80 | 13 | 80 | R | 233 | 421 | 193 | 144 | 71 | 215 | 22 | $5,000 | $400,000,000 |
| 2027 | Hydro Sm-100 | 100 | 45 | 90 | R | 278 | 511 | 196 | 145 | 116 | 261 | 64 | $4,000 | $400,000,000 |
| 2028 | SCCT S Aero-141 | 141 | 11 | 141 | | 290 | 652 | 202 | 113 | 116 | 228 | 26 | $1,063 | $149,883,000 |
| 2029 | Hydro Sm-80 | 80 | 36 | 72 | R | 326 | 724 | 206 | 114 | 152 | 265 | 59 | $4,000 | $320,000,000 |
| 2030 | Hydro Sm-60 | 60 | 27 | 54 | R | 353 | 778 | 211 | 115 | 179 | 294 | 83 | $4,000 | $240,000,000 |
| | **Total** | **816** | **353** | **778** | | | | | | | | | | **$2,640,283,000** |

* R=Renewable Resource

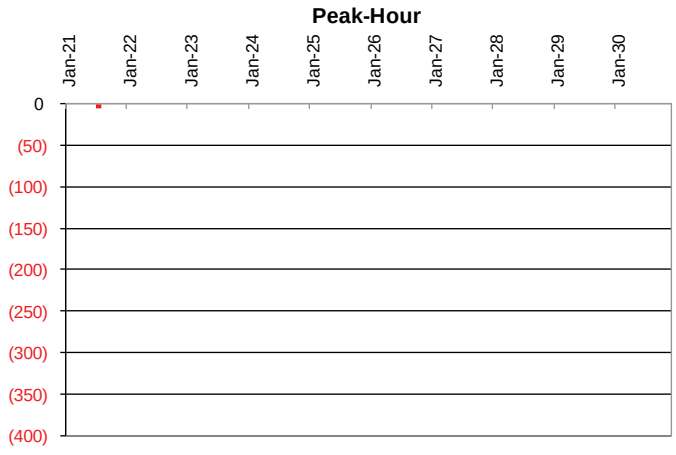


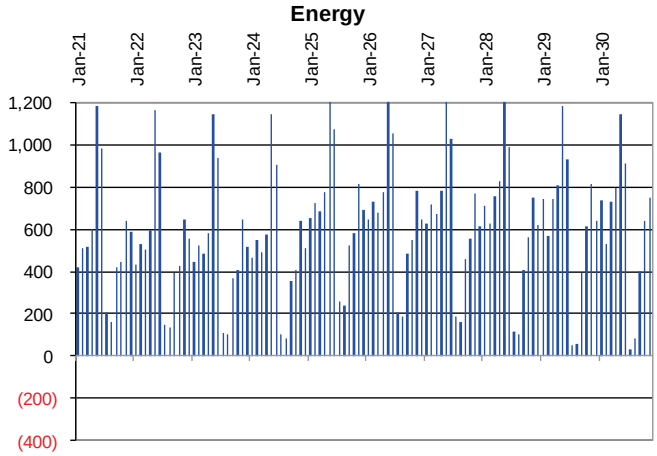



## 2-6 Balanced 1

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Geothermal-52 | 52 | 48 | 52 | R | 48 | 52 | 174 | 139 | 48 | 187 | 13 | $6,385 | $332,020,000 |
| 2022 | SCCT Frame | 170 | 10 | 170 | | 58 | 222 | 178 | 140 | 48 | 188 | 10 | $746 | $126,820,000 |
| 2023 | | 0 | 0 | 0 | | 58 | 222 | 182 | 141 | 48 | 189 | 7 | | |
| 2024 | Solar PT-50 | 50 | 14 | 46 | R | 72 | 268 | 185 | 142 | 62 | 204 | 19 | $3,220 | $161,000,000 |
| 2025 | CCCT | 300 | 195 | 300 | | 267 | 568 | 189 | 143 | 62 | 205 | 16 | $1,216 | $364,800,000 |
| 2026 | | 0 | 0 | 0 | | 267 | 568 | 193 | 144 | 62 | 206 | 13 | | |
| 2027 | | 0 | 0 | 0 | | 267 | 568 | 196 | 145 | 62 | 207 | 11 | | |
| 2028 | Hydro Sm-60 | 60 | 27 | 54 | R | 294 | 622 | 202 | 113 | 89 | 201 | (0) | $4,000 | $240,000,000 |
| 2029 | SCCT Frame | 170 | 10 | 170 | | 304 | 792 | 206 | 114 | 89 | 203 | (4) | $746 | $126,820,000 |
| 2030 | | 0 | 0 | 0 | | 304 | 792 | 211 | 115 | 89 | 204 | (7) | | |
| | **Total** | **802** | **304** | **792** | | | | | | | | | | **$1,351,460,000** |

* R=Renewable Resource

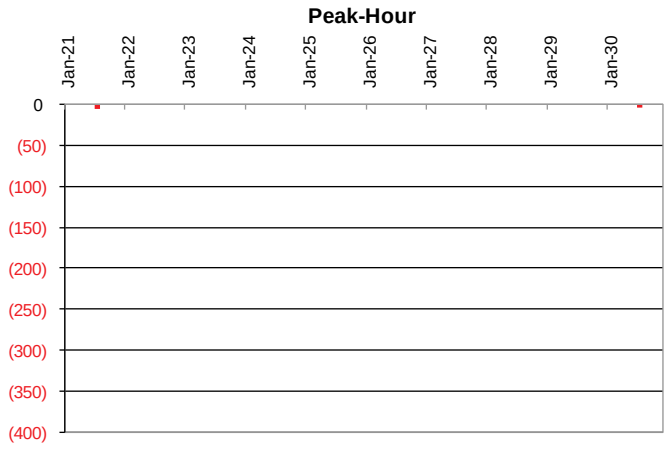


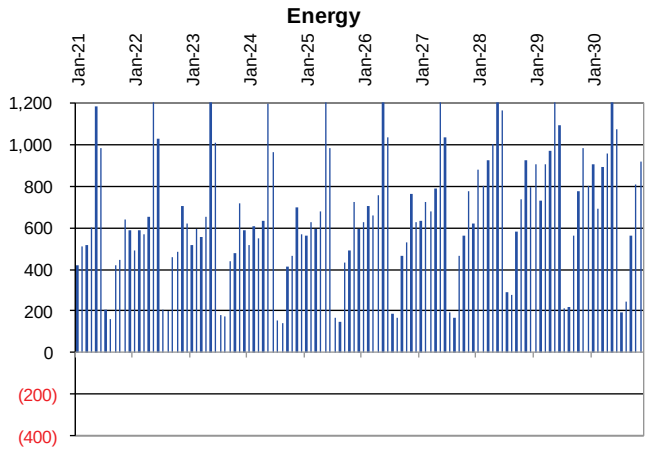



# 2-7 Balanced 2

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | Geothermal-52 | 52 | 48 | 52 | R | 48 | 52 | 174 | 139 | 48 | 187 | 13 | $6,385 | $332,020,000 |
| 2022 | CHP-75 | 75 | 70 | 75 | | 118 | 127 | 178 | 140 | 48 | 188 | 10 | $1,888 | $141,600,000 |
| 2023 | SCCT Frame | 170 | 10 | 170 | | 128 | 297 | 182 | 141 | 48 | 189 | 7 | $746 | $126,820,000 |
| 2024 | | 0 | 0 | 0 | | 128 | 297 | 185 | 142 | 48 | 190 | 5 | | |
| 2025 | Geothermal-52 | 52 | 48 | 52 | R | 176 | 349 | 189 | 143 | 96 | 239 | 50 | $6,385 | $332,020,000 |
| 2026 | CHP-75 | 75 | 70 | 75 | | 245 | 424 | 193 | 144 | 96 | 240 | 47 | $1,888 | $141,600,000 |
| 2027 | Hydro Sm-60 | 60 | 27 | 54 | R | 272 | 478 | 196 | 145 | 123 | 268 | 71 | $4,000 | $240,000,000 |
| 2028 | CCCT | 300 | 195 | 300 | | 467 | 778 | 202 | 113 | 123 | 235 | 34 | $1,216 | $364,800,000 |
| 2029 | | 0 | 0 | 0 | | 467 | 778 | 206 | 114 | 123 | 236 | 30 | | |
| 2030 | | 0 | 0 | 0 | | 467 | 778 | 211 | 115 | 123 | 238 | 27 | | |
| | **Total** | **784** | **467** | **778** | | | | | | | | | | **$1,678,860,000** |

* R=Renewable Resource

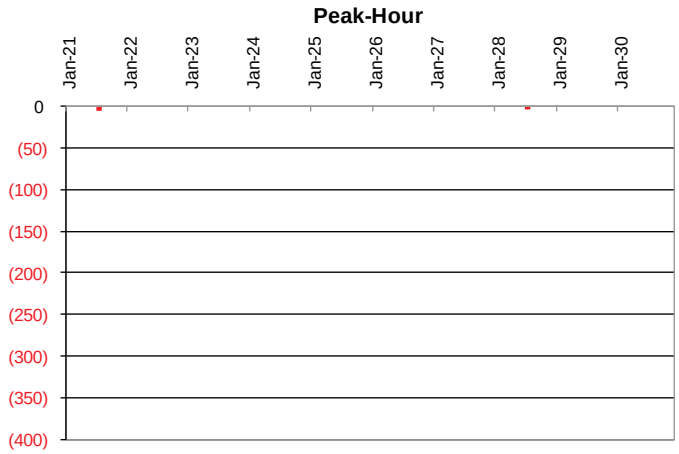


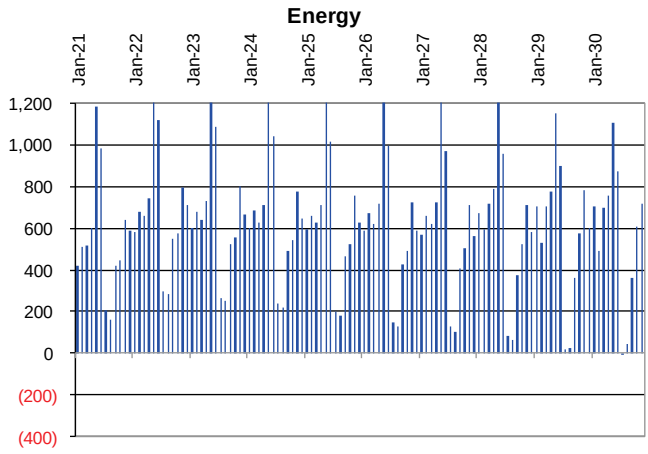



## 2-8 Pacific Northwest Transmission

| | | | | | | Cumm. | | | | | | | Capital Cost | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | E | P | Type | E | P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | $/kW | Total $ |
| 2021 | Geothermal-52 | 52 | 48 | 52 | R | 48 | 52 | 174 | 139 | 48 | 187 | 13 | $6,385 | $332,020,000 |
| 2022 | PNW Purchase | 500 | 160 | 500 | | 208 | 552 | 178 | 140 | 48 | 188 | 10 | $381 | $190,500,000 |
| 2023 | | 0 | 0 | 0 | | 208 | 552 | 182 | 141 | 48 | 189 | 7 | | |
| 2024 | | 0 | 0 | 0 | | 208 | 552 | 185 | 142 | 48 | 190 | 5 | | |
| 2025 | | 0 | 0 | 0 | | 208 | 552 | 189 | 143 | 48 | 191 | 2 | | |
| 2026 | | 0 | 0 | 0 | | 208 | 552 | 193 | 144 | 48 | 192 | (1) | | |
| 2027 | Solar PV-20 | 20 | 3 | 11 | R | 211 | 563 | 196 | 145 | 51 | 196 | (1) | $3,750 | $75,000,000 |
| 2028 | Geothermal-52 | 52 | 48 | 52 | R | 258 | 615 | 202 | 113 | 98 | 211 | 9 | $6,385 | $332,020,000 |
| 2029 | SCCT Frame | 170 | 10 | 170 | | 269 | 785 | 206 | 114 | 98 | 212 | 6 | $746 | $126,820,000 |
| 2030 | | 0 | 0 | 0 | | 269 | 785 | 211 | 115 | 98 | 214 | 2 | | |
| | **Total** | **794** | **269** | **785** | | | | | | | | | | **$1,056,360,000** |

* R=Renewable Resource

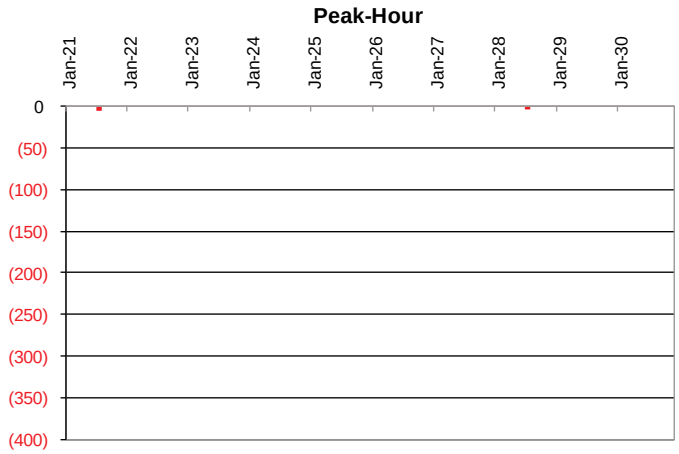


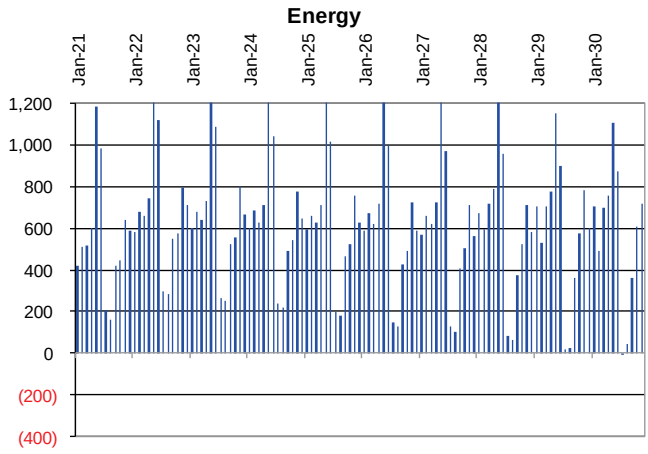



## 2-9 Eastside Transmission

| | | | | | | Cumm. | | | | | | | Capital Cost | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Resource | MW | E | P | Type | E | P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | $/kW | Total $ |
| 2021 | Geothermal-52 | 52 | 48 | 52 | R | 48 | 52 | 174 | 139 | 48 | 187 | 13 | $6,385 | $332,020,000 |
| 2022 | E/S Purchase | 500 | 160 | 500 | | 208 | 552 | 178 | 140 | 48 | 188 | 10 | $381 | $190,500,000 |
| 2023 | | 0 | 0 | 0 | | 208 | 552 | 182 | 141 | 48 | 189 | 7 | | |
| 2024 | | 0 | 0 | 0 | | 208 | 552 | 185 | 142 | 48 | 190 | 5 | | |
| 2025 | | 0 | 0 | 0 | | 208 | 552 | 189 | 143 | 48 | 191 | 2 | | |
| 2026 | | 0 | 0 | 0 | | 208 | 552 | 193 | 144 | 48 | 192 | (1) | | |
| 2027 | Solar PV-20 | 20 | 3 | 11 | R | 211 | 563 | 196 | 145 | 51 | 196 | (1) | $3,750 | $75,000,000 |
| 2028 | Geothermal-52 | 52 | 48 | 52 | R | 258 | 615 | 202 | 113 | 98 | 211 | 9 | $6,385 | $332,020,000 |
| 2029 | SCCT Frame | 170 | 10 | 170 | | 269 | 785 | 206 | 114 | 98 | 212 | 6 | $746 | $126,820,000 |
| 2030 | | 0 | 0 | 0 | | 269 | 785 | 211 | 115 | 98 | 214 | 2 | | |
| | **Total** | **794** | **269** | **785** | | | | | | | | | | **$1,056,360,000** |

* R=Renewable Resource

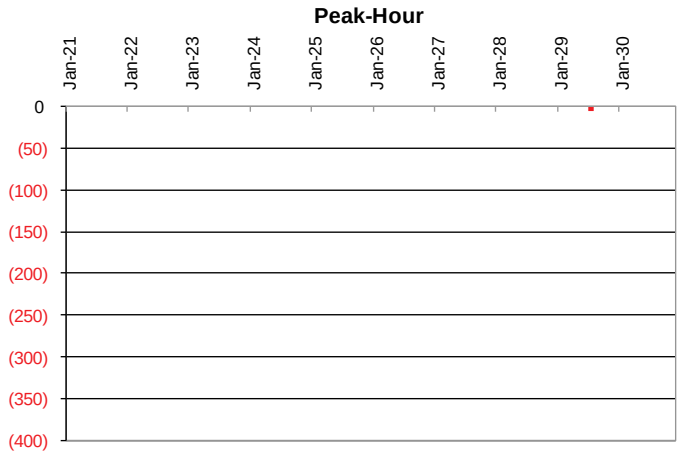


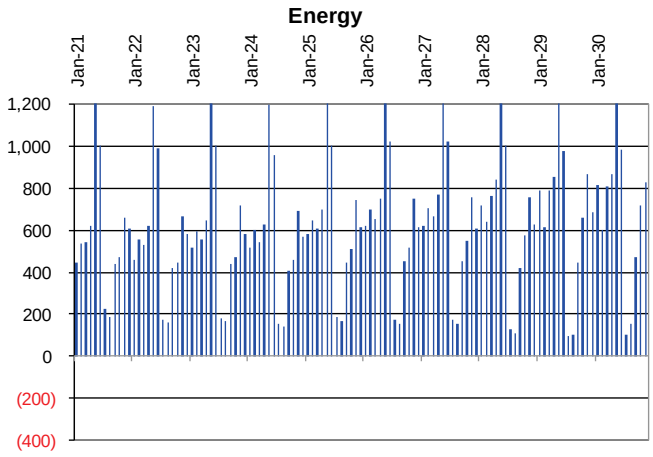



## 2-10 Renewable

| Year | Resource | MW | E | P | Type | Cumm. E | Cumm. P | REC Req. | Existing RECs | New RECs | Total RECs | REC Position | Capital Cost $/kW | Capital Cost Total $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | CHP-75 | 75 | 70 | 75 | | 70 | 75 | 174 | 139 | 0 | 139 | (35) | $1,888 | $141,600,000 |
| 2022 | Pump St-80 | 80 | 13 | 80 | R | 83 | 155 | 178 | 140 | 13 | 153 | (25) | $5,000 | $400,000,000 |
| 2023 | Solar PT-150 | 150 | 42 | 137 | R | 125 | 292 | 182 | 141 | 55 | 196 | 14 | $3,220 | $483,000,000 |
| 2024 | | 0 | 0 | 0 | | 125 | 292 | 185 | 142 | 55 | 197 | 12 | | |
| 2025 | CHP-75 | 75 | 70 | 75 | | 194 | 367 | 189 | 143 | 55 | 198 | 9 | $1,888 | $141,600,000 |
| 2026 | Solar PT-150 | 150 | 42 | 137 | R | 236 | 503 | 193 | 144 | 97 | 241 | 48 | $3,220 | $483,000,000 |
| 2027 | Solar PV-150 | 150 | 21 | 83 | R | 257 | 586 | 196 | 145 | 118 | 263 | 67 | $3,750 | $562,500,000 |
| 2028 | Geothermal-52 | 52 | 48 | 52 | R | 305 | 638 | 202 | 113 | 166 | 278 | 77 | $6,385 | $332,020,000 |
| 2029 | Hydro Sm-100 | 100 | 45 | 90 | R | 350 | 728 | 206 | 114 | 211 | 324 | 118 | $4,000 | $400,000,000 |
| 2030 | Solar PV-200 | 200 | 28 | 110 | R | 378 | 838 | 211 | 115 | 239 | 354 | 143 | $3,750 | $750,000,000 |
| | **Total** | **1,032** | **378** | **838** | | | | | | | | | | **$3,693,720,000** |

* R=Renewable Resource



# Stochastic Analysis Results

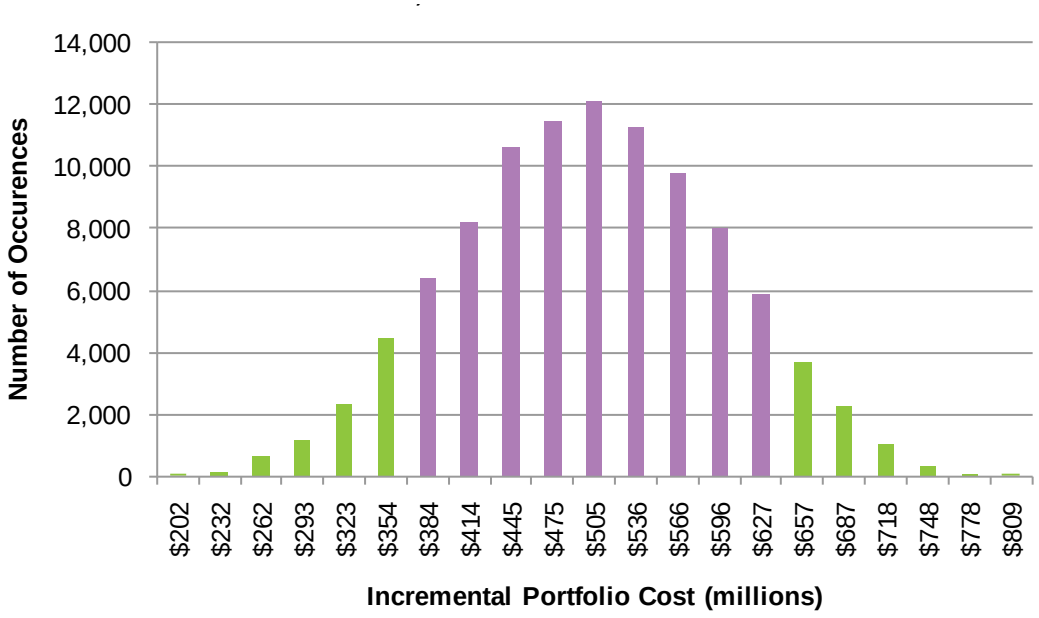
## *1-1 Sun and Steam (2011–2020)*

**Base Portfolio Cost[1]=$496,198[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$54,445 | $61,186 | $441,753 | $557,384 |
| REC | -$47,738 | $23,869 | $448,460 | $520,067 |
| Carbon | -$5,748 | $31,584 | $490,450 | $527,782 |
| Load | -$2,281 | $2,516 | $493,917 | $498,714 |
| DSM | -$48,508 | $100,453 | $447,690 | $596,651 |
| Capital | -$135,692 | $92,944 | $360,506 | $589,142 |
| **Total** | **-$294,412** | **$312,552** | **$201,786** | **$808,750** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *1-2 Solar (2011–2020)*

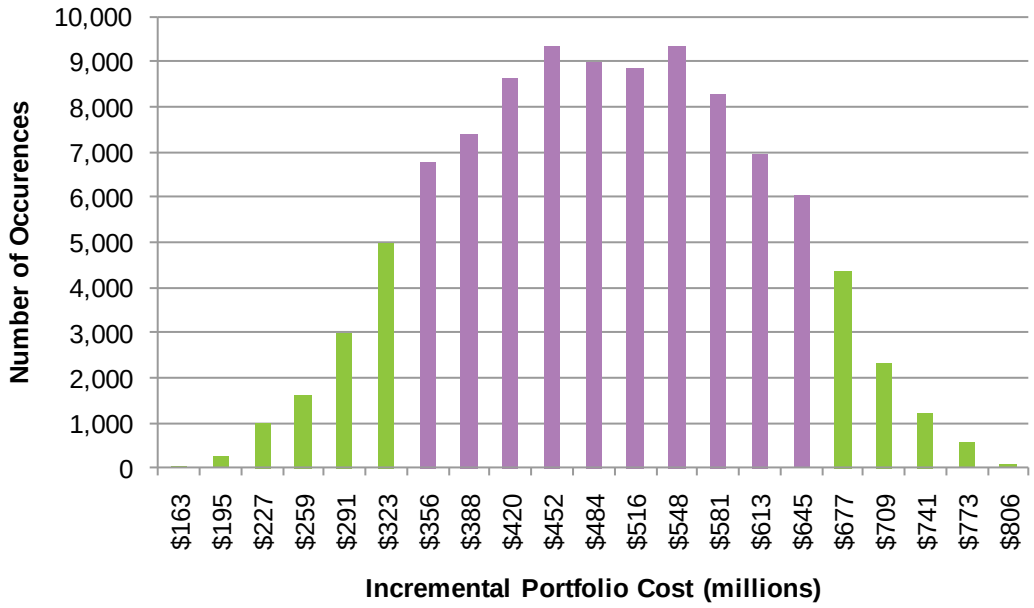
**Base Portfolio Cost[1]=$505,407[2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost Low | Adjustment to Base Incremental Portfolio Cost High | Incremental Portfolio Cost Range Low | Incremental Portfolio Cost Range High |
|---|---|---|---|---|
| Natural gas | -$742 | $515 | $504,665 | $505,922 |
| REC | -$63,012 | $31,506 | $442,395 | $536,913 |
| Carbon | -$12,519 | $36,499 | $492,888 | $541,906 |
| Load | -$3,623 | $2,122 | $501,784 | $507,529 |
| DSM | -$50,344 | $100,172 | $455,063 | $605,579 |
| Capital | -$212,449 | $129,300 | $292,958 | $634,707 |
| **Total** | **-$342,689** | **$300,114** | **$162,718** | **$805,521** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



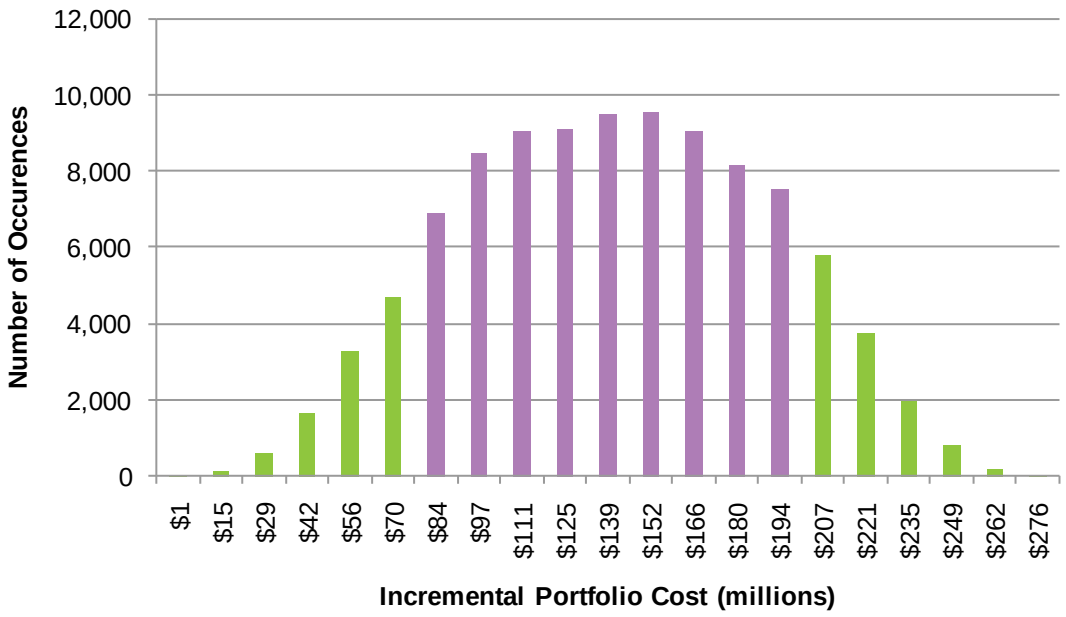
## *1-3 Boardman to Hemingway (2011–2020)*

**Base Portfolio Cost[1]=$86,079[2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| | Low | High | Low | High |
| Natural gas | $0 | $21,793 | $86,079 | $107,872 |
| REC | -$18,827 | $9,413 | $67,252 | $95,492 |
| Carbon | -$3,542 | $20,399 | $82,537 | $106,478 |
| Load | $0 | $19,089 | $86,079 | $105,168 |
| DSM | -$47,727 | $99,606 | $38,352 | $185,685 |
| Capital | -$14,840 | $19,785 | $71,239 | $105,864 |
| **Total** | **-$84,936** | **$190,085** | **$1,143** | **$276,164** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



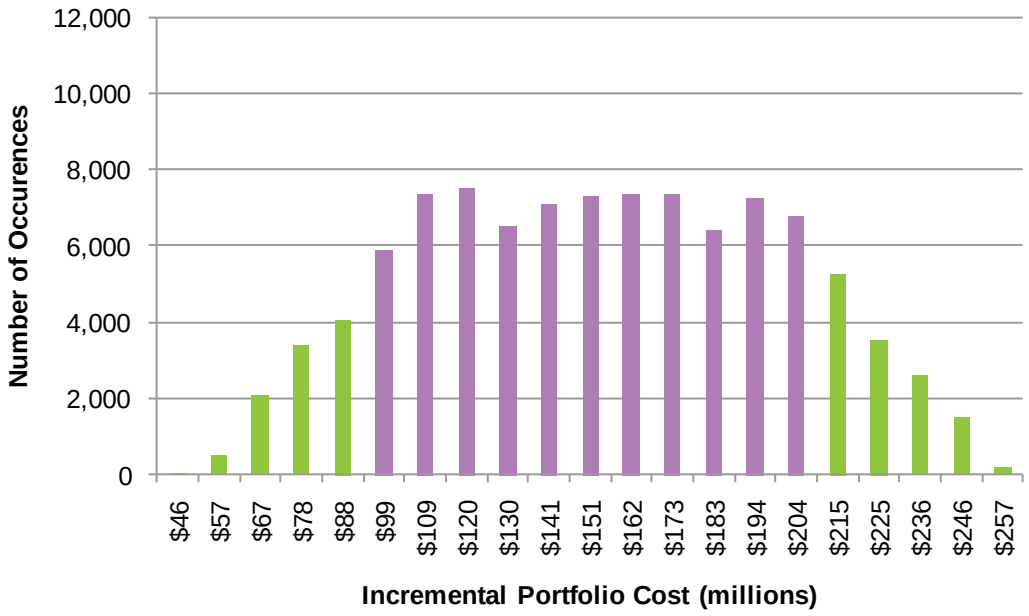
## *1-4 SCCT (2011–2020)*

**Base Portfolio Cost[1]=$129,443[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | $0 | $1,853 | $129,443 | $131,296 |
| REC | -$18,826 | $9,413 | $110,617 | $138,856 |
| Carbon | $0 | $3,473 | $129,443 | $132,916 |
| Load | -$337 | $1,639 | $129,106 | $131,082 |
| DSM | -$47,895 | $100,184 | $81,548 | $229,627 |
| Capital | -$16,325 | $10,884 | $113,118 | $140,327 |
| **Total** | **-$83,383** | **$127,446** | **$46,060** | **$256,889** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *1-5 CCCT (2011–2020)*

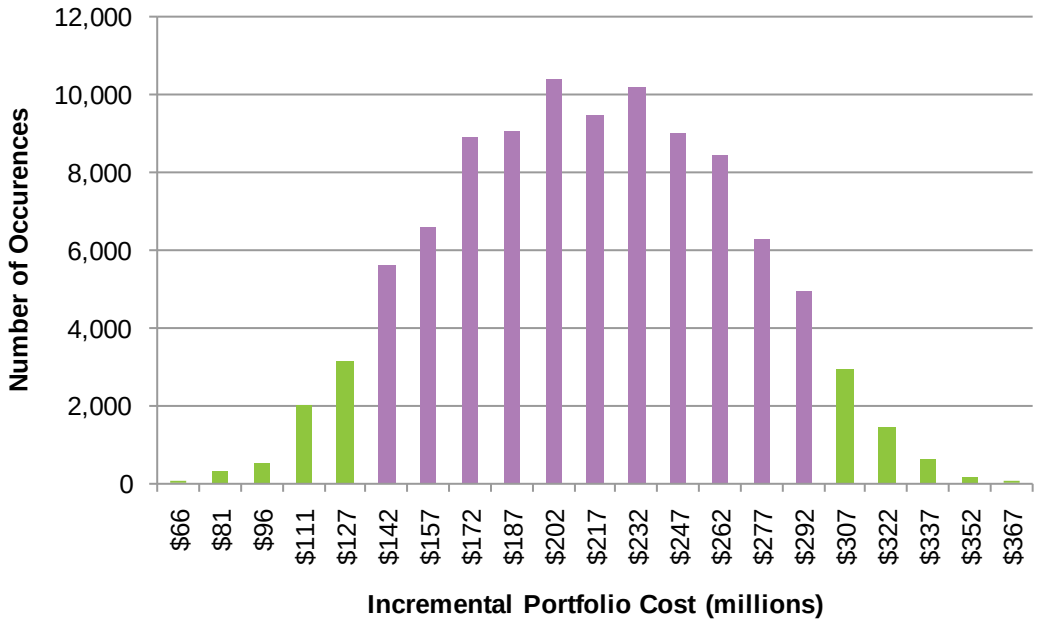
**Base Portfolio Cost[1]=$222,177[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$55,246 | $3,167 | $166,931 | $225,344 |
| REC | -$18,827 | $9,413 | $203,350 | $231,590 |
| Carbon | -$3,158 | $3,282 | $219,019 | $225,459 |
| Load | -$1,364 | $2,170 | $220,813 | $224,347 |
| DSM | -$48,975 | $101,023 | $173,202 | $323,200 |
| Capital | -$28,262 | $27,371 | $193,915 | $249,548 |
| **Total** | **-$155,832** | **$146,426** | **$66,345** | **$368,603** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *1-6 CHP (2011–2020)*

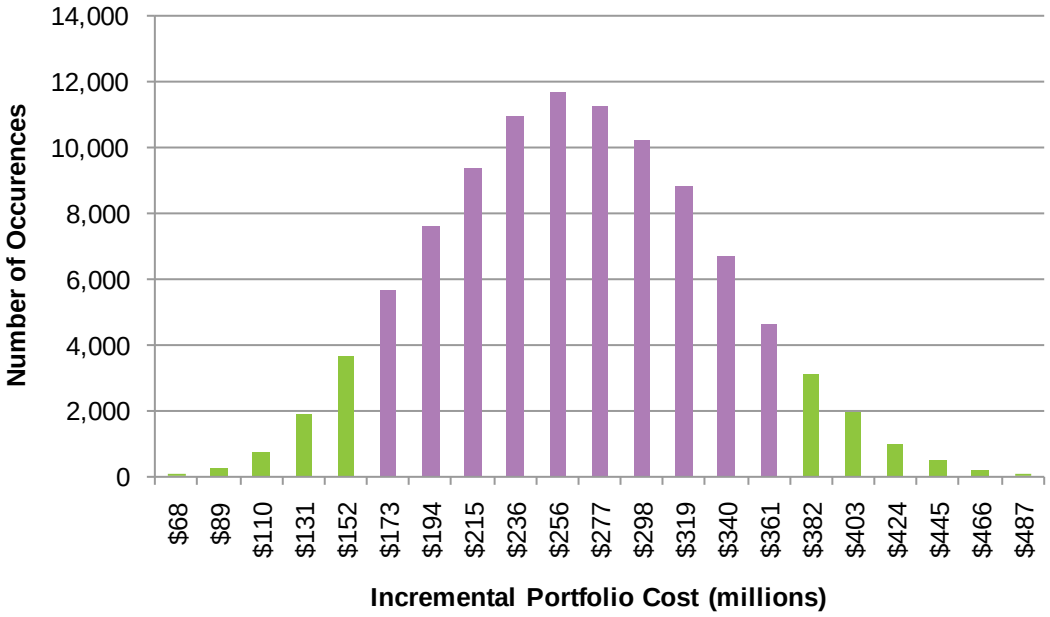
**Base Portfolio Cost[1]=$267,462[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$63,805 | $66,362 | $203,657 | $333,824 |
| REC | -$18,827 | $9,413 | $248,635 | $276,875 |
| Carbon | -$412 | $11,109 | $267,050 | $278,571 |
| Load | -$1,632 | $3,561 | $265,830 | $271,023 |
| DSM | -$49,437 | $103,010 | $218,025 | $370,472 |
| Capital | -$28,566 | $25,850 | $238,896 | $293,312 |
| **Total** | **-$162,679** | **$219,305** | **$104,783** | **$486,767** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *1-7 Balanced (2011–2020)*

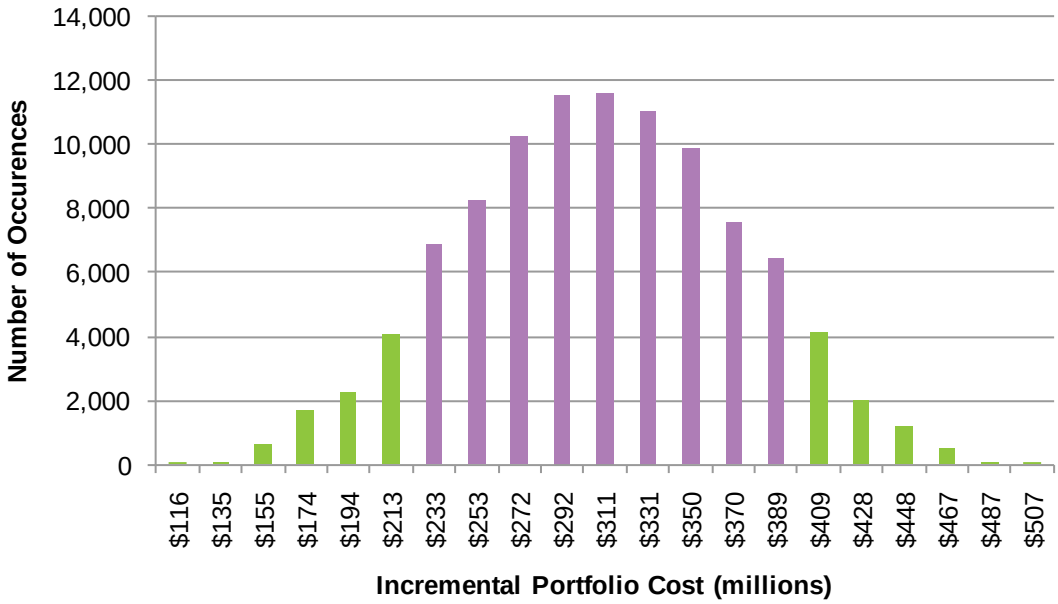
**Base Portfolio Cost[1]=$288,613[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$30,861 | $37,401 | $257,752 | $326,014 |
| REC | -$29,714 | $14,858 | $258,899 | $303,471 |
| Carbon | $0 | $15,355 | $288,613 | $303,968 |
| Load | -$190 | $2,437 | $288,423 | $291,050 |
| DSM | -$48,139 | $100,745 | $240,474 | $389,358 |
| Capital | -$63,931 | $47,593 | $224,682 | $336,206 |
| **Total** | **-$172,835** | **$218,389** | **$115,778** | **$507,002** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



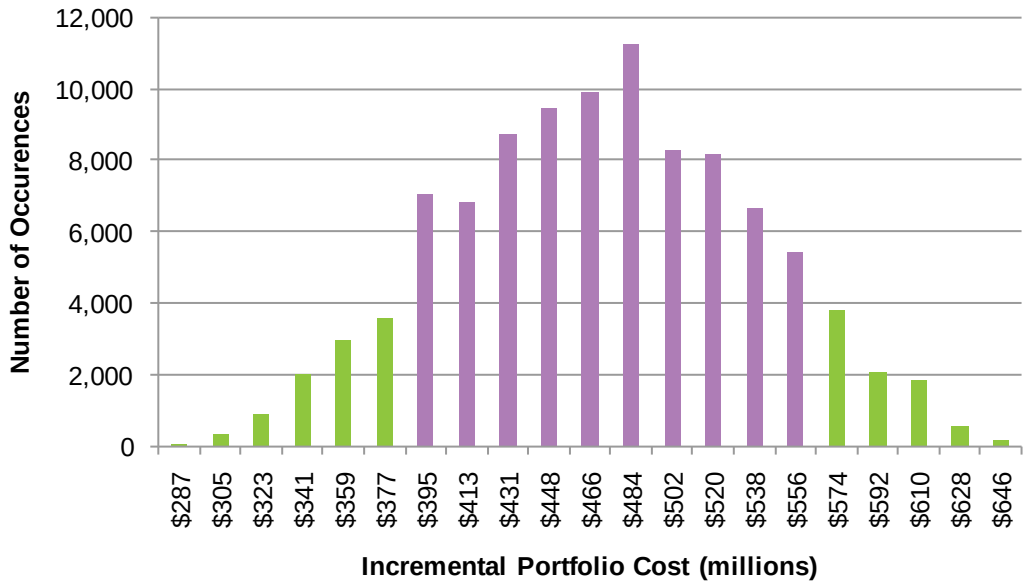
## 1-8 Pumped Storage (2011–2020)

**Base Portfolio Cost[1]=$426,601[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | $0 | $2,111 | $426,601 | $428,712 |
| REC | -$29,358 | $14,680 | $397,243 | $441,281 |
| Carbon | -$609 | $2,871 | $425,992 | $429,472 |
| Load | -$177 | $2,289 | $426,424 | $428,890 |
| DSM | -$46,741 | $100,939 | $379,860 | $527,540 |
| Capital | -$62,533 | $96,069 | $364,068 | $522,670 |
| **Total** | **-$139,418** | **$218,959** | **$287,183** | **$645,560** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *1-9 Distributed Gen (2011–2020)*

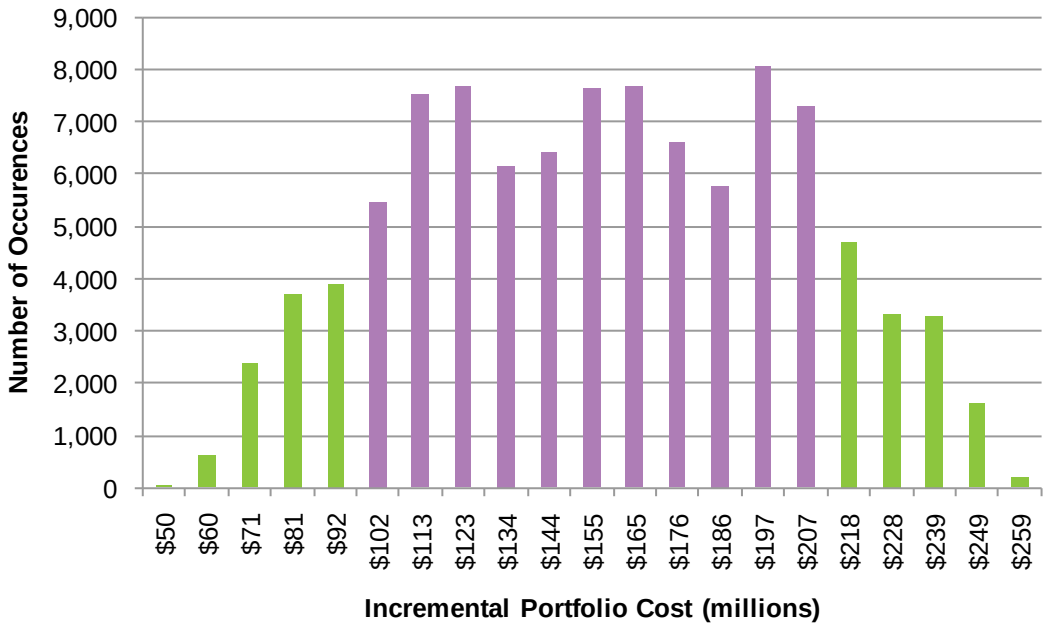
**Base Portfolio Cost[1]=$135,055[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | $0 | $1,043 | $135,055 | $136,098 |
| REC | -$18,827 | $9,413 | $116,228 | $144,468 |
| Carbon | $0 | $2,678 | $135,055 | $137,733 |
| Load | -$424 | -$123 | $134,631 | $134,932 |
| DSM | -$49,333 | $100,263 | $85,722 | $235,318 |
| Capital | -$16,592 | $11,149 | $118,463 | $146,204 |
| **Total** | **-$85,176** | **$124,423** | **$49,879** | **$259,478** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## 2-1 Nuclear (2021–2030)

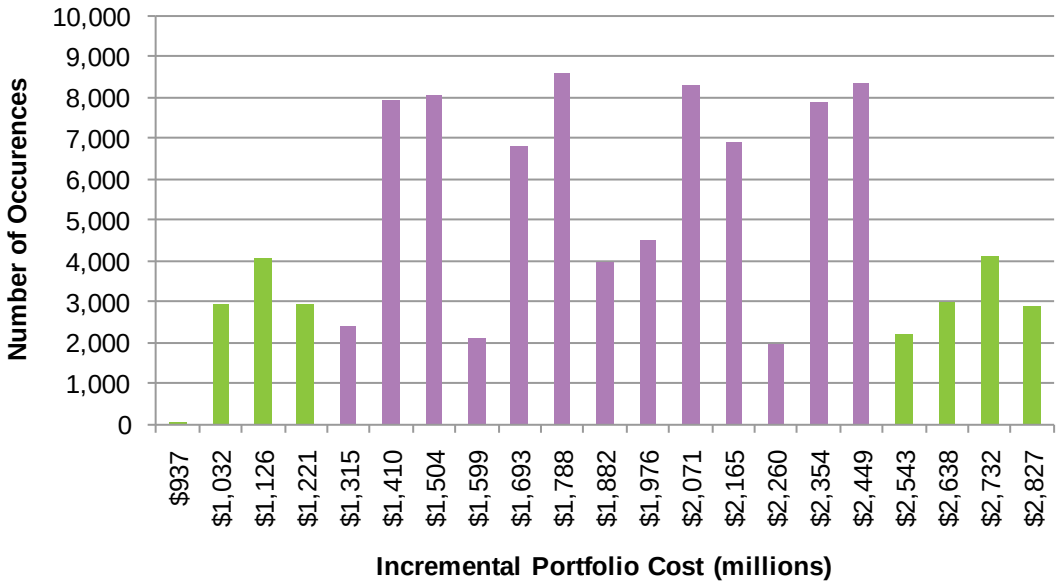
**Base Portfolio Cost[1]=$1,323,279[2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$3,545 | $5,887 | $1,319,734 | $1,329,166 |
| REC | -$1,426 | $713 | $1,321,853 | $1,323,992 |
| Carbon | -$82,907 | $138,144 | $1,240,372 | $1,461,423 |
| Load | -$20,601 | $7,743 | $1,302,678 | $1,331,022 |
| DSM | -$2,183 | $18,523 | $1,321,096 | $1,341,802 |
| Capital | -$275,138 | $1,332,273 | $1,048,141 | $2,655,552 |
| **Total** | **-$385,800** | **$1,503,283** | **$937,479** | **$2,826,562** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



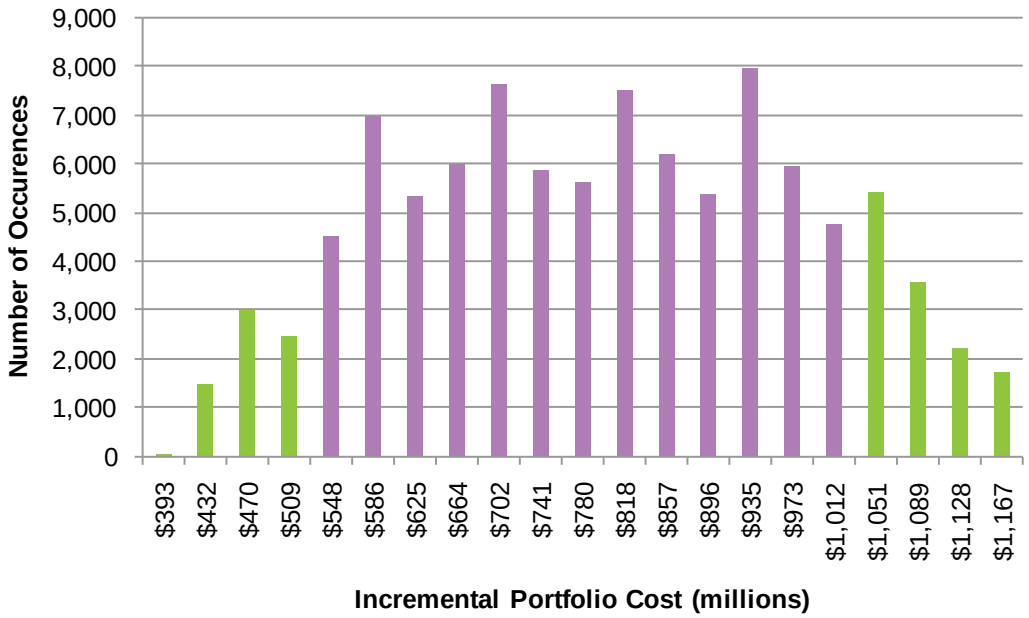
## 2-2 IGCC (2021–2030)

**Base Portfolio Cost[1]=$625,319[2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost Low | Adjustment to Base Incremental Portfolio Cost High | Incremental Portfolio Cost Range Low | Incremental Portfolio Cost Range High |
|---|---|---|---|---|
| Natural gas | -$31,374 | -$5,816 | $593,945 | $619,503 |
| REC | -$5,816 | $2,907 | $619,503 | $628,226 |
| Carbon | -$66,620 | $102,031 | $558,699 | $727,350 |
| Load | -$17,198 | $2,835 | $608,121 | $628,154 |
| DSM | -$1,438 | $15,377 | $623,881 | $640,696 |
| Capital | -$147,025 | $458,193 | $478,294 | $1,083,512 |
| **Total** | **-$269,471** | **$575,527** | **$355,848** | **$1,200,846** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## 2-3 SCCT and Wind (2021–2030)

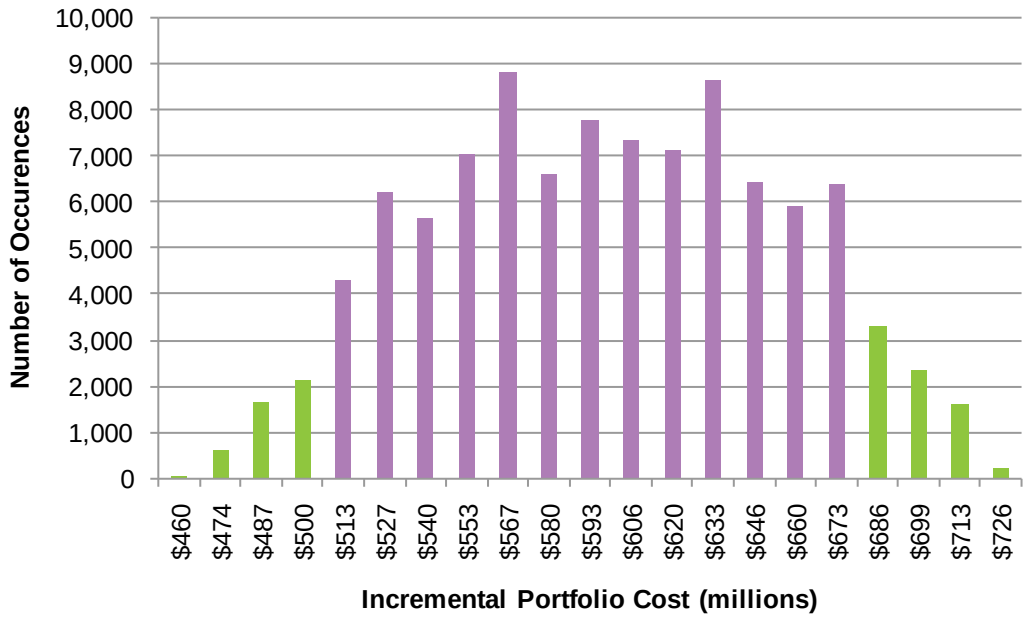
**Base Portfolio Cost[1]=$564,334 [2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | $0 | $2,979 | $564,334 | $567,313 |
| REC | -$5,090 | $2,546 | $559,244 | $566,880 |
| Carbon | -$20,394 | $33,400 | $543,940 | $597,734 |
| Load | -$12,334 | $85 | $552,000 | $564,419 |
| DSM | $0 | $11,526 | $564,334 | $575,860 |
| Capital | -$66,147 | $111,065 | $498,187 | $675,399 |
| **Total** | **-$103,965** | **$161,601** | **$460,369** | **$725,935** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



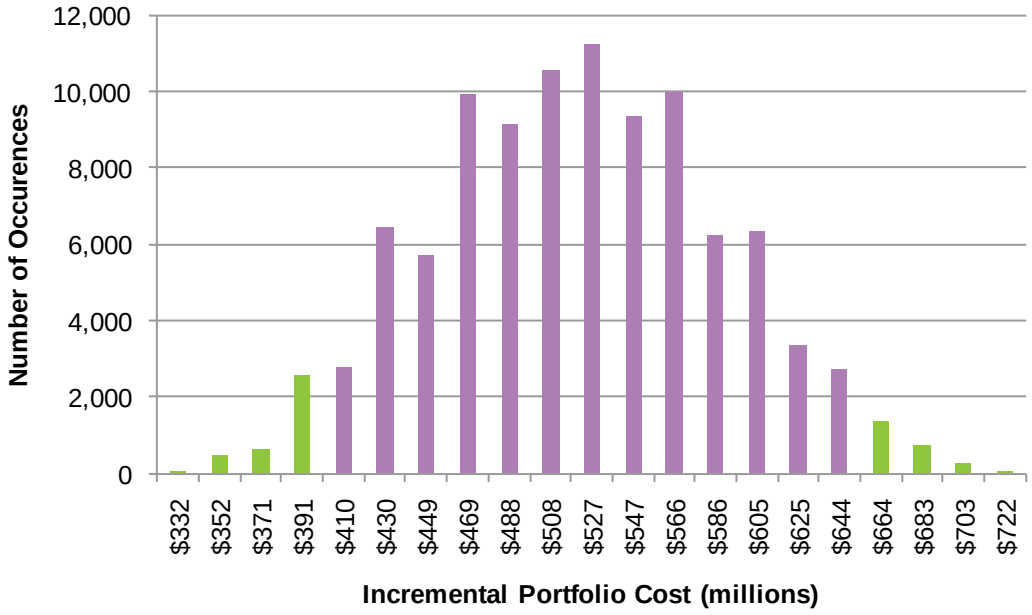
## 2-4 CCCT and Wind (2021–2030)

**Base Portfolio Cost[1]=$565,377 [2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$125,279 | $6,247 | $440,098 | $571,624 |
| REC | -$247 | $493 | $565,130 | $565,870 |
| Carbon | -$23,134 | $29,801 | $542,243 | $595,178 |
| Load | -$19,581 | $3,153 | $545,796 | $568,530 |
| DSM | -$1,600 | $15,457 | $563,777 | $580,834 |
| Capital | -$63,506 | $101,560 | $501,871 | $666,937 |
| **Total** | **-$233,347** | **$156,711** | **$332,030** | **$722,088** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## 2-5 Hydro and CHP (2021–2030)

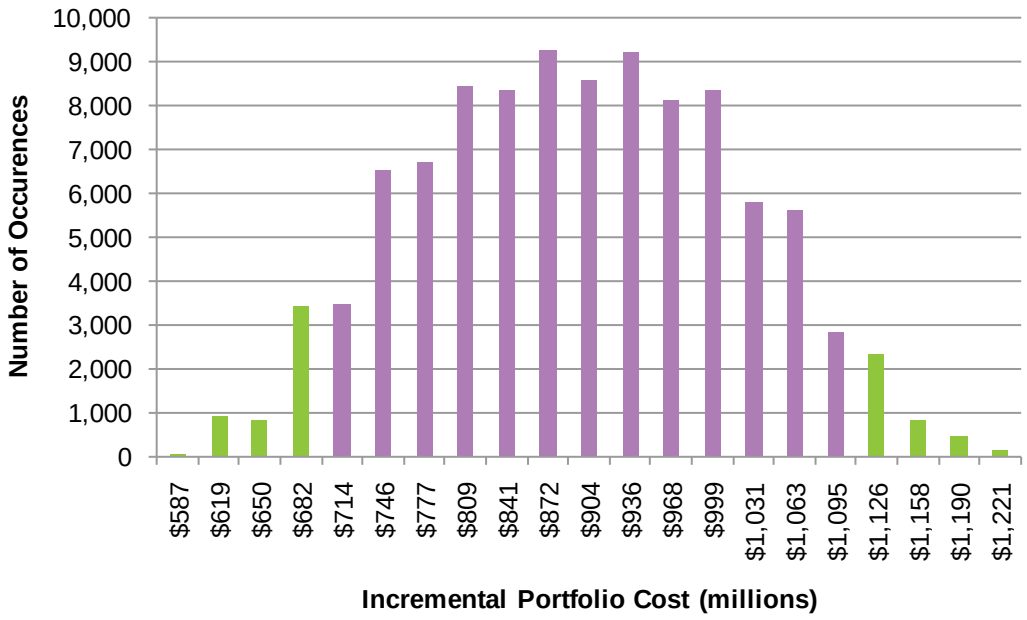
**Base Portfolio Cost[1]=$860,503 [2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost Low | Adjustment to Base Incremental Portfolio Cost High | Incremental Portfolio Cost Range Low | Incremental Portfolio Cost Range High |
|---|---|---|---|---|
| Natural gas | -$90,313 | $89,874 | $770,190 | $950,377 |
| REC | -$13,337 | $6,669 | $847,166 | $867,172 |
| Carbon | -$17,244 | $27,143 | $843,259 | $887,646 |
| Load | -$18,627 | $2,041 | $841,876 | $862,544 |
| DSM | -$2,014 | $14,674 | $858,489 | $875,177 |
| Capital | -$132,066 | $220,580 | $728,437 | $1,081,083 |
| **Total** | **-$273,601** | **$360,981** | **$586,902** | **$1,221,484** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *2-6 Balanced 1 (2021–2030)*

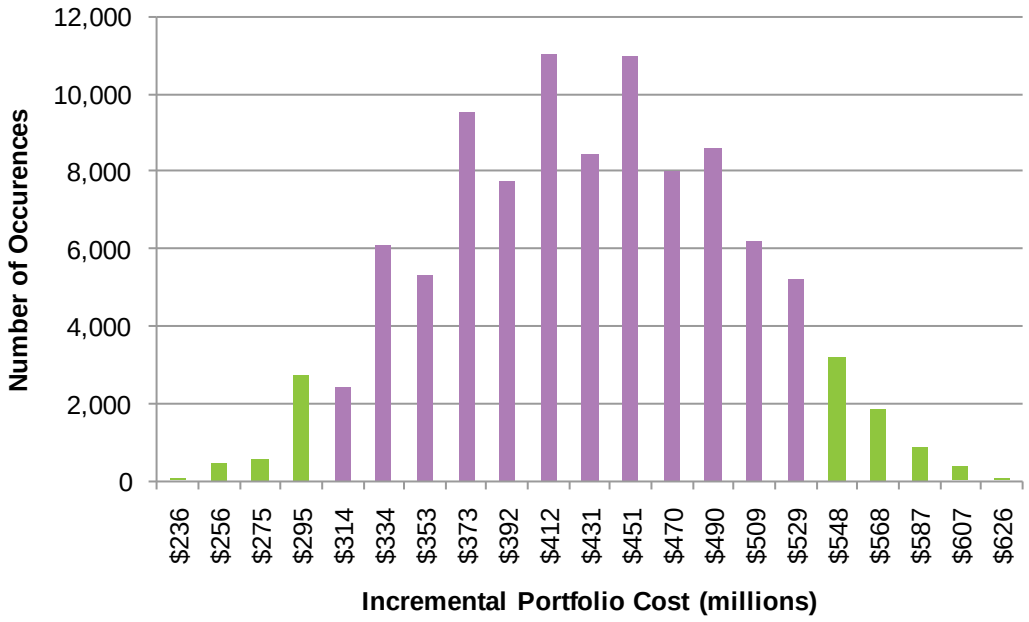
**Base Portfolio Cost[1]=$445,704 [2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$60,770 | $21,871 | $384,934 | $467,575 |
| REC | -$5,292 | $2,646 | $440,412 | $448,350 |
| Carbon | -$27,539 | $41,639 | $418,165 | $487,343 |
| Load | -$17,483 | $2,948 | $428,221 | $448,652 |
| DSM | -$784 | $15,763 | $444,920 | $461,467 |
| Capital | -$97,378 | $95,892 | $348,326 | $541,596 |
| **Total** | **-$209,246** | **$180,759** | **$236,458** | **$626,463** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## 2-7 Balanced 2 (2021–2030)

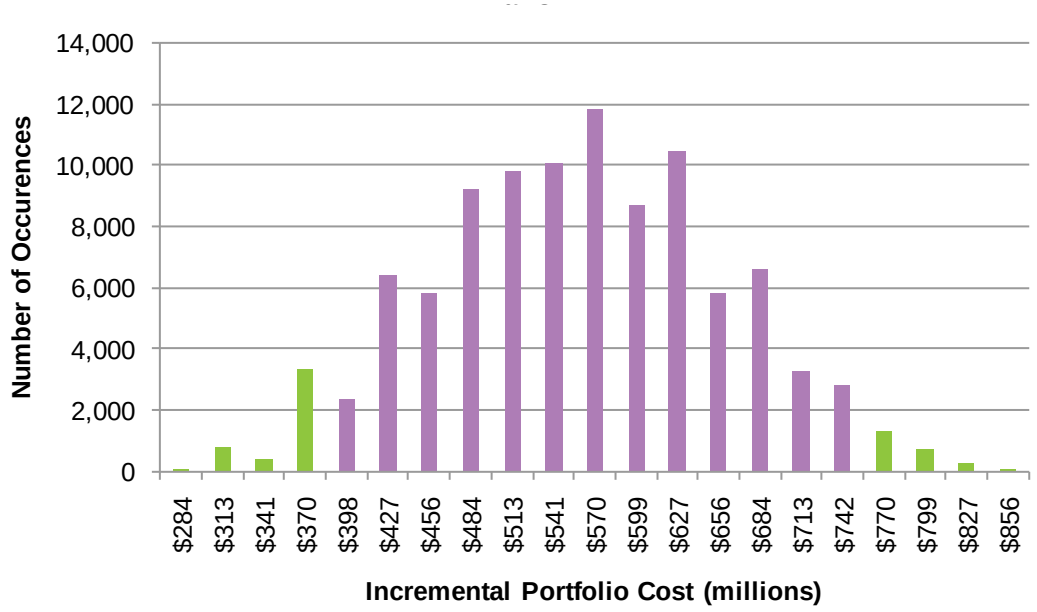
**Base Portfolio Cost[1]=$567,780 [2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$100,644 | $86,232 | $467,136 | $654,012 |
| REC | -$17,679 | $8,840 | $550,101 | $576,620 |
| Carbon | -$32,720 | $52,081 | $535,060 | $619,861 |
| Load | -$18,735 | $3,957 | $549,045 | $571,737 |
| DSM | -$2,067 | $16,029 | $565,713 | $583,809 |
| Capital | -$111,939 | $120,961 | $455,841 | $688,741 |
| **Total** | **-$283,784** | **$288,100** | **$283,996** | **$855,880** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## 2-8 Pacific Northwest Transmission (2021–2030)

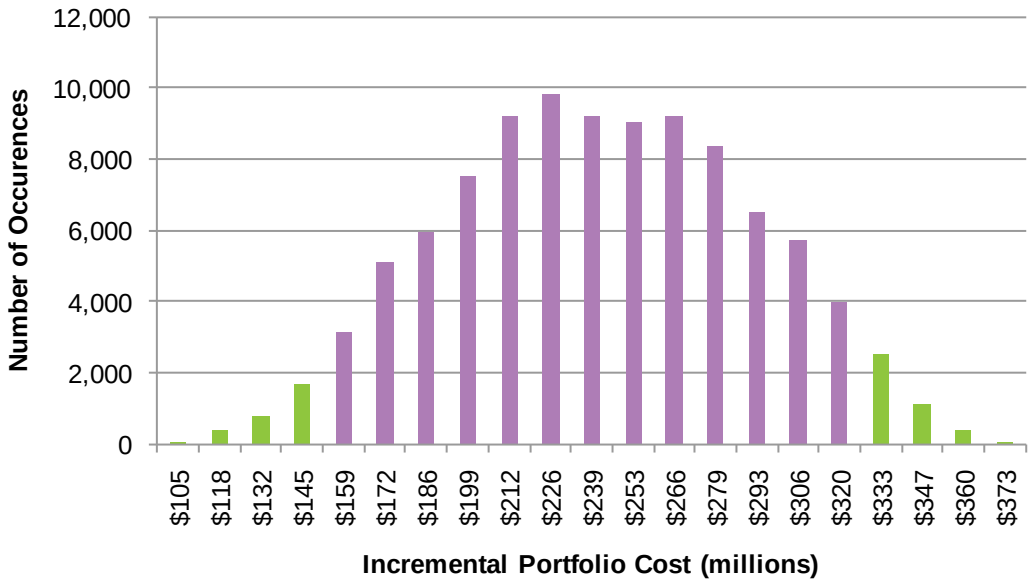
**Base Portfolio Cost[1]=$240,492 [2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| | Low | High | Low | High |
| Natural gas | -$12,338 | $15,040 | $228,154 | $255,532 |
| REC | -$3,545 | $1,773 | $236,947 | $242,265 |
| Carbon | -$27,435 | $34,509 | $213,057 | $275,001 |
| Load | -$16,963 | -$278 | $223,529 | $240,214 |
| DSM | -$2,142 | $13,059 | $238,350 | $253,551 |
| Capital | -$73,081 | $68,842 | $167,411 | $309,334 |
| **Total** | **-$135,504** | **$132,945** | **$104,988** | **$373,437** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



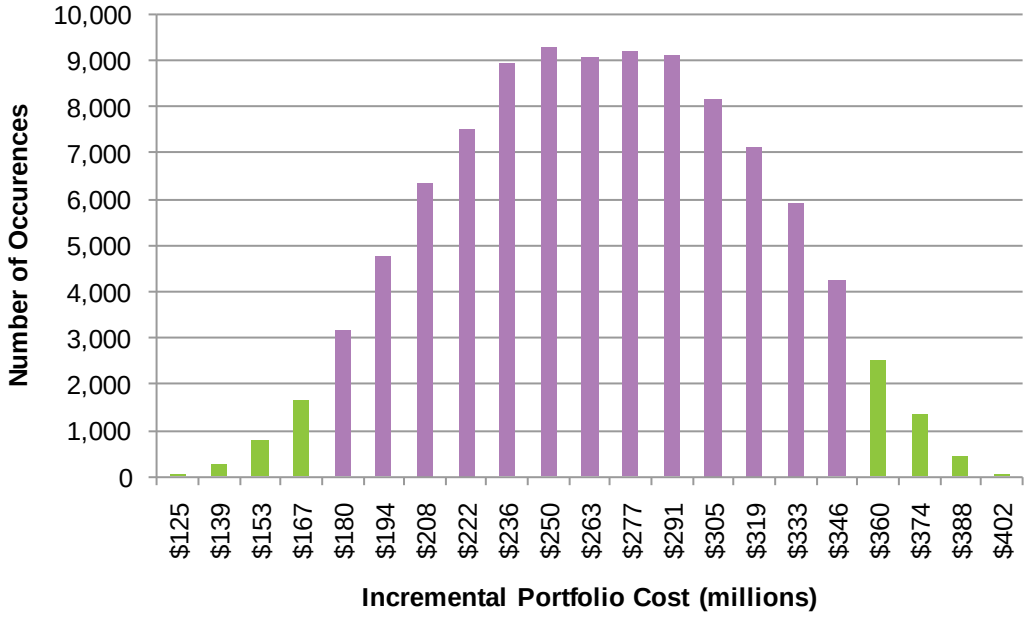
## 2-9 Eastside Transmission (2021–2030)

**Base Portfolio Cost[1]=$260,903 [2]**

| Risk Factor Adjustments | Adjustment to Base Incremental Portfolio Cost Low | Adjustment to Base Incremental Portfolio Cost High | Incremental Portfolio Cost Range Low | Incremental Portfolio Cost Range High |
|---|---|---|---|---|
| Natural gas | -$9,856 | $10,461 | $251,047 | $271,364 |
| REC | -$3,545 | $1,773 | $257,358 | $262,676 |
| Carbon | -$25,113 | $39,456 | $235,790 | $300,359 |
| Load | -$19,808 | $1,783 | $241,095 | $262,686 |
| DSM | -$1,301 | $14,522 | $259,602 | $275,425 |
| Capital | -$76,125 | $72,900 | $184,778 | $333,803 |
| **Total** | **-$135,748** | **$140,895** | **$125,155** | **$401,798** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



## *2-10 Renewable (2021–2030)*

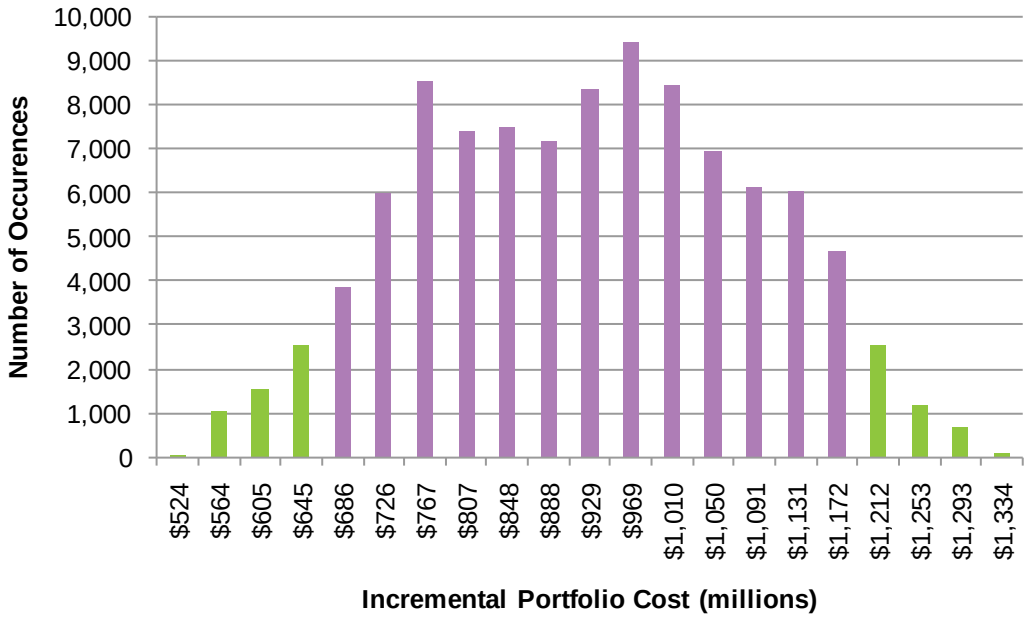
**Base Portfolio Cost[1]=$966,716 [2]**

| | Adjustment to Base Incremental Portfolio Cost | | Incremental Portfolio Cost Range | |
|---|---|---|---|---|
| **Risk Factor Adjustments** | **Low** | **High** | **Low** | **High** |
| Natural gas | -$82,345 | $80,758 | $884,371 | $1,047,474 |
| REC | -$23,073 | $11,537 | $943,643 | $978,253 |
| Carbon | -$32,724 | $42,734 | $933,992 | $1,009,450 |
| Load | -$21,036 | $2,232 | $945,680 | $968,948 |
| DSM | -$1,710 | $14,726 | $965,006 | $981,442 |
| Capital | -$282,005 | $215,025 | $684,711 | $1,181,741 |
| **Total** | **-$442,893** | **$367,012** | **$523,823** | **$1,333,728** |

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

### Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



# Regulatory Environmental Compliance Costs

| | 2011$s—000's | | | |
|---|---|---|---|---|
| **Expected Case 2011–2020 Portfolios** | **$NO_x$[1]** | **$SO_2$[2]** | **Hg[3]** | **$CO_2$[4]** |
| 1-1 Sun and Steam | $91,290 | $124 | $2,259 | $605,384 |
| 1-2 Solar | $89,818 | $124 | $2,260 | $555,413 |
| 1-3 Boardman to Hemingway | $89,798 | $124 | $2,327 | $555,740 |
| 1-4 SCCT | $90,168 | $125 | $2,281 | $557,397 |
| 1-5 CCCT | $90,534 | $124 | $2,240 | $578,372 |
| 1-6 CHP | $90,961 | $124 | $2,257 | $599,447 |
| 1-7 Balanced | $90,835 | $125 | $2,257 | $588,094 |
| 1-8 Pumped Storage | $90,121 | $125 | $2,251 | $558,767 |
| 1-9 Distributed Gen | $90,216 | $125 | $2,250 | $557,458 |
| **Expected Case 2021–2030 Portfolios** | | | | |
| 2-1 Nuclear | $99,226 | $74 | $1,504 | $761,248 |
| 2-2 IGCC | $100,599 | $75 | $2,031 | $798,966 |
| 2-3 SCCT and Wind | $99,903 | $74 | $1,567 | $764,301 |
| 2-4 CCCT and Wind | $100,428 | $75 | $1,465 | $804,847 |
| 2-5 Hydro and CHP | $100,969 | $75 | $1,471 | $826,847 |
| 2-6 Balanced 1 | $99,432 | $74 | $1,440 | $779,020 |
| 2-7 Balanced 2 | $100,379 | $75 | $1,438 | $816,536 |
| 2-8 Pacific Northwest Transmission | $99,082 | $74 | $1,463 | $763,495 |
| 2-9 Eastside Transmission | $98,812 | $73 | $1,395 | $757,107 |
| 2-10 Renewable | $100,537 | $75 | $1,428 | $818,227 |
| **Low Case 2011–2020 Portfolios** | | | | |
| 1-1 Sun and Steam | $68,468 | $93 | $1,694 | $427,944 |
| 1-2 Solar | $67,364 | $93 | $1,695 | $392,826 |
| 1-3 Boardman to Hemingway | $67,349 | $93 | $1,745 | $393,070 |
| 1-4 SCCT | $67,626 | $93 | $1,710 | $394,313 |
| 1-5 CCCT | $67,900 | $93 | $1,680 | $409,167 |
| 1-6 CHP | $68,221 | $93 | $1,692 | $423,540 |
| 1-7 Balanced | $68,127 | $93 | $1,692 | $415,882 |
| 1-8 Pumped Storage | $67,590 | $94 | $1,688 | $395,262 |
| 1-9 Distributed Gen | $67,662 | $94 | $1,687 | $394,323 |
| **Low Case 2021–2030 Portfolios** | | | | |
| 2-1 Nuclear | $74,419 | $55 | $1,128 | $448,091 |
| 2-2 IGCC | $75,449 | $56 | $1,523 | $468,986 |
| 2-3 SCCT and Wind | $74,927 | $56 | $1,175 | $449,817 |
| 2-4 CCCT and Wind | $75,321 | $56 | $1,099 | $473,483 |
| 2-5 Hydro and CHP | $75,727 | $56 | $1,103 | $485,554 |
| 2-6 Balanced 1 | $74,574 | $55 | $1,080 | $457,832 |
| 2-7 Balanced 2 | $75,285 | $56 | $1,078 | $479,178 |
| 2-8 Pacific Northwest Transmission | $74,312 | $55 | $1,097 | $449,233 |
| 2-9 Eastside Transmission | $74,109 | $55 | $1,046 | $445,686 |
| 2-10 Renewable | $75,403 | $56 | $1,071 | $480,823 |

[1] $NO_x$=Nitrogen Oxides, [2] $SO_2$=Sulfur Oxides, [3] Hg=Mercury, [4] $CO_2$=Carbon Dioxide

| | 2011$s—000's | | | |
|---|---|---|---|---|
| **High Case 2011–2020 Portfolios** | **$NO_x$** | **$SO_2$** | **Hg** | **$CO_2$** |
| 1-1 Sun and Steam | $114,113 | $155 | $2,822 | $803,059 |
| 1-2 Solar | $112,273 | $155 | $2,824 | $736,402 |
| 1-3 Boardman to Hemingway | $112,248 | $155 | $2,907 | $736,818 |
| 1-4 SCCT | $112,710 | $156 | $2,850 | $738,882 |
| 1-5 CCCT | $113,167 | $155 | $2,799 | $766,656 |
| 1-6 CHP | $113,702 | $155 | $2,820 | $795,577 |
| 1-7 Balanced | $113,544 | $156 | $2,820 | $779,836 |
| 1-8 Pumped Storage | $112,651 | $156 | $2,813 | $740,737 |
| 1-9 Distributed Gen | $112,770 | $156 | $2,811 | $739,022 |
| **High Case 2021–2030 Portfolios** | | | | |
| 2-1 Nuclear | $124,032 | $92 | $1,879 | $1,211,169 |
| 2-2 IGCC | $125,749 | $93 | $2,537 | $1,274,632 |
| 2-3 SCCT and Wind | $124,879 | $93 | $1,958 | $1,216,209 |
| 2-4 CCCT and Wind | $125,535 | $93 | $1,831 | $1,281,220 |
| 2-5 Hydro and CHP | $126,211 | $94 | $1,838 | $1,318,497 |
| 2-6 Balanced 1 | $124,290 | $92 | $1,800 | $1,241,332 |
| 2-7 Balanced 2 | $125,474 | $93 | $1,797 | $1,303,001 |
| 2-8 Pacific Northwest Transmission | $123,853 | $92 | $1,828 | $1,215,227 |
| 2-9 Eastside Transmission | $123,516 | $92 | $1,743 | $1,204,482 |
| 2-10 Renewable | $125,672 | $93 | $1,784 | $1,303,934 |

# Portfolio Incremental Transmission Analysis

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-1 Sun and Steam | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $46,000,000 |
| Network upgrades | $27,600,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$73,600,000** |
| New revenue requirements for project(s) | $11,176,616 |
| New net revenue requirements | $107,350,291 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $17.71 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($353,043) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,218,663 |
| Long-term point-to-point revenue | $12,679,447 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $83,452,181 |
| **Net change** | **$10,663,670** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-2 Solar | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $39,537,000 |
| Network upgrades | $273,687,209 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$313,224,209** |
| New revenue requirements for project(s) | $47,565,038 |
| New net revenue requirements | $143,738,713 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $23.71 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($4,060,702) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $5,507,193 |
| Long-term point-to-point revenue | $16,977,387 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $114,254,133 |
| **Net change** | **$41,465,622** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-3 with additional Boardman to Hemingway Third-Party Subscription | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $228,837,209 |
| Network upgrades | $18,377,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$247,214,209** |
| New revenue requirements for project(s) | $37,541,010 |
| New net revenue requirements | $133,714,685 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $22.06 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($3,039,342) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $5,152,238 |
| Long-term point-to-point revenue | $15,793,420 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $105,769,027 |
| **Net change** | **$32,980,516** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-4 SCCT | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $– |
| Network upgrades | $47,150,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$47,150,000** |
| New revenue requirements for project(s) | $7,160,020 |
| New net revenue requirements | $10,333,695 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $17.05 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $56,213 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,076,434 |
| Long-term point-to-point revenue | $12,205,036 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $80,052,225 |
| **Net change** | **$7,263,714** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-5 CCCT | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $– |
| Network upgrades | $47,150,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$47,150,000** |
| New revenue requirements for project(s) | $7,160,020 |
| New net revenue requirements | $10,333,695 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $17.05 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $56,213 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,076,434 |
| Long-term point-to-point revenue | $12,205,036 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $80,052,225 |
| **Net change** | **$7,263,714** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-6 CHP | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $4,370,000 |
| Network upgrades | $29,900,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$34,270,000** |
| New revenue requirements for project(s) | $5,204,112 |
| New net revenue requirements | $101,377,787 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $16.72 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $255,503 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,007,174 |
| Long-term point-to-point revenue | $11,974,018 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $78,396,595 |
| **Net change** | **$5,608,084** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-7 Balanced | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $12,897,500 |
| Network upgrades | $28,600,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$41,497,500** |
| New revenue requirements for project(s) | $6,301,653 |
| New net revenue requirements | $102,475,328 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $16.90 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $143,673 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,046,039 |
| Long-term point-to-point revenue | $12,103,651 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $79,325,637 |
| **Net change** | **$6,537,127** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-8 Pumped Storage | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $15,525,000 |
| Network upgrades | $34,500,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$50,025,000** |
| New revenue requirements for project(s) | $7,596,606 |
| New net revenue requirements | $103,770,281 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $17.12 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $11,729 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,091,894 |
| Long-term point-to-point revenue | $12,256,602 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $80,421,786 |
| **Net change** | **$7,633,275** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 1-9 Distributed Generation | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $– |
| Network upgrades | $47,150,000 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$47,150,000** |
| New revenue requirements for project(s) | $7,160,020 |
| New net revenue requirements | $103,333,695 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **450** |
| New system demand—including new uses | 6,062 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $17.05 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | $56,213 |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $4,076,434 |
| Long-term point-to-point revenue | $12,205,036 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $80,052,225 |
| **Net change** | **$7,263,714** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-1 Nuclear | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $39,652,000 |
| Network upgrades | $570,767,399 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$610,419,399** |
| New revenue requirements for project(s) | $92,695,970 |
| New net revenue requirements | $188,869,645 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $27.86 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($6,621,196) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $6,385,760 |
| Long-term point-to-point revenue | $19,945,526 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $155,538,359 |
| **Net change** | **$82,749,848** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-2 IGCC | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $57,592,000 |
| Network upgrades | $1,066,803,876 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$1,124,395,876** |
| New revenue requirements for project(s) | $170,746,484 |
| New net revenue requirements | $266,920,159 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $39.37 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($13,731,672) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $8,871,411 |
| Long-term point-to-point revenue | $28,188,029 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $222,860,720 |
| **Net change** | **$150,072,209** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-3 SCCT/Wind | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $39,077,000 |
| Network upgrades | $599,079,709 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$638,156,709** |
| New revenue requirements for project(s) | $96,908,052 |
| New net revenue requirements | $193,081,727 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $28.48 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($7,004,921) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $6,519,900 |
| Long-term point-to-point revenue | $20,390,342 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $159,171,485 |
| **Net change** | **$86,382,974** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-4 CCCT/Wind | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $32,177,000 |
| Network upgrades | $599,079,709 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$631,256,709** |
| New revenue requirements for project(s) | $95,860,245 |
| New net revenue requirements | $193,033,920 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $28.32 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($6,909,465) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $6,486,531 |
| Long-term point-to-point revenue | $20,279,688 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $158,267,700 |
| **Net change** | **$85,479,189** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-5 Hydro/CHP | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $72,772,000 |
| Network upgrades | $572,514,709 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$645,286,709** |
| New revenue requirements for project(s) | $97,990,787 |
| New net revenue requirements | $194,164,462 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $28.64 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($7,103,559) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $6,554,382 |
| Long-term point-to-point revenue | $20,504,684 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $160,105,396 |
| **Net change** | **$87,316,886** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-6 Balanced 1 | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $57,994,500 |
| Network upgrades | $332,337,209 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$390,331,709** |
| New revenue requirements for project(s) | $59,274,290 |
| New net revenue requirements | $155,447,965 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $22.93 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($3,576,450) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $5,321,390 |
| Long-term point-to-point revenue | $16,416,039 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $126,710,536 |
| **Net change** | **$53,922,026** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-7 Balanced 2 | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $63,342,000 |
| Network upgrades | $330,037,209 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$393,379,209** |
| New revenue requirements for project(s) | $59,737,072 |
| New net revenue requirements | $155,910,746 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $23.00 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($3,618,610) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $5,336,128 |
| Long-term point-to-point revenue | $16,464,911 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $127,109,708 |
| **Net change** | **$54,321,197** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-8 PNW Transmission | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $55,694,500 |
| Network upgrades | $614,467,399 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$670,161,899** |
| New revenue requirements for project(s) | $101,768,239 |
| New net revenue requirements | $197,941,914 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $29.19 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($7,447,689) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $6,674,681 |
| Long-term point-to-point revenue | $20,903,600 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $163,363,632 |
| **Net change** | **$90,575,121** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-9 Eastside Transmission | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $55,694,500 |
| Network upgrades | $976,337,209 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$1,132,031,709** |
| New revenue requirements for project(s) | $156,720,413 |
| New net revenue requirements | $252,894,088 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $37.30 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($12,453,884) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $8,424,727 |
| Long-term point-to-point revenue | $26,706,809 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $210,762,552 |
| **Net change** | **$137,974,041** |

| Idaho Power Transmission Rate Approximation for 2011 IRP Analysis<br>Portfolio 2-10 Renewable | |
|---|---|
| Project capital cost | |
| Local interconnection costs | $85,767,000 |
| Network upgrades | $302,437,209 |
| **Annual Revenue Requirements** | |
| Existing revenue requirements | $106,758,681 |
| Existing revenue credits | ($10,585,006) |
| Existing net revenue requirements | $96,173,675 |
| **New Project Capital** | **$388,204,209** |
| New revenue requirements for project(s) | $58,951,216 |
| New net revenue requirements | $155,124,891 |
| **System In Use (MW)** | |
| Existing system peak demand | 5,612 |
| **Future additional Idaho Power network use** | **1,168** |
| New system demand—including new uses | 6,780 |
| **Point-to-Point Transmission Rate (Dollars/kW-year)** | |
| a) Existing rate | $17.14 |
| b) New rate without third-party use | $22.88 |
| **Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits** | |
| Change in existing uses (increase > 100%) | 100% |
| Existing uses adjusted at new rate b) | ($3,547,018) |
| **Network Transmission Revenue Requirements** | |
| **a) Existing** | |
| BPA load ratio share | $4,114,966 |
| Long-term point-to-point revenue | $12,270,198 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $72,788,511 |
| **b) Future—new projects without additional participation** | |
| BPA load ratio share | $5,311,101 |
| Long-term point-to-point revenue | $16,381,921 |
| Legacy contract revenue | $7,000,000 |
| Assigned to Idaho Power retail load service | $126,431,869 |
| **Net change** | **$53,643,359** |

# Loss of Load Expectation Analysis

**Loss of Load Expectation Summary Data–Preferred Portfolio (1-3 Boardman to Hemmingway and 2-6 Balanced 1)***

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 1.68 | 0.15 | 0.13 | 0.00 | 0.00 | 0.01 |
| 2012 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.57 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2013 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.42 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2014 | 1.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 1.39 | 0.08 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2015 | 1.92 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.38 | 1.40 | 0.06 | 0.08 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.19 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.69 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 2.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 2.01 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2021 | 2.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 2.93 | 0.17 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.16 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.21 | 0.20 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.51 | 0.10 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2025 | 2.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.31 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.95 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.59 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 2.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.92 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 2.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.47 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.88 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW and 83 MW & 158 MW Jul Eastside Purchases in 2013/2014.

**Loss of Load Expectation Summary Data–Alternate Portfolio (1-4 SCCT)***

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | 2.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 1.68 | 0.15 | 0.13 | 0.00 | 0.00 | 0.01 |
| 2012 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.57 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2013 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.42 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2014 | 1.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 1.39 | 0.08 | 0.03 | 0.00 | 0.00 | 0.00 |
| 2015 | 1.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 1.06 | 0.05 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2016 | 1.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.18 | 1.63 | 0.11 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.77 | 0.13 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2018 | 1.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.58 | 0.07 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2019 | 1.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.24 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2020 | 1.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.24 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

| Loss of Load Expectation Summary Data–Alternate Portfolio (2-8 Pacific Northwest Transmission)* | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Annual** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sept** | **Oct** | **Nov** | **Dec** |
| 2021 | 2.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 2.93 | 0.17 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 2.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.17 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 2.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.55 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 2.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.89 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 1.72 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.53 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.25 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.53 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

# Boardman to Hemingway Tipping Point Analysis Data

| Market Price Increase Tipping Point Calculation | | | | |
|---|---|---|---|---|
| | **Unit** | **1-3 Boardman to Hemingway** | **1-4 SCCT** | **Variance** |
| Total portfolio cost (from Table 9.2) | 2011 $s—000's | $3,177,308 | $3,220,672 | $43,364 |
| 2016-2020 market purchases (from AURORA) | MWh | 6,826,175 | 6,763,722 | (62,453) |

Note: Market price increase necessary to make total portfolio cost equivalent: $694 $/MWh ($43,364,000/62,453 MWh)

# STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| PUBLIC UTILITY COMMISSION OF OREGON | ) | ERRATA ORDER |
| | ) | |
| | ) | |
| Investigation Into Integrated Resource Planning. | ) | |
| | ) | |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 09 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

*c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

*a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

*b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

*c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

*d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

*e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

*f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# SUMMARY OF NORTHWEST UTILITY PLANNING CRITERIA

| Utility | Planning Criteria |
|---|---|
| **Avista Corporation** | *Peak Load*—The maximum one-hour obligation, including operating reserves, on the expected average coldest day in January and the average hottest day in August.[1] |
| | *Peak Resource Capability*—The maximum one-hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak, and excluding resources that are on maintenance during peak load periods.[1] |
| | *Planning Reserve*—Set at a level equal to 15% planning reserve margin during the company's peak load hour.[1] |
| | *Confidence Interval*—Ninety percent confidence interval based on the monthly variability of load and the 10$^{th}$ percentile of monthly historical hydro energy. This results in a 10% chance of load exceeding the planning criteria for each month. In other words, there is a 10% chance that the company would need to purchase energy from the market in any given month.[1] |
| **Bonneville Power Administration** | *Load Forecast*—Based on normal weather conditions.[2] |
| | *Hydro Conditions*—Firm hydro energy and capacity estimates based on 1937 critical water conditions.[2] |
| | *Hydro Energy*—Based on current generation capability under average monthly river discharge. Uses operating year (OY) 1937 water conditions (the 12-month period from August 1936 through July 1937) to estimate the firm hydro energy capability in low water conditions.[2] |
| | *Federal Firm Energy Surplus Analysis*—The amount of generation that can be produced in excess of firm loads using 1937 critical water conditions.[2] |
| | *Hydroelectric Capacity*—The monthly instantaneous capacity of hydroelectric projects is defined as the full-gate-flow maximum generation at mid-month reservoir elevation using 1929 through 1998 historical water conditions.[2] |
| **Idaho Power** | *Hydro Conditions*—70$^{th}$ percentile hydro conditions based on historical data from 1928–2009.[3] |
| | *Load Forecast*—Based on 50$^{th}$ percentile weather conditions.[3] |
| | *Monthly Average Energy*—Based on 70$^{th}$ percentile water and 70$^{th}$ percentile average load conditions.[3] |
| | *Capacity*—Based on monthly peak-hour Northwest transmission deficit assuming 90$^{th}$ percentile water, 70$^{th}$ percentile average load, and 95$^{th}$ percentile peak-hour load conditions.[3] |
| **Northwest Power and Conservation Council** | *Uses a fully probabilistic model*—Prospective plans are tested against 20 years of future conditions. The test process uses random simulations of the principal sources of uncertainty, including hydro conditions, regional electric loads, fuel prices, $CO_2$ control requirements, import and export markets, resource availability, and other factors. The council's analytical process creates a 2-dimensional mathematical surface defined by portfolio cost and portfolio risk. A subset of resource portfolios along the mathematical cost–risk frontier are selected for further consideration. The preferred portfolio is selected from the set of finalist portfolios using qualitative criteria.[4] |
| **PacifiCorp** | *Thermal*—Maximum dependable capacity for peak-hour assessment. Energy assessments used maximum dependable capacity de-rated for forced outages and maintenance.[5] |
| | *Hydro Conditions*—Critical water conditions. For peak hour assessment, decision support software is used to shape critical hydro energy to estimate maximum capability sustainable for one hour.[5] |
| | *Loads*—Average energy requirements based on normal weather conditions.[5] |
| | *Planning Reserve*—Planning reserve margin of 13% assumed for energy and peak-hour assessments.[5] |

[1] 2009 Integrated Resource Plan, Avista Utilities, August 2009, Chapter 2.

[2] 2009 Pacific Northwest Loads and Resources Study, Bonneville Power Administration, July 2009, Sections 2 & 4.

[3] 2011 Integrated Resource Plan, Idaho Power Company, June 2011.

[4] Sixth Northwest Power Plan, Northwest Power and Conservation Council, February 2010.

[5] 2011 Integrated Resource Plan, PacifiCorp, March 31, 2011, Chapter 5.

| Utility | Planning Criteria |
|---|---|
| **Portland General Electric Company (PGE)** | *Hydro Conditions*—Normal hydro conditions.[6] |
| | *Loads*—PGE identifies annual energy needs under a reference case (i.e., expected or most likely) and high-load and low-load forecasts, assuming normal weather conditions.[6] |
| | *Capacity*—PGE evaluates peaking needs by comparing the annual one-hour maximum load inclusive of 12% reserves (6% operating margin, 6% planning margin), calculated on a 1-in-2 or average basis, to the capability of energy-producing resources. Reports both the winter and the summer peak loads.[6] |
| **Puget Sound Energy** | *Loads*—For capacity, power demand was estimated at normal winter minimum temperature (23° F) plus a 15% planning margin. Five different economic growth scenarios were modeled in the resource plan.[7] |
| | *Hydro*—For capacity resource need, hydro projects assumed at full-capacity output.[7] |
| | *Thermal*—For capacity resource need, thermal projects assumed at full-capacity output.[7] |

[6] PGE 2009 Integrated Resource Plan, Portland General Electric, November 2009, Chapter 3.

[7] Integrated Resource Plan, Puget Sound Energy, July 2009, Chapters 5 & 8.

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# ATTACHMENT N-3
# IDAHO POWER COMPANY'S 2013 INTEGRATED RESOURCE PLAN (DOCKET LC 58)



# 2013
## Integrated Resource Plan

June 2013

IDAHO POWER®
An IDACORP Company

# 2013

# Integrated Resource Plan

## ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the Advisory Council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

**June 2013**

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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... v
List of Figures ..... vi
List of Appendices ..... viii
1. Summary ..... 1
Introduction ..... 1
Public Advisory Process ..... 2
IRP Methodology ..... 3
Supply-Side Resource Costs ..... 4
Greenhouse Gas Emissions ..... 6
Preferred Resource Portfolio ..... 8
Action Plan ..... 9
2. Political, Regulatory, and Operational Issues ..... 11
Idaho Energy Plan ..... 11
Idaho Strategic Energy Alliance ..... 11
FERC Relicensing ..... 12
Idaho Water Issues ..... 13
Wind Integration Study ..... 16
Northwest Power Pool Energy Imbalance Market ..... 17
Renewable Energy Certificates ..... 17
Renewable Portfolio Standard ..... 18
Renewable Energy Credit Management Plan ..... 18
Federal Energy Legislation ..... 19
3. Idaho Power Today ..... 21
Customer Load and Growth ..... 21
2012 Energy Sources ..... 23
Existing Supply-Side Resources ..... 25
Hydroelectric Facilities ..... 26
Hells Canyon Complex ..... 26
Upper Snake and Mid-Snake Projects ..... 28

Water Lease Agreements ..... 28
Cloud Seeding ..... 29
Thermal Facilities ..... 30
Jim Bridger ..... 30
North Valmy ..... 30
Boardman ..... 30
Langley Gulch ..... 30
Peaking Facilities ..... 31
Danskin ..... 31
Bennett Mountain ..... 31
Salmon Diesel ..... 31
Solar Facilities ..... 31
Net Metering Service ..... 31
Oregon Solar Photovoltaic Pilot Program ..... 32
Power Purchase Agreements ..... 32
Elkhorn Valley Wind Project ..... 32
Raft River Geothermal Project ..... 33
Neal Hot Springs Geothermal Project ..... 33
Clatskanie Energy Exchange ..... 33
Public Utility Regulatory Policies Act ..... 33
Published Avoided Cost Rates ..... 34
Wholesale Contracts ..... 35
Market Purchases and Sales ..... 36
Committed Supply-Side Resources ..... 36
Shoshone Falls Upgrade Project ..... 36
4. Demand-Side Resources ..... 37
DSM Program Performance ..... 38
Energy Efficiency Performance ..... 38
Demand Response Performance ..... 40
New Energy Efficiency Resources ..... 41
Demand Response Resources ..... 44
Conservation Voltage Reduction ..... 45
5. Planning Period Forecasts ..... 47

Load Forecast....47
Weather Effects....48
Economic Effects....48
Peak-Hour Load Forecast....51
Average-Energy Load Forecast....52
Additional Firm Load....54
Micron Technology....54
Simplot Fertilizer....54
Idaho National Laboratory....54
Hoku Materials....54
"Special" Contract....55
Existing Resources....55
Hydroelectric Resources....55
Coal Resources....58
Planned Upgrades at Jim Bridger....59
Natural Gas Resources....59
Load and Resource Balance....59
Average Monthly Energy Planning....60
Peak-Hour Planning....60
Natural Gas Price Forecast....62
Resource Cost Analysis....63
Emissions Adders for Fossil Fuel-Based Resources....63
Resource Cost Analysis II—Resource Stack....64
Levelized Capacity (Fixed) Cost....64
Levelized Cost of Production....65
Carbon Adder....68
Carbon-Adder Generation Dispatch Analysis....69
6. Transmission Planning....71
Past and Present Transmission....71
Transmission Planning Process....72
Local Transmission Planning Process....72
Local-Area Transmission Advisory Process....72
Biennial Local Transmission Planning Process....72

Regional Transmission Planning ....73
Interconnection-Wide Transmission Planning....73
Existing Transmission System....73
Idaho–Northwest Path....74
Brownlee East Path....74
Idaho–Montana Path....75
Borah West Path....75
Midpoint West Path....75
Idaho–Nevada Path....76
Idaho–Wyoming Path....76
Idaho–Utah Path....76
Boardman to Hemingway....77
Gateway West....79
Transmission Assumptions in the IRP Portfolios....80
7. Resource Alternatives Analysis....83
Solar Parking Lot Lighting Demonstration Project....86
Risk Analysis and Results....86
8. Planning Criteria and Portfolio Selection....89
Planning Scenarios and Criteria....89
Portfolio Design and Selection....90
Boardman to Hemingway Resource Portfolios....90
Resource Portfolio 1—Boardman to Hemingway plus Demand Response and an SCCT....90
Resource Portfolio 2—Boardman to Hemingway plus Demand Response....91
Alternative to Boardman to Hemingway Resource Portfolios....91
Resource Portfolio 3—Demand Response plus a CCCT and an SCCT....91
Resource Portfolio 4—Demand Response plus Two CCCTs....92
Resource Portfolio 5—Demand Response plus Two Consecutive CCCTs....92
Coal Alternative Resource Portfolios....93
Resource Portfolio 6—ICL–BSU....93
Resource Portfolio 7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response....94

Resource Portfolio 8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT ..... 95
Resource Portfolio 9—North Valmy Closure, Boardman to Hemingway Alternative ..... 95
9. Modeling Analysis and Results ..... 97
Portfolio Costs ..... 97
Portfolio Emissions ..... 99
$CO_2$ Emissions ..... 99
$NO_x$ Emissions ..... 100
$SO_2$ Emissions ..... 101
Hg Emissions ..... 102
Stochastic Analysis ..... 103
Carbon-Adder Analysis ..... 105
Capacity Planning Margin ..... 106
Flexible Resource Needs Assessment ..... 109
Loss of Load Expectation ..... 110
Regional Resource Adequacy ..... 111
10. Action Plan ..... 113
Action Plan (2013–2032) ..... 113
Conclusion ..... 114

## LIST OF TABLES

Table 1.1 Action plan ..... 9
Table 2.1 Phase I measures included in the ESPA CAMP ..... 15
Table 3.1 Historical capacity, load, and customer data ..... 22
Table 3.2 2012 REC Accounting ..... 25
Table 3.3 Existing resources ..... 26
Table 3.4 Net metering service customer count and generation capacity as of June 1, 2013 ..... 32
Table 4.1 Total energy efficiency current portfolio forecasted effects (2013–2032) (aMW) ..... 43
Table 4.2 Total energy efficiency portfolio cost-effectiveness summary ..... 43
Table 4.3 New energy efficiency resources (2017–2032) (aMW) ..... 44

Table 5.1 Load forecast—peak hour (MW) ..... 52
Table 5.2 Load forecast—average monthly energy (aMW) ..... 53
Table 5.3 Emissions intensity rates (pound/MWh) ..... 64
Table 5.4 Carbon-adder scenarios ..... 69
Table 6.1 Available transmission import capacity ..... 76
Table 6.2 Boardman to Hemingway capacity and permitting cost allocation ..... 77
Table 6.3 Transmission assumptions ..... 81
Table 7.1 Resource alternatives to achieve 200 MW of peak-hour contribution in 2018 (NPV years 2013–2022, 2013 dollars, 000s) ..... 84
Table 7.2 Risk scenario results ..... 87
Table 8.1 Coal resource fixed-cost accounting ..... 90
Table 8.2 Resource portfolio 1 ..... 91
Table 8.3 Resource portfolio 2 ..... 91
Table 8.4 Resource portfolio 3 ..... 92
Table 8.5 Resource portfolio 4 ..... 92
Table 8.6 Resource portfolio 5 ..... 93
Table 8.7 Resource portfolio 6 ..... 94
Table 8.8 Resource portfolio 7 ..... 94
Table 8.9 Resource portfolio 8 ..... 95
Table 8.10 Resource portfolio 9 ..... 96
Table 9.1 Financial assumptions ..... 97
Table 9.2 2013 IRP portfolios, NPV years 2013–2032 (2013 dollars, 000s) ..... 98
Table 9.3 Capacity planning margin ..... 107
Table 10.1 Portfolio 2 action plan ..... 113

## LIST OF FIGURES

Figure 1.1 Capacity cost of new supply-side resources ..... 5
Figure 1.2 Energy cost of new supply-side resources ..... 6
Figure 1.3 $CO_2$ emissions intensity of the largest 100 utilities ..... 7
Figure 1.4 $CO_2$ emissions of the largest 100 utilities ..... 7
Figure 2.1 Brownlee total annual inflow—forecasted flows, 2013–2032 ..... 16

Figure 3.1 Historical capacity, load, and customer data ....22
Figure 3.2 2012 energy sources by type....24
Figure 3.3 2012 energy sources....24
Figure 3.4 2012 Idaho Power system nameplate (MW) (owned resources plus PPAs) ....24
Figure 3.5 2012 long-term power purchases by resource type....24
Figure 3.6 PURPA contracts by resource type....34
Figure 4.1 Cumulative energy efficiency savings, 2002–2012 (aMW) ....39
Figure 4.2 Annual energy efficiency savings and IRP targets, 2002–2012 (aMW)....39
Figure 4.3 Demand response peak reduction capacity, 2004–2012 (MW)....40
Figure 4.4 Demand response peak reduction capacity with IRP targets, 2004–2012 (MW)....41
Figure 5.1 Peak-hour load-growth forecast (MW)....51
Figure 5.2 Average monthly load-growth forecast (aMW)....53
Figure 5.3 Brownlee historical and forecast inflows....58
Figure 5.4 Monthly average-energy surpluses and deficits with existing and committed resources and existing DSM ($70^{th}$-percentile water and $70^{th}$-percentile load) ....60
Figure 5.5 Monthly peak-hour deficits without existing and committed resources and existing DSM ($90^{th}$-percentile water and $95^{th}$-percentile load)....61
Figure 5.6 Henry Hub Price Forecast—EIA *Annual Energy Outlook 2012* (nominal dollars)....62
Figure 5.7 30-year levelized capacity (fixed) costs....66
Figure 5.8 30-year levelized cost of production (at stated capacity factors)....67
Figure 5.9 2013 IRP carbon adder....68
Figure 5.10 Dispatch costs, 2020 ....70
Figure 6.1 Idaho Power transmission system map ....74
Figure 6.2 Boardman to Hemingway routes with the BLM preliminary environmentally preferred route ....78
Figure 6.3 Gateway West Map....79
Figure 7.1 Relative costs per delivered on-peak kW....84
Figure 7.2 Solar generation recovery period....85
Figure 7.3 Inovus solar light....86

Figure 8.1 Resource portfolio 1....90
Figure 8.2 Resource portfolio 2....91
Figure 8.3 Resource portfolio 3....91
Figure 8.4 Resource portfolio 4....92
Figure 8.5 Resource portfolio 5....92
Figure 8.6 Resource portfolio 6....93
Figure 8.7 Resource portfolio 7....94
Figure 8.8 Resource portfolio 8....95
Figure 8.9 Resource portfolio 9....96
Figure 9.1 Total portfolio costs, NPV 2013–2032 (2013 dollars, 000s)....99
Figure 9.2 Total $CO_2$ emissions for 2013–2032....100
Figure 9.3 Total $NO_x$ emissions for 2013–2032....101
Figure 9.4 Total $SO_2$ emissions for 2013–2032....102
Figure 9.5 Total Hg emissions for 2013–2032....103
Figure 9.6 Portfolio stochastic analysis....104
Figure 9.7 Stochastic-based carbon-adder tipping point....105
Figure 9.8 LOLE (hours per year)....111

## LIST OF APPENDICES

Appendix A—Sales and Load Forecast
Appendix B—Demand-Side Management 2012 Annual Report
Appendix C—Technical Appendix

# 1. SUMMARY

## Introduction

The *2013 Integrated Resource Plan* (IRP) is Idaho Power's 11th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). The Idaho Power resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within the Idaho Power service area throughout the 20-year planning period.

2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.

3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

The 2013 IRP assumes that during the 20-year planning period—2013 through 2032—Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of the retail electricity customers in the company's Idaho and Oregon service areas and that Idaho Power will continue to operate as a vertically integrated electric utility.

The number of customers in the Idaho Power service area is expected to increase from approximately 500,000 in 2012 to nearly 670,000 by the end of the planning period in 2032. Population growth in the Idaho Power service area will require the company to add physical resources to meet the energy demands of the growing customer base.

Hydroelectric generation is the foundation of Idaho Power's energy production. Idaho Power has an obligation to serve customer loads regardless of the water conditions. Public input and regulatory support encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP, and Idaho Power continues to develop the resource plans using more conservative streamflow projections and planning criteria than median water planning but less stringent than critical water planning. Further discussion of the Idaho Power planning criteria can be found in Chapter 5.

Demand-side management (DSM) is another key resource used by Idaho Power to meet customer load. Idaho Power's main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from the demand response programs as determined through the IRP planning process. Idaho Power also strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve Idaho Power retail customers. Transmission projects are often regional resources and regional transmission planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG). Idaho Power coordinates local transmission planning with the regional forums as well as the Federal Energy Regulatory Commission (FERC). Idaho Power is obligated under FERC regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers[1] and Idaho Power retail customers.[2] The total transfer capacity of proposed transmission projects may be larger than the capacity identified in the Idaho Power IRP to accommodate the other ownership partners, third-party requests, and network customer obligations for transmission capacity.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Some earlier Idaho Power resource plans used a 10-year planning horizon. With the need for resources with long permitting and construction lead times, the requirement for a 20-year resource plan supporting independent power production contracts under the *Public Utility Regulatory Policies Act of 1978* (PURPA), and with support from the IRP Advisory Council, Idaho Power extended the planning horizon to 20 years.

The IRPs address Idaho Power long-term resource needs. Idaho Power plans for near term energy and capacity needs in accordance with the *Energy Risk Management Policy and Standards*. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC E-01-16). The *Energy Risk Management Policy and Standards* specifies an 18-month period, and Idaho Power assesses the resulting operations plan monthly.

## Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council. The IRP Advisory Council generally meets monthly during the development of the resource plan, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public participate even though they are not members of the IRP Advisory Council. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2013 IRP Advisory Council members can be found in *Appendix C—Technical Appendix*.

---

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

Idaho Power conducted 11 IRP Advisory Council meetings, including a resource portfolio design workshop. Idaho Power and members from the IRP Advisory Council also met in several small break-out sessions to discuss certain topics in greater detail.

As part of the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and natural gas power generation. The IRP Advisory Council visited the Hemingway Substation and Langley Gulch Power Plant on the field trip.



The IRP Advisory Council visits the Hemingway Substation.

The IRP Advisory Council actively participated throughout the resource planning process. Members of the IRP Advisory Council representing the Idaho Conservation League (ICL) and Boise State University (BSU) suggested a resource portfolio that was included and analyzed as part of the 2013 resource plan.

Idaho Power believes working with members of the IRP Advisory Council and the public improves the Idaho Power IRP. Idaho Power and the members of the IRP Advisory Council recognize that final decisions on the resource plan are made by Idaho Power. Idaho Power encourages IRP Advisory Council members and members of the public to submit comments expressing their views regarding the 2013 IRP and the resource planning process in general.

Following the filing of the final resource plan, Idaho Power presents the resource plan at public meetings in various cities around the company service area. In addition, Idaho Power staff present the plan and discuss the planning process with various civic groups and at educational seminars as requested.

## IRP Methodology

Preparation of the Idaho Power 2013 IRP began with the forecast of future customer demand. Existing generation resources and transmission import capacity are combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated demand response, new DSM programs, and the expansion of existing programs to revise any energy and capacity deficits. Finally, Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits.

Idaho Power evaluates resources and resource portfolios using a financial analysis. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), necessary transmission upgrades, and anticipated environmental control and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy credits (REC).

Idaho Power is part of the larger northwest and western regional energy markets, and market prices are an important component of evaluating energy purchases and sales. Idaho Power faces transmission import constraints and, at times of peak customer load, must rely on its own generation resources regardless of the regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds Idaho Power customer demand and the transmission export capacity, and Idaho Power must curtail generation on its system.

The 49 megawatt (MW) Shoshone Falls upgrade is the only committed resource in the Idaho Power 2013 IRP. The Shoshone Falls upgrade is expected to be in operation in July 2019. Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility. Committed resources are treated the same as existing resources in the IRP analysis.

An additional transmission connection to the Pacific Northwest has been part of the Idaho Power preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line and, since 2009, the addition has been called the Boardman to Hemingway transmission line. Idaho Power revaluated the Boardman to Hemingway transmission line in the 2013 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Idaho Power analyzed the resource portfolios over the entire 20-year planning period in the 2013 IRP. Idaho Power does not intend to add any resources until 2018, and Idaho Power determined it is practical to consider the 20-year planning period in total. For the 2011 IRP, the 20-year planning period was divided into two 10-year segments due to the anticipated near-term resource acquisition of the Langley Gulch combined-cycle combustion turbine (CCCT).

## Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. The National Renewable Energy Laboratory (NREL) published the *Cost and Performance Data for Power Generation Technologies* in February 2012, and Idaho Power relied on the data from this publication to estimate the supply-side resource costs for the 2013 IRP.[3] Idaho Power used cost data from the company's Langley Gulch Power Plant to estimate the costs for natural gas CCCT.

The 2013 IRP forecasts load growth in the Idaho Power service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2013 IRP has identified periods of future capacity deficiencies. New resource costs are 30-year levelized estimates (based on expected annual generation) that include capital, fuel, non-fuel O&M, and the planning-case carbon adder. Figure 1.1 shows the 2013 capacity costs in dollars per kilowatt (kW) for various new supply-side resources considered in the 2013 IRP.

[3] National Renewable Energy Laboratory, *Cost and Performance Data for Power Generation Technologies,* February 2012, available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

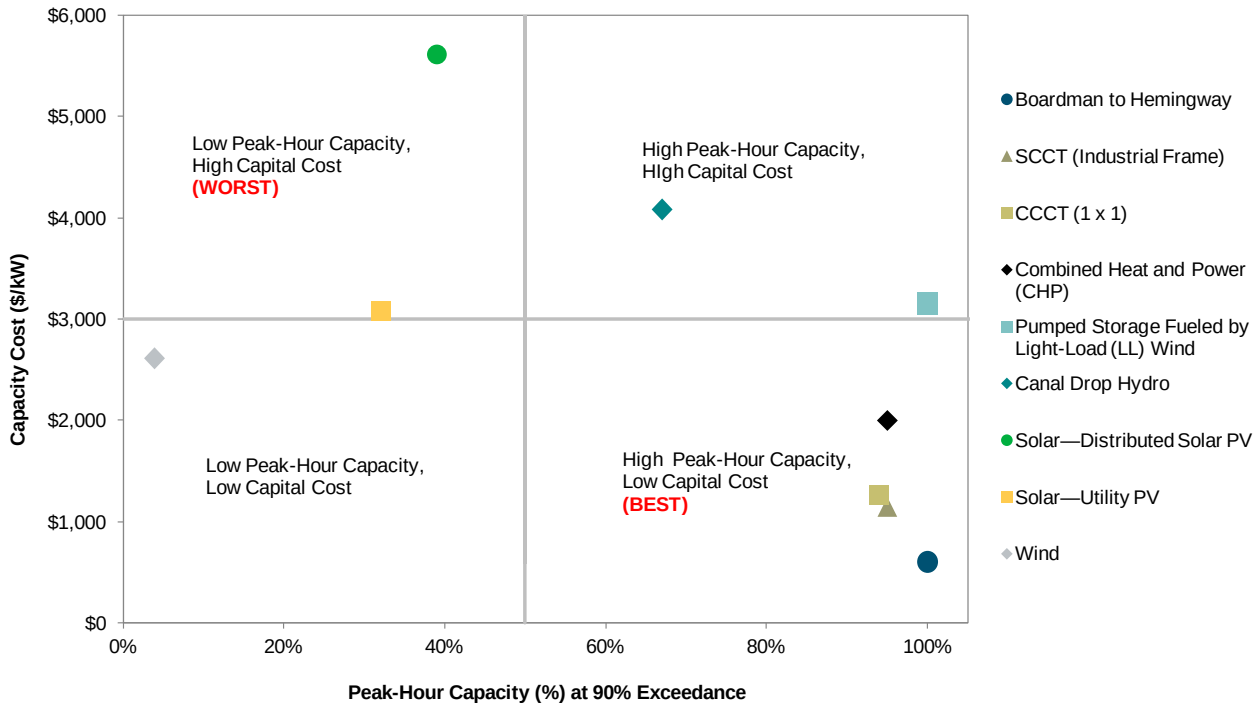


**Figure 1.1 Capacity cost of new supply-side resources**

Figure 1.1 shows the Boardman to Hemingway transmission line is the least-cost resource analyzed and provides the greatest level of peak-hour capacity. Simple-cycle combustion turbines (SCCT) and CCCTs are the second and third resources, respectively, in terms of capacity cost and provide slightly less peak-hour capacity than the Boardman to Hemingway line.

While it is important to evaluate the costs presented in Figure 1.1, the costs represent only part of the total resource cost (TRC). In preparing the IRP, Idaho Power also considers the value each resource provides in conjunction with the existing resources in the company's generation portfolio. A more complete analysis is presented in the Resource Alternatives Analysis section in Chapter 7. Supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 1.2 shows the 2013 cost of energy in dollars per megawatt-hour (MWh) for various new supply-side resources considered in the 2013 IRP. Figure 1.2 allows for resource alternatives to be compared based on the capacity cost and cost of production.

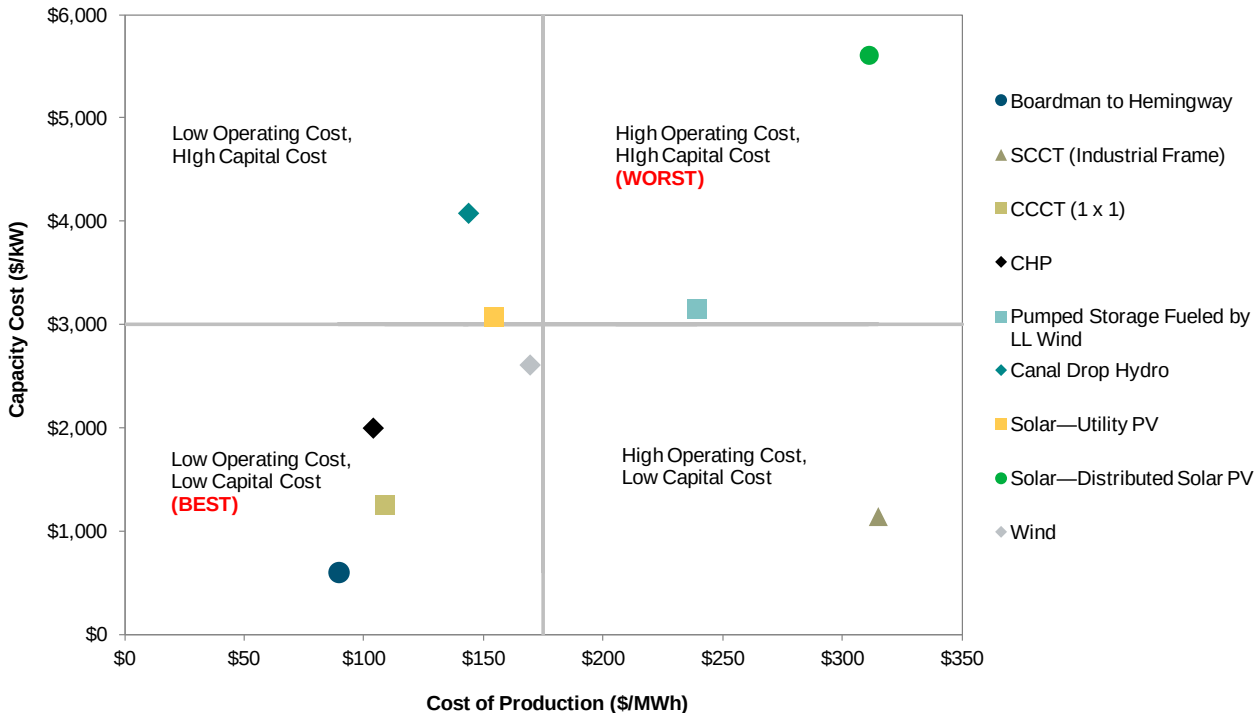


**Figure 1.2 Energy cost of new supply-side resources**

Figure 1.2 shows that the Boardman to Hemingway transmission line has the lowest capacity cost and the lowest cost of production. Natural gas-fueled resources are the next resources in terms of low capacity cost. CCCTs have a lower cost of energy production than SCCTs. Figures 1.1 and 1.2 show that a SCCT, with a relatively low cost of capacity, is a good resource to meet capacity deficiencies. Conversely, a SCCT is less efficient at meeting long periods of energy deficiencies. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2013 IRP is presented in Chapter 5.

## Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide ($CO_2$) emission levels have historically been well below the national average for the 100 largest electric utilities in the United States (US), both in terms of total $CO_2$ emissions (tons) and $CO_2$ emissions intensity (pounds per MWh). In 2010, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 37$^{th}$ lowest emitter of $CO_2$ per MWh produced and the 35$^{th}$ lowest emitter of $CO_2$ by tons of emissions among the nation's 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, Entergy, Exelon, Bank of America, Tenaska, and by grants from the Energy Foundation and the Surdna Foundation using publicly reported 2010 generation and emissions data. Figures 1.3 and 1.4 show Idaho Power's relative position to other utilities in terms of $CO_2$ emissions intensity and the overall quantity of $CO_2$ emissions. According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 58$^{th}$ largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.




**Figure 1.3 $CO_2$ emissions intensity of the largest 100 utilities**

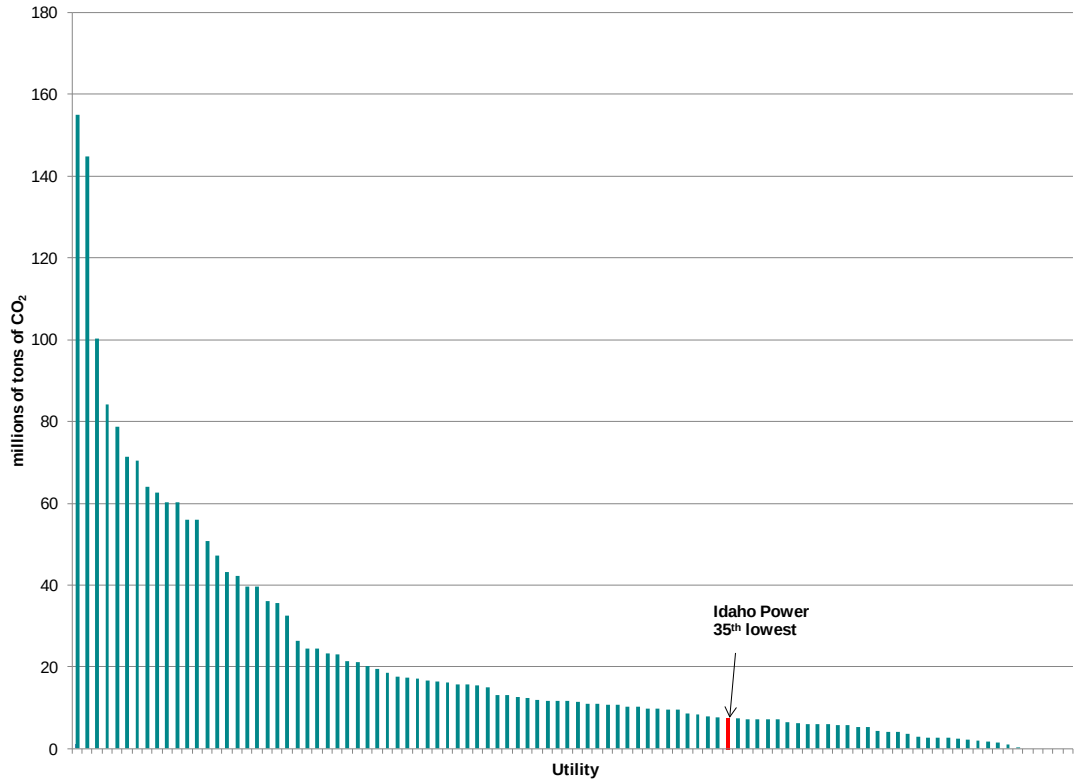


**Figure 1.4 $CO_2$ emissions of the largest 100 utilities**

In September 2009, Idaho Power's Board of Directors approved guidelines to reduce Idaho Power's resource portfolio average $CO_2$ emissions intensity from 2010 through 2013 to 10 to 15 percent below the company's 2005 $CO_2$ emissions intensity of 1,194 pounds per MWh. Because Idaho Power's $CO_2$ emissions intensity fluctuates with streamflows and production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

Currently, generation and emissions from company-owned resources are included in the $CO_2$ intensity calculation. The company's progress toward achieving this intensity reduction goal and additional information on Idaho Power's $CO_2$ emissions are reported on the company's website:

http://www.idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm.

Information related to Idaho Power's $CO_2$ emissions is also available through the Carbon Disclosure Project at www.cdproject.net. In November 2012, the Board of Directors approved the extension of the company's 2010 to 2013 goal for reducing $CO_2$ emission intensity. The goal is to achieve $CO_2$ emission intensity 10 to 15 percent below the 2005 $CO_2$ emission intensity from 2010 to 2015.

The 2013 IRP quantifies the cost and longer term effects of carbon regulations by including a carbon adder applied to all resources that emit $CO_2$. Additional details regarding the assumptions and analysis are presented in Chapter 5 and Chapter 9.

Idaho Power included a more complete discussion of climate change and the regulation of greenhouse gas emissions on pages 65 through 67 of the IDACORP, Inc., 2012 Annual Report. This climate change section is also included in *Appendix C—Technical Appendix*.

## Preferred Resource Portfolio

The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was first mentioned in the 2000 IRP, and the upgrade was specifically identified in the 2006 Idaho Power resource plan. Idaho Power continues the efforts to acquire the necessary regulatory approvals and permits to begin construction. The construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018.

Idaho Power's demand response programs will be used throughout the planning period to meet resource needs. Idaho Power expects to use up to approximately 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission. The preferred resource portfolio assumes a demand response capacity of 50 MW is available beginning in 2024 and steps up to approximately 370 MW by 2032. The level of demand response capacity available will be based on the deficits identified through the IRP process or operational needs identified between IRP cycles.

The preferred resource portfolio includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional

emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to the installation and operation of the additional emission-control systems. The approximate financial commitment dates are identified in the action plan. The commitment dates are derived from the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (coal study) that Idaho Power filed in February 2013 as part of the 2011 IRP Update.

Idaho Power prepares an IRP every two years and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

## Action Plan

Table 1.1 identifies the actions Idaho Power will take over the next 20 years to meet the projected capacity deficits. The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission line project has outperformed the other resource portfolios in the 2013 resource plan. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.

Idaho Power treated the Boardman to Hemingway transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

**Table 1.1 Action plan**

| Year | Resource | Action |
|---|---|---|
| 2013–2018 | Boardman to Hemingway | Ongoing permitting, planning studies, and regulatory filings. |
| 2013– | Gateway West | Ongoing permitting, planning studies, and regulatory filings. |
| 2013 | North Valmy Unit 1 | Commit to the installation of dry sorbent injection emission-control technology. |
| 2013 | Jim Bridger Units 3 and 4 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2016–2017 | Demand response | Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. |
| 2018 | Boardman to Hemingway | Transmission line complete and in service. |
| 2019 | Shoshone Falls | Shoshone Falls upgrade complete and in service. |
| 2019 | Jim Bridger Unit 2 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2020 | Jim Bridger Unit 1 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2020 | Boardman | Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020. |
| 2024–2032 | Demand response | Have demand response capacity available to satisfy deficiencies up to approximately 370 MW. |

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# 2. POLITICAL, REGULATORY, AND OPERATIONAL ISSUES

## Idaho Energy Plan

In 2007, the Idaho Legislature's Interim Committee on Energy, Environment and Technology prepared, and the Idaho Legislature approved, a new Idaho Energy Plan for the first time in 25 years. With rapid changes in energy resources and policies, the committee recommended the legislature revisit the Idaho Energy Plan every five years to properly reflect the interests of Idaho citizens and businesses. In keeping with this recommendation, the plan was reviewed and updated by the Interim Committee and approved by the legislature in 2012. The Idaho Office of Energy Resources (IOER) and the Idaho Strategic Energy Alliance provided assistance to the Interim Committee during the update of the energy plan.

The 2012 update finds that Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy, despite the potential economic and political vulnerability caused by Idaho's reliance on energy imports. Idaho currently lacks significant commercial natural gas and oil wells and only generates about half the electricity it uses. Yet the state has abundant hydropower, wind, biomass, and other renewable energy sources.

Ongoing changes in energy generation and consumption provide an opportunity for economic growth within the state. While the Idaho Energy Plan acknowledges the risks attributed to advances in energy generation, transmission, and end-use technologies, it also recognizes the prospective benefits. With this recognition, the 2012 Idaho Energy Plan emphasizes five core objectives:

1. Ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho.

2. Maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans.

3. Protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources.

4. Promote sustainable economic growth, job creation, and rural economic development.

5. Provide the means for Idaho's energy policies and actions to adapt to changing circumstances.

## Idaho Strategic Energy Alliance

In 2007, Governor C. L. "Butch" Otter established the IOER to oversee energy planning, policy, and coordination in Idaho. Under the umbrella of the IOER, the Idaho Strategic Energy Alliance was established to respond to rising energy costs and other energy challenges facing the state. The governor's philosophy is that there should be a joint effort between all stakeholders in developing options and solutions for Idaho's energy future.

The alliance promotes the development of a sound energy portfolio for Idaho that diversifies energy resources and provides stewardship of the environment. The alliance consists of a board of directors and 13 volunteer task forces working in the following areas:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

Idaho Power representatives serve on many of the task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council—a group of cabinet members assigned responsibility by executive order to review suggestions from the board and interact directly with the governor. The council is led by the administrator of the IOER.

## FERC Relicensing

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years, depending on the size, complexity, and cost of the project.

Idaho Power filed a final license application (FLA) for the Swan Falls Hydroelectric Project (Swan Falls Project) with FERC in June 2008, and the new license for the Swan Falls Project was issued by FERC on September 8, 2012, for a 30-year term expiring September 1, 2042.

Idaho Power's remaining and most significant ongoing relicensing effort is the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 34 percent of the company's total generating capacity. The current license for the HCC expired at the end of July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1978* (ESA); and other applicable federal laws.

Administrative work on relicensing the HCC is expected to continue until a new license is issued. After a new license is issued, further costs will be incurred to comply with the terms of

the new license. Because the new license for the HCC has not been issued, and discussions on the protection, mitigation, and enhancement (PM&E) packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include the following:

1. Coordinating the relicensing process
2. Consulting with regulatory agencies, tribes, and interested parties
3. Preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites
4. Preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
5. Studying and analyzing data
6. Preparing all necessary reports, exhibits, and filings responding to requests for additional information from FERC
7. Consulting on legal matters

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental PM&E measures imposed as a condition of relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2013 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

## Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues is expected to affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended

to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984.



The Snake River at the Murphy gage below Swan Falls.

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power over the company's water rights at the Swan Falls Project. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The Swan Falls Agreement placed the portion of the company's water rights beyond the minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked the court to resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the State of Idaho are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric

generation. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board (IWRB).

Idaho Power actively participated in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between the ESPA and Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River. The company had hoped implementation of the ESPA CAMP would improve aquifer levels and tributary spring flows to the Snake River. However, some of the Phase I recommendations, outlined in Table 2.1, have been slow to fully develop.

One major issue not fully resolved through the CAMP process was funding for proposed management practices. Several funding alternatives were discussed, but no long-term funding mechanisms have been established. While there have been two practices—recharge and weather modification—that have received adequate funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program and, through the cooperative effort, has greatly expanded the existing weather modification program as well as added additional forecasting and meteorological data support. The company has also established a long-term plan to continue the expansion of this program.

**Table 2.1 Phase I measures included in the ESPA CAMP**

| Measure | Target (acre-feet) | Estimated to Date (acre-feet) |
|---|---|---|
| Groundwater to surface-water conversions | 100,000 | 19,156 |
| Managed aquifer recharge | 100,000 | 115,000* |
| Demand reduction | – | – |
| Surface-water conservation | 50,000 | 26,000 |
| Crop mix modification | 5,000 | 0 |
| Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP) | 40,000 | 33,368 |
| Weather modification | 50,000 | 124,000 |

*Average annual recharge from 2009 – 2012. Includes estimated for 2012

For the 2013 IRP, Idaho Power forecasted flows similar to those in the 2011 IRP; however, the declines in reach gains are extended through 2027. Based on modeling under the 90-percent exceedance forecast, declining flows reach the Swan Falls 3,900-cfs minimum in 2027. At that time, Idaho Power assumes the State of Idaho will provide appropriate management and water-rights administration under the Swan Falls Agreement to prevent further declines in surface-water flows. Figure 2.1 provides the yearly inflow to Brownlee Reservoir as forecasted for the 2013 IRP.

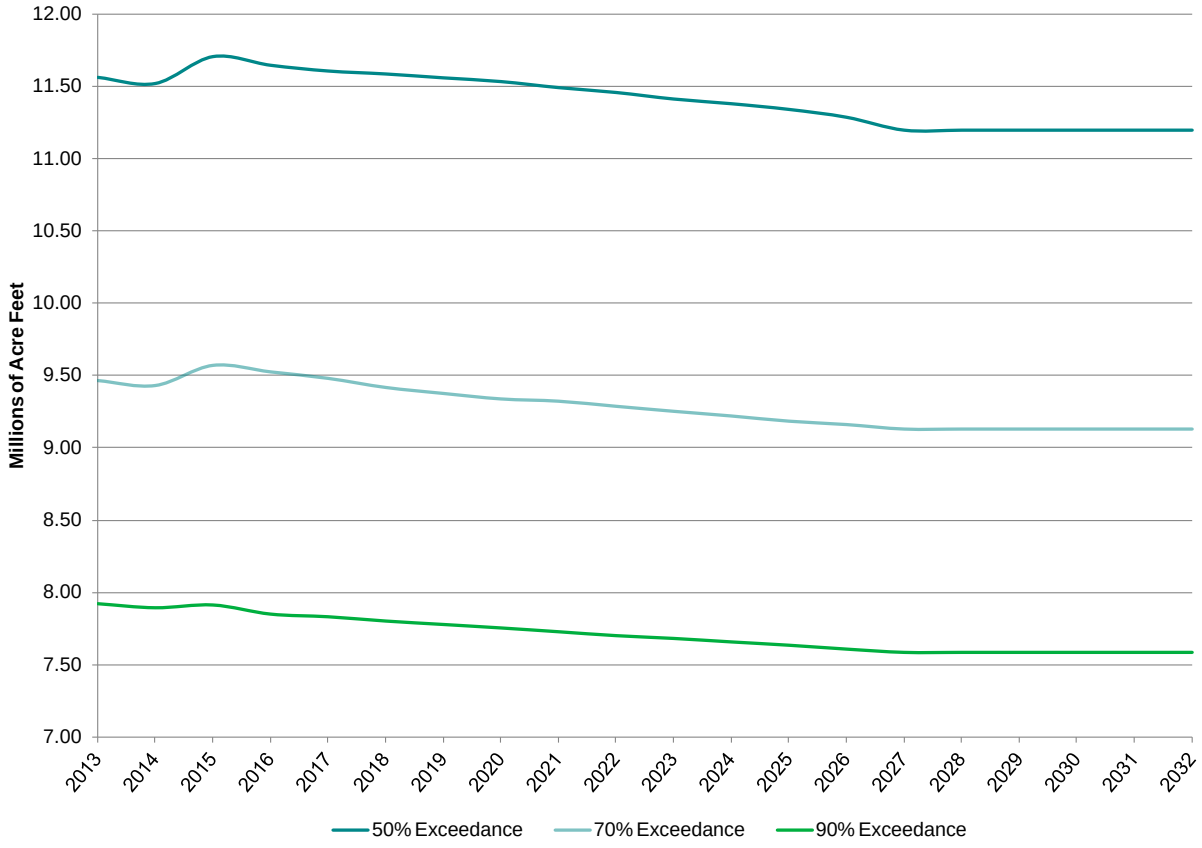


**Figure 2.1 Brownlee total annual inflow—forecasted flows, 2013–2032**

## Wind Integration Study

Because wind generators require Idaho Power to modify the power system operations to successfully integrate wind energy, wind is a variable and uncertain generating resource. Idaho Power must adjust the generation schedule to include additional operating reserves that allow Idaho Power dispatchable generators to respond to wind variability and uncertainty.

The wind integration study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources, transmission interconnections, and customer load may be unable to provide the incremental balancing reserves to successfully integrate wind. Under low demand circumstances, the curtailment of wind generation may be necessary to balance generation with customer load. The wind integration study demonstrates that the frequency of curtailment is expected to increase when the installed wind generation capacity exceeds 800 MW. The study results indicate that wind development beyond 800 MW may lead to a considerable curtailment risk.

Idaho Power prepared the wind integration study and filed the study as part of the 2011 IRP Update. The *Wind Integration Study Report* is available at:

http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

## Northwest Power Pool Energy Imbalance Market

In May 2012, the Northwest Power Pool (NWPP) initiated a study of an energy imbalance market (EIM) for the NWPP region. The 2012 study extended earlier work by WECC and various utility commissions. The NWPP study focused on issues related to hydroelectric resources in the Northwest. The NWPP analyzed the dispatch costs of the region to capture the diversity of load and wind variations that occur during the operating hour. In addition to the analysis, the NWPP study considered a mathematical simulation of the Northwest EIM. Idaho Power was 1 of over 20 entities supporting the study. The study found that an EIM would reduce the dispatch costs for the NWPP by about 3 percent when applied to the observed annual thermal dispatch cost of about $3 billion and resulted in savings between $40 and $120 million depending on the specific study assumptions. While the NWPP study found a positive benefit to cost ratio, many institutional issues remain before an EIM can be implemented in the Pacific Northwest.

For Idaho Power, there are several principle benefits to an EIM:

1. The market would provide greater access to balancing energy to accommodate intermittent generation variations within Idaho Power's balancing area.

2. There would be a slight improvement in real-time dispatch costs.

3. The market would provide better real-time pricing for power imbalances that occur in real-time for wholesale power customers. Idaho Power supports, and will continue to participate in, the NWPP discussions; however, participation by a majority of the NWPP members will be required to realize the benefits of an EIM.

## Renewable Energy Certificates

RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The RECs and the electricity produced by a certified renewable resource can either be sold together (bundled) or separately (unbundled). The purchase of a REC buys the "greenness" of that energy.

In states with REC programs, a renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hour (kWh), or 1 MWh, of electricity produced. An average residential Idaho Power customer uses about 1,025 kWh a month.

A certifying tracking system gives each REC a unique identification number to ensure the REC is used only once. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used, held, or traded.

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- Whether there is a tight supply/demand situation
- Whether the REC is used for renewable portfolio standards (RPS) compliance
- The type of power
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds from the REC sales are returned to Idaho Power customers through the power cost adjustment (PCA) as directed by the IPUC in Order No. 32002 and by the OPUC in Order No. 11-086. Because the RECs were sold, Idaho Power cannot claim the renewable electricity associated with those RECs was delivered to retail customers. The new REC owner has purchased the rights to claim the renewable attributes, or "greenness," of that energy.

If Idaho Power retains and retires its RECs, the company can claim electricity delivered to customers was generated by renewable resources.

## Renewable Portfolio Standard

Some states have an RPS, a state policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy. In the future, there may be similar federal standards. Idaho Power anticipates that existing hydroelectric facilities will not be included in RPS calculations. However, hydroelectric upgrades on existing facilities, such as the Shoshone Falls upgrade, will likely be included in RPS calculations.

Under the Oregon RPS, Idaho Power is classified as a "smaller utility" because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 10-percent RPS requirement beginning in 2025.

While the State of Idaho does not have an RPS, a federal Renewable Energy Standard (RES) is a possibility. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to position the company's resource and REC portfolio to minimize the potential effect on customers if a federal RES is implemented.

### *Renewable Energy Credit Management Plan*

In December 2009, Idaho Power filed a REC management plan with the IPUC that detailed the company's plans to continue acquiring long-term rights to RECs in anticipation of a federal RES but to sell RECs in the near term and return their share of the proceeds to customers through the PCA mechanism. Public comments regarding the plan mirrored the positions expressed by IRP Advisory Council members, many of whom filed comments with the IPUC. In June 2010, the IPUC accepted Idaho Power's REC management plan.

## Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local environmental laws and regulations. Current and pending environmental legislation relates to climate change, greenhouse gas emissions and air quality, mercury (Hg) and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species. The legislation includes the *Clean Air Act of 1970* (CAA), the *Clean Water Act of 1972* (CWA); the *Resource Conservation and Recovery Act of 1976* (RCRA); the *Toxic Substances Control Act of 1976* (TSCA); the *Comprehensive Environmental Response, Compensation and Liability Act of 1980* (CERCLA); and the ESA.

While the utility industry will continue to respond to changes in environmental legislation associated with utility operations, including emissions regulations associated with the operation of coal- and natural gas-fired generating facilities, the introduction or passage of federal energy legislation resulting in a comprehensive shift in national energy policy does not appear to be imminent. However, with atmospheric $CO_2$ reaching 400 parts per million (ppm), grass roots and local activities related to energy policy have increased in some parts of the country, which may lead to renewed interest in advancing comprehensive federal energy legislation.

In February 2013, Senators Bernie Sanders and Barbara Boxer introduced comprehensive legislation on climate change. The legislation has been introduced as two separate measures, cited as the following:

1. *Climate Protection Act of 2013*

2. *Sustainable Energy Act of 2013*

The package of legislation would, among other things, set a long-term emissions reduction goal of 80 percent or more by 2050; establish a carbon fee of $20 per ton of $CO_2$ content (or $CO_2$ equivalent content of methane), rising at 5.6 percent per year over a 10-year period; create a Family Clean Energy Rebate program; create a Sustainable Technologies Finance Program; and require disclosure of the chemicals used in the fracking process. Both bills are in committee.

The utility industry will continue to respond to, and be shaped by, changes in state and federal regulations, especially the changes affecting coal-fired generating facilities, the permitting of transmission facilities, PURPA regulations and implementation, and renewable energy incentives (production tax credits, cash grants, bonus depreciation, etc.). As noted previously, local activities related to climate change and energy policy may create sufficient interest to introduce climate change or comprehensive energy policy legislation that would affect the utility industry. Absent comprehensive federal energy legislation, a utility's resource portfolios will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes.

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# 3. IDAHO POWER TODAY

## Customer Load and Growth




An Idaho Power employee installs a Smart Meter.

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 500,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW. In July 2012, the peak-hour load reached 3,245 MW—the system peak-hour record. Idaho Power's successful demand-reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand from 2009 through 2011.

Average firm load increased from 1,200 aMW in 1990 to 1,745 aMW in 2012 (load calculations exclude the load from the former special-contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,595 MW. The 960-MW increase in capacity represents enough generation to serve approximately 150,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 318-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is located in the western Treasure Valley in Payette County, Idaho. Construction of the plant began in August 2010, and the plant became commercially available in June 2012.

The data in Table 3.1 suggests each new customer adds approximately 5.5 kW to the peak-hour load and about 2.5 average kilowatts (akW) to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to the average load; industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 210,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 210,000 customers require approximately 1,150 MW of additional peak-hour capacity and about 525 aMW of energy.

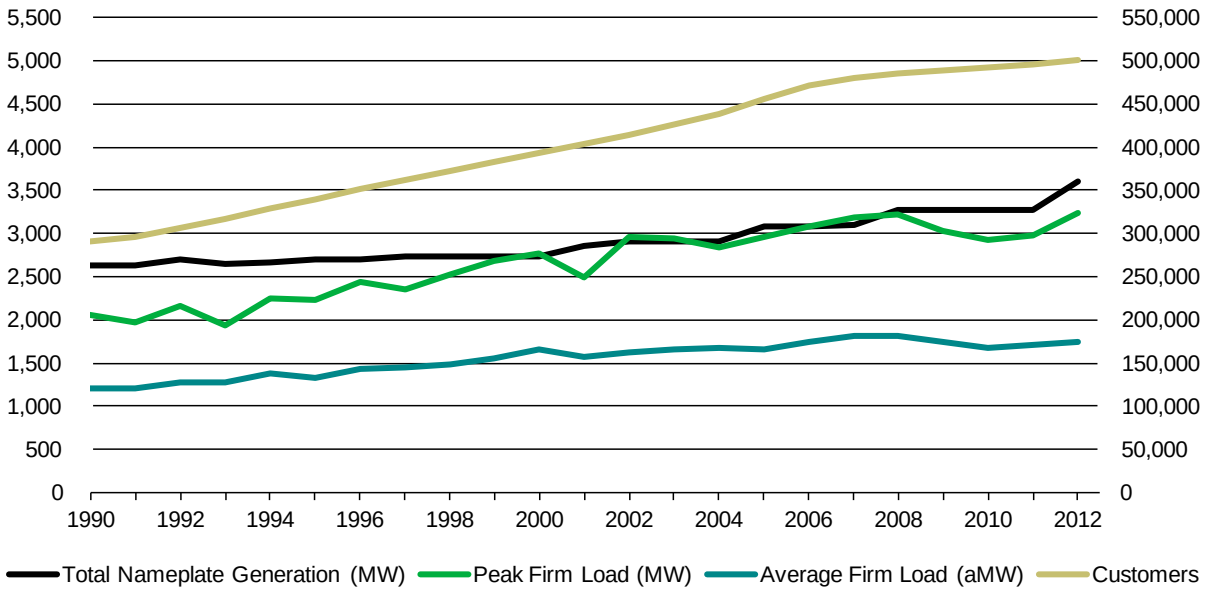


**Figure 3.1 Historical capacity, load, and customer data**

**Table 3.1 Historical capacity, load, and customer data**

| Year | Total Nameplate Generation (MW) | Peak Firm Load (MW) | Average Firm Load (aMW) | Customers[1] |
|---|---|---|---|---|
| 1990 | 2,635 | 2,052 | 1,205 | 290,492 |
| 1991 | 2,635 | 1,972 | 1,206 | 296,584 |
| 1992 | 2,694 | 2,164 | 1,281 | 306,292 |
| 1993 | 2,644 | 1,935 | 1,274 | 316,564 |
| 1994 | 2,661 | 2,245 | 1,375 | 329,094 |
| 1995 | 2,703 | 2,224 | 1,324 | 339,450 |
| 1996 | 2,703 | 2,437 | 1,438 | 351,261 |
| 1997 | 2,728 | 2,352 | 1,457 | 361,838 |
| 1998 | 2,738 | 2,535 | 1,491 | 372,464 |
| 1999 | 2,738 | 2,675 | 1,552 | 383,354 |
| 2000 | 2,738 | 2,765 | 1,653 | 393,095 |
| 2001 | 2,851 | 2,500 | 1,576 | 403,061 |
| 2002 | 2,912 | 2,963 | 1,622 | 414,062 |
| 2003 | 2,912 | 2,944 | 1,657 | 425,599 |
| 2004 | 2,912 | 2,843 | 1,671 | 438,912 |
| 2005 | 3,085 | 2,961 | 1,660 | 456,104 |
| 2006 | 3,085 | 3,084 | 1,745 | 470,950 |
| 2007 | 3,093 | 3,193 | 1,808 | 480,523 |
| 2008 | 3,276 | 3,214 | 1,815 | 486,048 |
| 2009 | 3,276 | 3,031 | 1,742 | 488,813 |
| 2010 | 3,276 | 2,930 | 1,679 | 491,368 |
| 2011 | 3,276 | 2,973 | 1,711 | 495,122 |
| 2012 | 3,595 | 3,245 | 1,745 | 500,731 |

[1] Year-end residential, commercial, and industrial count plus the maximum number of active irrigation customers

Idaho Power anticipates adding approximately 8,400 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 55 MW per year, and the average-energy requirement is forecast to grow at 21 aMW per year. More detailed customer and load forecast information is presented in Chapter 5 and in *Appendix A—Sales and Load Forecast*.

The simple peak-hour load-growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 318-MW Langley Gulch CCCT plant every six years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The plan to meet the requirements of Idaho Power's load growth is discussed in Chapter 10.

The generation costs per kW included in Chapter 5 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch Power Plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs are in 2013 US dollars and do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,400 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

## 2012 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and thermal generation facilities and long-term power purchase agreements (PPA) to supply the energy to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year.

In 2012, 79 percent of Idaho Power's supply of electricity came from company-owned generation resources as shown in Figure 3.2. Idaho Power purchased 11 percent of its energy from PURPA resources in 2012, and the remainder of the energy was purchased on the market or from PPAs (the four PPAs are described later in this section).

In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.3 shows Idaho Power's electricity sources for 2012, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

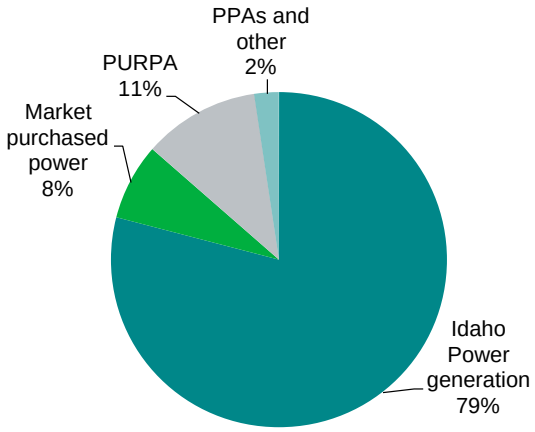


**Figure 3.2 2012 energy sources by type**

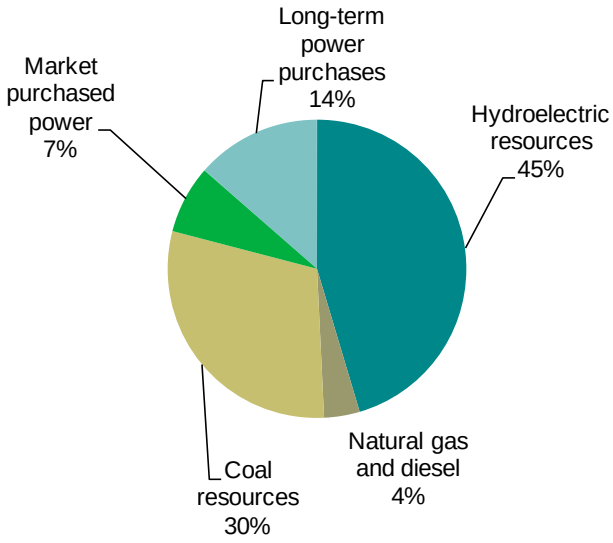


**Figure 3.3 2012 energy sources**

Figure 3.4 identifies the generation source by nameplate MW for Idaho Power generation in 2012. Figure 3.4 includes generation owned by Idaho Power and generation Idaho Power purchases through PPAs.

In 2012, Idaho Power purchased 2,374,795 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.5. Long-term power purchases that cannot be identified by resource type are shown as Other.

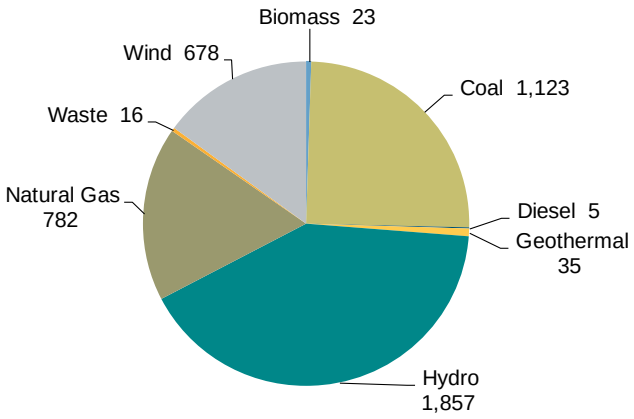


**Figure 3.4 2012 Idaho Power system nameplate (MW) (owned resources plus PPAs)**

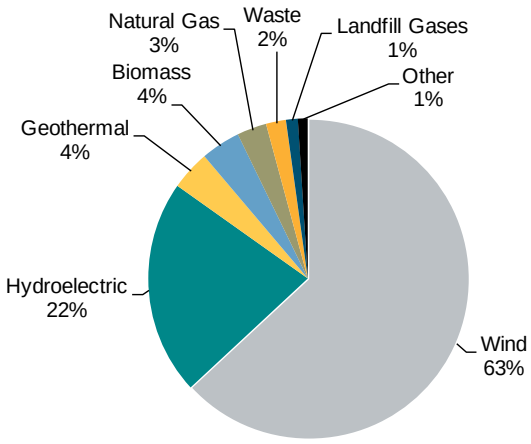


**Figure 3.5 2012 long-term power purchases by resource type**

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. The Idaho Power REC policy is described in Chapter 2 of this IRP.

Table 3.2 shows that the Idaho Power Green Power Program delivered 18,593 RECs to Idaho Power retail customers in 2012. The energy from the Green Power Program is reported as renewable energy delivered to Idaho Power customers.

Table 3.2 shows that no hydroelectric, wind, geothermal, or solar generation is represented as being delivered to Idaho Power retail customers in 2012 because the RECs associated with such generation were sold to other parties who purchased the right to claim that the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with the renewable generation rather than sell the RECs, the company would have been able to claim that the renewable energy had been delivered to customers. The proceeds from REC sales are returned to Idaho Power customers through the PCA as directed by the Idaho Commission in Order No. 32002 and by the Oregon Commission in Order No. 11-086.

Idaho Power generates energy at several hydroelectric projects that qualify under the State of Nevada RPS, and some of the RECs from the hydroelectric projects were sold to NV Energy in 2012. The 222,854 unsold RECs from hydroelectric projects are RECs that can only be used in Nevada, and a buyer for the RECs has not been found.

**Table 3.2 2012 REC Accounting**

| Resource by Type | RECs Generated or Acquired | RECs Sold Off-System[1] | RECs Delivered to Idaho Power Retail Customers | Unsold RECs |
|---|---|---|---|---|
| Hydroelectric | 276,843 | (53,989) | 0 | 222,854 |
| Solar (Oregon Solar) | 238 | (173) | 0 | 65 |
| Wind (Elkhorn) | 314,145 | (314,145) | 0 | 0 |
| Geothermal (Neal Hot Springs) | 23,690 | (23,690) | 0 | 0 |
| Purchased renewables (Green Power Program) | 18,593 | 0 | (18,593) | 0 |
| **Total** | **633,509** | **(391,997)** | **(18,593)** | **222,919** |

[1] When RECs are sold, Idaho Power can no longer claim the environmental attributes associated with the renewable resource. Therefore, the energy from REC sales is reclassified as Purchased Power.

## Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are presented in *Appendix C—Technical Appendix*. Table 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

**Table 3.3 Existing resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydroelectric | 92.3 | Upper Snake |
| Bliss | Hydroelectric | 75.0 | Mid-Snake |
| Brownlee | Hydroelectric | 585.4 | Hells Canyon |
| C. J. Strike | Hydroelectric | 82.8 | Mid-Snake |
| Cascade | Hydroelectric | 12.4 | North Fork Payette |
| Clear Lake | Hydroelectric | 2.5 | South Central Idaho |
| Hells Canyon | Hydroelectric | 391.5 | Hells Canyon |
| Lower Malad | Hydroelectric | 13.5 | South Central Idaho |
| Lower Salmon | Hydroelectric | 60.0 | Mid-Snake |
| Milner | Hydroelectric | 59.4 | Upper Snake |
| Oxbow | Hydroelectric | 190.0 | Hells Canyon |
| Shoshone Falls | Hydroelectric | 12.5 | Upper Snake |
| Swan Falls | Hydroelectric | 27.2 | Mid-Snake |
| Thousand Springs | Hydroelectric | 8.8 | South Central Idaho |
| Twin Falls | Hydroelectric | 52.9 | Mid-Snake |
| Upper Malad | Hydroelectric | 8.3 | South Central Idaho |
| Upper Salmon A | Hydroelectric | 18.0 | Mid-Snake |
| Upper Salmon B | Hydroelectric | 16.5 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| Valmy | Coal | 283.5 | North Central Nevada |
| Langley Gulch | Natural Gas—CCCT | 318.5 | Southwest Idaho |
| Bennett Mountain | Natural Gas—SCCT | 172.8 | Southwest Idaho |
| Danskin | Natural Gas—SCCT | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | Eastern Idaho |
| **Total existing nameplate capacity** | | **3,594.4** | |

The following sections describe Idaho Power's existing supply-side generation resources and long term PPAs.

## *Hydroelectric Facilities*

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 960 aMW, or 8.4 million MWh under median water conditions.

### Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the HCC in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately

70 percent of Idaho Power's annual hydroelectric generation and approximately 30 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability.

Idaho Power operates the HCC to comply with the existing FERC license as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall Chinook plan, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the ESA.

Brownlee Reservoir is the only HCC reservoir—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used for flood control, navigation, recreation, and the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood-control directions received from the US Army Corps of Engineers (USACE) as outlined in Article 42 of the existing FERC license.

After flood-control requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake (mid-Snake) projects, with all of the flow augmentation eventually passing through the HCC before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the fall Chinook plan adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook plan operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

## Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C. J. Strike, Bliss, Lower Salmon, Upper Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, and C. J. Strike projects. The three projects are operated within the FERC license requirements to coincide with the daily system peak demand when the load-following capacity is available.

Idaho Power completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail, a threatened species under the ESA. The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to license the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power operated the Bliss and Lower Salmon facilities under both ROR and load-following operations. Study results indicated that while load-following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A *Bliss Rapids Snail Protection Plan* developed in consultation with the FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company will be able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has received a license amendment from FERC for both projects that allows load-following operations to resume.

## Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the water is needed are especially beneficial. Acquiring water through the water bank also helps the company to improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2012 with Water District 65 in the Payette River system to rent 10,000 acre-feet of storage water released in February 2012.

In August 2009, Idaho Power also entered into a five-year (2009–2013) water-rental agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of main stem Snake River hydroelectric projects.

In 2011, the company extended the Shoshone–Bannock rental agreement for two additional years, 2014 and 2015. The company plans to schedule delivery of the water between July and October of each year during the term of the agreement. The Shoshone–Bannock agreement was executed in part to offset the effect of drought and changing water-use patterns in southern Idaho

and to provide additional generation in summer months when customer demand is high. Idaho Power intends to continue to pursue water-rental opportunities as part of its regular operations.

## Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River system above Milner Dam. Idaho Power is continuing to work with the stakeholders in the upper Snake River to expand the program.

Idaho Power seeds clouds by introducing silver iodide (AgI) into winter storms. Cloud seeding increases precipitation from passing winter storm systems. If a storm has the right combination of abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation.



An Idaho Power remote cloud-seeding generator.

Idaho Power uses two methods to seed clouds:

1. Remotely operated ground generators at high elevations

2. Modified aircraft burning flares containing AgI

Benefits of either method vary by storm, and the combination of the two methods provides the most flexibility to successfully place AgI into passing storms. Minute water particles within the clouds freeze on contact with the AgI particles and eventually grow and fall to the ground as snow.

AgI is a very efficient ice nucleus that allows it to be used in minute quantities. It has been used as a seeding agent in numerous western states for decades without any known harmful effects (http://weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 5 and 28 percent annually. Idaho Power estimates cloud seeding provides an additional 124,000 acre-feet from the upper Snake River, and 224,000 acre-feet from the Payette River. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2012 to 2013 winter season, the program included 17 remote-controlled, ground-based generators and 1 aircraft for operations in the Payette Basin. The Upper Snake River Basin program included 19 remote-controlled, ground-based generators operated by Idaho Power and

25 manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

## Thermal Facilities

### Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

### North Valmy

Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

### Boardman

Idaho Power owns 10 percent, or 64.2 MW (generator nameplate rating), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. Portland General Electric (PGE) has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative has 10 percent ownership. As the majority owner of the plant, PGE is the operator of the Boardman facility.

The 2013 IRP assumes Idaho Power's share of Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the Environmental Protection Agency (EPA) related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide ($SO_2$), and nitrogen oxide ($NO_x$) emissions. At the end of 2012, the net-book value of Idaho Power's share of the Boardman facility was approximately $23.1 million. Additional emission controls are required to be installed to continue operating the Boardman plant through 2020.

### Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens STG-5000F4 combustion turbine and one 131.5-MW Siemens SST-700/SST-900 reheat steam turbine.

The Langley Gulch plant is located south of New Plymouth in Payette County, Idaho. Construction commenced in 2010, and the plant became commercially available in June 2012. The Langley Gulch project connects to existing 230-kilovolt (kV) transmission lines to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon.

## Peaking Facilities

### Danskin

Idaho Power owns and operates the 271-MW Danskin natural gas-fired SCCT facility. The facility consists of one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse W251B12A combustion turbines. The Danskin facility is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

### Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173-MW Siemens–Westinghouse 501F natural gas-fired SCCT located east of the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant is also dispatched as needed to support system load.

### Salmon Diesel

Idaho Power owns and operates two diesel generation units located in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are operated during emergency conditions, primarily for voltage and load support.

## Solar Facilities

In 1994, a 25-kW solar photovoltaic (PV) array with 90 panels was installed on the rooftop of Idaho Power's corporate headquarters (CHQ) in Boise, Idaho. The 25-kW solar array is still operational, and Idaho Power uses the hourly generation data from the solar array for resource planning.

Idaho Power uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring streamflows, and operating cloud-seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program; owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events; and has a 200-watt (W) solar water pump used for demonstrations and promoting solar PV technology.

### Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. The majority of net metering customers use solar PV systems. As of June 1, 2013, there were 287 solar PV systems interconnected through the company's net metering service with a total

capacity of 1.896 MW. At that time, the company had received completed applications for an additional 15 net metered solar PV systems representing an incremental capacity of 0.13 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.4.

**Table 3.4 Net metering service customer count and generation capacity as of June 1, 2013**

| | Number of Customers | | | Generation Capacity (MW) | | |
|---|---|---|---|---|---|---|
| **Resource Type** | **Active** | **Pending** | **Total** | **Active** | **Pending** | **Total** |
| Solar PV | 287 | 15 | **302** | 1.896 | 0.130 | **2.026** |
| Wind | 71 | 3 | **74** | 0.577 | 0.010 | **0.587** |
| Other/hydroelectric | 10 | 0 | **10** | 0.147 | 0.000 | **0.147** |
| **Total** | **368** | **18** | **386** | **2.620** | **0.140** | **2.760** |

### Oregon Solar Photovoltaic Pilot Program

In 2009, the Oregon legislature passed Oregon Revised Statute (ORS) 757.365 as amended by House Bill 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to customers in Oregon. Under the pilot program, Idaho Power will acquire up to 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW were allocated, and the remaining 200 kW were offered during an enrollment period in October 2011. However, because some PV systems were not completed from the last enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In addition to the smaller facilities under the pilot program, Idaho Power is required to either own or purchase the generation from a 500-kW, utility-scale solar PV facility by 2020. Under the rules, if the utility scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the State of Oregon RPS.

## *Power Purchase Agreements*

### Elkhorn Valley Wind Project

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn Valley Wind Project was constructed during 2007 and began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project.

### Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. The Raft River geothermal project has not exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is not currently receiving RECs from the Raft River geothermal project. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of all RECs generated by the project.

### Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project.



The Neal Hot Springs Geothermal Project.

### Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

## *Public Utility Regulatory Policies Act*

In 1978, the US congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. The acronym CSPP (cogeneration and small power producers) is often used in association with PURPA. Individual states were tasked with establishing PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in the state of Idaho and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar but not

identical for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2013 IRP was completed in August 2012.

As of March 31, 2013, Idaho Power had 105 PURPA contracts with independent developers for approximately 789 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power projects. Of the 105 contracts, 103 were on-line as of March 31, 2013, with a cumulative nameplate rating of approximately 783 MW. Figure 3.6 shows the percentage of the total PURPA capacity of each resource type under contract.

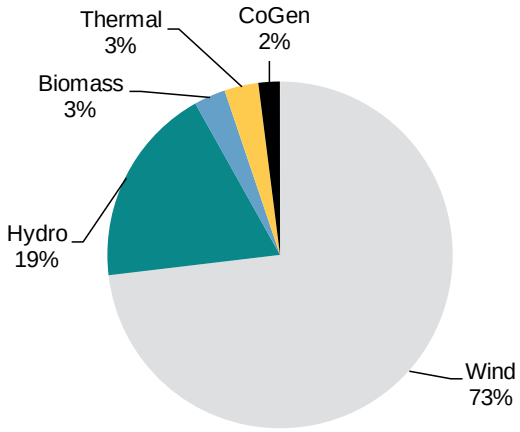


**Figure 3.6 PURPA contracts by resource type**

## Published Avoided Cost Rates

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided cost. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost rate Idaho Power is required to include in PURPA contracts.

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04, GNR-E-11-01, and GNR-E-11-03). The main issues in the cases included the disaggregation of larger, utility-scale projects to qualify for the published avoided cost rate and the methods used to calculate the published rate.

On December 18, 2012, the IPUC issued Order No. 32697. Order No. 32697 included new rules and regulations in regard to the numerous PURPA issues presented in the various cases that began in November 2010. Some highlights are as follows:

- The published avoided cost rate is available only for wind and solar projects with a nameplate rating of less than 100 kW.
- For all other resource types, the eligibility cap will remain at 10 aMW.
- Idaho Power's proposed incremental cost IRP method was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A different published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project retains the RECs associated with the project for QF contracts containing published avoided costs.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that are negotiated agreements.

On May 6, 2013, the IPUC issued Order No. 32802 concerning the reconsideration of Case No. GNR-E-11-03. Order No. 32802 affirms many of the commission rulings in Order No. 32697. PURPA contracting continues to be an issue in Idaho, and approximately 200 MW of various QF projects currently have some form of a filed dispute in regards to PURPA contracts with Idaho Power.

In April 2012, the OPUC issued Order No. 12-146, which opened OPUC Docket UM 1610. Docket UM 1610 addresses many of the same PURPA issues identified in the recent Idaho PURPA cases as well as unique PURPA issues associated with the Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013.

## *Wholesale Contracts*

The fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative expired in 2011. The 83-MW contract with PPL EnergyPlus, LLC expired in 2012. Idaho Power imported the energy from PPL EnergyPlus using the Jefferson line, and Idaho Power continues to explore opportunities to use transfer capacity on the Jefferson line.

Idaho Power presently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts). The Elkhorn, Raft River Geothermal, Neal Hot Springs, and Clatskanie Exchange contracts were described previously in the Power Purchase Agreements section of this IRP.

### *Market Purchases and Sales*

Idaho Power relies on regional markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power is especially dependent on the regional markets during peak-load periods, and the existing transmission system is used to import the energy purchases. A reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the PCA.

## Committed Supply-Side Resources

Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility and are treated like existing resources in the IRP analysis.

### *Shoshone Falls Upgrade Project*

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric Project (Shoshone Falls project0 from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single 50-MW unit that will result in a net upgrade of 49 MW.

In July 2010, FERC issued a license amendment for the project. The license amendment allows two years to begin construction and five years to complete the project. The company requested and received a two-year extension from FERC on May 1, 2012, that requires construction to commence by July 1, 2014. A project team was assembled in 2012 and has started project preparations, including completing a geotechnical investigation and a survey of the construction site. Currently, Idaho Power intends to request an additional two-year extension from FERC regarding the major segments of the expansion project while progressing with the replacement of the existing gated spillway, which will occur during the next two years. Construction of the main expansion project will start in 2016 and finish in 2019.

For the 2013 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in 2019. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median and other projected water conditions, some uncertainty exists regarding future Snake River streamflows that would not only effect the Shoshone Falls project, but also all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls upgrade, it is included in the 2013 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the Idaho. Prior to filing for a Certificate of Public Convenience and Necessity (CPCN) with the IPUC, Idaho Power plans to update the economic analysis of the Shoshone Falls upgrade, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

# 4. DEMAND-SIDE RESOURCES

DSM programs are an essential component of Idaho Power's resource strategy, and its portfolio of programs consists of demand response and energy efficiency programs.



Interior view of the Micron Center for Professional Technical Education at the College of Western Idaho. Energy efficiency upgrades were made using incentives from Idaho Power's Building Efficiency program.

Demand response targets decreasing peak loads through either customer behavior or automations that respond during periods of extreme loads when all other resources, including market purchases, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side baseload resources. Energy efficiency, demand response, and energy efficiency education programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations and funded Northwest Energy Efficiency Alliance (NEEA) market transformation activities since 1997. Due to the indirect nature of savings from market transformation, NEEA effects are not forecasted or accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs of offering them, are published annually. The most recent analysis can be found in the *Demand-Side Management 2012 Annual Report Supplement 1: Cost Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their potential effect over the 20-year IRP planning horizon as part of the IRP process. For the 2013 IRP process, Idaho Power engaged in a comprehensive energy efficiency potential study that also analyzed potential energy-saving opportunities not currently offered as part of its portfolio of programs. The forecast of energy savings was developed from the potential study. The resulting forecast and program history were analyzed against the load forecast process to better understand the energy efficiency opportunities not accounted for in the load forecast.

Demand response was treated as a resource option during the 2013 IRP portfolio selection process. The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. Idaho Power's demand response programs have been available to meet that need. However, an analysis done for the 2013 IRP indicates no peak-hour shortages until 2016.

The anticipated lack of peak-hour capacity deficits from 2013 to 2015 is primarily due to a slower-than-expected economic recovery, causing slower customer growth than previously forecasted, as well as two previously anticipated large-load customers that did not materialize. Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program.

Cost-effectiveness analyses of DSM forecasts for the 2013 IRP are presented in more detail in the *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2012 Annual Report* contains a detailed description of Idaho Power's 2012 energy efficiency program portfolio along with historical program performance (appendices B and C are filed as part of this IRP). A complete review of the energy efficiency potential study and report can be found in the 2012 annual report filing supplement, *Demand-Side Management 2012 Annual Report Supplement 2: Evaluation*, which is available on the Idaho Power website at:

http://www.idahopower.com/EnergyEfficiency/reports.cfm

## DSM Program Performance

While the IRP planning process primarily looks forward, it also important to review the past DSM investments to understand their effects on system sales and loads. Accumulated annual savings from energy efficiency investments grow over time as loads decrease based on measure lives of the more efficient equipment and measures adopted and maintained by customers each year. Additionally, past performance of demand response programs provides a good indication of future potential for reducing peak summer loads and affecting IRP resource portfolios.

### *Energy Efficiency Performance*

Energy efficiency investments since 2002 have resulted in an annual load reduction of over 111 aMW or over 960,000 MWh of reduced supply-side energy production to customers through 2012. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 11-year period from 2002 through 2012. Over two-thirds (67%) of savings since 2002 from energy efficiency have come from programs available to commercial and industrial customers, with the other third of savings coming from residential and irrigation customer programs.

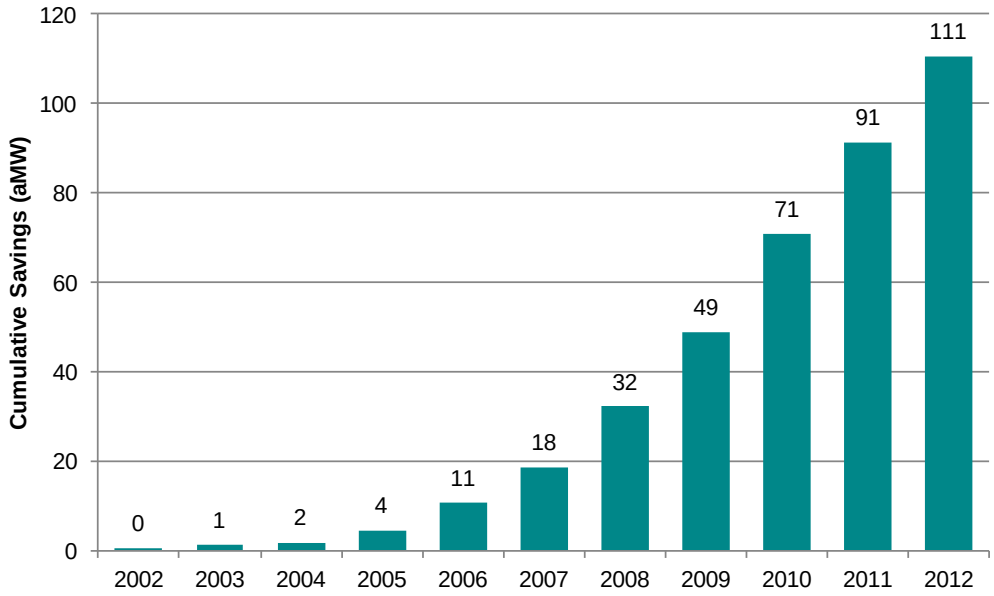


**Figure 4.1 Cumulative energy efficiency savings, 2002–2012 (aMW)**

Energy efficiency has proven a reliable, low-cost resource for Idaho Power, as the annual performance targets set for resource planning as part of IRPs from 2004 to 2011 have consistently been met or exceeded. Figure 4.2 shows the annual or incremental savings from energy efficiency and its associated planning targets starting with the 2004 IRP, when DSM programs were first fully implemented in the IRP process.

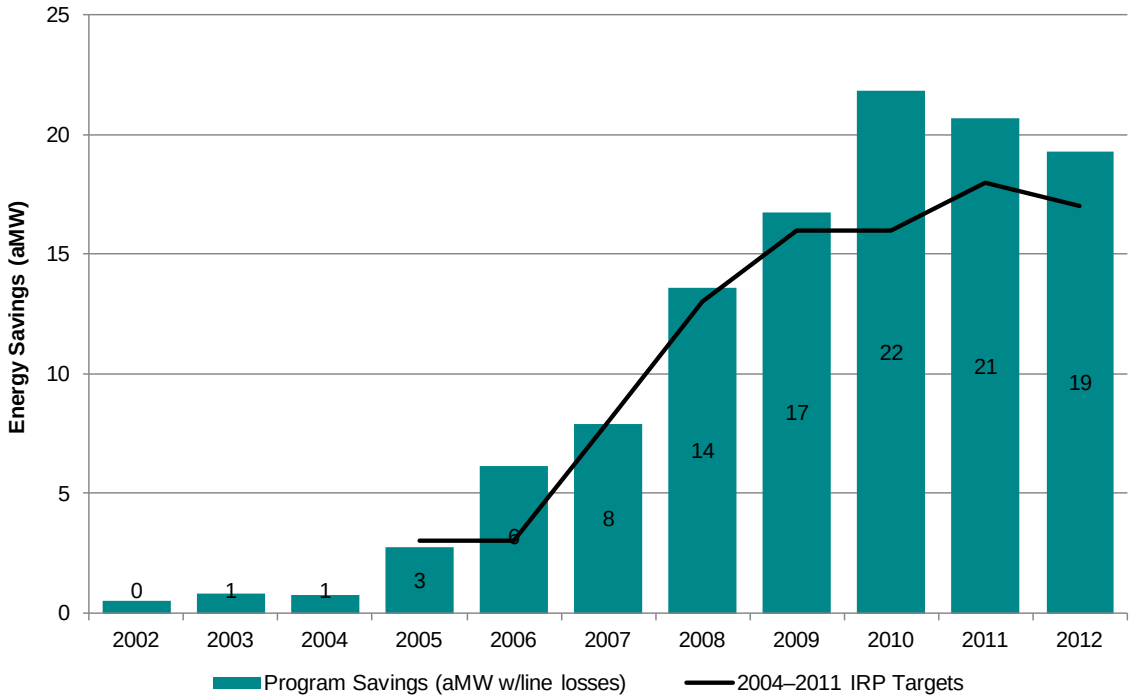


**Figure 4.2 Annual energy efficiency savings and IRP targets, 2002–2012 (aMW)**

## Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP and have provided a low-cost capacity resource. Three distinct programs, each targeting different customer classes, have made up the demand response portfolio:

- *A/C Cool Credit*—The A/C Cool Credit program cycles residential air conditioners on and off. A/C Cool Credit has provided 11 percent of the demand response portfolio, or an average of 37 MW, since 2009.

- *Irrigation Peak Rewards*—Irrigation Peak Rewards is a direct load-control program allowing irrigation pumps to be turned off during called events. Irrigation Peak Rewards contributes the largest load reduction, with 76 percent of demand response capacity, or an average of 268 MW.

- *FlexPeak Management*—Commercial and industrial customers can participate in the FlexPeak Management program, where customers commit to reduce demand at their facilities during called events. The FlexPeak Management program has averaged 45 MW of program capacity, or 12 percent of demand response reduction potential, since 2009.

Figure 4.3 shows the annual demand response program capacity between 2004 and 2012. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards program to a dispatch program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity from the Irrigation Peak Rewards program, respectively, which was not used based on the lack of need and the cost to dispatch.

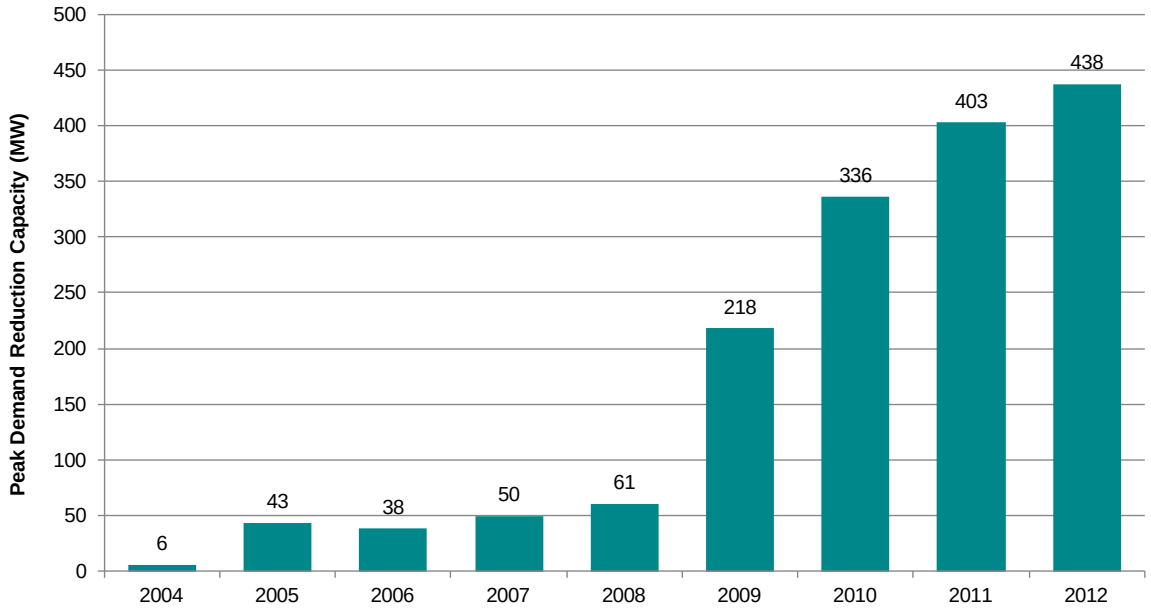


**Figure 4.3 Demand response peak reduction capacity, 2004–2012 (MW)**

Demand response programs have been a low-cost and reliable capacity resource for helping meet extreme summer peak loads. Programs have traditionally cost between $35 and $50/kW over a 20-year horizon to build, maintain, and manage—less than the cost of other peak capacity resources available for meeting capacity deficits. Figure 4.4 shows the annual program reduction capacity along with the committed demand reductions for the 2004 to 2011 IRPs.

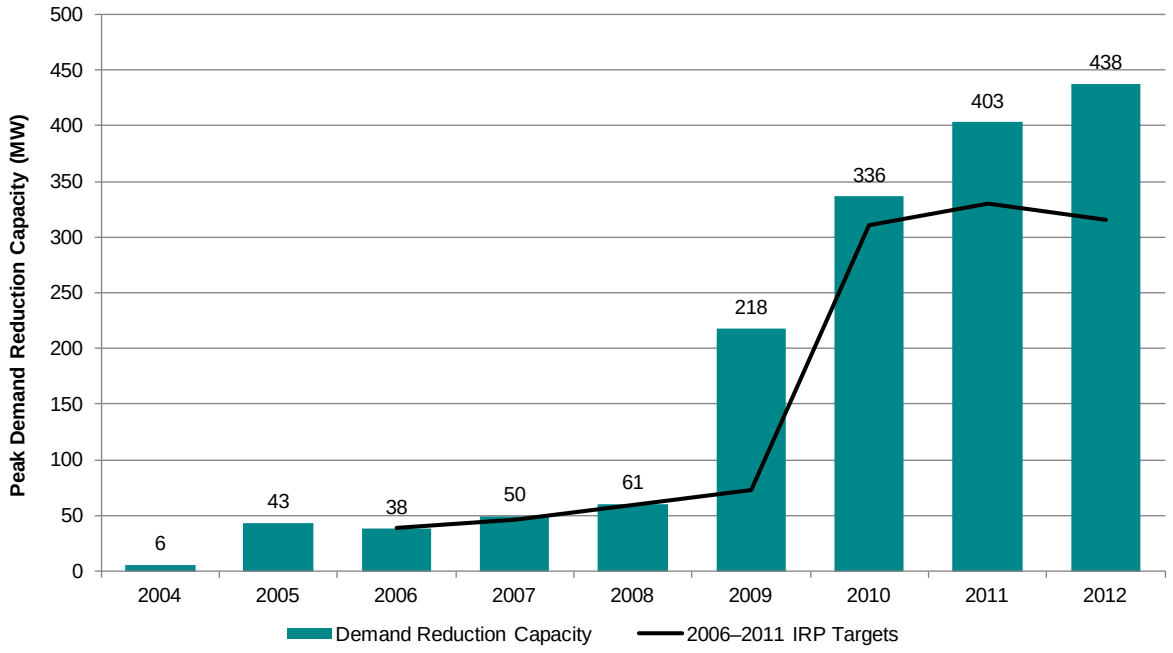


**Figure 4.4 Demand response peak reduction capacity with IRP targets, 2004–2012 (MW)**

## New Energy Efficiency Resources

For the 2013 IRP, EnerNOC, Inc., was retained to develop a 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the potential study were as follows:

- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 21 years (2012–2032) within the Idaho Power service area.
- Assess potential energy savings associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide an executable dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Review and update load profiles by sector, program, and end use.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2012 through 2032.

Because the market characterization process bundles industries and building types into homogenous groupings, special contract customers were treated outside of the potential study model. Forecasts for these unique customers, who tend to be very active in efficiency, were based on the individual customer's efficiency goals and prior history of participation along with projects that are known and projected to occur in the future.

There were three levels of potential considered as part of the study:

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every available other measure, where applicable. The retrofit measures are phased in over a number of years, which is greater for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the TRC test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market adoption factors to the economic potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The potential study followed a typical approach in developing the achievable potential. First, the market was characterized by customer class. The classification phase included segmenting the market by housing type for residential and understanding the various industries and building types within the commercial and industrial customer classes. Saturations of end-use technologies within customer segments are assessed to help determine which technologies are available for efficient upgrades. The next step was screening measures and technologies for cost-effectiveness, then assessing the adoption rates of technologies to determine the forecast of achievable potential. More detailed information about cost-effectiveness methodologies and approaches can be found in *Appendix C—Technical Appendix*.

The annual savings potential forecast is measured in MWh, but to convert the savings to average annual or monthly demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are divided by either 8,760 hours (hours in a year) or a corresponding number of monthly hours subject to a load shape. All forecasts are prepared in terms of generation equivalency and therefore include line losses of 10.9 percent that account for

energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the customer.

Table 4.1 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2013 to 2032 in five-year blocks, in terms of average demand reduction (aMW) by customer class. In 2017, the forecast reduction for 2013-to-2017 programs will be 69 aMW; by the year 2022, the reduction across all customer classes increases to 129 aMW. By the end of the IRP planning horizon in 2032, 261 aMW of reduction are forecast to come from the energy efficiency portfolio, with 60 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C—Technical Appendix*.

**Table 4.1 Total energy efficiency current portfolio forecasted effects (2013–2032) (aMW)**

| | 2017 | 2022 | 2027 | 2032 |
|---|---|---|---|---|
| Industrial/Commercial | 45 | 86 | 125 | 157 |
| Residential | 18 | 30 | 50 | 76 |
| Irrigation | 6 | 13 | 21 | 28 |
| **Total** | **69** | **129** | **196** | **261** |

Table 4.2 shows the cost-effectiveness summary from the potential study. The table shows the net present value (NPV) analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficiency technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing resources, the 2011 IRP preferred portfolio of generation resources, and the 2013 IRP natural gas price forecast and carbon-adder assumptions.

**Table 4.2 Total energy efficiency portfolio cost-effectiveness summary**

| | 2032 Load Reduction (aMW) | Resource Costs (20-Year NPV) | Alternate Energy Benefits (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs ($/kWh) |
|---|---|---|---|---|---|
| Industrial/Commercial | 157 | $188,245,928 | $467,521,430 | 2.5 | 0.028 |
| Residential | 76 | $123,886,346 | $190,935,664 | 1.5 | 0.046 |
| Irrigation | 28 | $52,623,496 | $76,220,052 | 1.4 | 0.049 |
| **Total** | **261** | **$364,755,770** | **$734,677,146** | **2.0** | **0.035** |

The value of avoided energy over the 20-year investment in the energy efficiency measures was twice the TRC when comparing benefits and costs resulting in an overall benefit to cost ratio of 2. The levelized cost to reduce energy demand by 261 aMW is 43.5 cents per kWh from a TRC perspective. Figure 5.7 in Chapter 5 compares the energy costs of the energy efficiency programs with the other supply-side resource options.

Once the energy efficiency forecast is complete, the forecasted energy efficiency is included in the IRP planning horizon and the load and resource balance analysis. Planning assumptions in

the energy efficiency potential forecast include new programs, technology, known codes and standards changes, customer adoption behavior, and cost-effectiveness that are explicitly incorporated into the potential study and reflect differences between the energy efficiency forecast and the amount of efficiency accounted for in the load forecast. A key difference between the two views of efficiency is that the load forecast accounts for energy efficiency effects based on previous years' program performance while the forecast from the potential study is more prospective in its approach. The amount of energy efficiency not captured by the load forecast is accounted for in the load and resource balance analysis.

Table 4.3 shows the new energy efficiency potential portion of the total energy efficiency forecast included in the load and resource balance. In 2017, the incremental energy efficiency savings will reduce energy loads by 38 aMW; in 2022, average loads will be reduced by 76 aMW. The full 20-year capacity of the program additions and changes is 188 aMW of average-energy reduction.

**Table 4.3 New energy efficiency resources (2017–2032) (aMW)**

| | 2017 | 2022 | 2027 | 2032 |
|---|---|---|---|---|
| Industrial/Commercial | 30 | 59 | 90 | 116 |
| Residential | 4 | 9 | 26 | 51 |
| Irrigation | 4 | 8 | 15 | 21 |
| **Total** | **38** | **76** | **131** | **188** |

## Demand Response Resources

In fall 2012, the company's IRP analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. The most recent analysis from the 2013 IRP indicates no peak-hour shortages until mid-2016. Based on the results of this analysis, Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.



Typical irrigation pivot supplied by a pump participating in the Irrigation Peak Rewards demand response program.

In the preferred 2013 IRP portfolio, demand response is used to satisfy temporary deficits from 2016 to 2018 prior to the build out of Northwest transmission. Demand response from 2016 to 2017 would be built out to 150 MW capacity, then it would be built up to 370 MW to meet the deficits from 2024 through the end of the planning period.

## Conservation Voltage Reduction

Conservation voltage reduction (CVR) regulates the feeder voltage within the lower half of the standard operation range. In acknowledging the 2011 IRP, the OPUC directed Idaho Power to assess available cost-effective CVR resource potential and propose a course of action. The OPUC also requested Idaho Power incorporate the energy savings and reduced peak demand from the CVR program in the load and resource balance forecast.

Idaho Power considers it prudent to validate the benefit of the CVR program before expanding it beyond the initial study area. New technologies and methods of measurement are available to validate energy savings and reduced peak demand. Idaho Power intends to analyze the CVR effects at two of the six substations—the Alameda and Meridian substations—where CVR has been implemented.

Idaho Power expects to complete the CVR analysis in 2016. If the analysis confirms energy savings and reduced peak demand, Idaho Power will evaluate extending CVR measures to other Idaho Power facilities.

The actual savings from the current CVR implementation are not significant enough to be incorporated into the IRP load and resource balance forecast.

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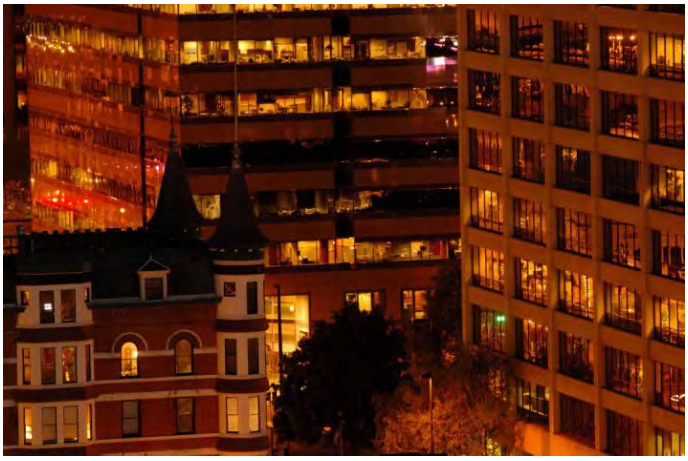
# 5. PLANNING PERIOD FORECASTS

The IRP process requires Idaho Power to prepare numerous forecasts that can be grouped into four main categories:

1. Load forecasts
2. Generation forecasts
3. Fuel price forecasts
4. Financial assumptions



Forecasting load growth is essential for Idaho Power to meet future needs of customers.

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2013 IRP.

## Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning (A/C) in the months of June, July, and August. For a number of years, the growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. However, both measures are important in planning future resources and are part of the load forecast prepared for the 2013 IRP.

The expected case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not precisely follow the path suggested by the expected case forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with abnormal weather. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced the 2013 IRP load forecast results. The national, state, metropolitan statistical area (MSA) and county economic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics are also used in developing the

2013 IRP load forecast. The forecasts of households, population, employment, output, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

## Weather Effects

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50-percent chance loads will be higher or lower than the expected-case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios are analyzed to address load variability due to weather. Idaho Power has generated load forecasts for 70$^{th}$-percentile and 90$^{th}$-percentile weather. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

Idaho Power's system load is highly dependent on weather. The three scenarios allow a careful examination of load variability and how the load variability may affect resource requirements. It is important to understand how the probabilities associated with the load forecasts apply to any given month. For example, an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal time horizon. Over the longer-term horizon, economic and demographic conditions influence the load forecast.

## Economic Effects

The national recession that began in 2008 affected the local economy and energy use in the Idaho Power service area. The severity of the recession resulted in a significant decline in new customers. Idaho Power added less than 2,500 new residential customers in 2011. Recently, the number of new residential customers added each year has increased to approximately 4,000.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by 0.9 percent in 2010 and a slight decline in 2011. The 2009 through 2011 time period was the first time overall energy use had declined since the energy crisis of 2001. In 2012, system electricity sales increased by 1.8 percent over 2011. The 2012 sales increase was due to economic recovery in the service area and higher irrigation sales.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period, and the population increase is included in the load forecast models. Idaho Power also continues to receive requests from prospective large-load customers attracted to southern Idaho due to the positive business climate and relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.1 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service-area household projections are derived from applying Idaho Power's share to county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with an expected declining consumption per household, results in a 1.1-percent average residential load-growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.5 percent annually from 416,000 at the end of 2012 to nearly 555,000 by the end of the planning period in 2032.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*. For example, the expected annual average system load growth of 1.1 percent (over the period 2013 through 2032) is comprised of a residential load growth of 1.1 percent, a commercial load growth of 1.1 percent, an irrigation load growth of 0 percent, an industrial load growth of 1.7 percent, and an additional firm load growth of 1.2 percent.

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery in the economic forecast used in the 2011 IRP was too optimistic, particularly in the near term. The updated economic forecast variables used as drivers in the 2013 IRP forecast reflect a lower near-term recovery relative to the 2011 IRP economic forecast drivers but are nonetheless conveying sustained and increased economic recovery. The stalled recovery in the national- and service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series. Longer term, the effect of economic recovery is tempered in the forecast by higher retail electricity price assumptions that incorporate estimates of assumed carbon legislation, which decreases the average load forecast. The decrease is especially evident in the second 10 years of the forecast period.

Additional significant factors that put downward pressure on load growth relative to the 2011 IRP forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected.

For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from the sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

## Peak-Hour Load Forecast

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts. Idaho Power uses the 95th-percentile forecast as the basis for peak-hour planning in the IRP. The 95th-percentile forecast is based on the 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,245 MW—was recorded on July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on June 30, 2008, at 3:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011, the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also had a significant effect on reducing peak demand. The 2013 IRP load forecast projects peak-hour load to grow by approximately 55 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance as a supply-side resource.

Figure 5.1 and Table 5.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th-percentile, and 95th-percentile weather effects on the expected (median) peak forecast. The 95th-percentile forecast uses the 95th-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity.

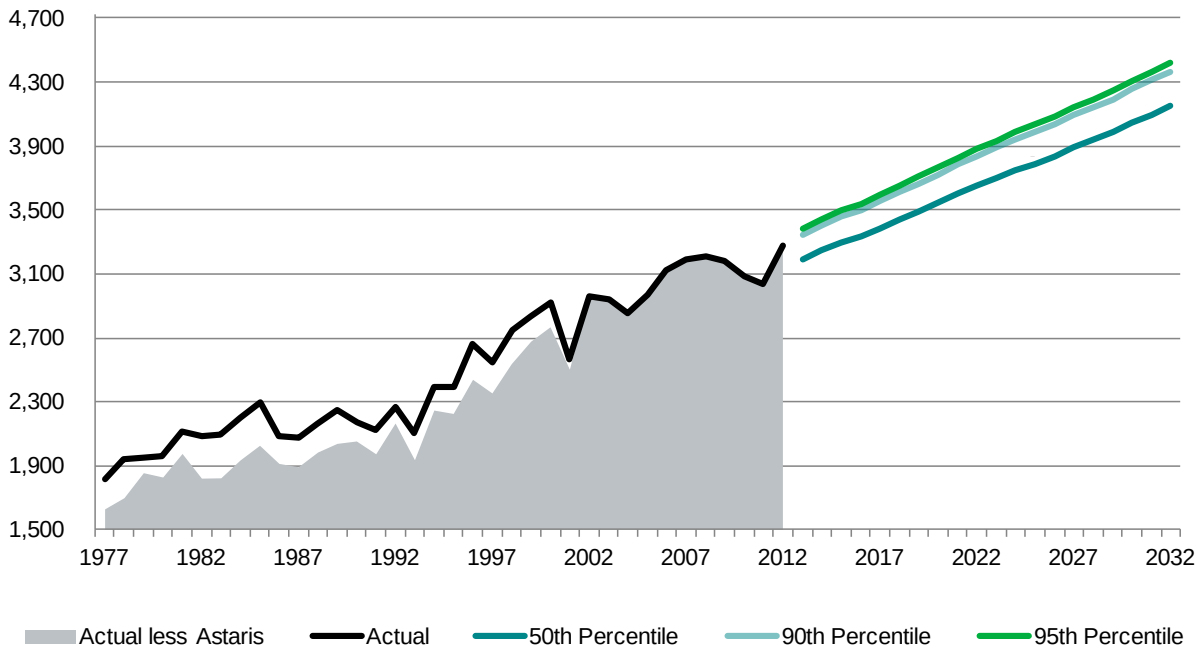



**Figure 5.1 Peak-hour load-growth forecast (MW)**

**Table 5.1 Load forecast—peak hour (MW)**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2012 (Actual) | 3,245 | 3,245 | 3,245 |
| 2013 | 3,189 | 3,344 | 3,382 |
| 2014 | 3,245 | 3,403 | 3,442 |
| 2015 | 3,294 | 3,456 | 3,495 |
| 2016 | 3,335 | 3,500 | 3,541 |
| 2017 | 3,387 | 3,555 | 3,596 |
| 2018 | 3,437 | 3,609 | 3,651 |
| 2019 | 3,489 | 3,664 | 3,707 |
| 2020 | 3,544 | 3,722 | 3,766 |
| 2021 | 3,601 | 3,782 | 3,827 |
| 2022 | 3,651 | 3,835 | 3,881 |
| 2023 | 3,701 | 3,889 | 3,935 |
| 2024 | 3,748 | 3,939 | 3,987 |
| 2025 | 3,790 | 3,985 | 4,033 |
| 2026 | 3,836 | 4,034 | 4,083 |
| 2027 | 3,888 | 4,090 | 4,139 |
| 2028 | 3,936 | 4,141 | 4,191 |
| 2029 | 3,984 | 4,192 | 4,244 |
| 2030 | 4,045 | 4,256 | 4,308 |
| 2031 | 4,097 | 4,312 | 4,365 |
| 2032 | 4,147 | 4,365 | 4,418 |
| **Growth rate (2013–2032)** | **1.4%** | **1.4%** | **1.4%** |

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,189 MW in 2013 to 4,147 MW in 2032—an average annual compound growth rate of 1.4 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.4 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

## *Average-Energy Load Forecast*

Potential monthly average-energy use by customers in Idaho Power's service area is defined by two load forecasts that reflect load uncertainty resulting from differing weather-related assumptions. Figure 5.2 and Table 5.2 show the results of the two forecasts used in the 2013 IRP reported as annual system load growth over the planning period. There is approximately a 50-percent probability Idaho Power's load growth will exceed the expected-case forecast and a 30-percent probability of load growth exceeding the 70th-percentile forecast. The projected 20-year average annual compound growth rate in the expected load forecast is 1.1 percent.

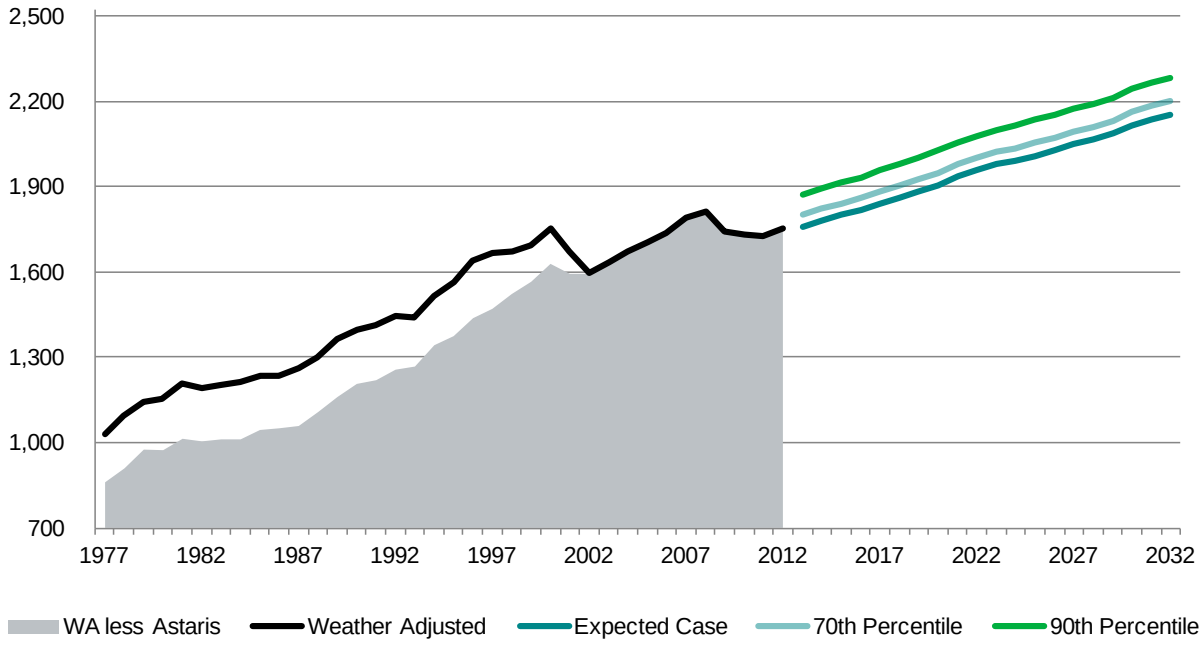



**Figure 5.2 Average monthly load-growth forecast (aMW)**

**Table 5.2 Load forecast—average monthly energy (aMW)**

| Year | Median | 70th Percentile | 90th Percentile |
|---|---|---|---|
| 2013 | 1,759 | 1,800 | 1,872 |
| 2014 | 1,782 | 1,823 | 1,895 |
| 2015 | 1,800 | 1,841 | 1,914 |
| 2016 | 1,818 | 1,859 | 1,933 |
| 2017 | 1,842 | 1,884 | 1,959 |
| 2018 | 1,862 | 1,904 | 1,980 |
| 2019 | 1,883 | 1,926 | 2,002 |
| 2020 | 1,906 | 1,949 | 2,026 |
| 2021 | 1,934 | 1,977 | 2,055 |
| 2022 | 1,956 | 2,000 | 2,078 |
| 2023 | 1,977 | 2,021 | 2,100 |
| 2024 | 1,992 | 2,036 | 2,116 |
| 2025 | 2,009 | 2,054 | 2,134 |
| 2026 | 2,028 | 2,073 | 2,153 |
| 2027 | 2,049 | 2,094 | 2,176 |
| 2028 | 2,065 | 2,110 | 2,192 |
| 2029 | 2,087 | 2,132 | 2,214 |
| 2030 | 2,116 | 2,162 | 2,244 |
| 2031 | 2,137 | 2,183 | 2,265 |
| 2032 | 2,154 | 2,201 | 2,284 |
| **Growth rate (2013–2032)** | **1.1%** | **1.1%** | **1.1%** |

Idaho Power uses the 70th-percentile forecast as the basis for monthly average-energy planning in the IRP. The 70th-percentile forecast is based on 70th-percentile weather to forecast average monthly load, 70th-percentile water to forecast hydroelectric generation, and 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

## Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), and Hoku Materials. The special-contract customers are described briefly as follows.

### Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance (Q/A), systems integration, and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

### Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly in 2013 and 2014, then stay flat throughout the remainder of the planning period.

### Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

### Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated have not been included in this sales and load forecast.

### "Special" Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm-load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared in August 2010, several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined at that time there was a real possibility of the new large load materializing. However, no customer signed a contract. The IPUC and OPUC directed Idaho Power not to include new large-load customers in the forecast until a contract is signed. Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are not included in the 2013 IRP sales and load forecast.

## Existing Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are shown in *Appendix C—Technical Appendix*. The following sections describe recent events or changes accounted for in the load and resource balance regarding Idaho Power's hydroelectric, thermal, and transmission resources.



Brownlee Dam is part of the HCC.

### *Hydroelectric Resources*

For the 2013 IRP, Idaho Power continues the practice of using 70$^{th}$-percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70$^{th}$ percentile means basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90$^{th}$-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ percentile means streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse-than-median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power

use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50th-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2013 IRP is included in *Appendix C—Technical Appendix*.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70th-percentile year in 2010 is identical to a 70th-percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the Eastern Snake River Plain Aquifer (ESPA) is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA Comprehensive Aquifer Management Plan (CAMP) includes demand reduction and weather-modification measures that will add new water to the basin water budget. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years are expected to continue and result in a return to declining basin outflows assumed to persist well into the 2020s. The declining basin outflows for this IRP are assumed to continue through 2027, when Swan Falls flows of the 90th-percentile forecast drop to the irrigation season minimum of 3,900 cfs. Idaho Power assumes the decline of flows to the Swan Falls minimum would cause the State of Idaho to take remedial action to prevent further decline. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on trends in Snake River Basin hydrologic conditions as a standard part of forecasting hydroelectric generation for future IRPs.



The Snake River canyon above Swan Falls.

A water-management practice affecting Snake River streamflows involves the release of water to augment flows during salmon outmigration. Various federal agencies involved in salmon migration studies have, in recent years, supported efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years. During 2013—a year with markedly worse-than-median water conditions—flow augmentation water from the Upper Snake River and Boise River basins was delivered during May.

Because worse-than-median water is assumed in the IRP, and because of the importance of July as a resource-constrained month, Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2013 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 5.3 shows historical April-to-July Brownlee inflow as well as forecast Brownlee inflow for the 50$^{th}$, 70$^{th}$, and 90$^{th}$ percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability but do include reductions related to declining base flows in the Snake River. As noted previously in this section, these declines are assumed to equilibrate beyond 2027.

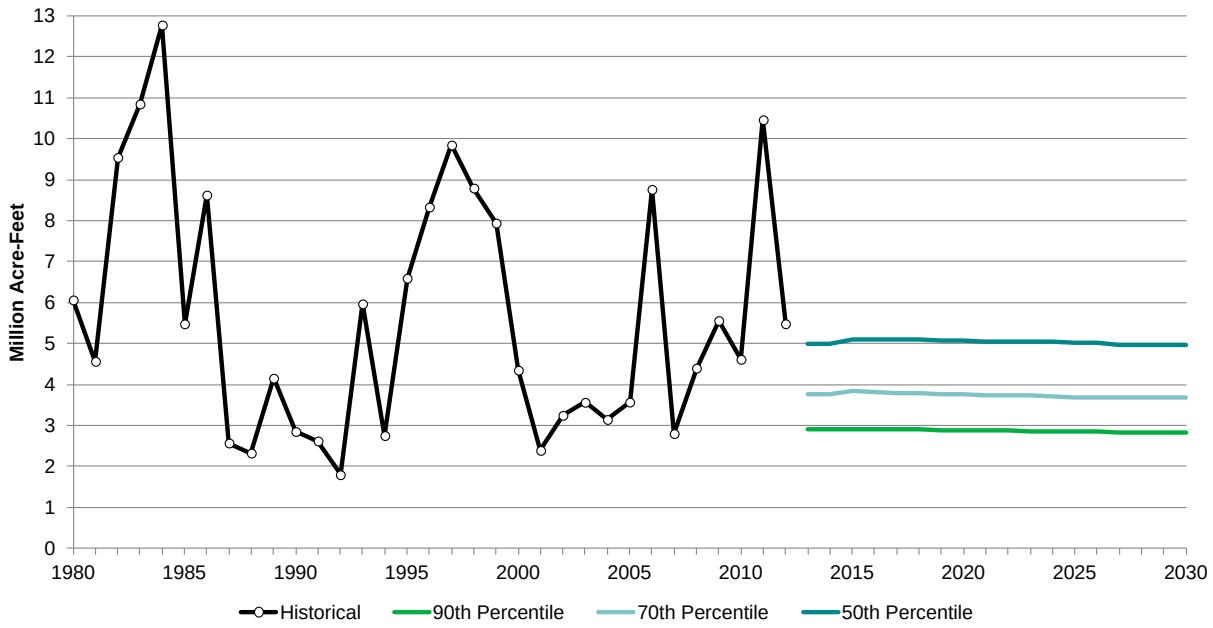



**Figure 5.3 Brownlee historical and forecast inflows**

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2013 IRP. A discussion of climate change, including expectations of possible effects on the Snake River water supply, is included in the *Appendix C—Technical Appendix*.

## Coal Resources

Idaho Power's coal-fired generating facilities have typically operated as baseload resources. Monthly average-energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the full-rated, maximum dependable capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C—Technical Appendix*.

Plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Boardman plant in 2014 and 2018, the North Valmy plant in 2015, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The EPA signed the proposed requirements and deadlines for the installation of pollution-control equipment for compliance with RH BART at the Jim Bridger plant on May 23, 2013. The EPA is planning to sign a notice of final rulemaking for RH BART for the Jim Bridger plant on November 21, 2013. The total generation loss for the air-quality modifications at all three plants is less than 1 percent.

The 2013 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The assumed date is the result of an agreement reached between the ODEQ and PGE related to compliance with RH BART rules on particulate matter, $SO_2$, and $NO_x$ emissions. The EPA formally approved the agreement, and the agreement was published in the Federal Register on July 5, 2011.

Idaho Power prepared the coal study as part of the 2011 IRP Update. The report was filed with the IPUC and OPUC in February 2013.

### Planned Upgrades at Jim Bridger

In addition to the selective catalytic reduction (SCR) emission-control upgrade mentioned previously, turbine upgrades are continuing at the Jim Bridger plant, and the replacement of the high-pressure/intermediate-pressure and low-pressure turbines on Unit 2 were completed in spring 2013. Upgrades of the high-pressure/intermediate-pressure and low-pressure turbines on Units 3 and 4 and upgrades to the low-pressure turbines on the remaining units are currently being evaluated.

## *Natural Gas Resources*

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT. The SCCT units are typically operated during high-load occurrences in summer and winter months. The monthly average-energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during January, June, July, August, and December and produce approximately 230 aMW of gas-fired generation for the five months. With respect to peak-hour output, the SCCTs are assumed capable of producing an on-demand peak capacity of 416 MW. While the peak dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power's CCCT, Langley Gulch, became commercially available in June 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. Langley Gulch is forecast to contribute approximately 165 aMW with an on-demand peaking capacity of 318 MW in the 2013 IRP.

# Load and Resource Balance

Idaho Power has adopted the practice of assuming drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources while using the conservative water and load conditions is considered comparable to requiring a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having a sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares the load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. The updated load and resource balance showing the Idaho Power existing and committed resources for average-energy and peak-hour load is shown in *Appendix C—Technical Appendix*.

## Average Monthly Energy Planning

Average-energy surpluses and deficits are determined using 70th-percentile water and 70th-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using a reserved network capacity. Figure 5.4 shows the monthly average-energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 5.4 also include the forecast effect of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade when it is available. Figure 5.4 illustrates there are no energy deficits through the planning period.

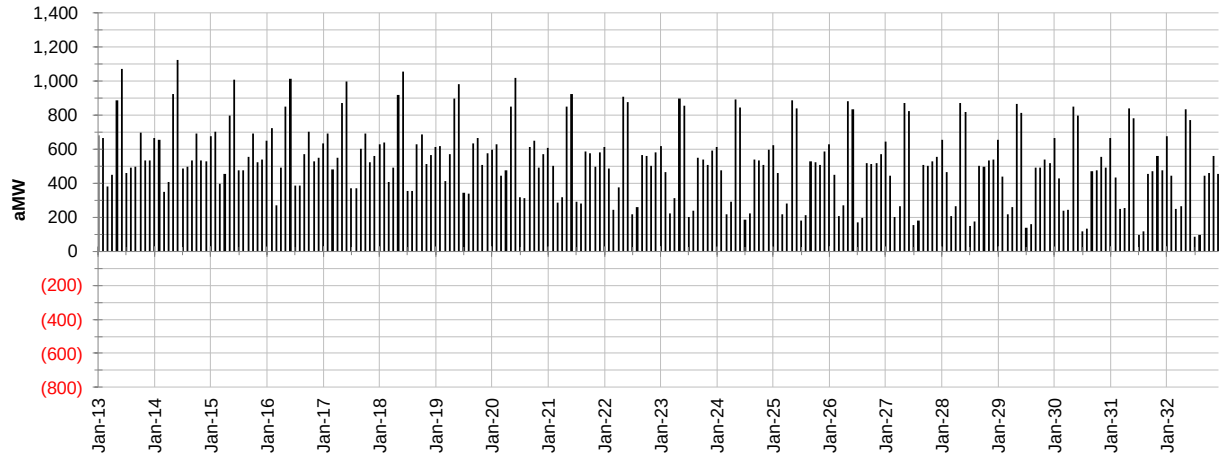



**Figure 5.4 Monthly average-energy surpluses and deficits with existing and committed resources and existing DSM (70th-percentile water and 70th-percentile load)**

Energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy. Peak-hour capacity continues to be the resource need in the 2013 IRP.

## Peak-Hour Planning

Peak-hour load deficits are determined using 90th-percentile water and 95th-percentile peak-hour load conditions. In addition to the peak-hour criteria, 70th-percentile average load conditions are analyzed for the average-energy load and resource balance. The hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

Idaho Power's customers reach a maximum energy demand in the summer. Idaho Power's existing and committed resources are insufficient to meet the projected peak-hour growth, and the company's customers in Oregon and Idaho face significant capacity deficits in the summer months if additional resources are not added.

At times of peak summer load, Idaho Power is using all available transmission capacity (ATC) from the Pacific Northwest. If Idaho Power was to face a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Figure 5.5 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 5.5 also include the forecast effect of existing energy efficiency programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade once it is available. Idaho Power assumes the existing PURPA projects will continue to deliver energy throughout the planning period unless the project developer has notified Idaho Power that the PURPA project intends to cease energy deliveries. Idaho Power assumes the existing PURPA projects will develop new contracts consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. The import capacity from the Boardman to Hemingway transmission line and the demand reduction due to the demand response programs are not included in Figure 5.5.

The first capacity deficit begins in July 2016, and monthly peak-hour deficit positions grow steadily in magnitude and the number of months affected. By July 2032, these capacity deficits are approximately 870 MW.

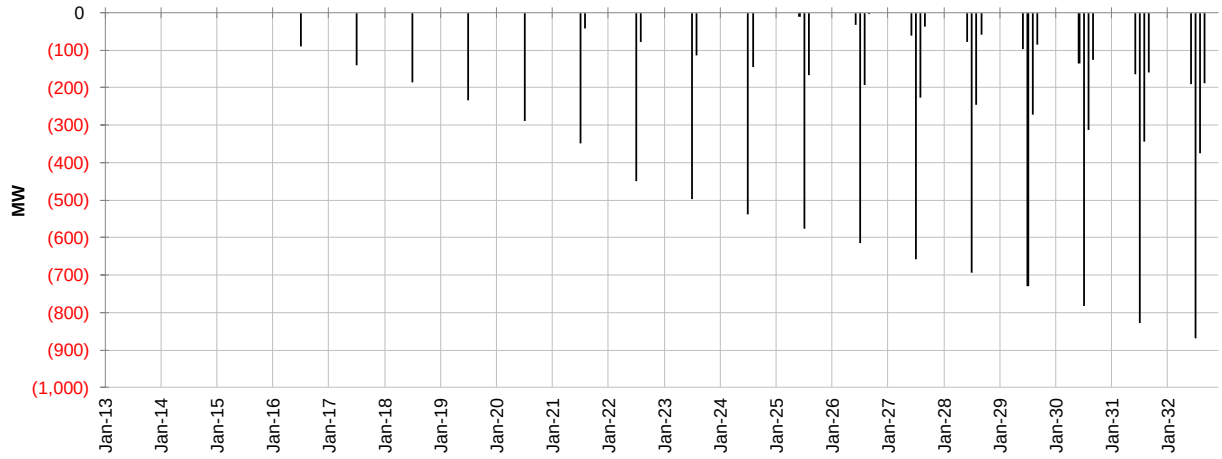



**Figure 5.5 Monthly peak-hour deficits without existing and committed resources and existing DSM (90th-percentile water and 95th-percentile load)**

Capacity and energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 5.5 were used to design the portfolios analyzed in the 2013 IRP.

## Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The IPUC has recently ruled on avoided cost rate methodologies (Case No. GNR-E-11-03, Order No. 32697; December 18, 2012). In the order, the IPUC stated the following (page 16):

> *We further find that, in order to remain flexible and responsive to the fluctuations in gas prices, it is appropriate to annually update the SAR model with the most recent gas forecasts provided by EIA's Annual Energy Outlook.*

Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast for IRP and avoided-cost calculations. The *Annual Energy Outlook 2012* Reference case was published by the EIA in June 2012, and Idaho Power used the *Annual Energy Outlook 2012* forecast for the 2013 IRP. A graph of the forecasted Henry Hub natural gas prices is shown in Figure 5.6. Idaho Power computed a high and low natural gas price forecast by adjusting the EIA natural gas price forecast upward and downward by 30 percent. The high and low forecasts are also shown in Figure 5.6. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city-gate price. The Idaho city-gate price is representative of the gas price delivered to the Idaho Power gas plants.

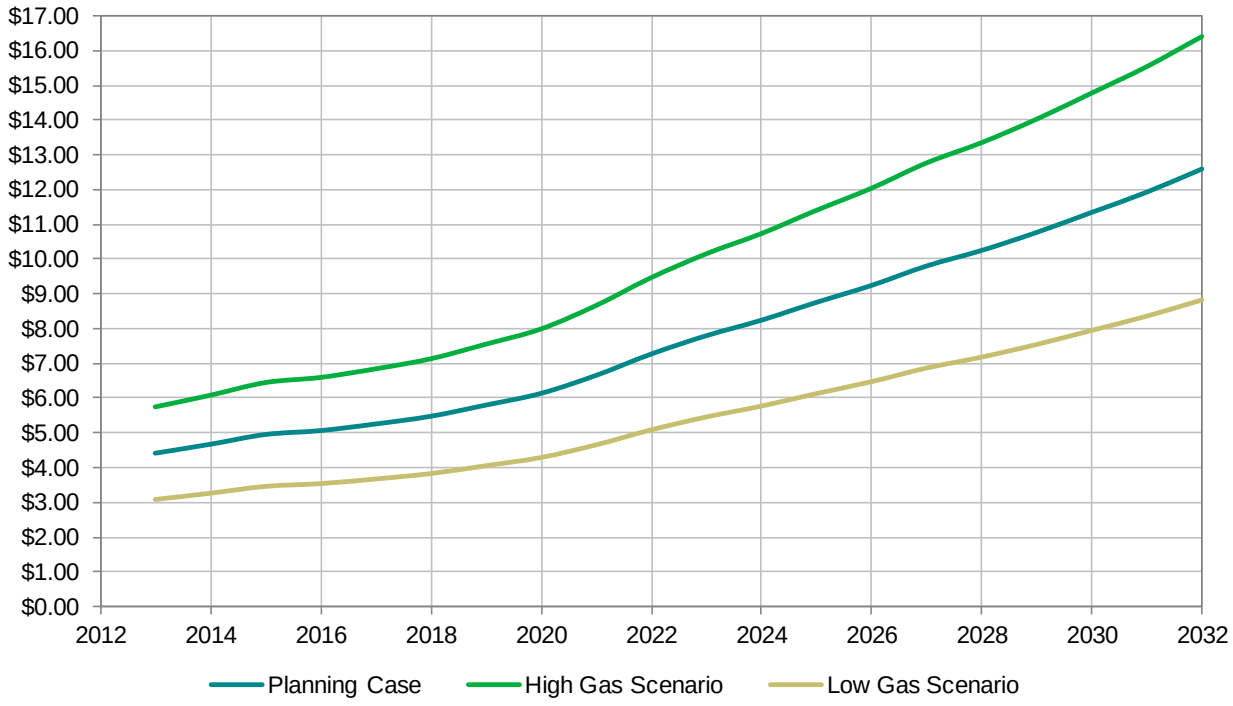



**Figure 5.6 Henry Hub Price Forecast—EIA *Annual Energy Outlook 2012* (nominal dollars)**

# Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2013 IRP. Cost inputs and operating data used to develop the resource cost analysis are primarily derived from NREL's *Cost and Performance Data for Power Generation Report* from February 2012. Idaho Power engineering studies and plant operating experience were also utilized. Resource costs are presented as follows:

- *30-year levelized capacity (fixed) costs*—Levelized fixed cost per kW of installed (nameplate) capacity per month

- *30-year levelized cost of production (at stated capacity factors)*—Total levelized cost per MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the capital cost of supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, applicable balance of plant construction costs, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system upgrade costs were estimated by Idaho Power's transmission planning group and were included in the total portfolio cost. The capital costs also include allowance for funds used during construction (AFUDC) (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, an annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial effects resulting from the load reduction programs.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are shown in *Appendix C—Technical Appendix*.

## *Emissions Adders for Fossil Fuel-Based Resources*

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil-fuel based generating resources are particularly sensitive to certain environmental and social costs. It is likely that additional emissions regulations will be implemented during the period covered in the 2013 IRP.

In the levelized resource cost analysis, Idaho Power incorporated an estimate for the future cost of $CO_2$ emissions in the overall cost of the various fossil fuel-based resources beginning in 2018. Additional information regarding the cost of carbon emissions is provided in the next section. Table 5.3 provides the emissions intensity rates assumed in the resource cost analysis and the

portfolio analysis. Idaho Power assumed that new fossil fuel-based resources will be designed and built to comply with $NO_x$, Hg, and $SO_2$ regulations, and therefore emissions adders for these emission types would not be applicable.

In addition to including a $CO_2$ emissions adder in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for $CO_2$, $NO_x$, Hg, and $SO_2$ emissions for each portfolio in the 20-year planning period. For $CO_2$ emissions, Idaho Power assumed a $CO_2$ adder beginning in 2018, which affects the variable operating cost. Instead of assuming $NO_x$, Hg, and $SO_2$ emissions adders, the 2013 IRP used the Idaho Power coal study to calculate the variable and fixed environmental compliance costs attributed to each emission type. The Idaho Power coal study also performed various sensitivity analyses on $NO_x$, Hg, and $SO_2$ environmental compliance.

**Table 5.3 Emissions intensity rates (pound/MWh)**

| | | | 2013 Emission Rate[1] (pound/MWh) | | | |
|---|---|---|---|---|---|---|
| **Plant** | **Nameplate (MW)** | **Fuel** | **$CO_2$** | **$NO_x$** | **$SO_2$** | **Hg** |
| Bennett Mountain | 173 | Natural Gas | 1,265 | 0.79 | 0.006 | – |
| Danskin 1 | 179 | Natural Gas | 1,252 | 0.42 | 0.006 | – |
| Danskin 2 | 46 | Natural Gas | 1,627 | 1.26 | 0.008 | – |
| Danskin 3 | 46 | Natural Gas | 1,653 | 1.28 | 0.008 | – |
| Langley Gulch | 318 | Natural Gas | 799 | 0.06 | 0.004 | – |
| Boardman | 64 | Coal | 2,063 | 2.56 | 7.923 | 0.00001 |
| Jim Bridger | 771 | Coal | 2,182 | 2.03 | 1.529 | 0.00004 |
| North Valmy | 284 | Coal | 2,293 | 3.33 | 4.518 | 0.00001 |
| IRP CCCT | 300 | Natural Gas | 799 | 0.06 | 0.004 | – |
| IRP SCCT | 170 | Natural Gas | 1,265 | 0.79 | 0.006 | – |

[1] Approximate

# Resource Cost Analysis II—Resource Stack

## *Levelized Capacity (Fixed) Cost*

The annual fixed-revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars per kW of plant nameplate capacity per month. Included in these costs are the cost of capital and fixed O&M estimates. Figure 5.7 provides a combined ranking of all the various resource options in order of lowest to highest levelized fixed cost per kW per month. The ranking shows that distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours per year to meet peak-hour demand.

## Levelized Cost of Production

Certain resource alternatives carry low fixed costs and high variable operating costs while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost of production measurement represents the estimated annual cost per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 5.8. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost of production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost of production calculation for a generation resource is the assumed level of annual capacity use over the life of the resource, referred to as the capacity factor. A capacity factor of 50 percent would suggest a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost would be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity-factor assumptions reduce the MWh, and the levelized cost would be higher.

Resource capital costs are annualized over a 30-year period for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.

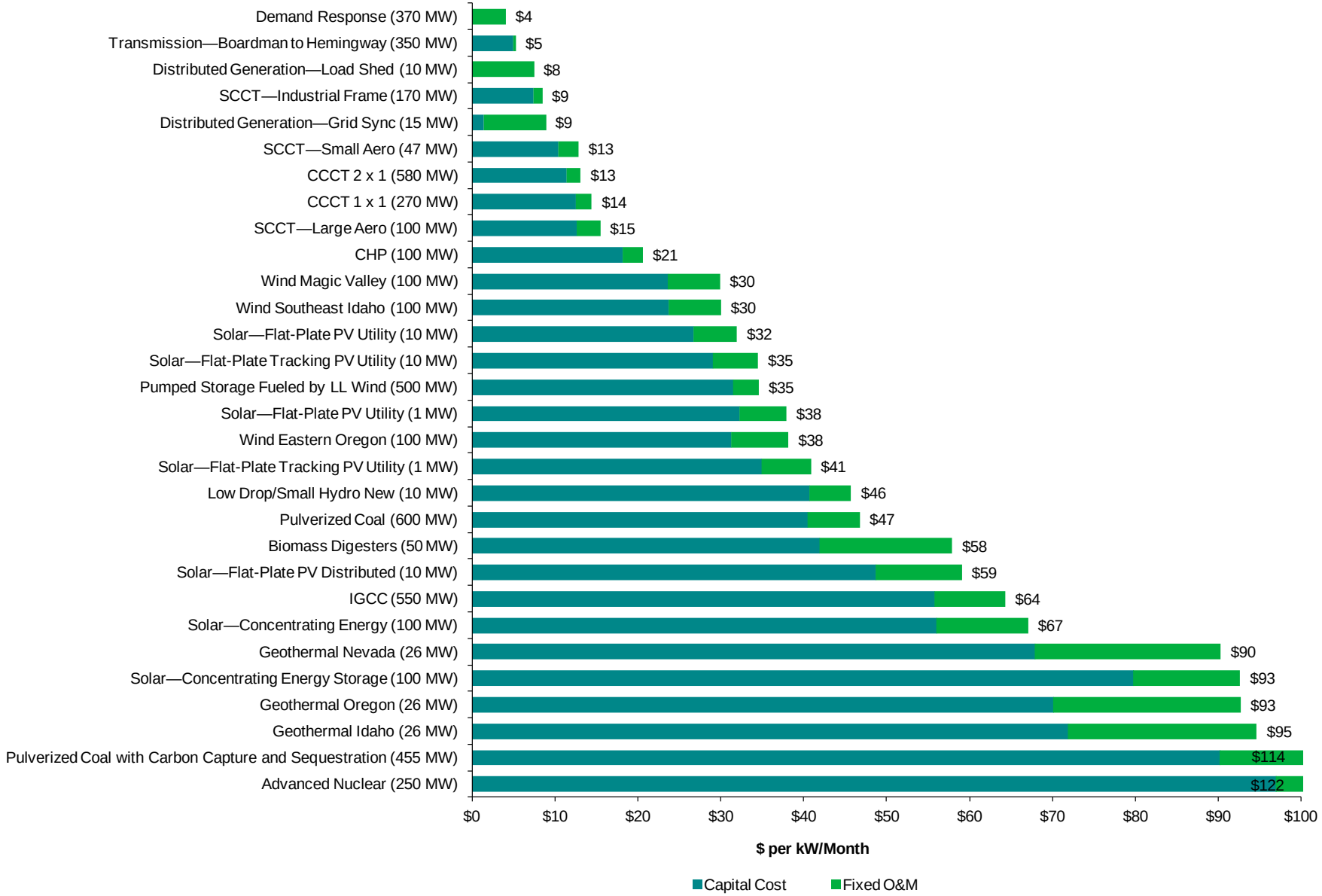



**Figure 5.7 30-year levelized capacity (fixed) costs**

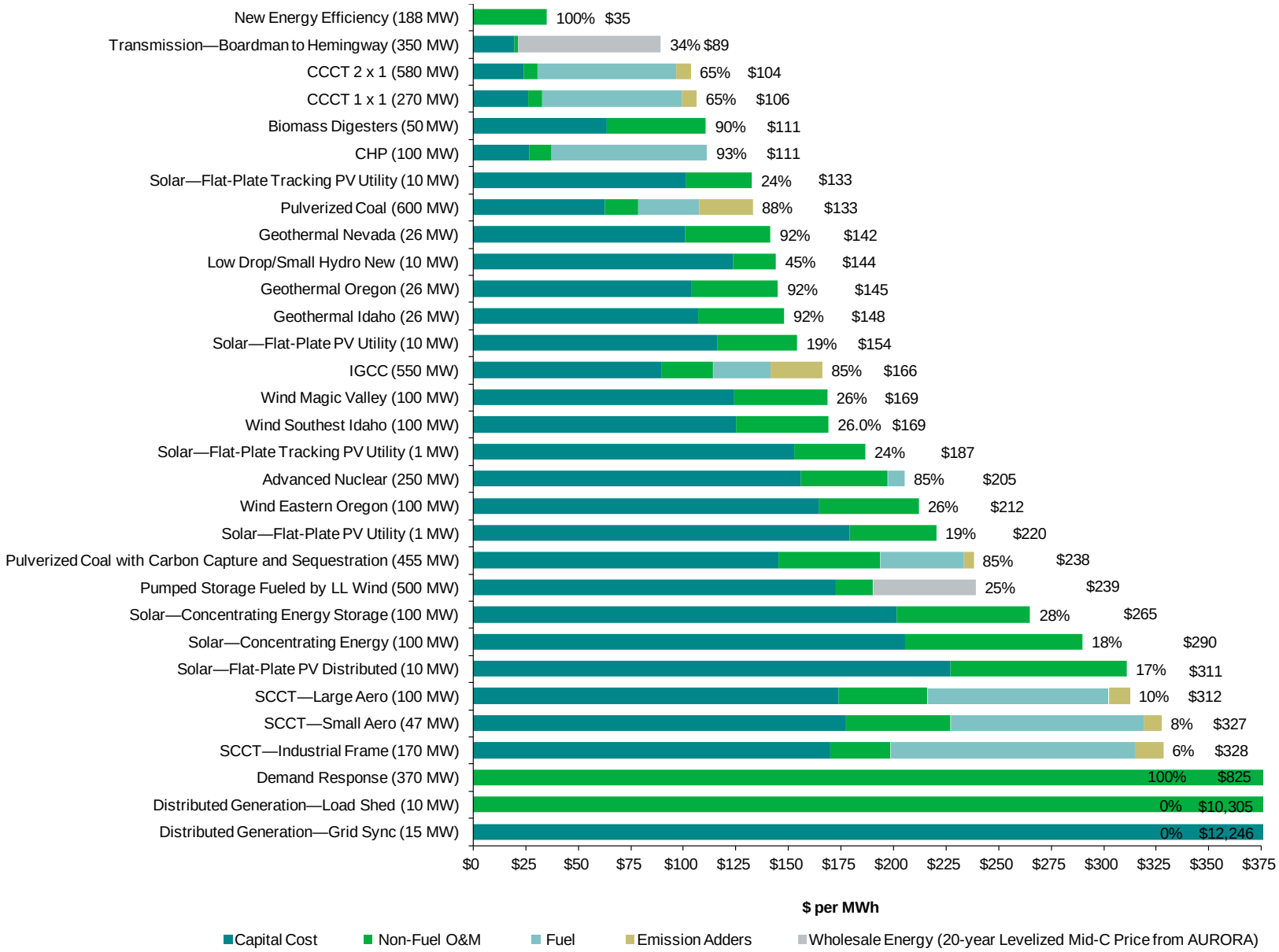



**Figure 5.8 30-year levelized cost of production (at stated capacity factors)**

## Carbon Adder

Regulatory requirements suggest a carbon analysis be performed using a carbon adder or carbon tax. Idaho Power applied a carbon adder in the 2013 IRP. The purpose of a carbon adder is to estimate the carbon costs in the price of energy produced by carbon-emitting resources.

Three carbon-adder scenarios were analyzed as part of the 2013 IRP (in nominal dollars):

1. *Planning case*—The planning case starting at $14.64 per ton in 2018 and escalating at 3 percent annually
2. *High carbon*—The upper case starting at $35 per ton in 2018 and escalating at 9 percent annually
3. *Low carbon*—The zero-cost case where no future cost is associated with carbon emissions

Idaho Power applies a 3-percent annual escalation rate to change nominal dollars to constant-year dollars. The carbon-adder planning case is selected to be consistent with the $16-per-ton value in 2021 used in the coal study that was part of the Idaho Power 2011 IRP Update filed with the IPUC and OPUC in February 2013.

Idaho Power worked with the IRP Advisory Council to determine the three carbon scenarios. The high scenario is based in part on data from the *2011 Carbon Dioxide Price Forecast* and the *2012 Carbon Dioxide Price Forecast* published by Synapse Energy Economics, Inc., of Cambridge, Massachusetts.

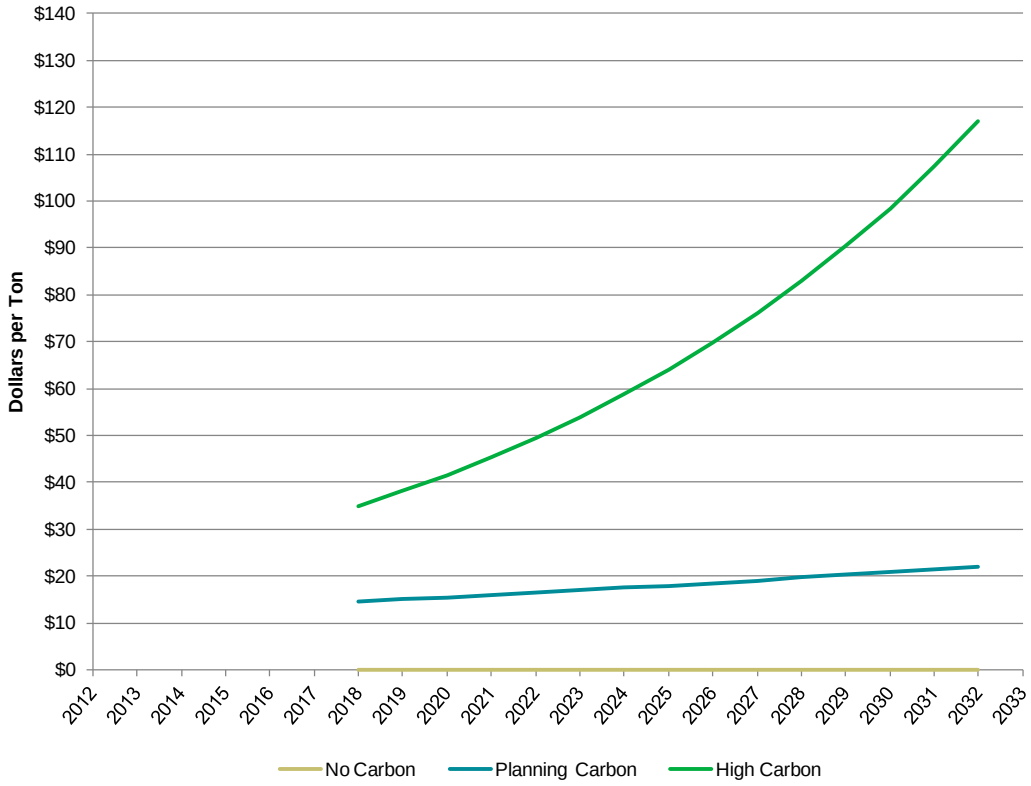



**Figure 5.9 2013 IRP carbon adder**

**Table 5.4 Carbon-adder scenarios**

| | Nominal Dollars | | | 2012 Dollars | | |
|---|---|---|---|---|---|---|
| Year | No Carbon | Planning | Upper | No Carbon | Planning | Upper |
| 2013 | – | – | – | – | – | – |
| 2014 | – | – | – | – | – | – |
| 2015 | – | – | – | – | – | – |
| 2016 | – | – | – | – | – | – |
| 2017 | – | – | – | – | – | – |
| 2018 | $0.00 | $14.64 | $35.00 | $0.00 | $12.26 | $29.31 |
| 2019 | $0.00 | $15.08 | $38.15 | $0.00 | $12.26 | $31.02 |
| 2020 | $0.00 | $15.53 | $41.58 | $0.00 | $12.26 | $32.83 |
| 2021 | $0.00 | $16.00 | $45.33 | $0.00 | $12.26 | $34.74 |
| 2022 | $0.00 | $16.48 | $49.41 | $0.00 | $12.26 | $36.76 |
| 2023 | $0.00 | $16.97 | $53.85 | $0.00 | $12.26 | $38.90 |
| 2024 | $0.00 | $17.48 | $58.70 | $0.00 | $12.26 | $41.17 |
| 2025 | $0.00 | $18.01 | $63.98 | $0.00 | $12.26 | $43.57 |
| 2026 | $0.00 | $18.55 | $69.74 | $0.00 | $12.26 | $46.11 |
| 2027 | $0.00 | $19.10 | $76.02 | $0.00 | $12.26 | $48.79 |
| 2028 | $0.00 | $19.68 | $82.86 | $0.00 | $12.26 | $51.63 |
| 2029 | $0.00 | $20.27 | $90.31 | $0.00 | $12.26 | $54.64 |
| 2030 | $0.00 | $20.88 | $98.44 | $0.00 | $12.26 | $57.83 |
| 2031 | $0.00 | $21.50 | $107.30 | $0.00 | $12.26 | $61.19 |
| 2032 | $0.00 | $22.15 | $116.96 | $0.00 | $12.26 | $64.76 |

## Carbon-Adder Generation Dispatch Analysis

Both the 2009 and the 2011 Idaho Power IRPs indicated it would take a large carbon adder before it would be cost effective for Idaho Power to replace high $CO_2$-emitting resources with new generating resources that emit less $CO_2$. Assuming Idaho Power has already made prudent long-term resource acquisition decisions, the short-term generation dispatch decisions may vary daily resource use under certain conditions. For example, during times of the year when Idaho Power is not facing peak load and the company does not need the capacity from all generation resources, a relatively small carbon adder may affect resource dispatch decisions. A relatively small carbon adder can affect daily dispatch decisions because short-term operation decisions are primarily based on the variable costs to operate resources, whereas long-term resource acquisition decisions consider both the fixed and variable costs of the resources.

Idaho Power simulated resource dispatch conditions in 2020 as part of the 2013 IRP carbon analysis. Figure 5.10 shows that a carbon adder of approximately $5 per ton can affect the Idaho Power dispatch stack. Using 2020 planning values for fuel prices, a carbon adder over $5 per ton in 2020 may lead Idaho Power to dispatch Langley Gulch prior to dispatching the North Valmy coal plant. Figure 5.10 shows it would take a significantly higher carbon adder—over $25 per ton in 2020—before Langley Gulch has a lower dispatch cost than the Jim Bridger

coal plant. Idaho Power assumed carbon adder values in 2020 of $0, $15.53, and $41.58 per ton in the 2013 IRP.

Displacing generation resources will only occur at times of low customer load. During peak seasons, it is very likely that Idaho Power will need all resources—supply side, demand side, and transmission—to meet customer load. The dispatch analysis does not suggest it is prudent or cost effective for Idaho Power to replace the coal-fired generation, but the dispatch analysis does indicate that a carbon adder may affect daily dispatch decisions under certain conditions.

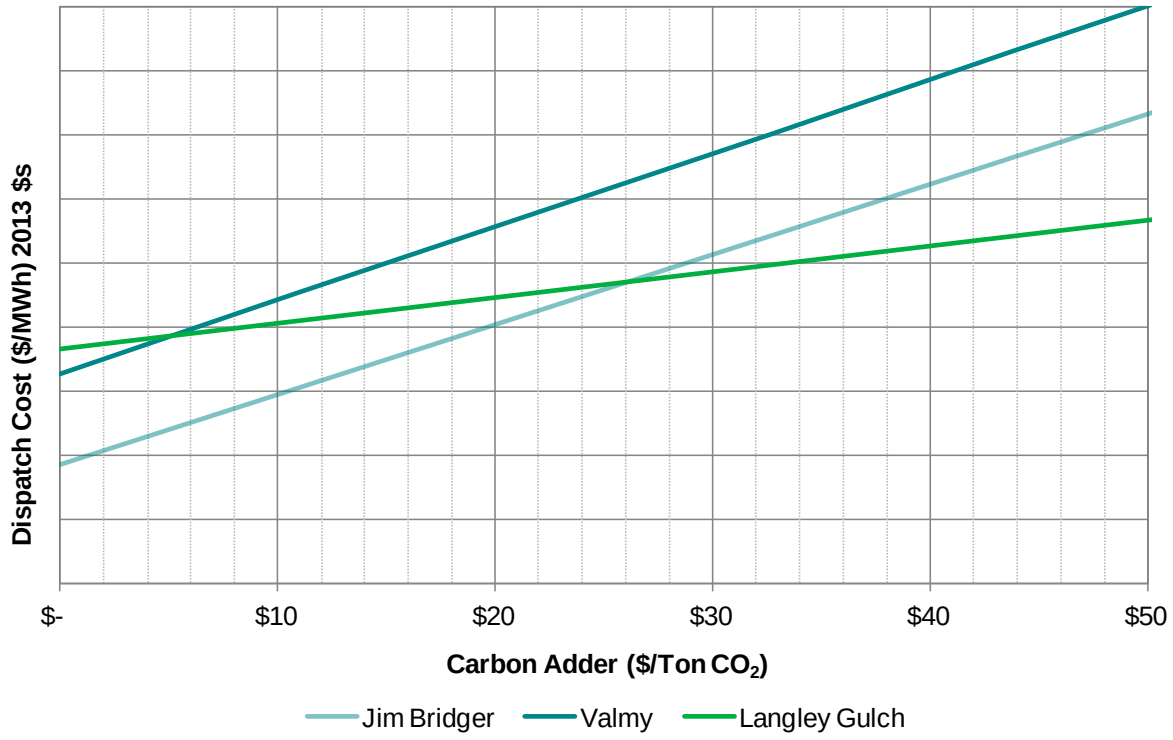



**Figure 5.10 Dispatch costs, 2020**

# 6. TRANSMISSION PLANNING

## Past and Present Transmission



High-voltage transmission lines are necessary to deliver electricity to load and connect with other regional utilities.

High-voltage transmission lines have been vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that have served the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and on to the Treasure Valley were central to the development of the HCC in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three coal-fired power plants located in neighboring states that supply approximately one-third of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric resources with access to wholesale energy markets.

Idaho Power's regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of the difference in peak seasons, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load, and Idaho Power sells excess energy to Pacific Northwest utilities during the winter and spring. New regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers through the following:

- The construction of additional peaking resources to serve summer peak load is delayed or avoided.
- Revenue from off-system sales during the winter and spring is credited to customers through the PCA.
- Revenue from others' use of the transmission system is credited to Idaho Power customers.
- In general, regional transmission allows the region to share regulation and provides capacity to help integrate intermittent resources, such as wind and solar.

# Transmission Planning Process

In recent years, FERC has mandated several aspects of the transmission planning process. FERC Order No. 1000 requires Idaho Power to participate in transmission planning on a local, regional, and interregional basis, as described in Attachment K of the Idaho Power Open-Access Transmission Tariff (OATT) and summarized in the following sections.

## *Local Transmission Planning Process*

The expansion planning of Idaho Power's transmission network occurs through a local-area transmission advisory process and the biennial local transmission planning process.

### Local-Area Transmission Advisory Process

Idaho Power develops long-term, local-area transmission plans with community advisory committees. The community advisory committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for the full development of the area limited by the land-use plan and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for four load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Treasure Valley

Recently, the *Treasure Valley Electric Plan* was divided into two plans:

1. *Western Treasure Valley Electrical Plan*—The western plan was completed in 2011 and encompasses Malheur County in Oregon and Canyon, Gem, Owyhee, Payette and Washington counties in Idaho.
2. *Eastern Treasure Valley Electric Plan*—The eastern plan was completed in 2012 and encompasses all or portions of Ada, Elmore, and Owyhee counties in Idaho.

### Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the planned supply-side resources identified in the IRP process, the transmission upgrades identified in the local-area transmission advisory process, the forecasted network customer load (e.g., Bonneville Power Administration [BPA] customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and point-to-point transmission customer requirements. By identifying potential resources, potential resource locations, and load-center growth, the required transmission system capacity

expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

### Regional Transmission Planning

Idaho Power is active in regional transmission planning through the NTTG. The NTTG was formed in early 2007 with the overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). The NTTG relies on a biennial process to develop a regional transmission plan. In preparing the regional transmission plan, the NTTG uses a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers.

### Interconnection-Wide Transmission Planning

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three distinct functions:

1. Oversee data management for the western interconnection.
2. Provide policy and management of the planning process.
3. Guide the analyses and modeling for Western Interconnection economic transmission expansion planning.

In addition to providing the means to model the transmission implications of various load and resource scenarios at an interconnection-wide level, the TEPPC coordinates planning between transmission owners, transmission operators, and regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. WECC activities include resource adequacy analyses and corresponding North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission line rating process.

## Existing Transmission System

Idaho Power's transmission system traverses from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

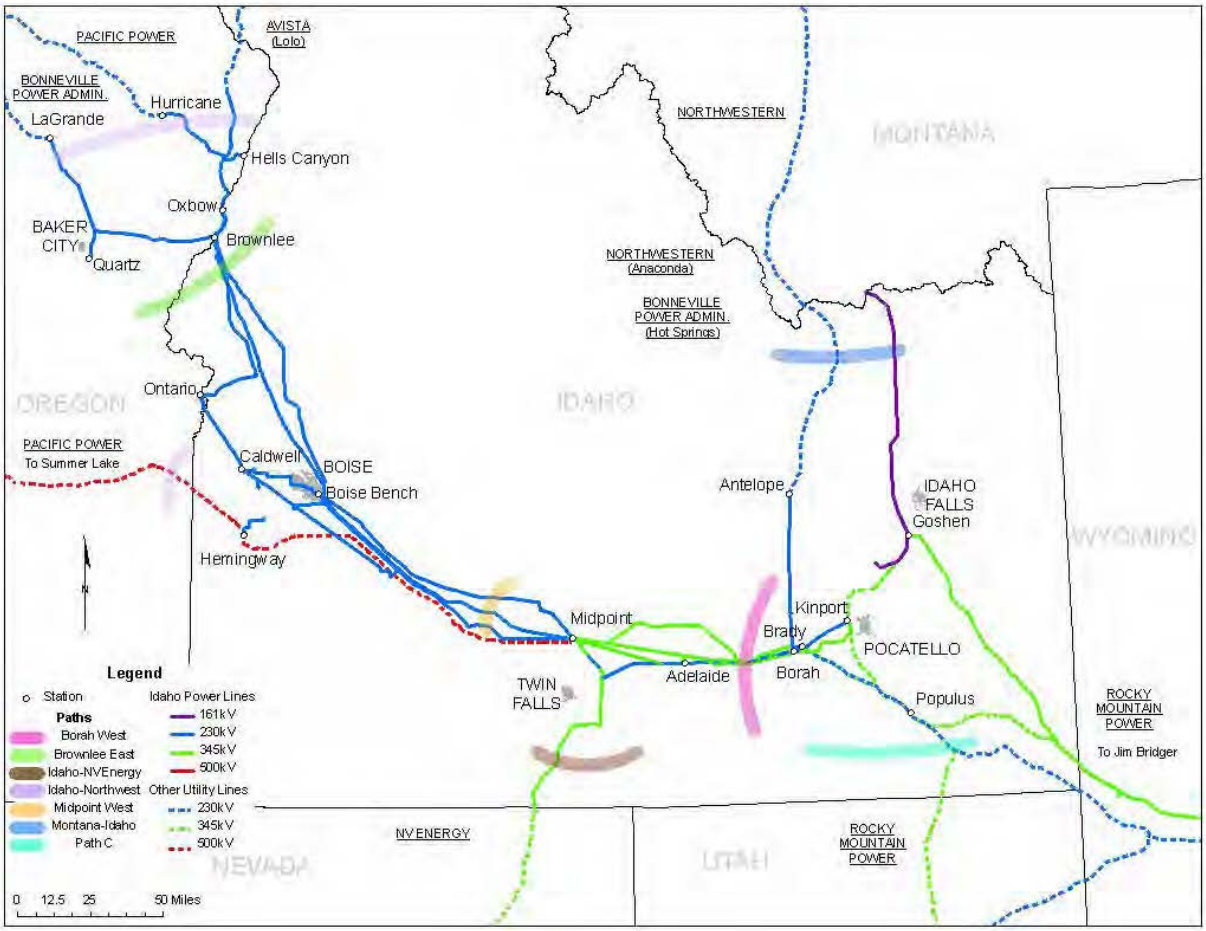



**Figure 6.1 Idaho Power transmission system map**

The transmission paths identified on the map are described in the following sections, along with the conditions that result in capacity limitations.

## Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney Substation near Burns, Oregon. The Idaho–Northwest path is most likely to be capacity-limited during summer months due to transmission-wheeling obligations for the BPA eastern Oregon and southern Idaho load and due to energy imports from the Pacific Northwest to serve Idaho Power retail load. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Idaho Power service area.

## Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the

HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Brownlee East Total path. The capacity limitation on the Brownlee East transmission path occurs between Brownlee and the Treasure Valley.

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA eastern Oregon and southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the HCC as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

## Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy south from Montana into Idaho.

## Borah West Path

The Borah West transmission path is internal to the Idaho Power system. The path is comprised of 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation located near American Falls, Idaho. Idaho Power's one-third share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric energy and energy imports from Montana, Wyoming, and Utah. PacifiCorp's two-thirds share of energy from the Jim Bridger plant also flows across this path to load centers in the Pacific Northwest. The Borah West path is capacity-limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production move east to west across the system to the Pacific Northwest. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Borah West path.

## Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. The Midpoint West path is capacity-limited due to east-side Idaho Power resources, PURPA resources, and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

## Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the North Valmy power plant was built in northern Nevada. Idaho Power is allocated 100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

## Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns one of the lines and is allocated 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the other two lines and is allocated the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

## Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path owner and operator of all of the transmission lines; however, several of the lines terminate at Idaho Power-owned substations. The path effectively feeds into Idaho Power's Borah West path when power is moving from east to west; consequently, the import capability of Path C is limited by Borah West path capacity limitations.

**Table 6.1 Available transmission import capacity**

| | Total Transmission Capacity* | | |
|---|---|---|---|
| **Transmission Path** | **Import Direction** | **Capacity (MW)** | **ATC (MW)**** |
| Idaho–Northwest | West to East | 1,200 | 0 |
| Idaho–Nevada | South to North | 262 | 0 |
| Idaho–Montana | North to South | 166 | 0 |
| Brownlee East | West to East | 1,915 | 0 |
| Midpoint West | East to West | 1,027 | 0 |
| Borah West | East to West | 2,557 | 0 |
| Idaho–Wyoming (Bridger West) | East to West | 2,400 | 60 |
| Idaho–Utah (Path C) | South to North | 1,250 | 0*** |

*Total transmission capacity and ATC as of April 1, 2013.

**The ATC of a specific path may change based on changes in the transmission service and generation interconnection request queue (i.e., the end of a transmission service, granting of transmission service, or cancelation of generation projects that have granted future transmission capacity).

***Idaho Power estimated value, actual ATC managed by PacifiCorp.

## Boardman to Hemingway

Idaho Power's IRP process has identified a transmission line to the Pacific Northwest electric market dating back to 2006. At that time, a line interconnecting at the McNary Substation to the greater Boise, Idaho, area was included in IRP portfolios. Since its initial identification, the project has been refined and developed over the years, including different terminus locations and the concept of "right sizing", or building the project to an appropriate potential. The project identified in 2006 has evolved into what is currently the Boardman to Hemingway project. The project involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and reduced capacity limitations on the regional transmission system as demand for energy grows
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon

The Boardman to Hemingway project was identified as part of the preferred portfolio in Idaho Power's 2011 IRP. Since 2011, significant progress has been made on the Boardman to Hemingway project. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the Boardman to Hemingway project. Table 6.2 shows each party's Boardman to Hemingway capacity and permitting cost allocation.

**Table 6.2 Boardman to Hemingway capacity and permitting cost allocation**

| | Idaho Power | BPA | PacifiCorp |
|---|---|---|---|
| Capacity (MW) west to east ..... | 350<br>200 winter/500 summer | 400<br>550 winter/250 summer | 300 |
| Capacity (MW) east to west ..... | 85 | 97 | 818 |
| Permitting cost allocation ..... | 21% | 24% | 55% |

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two Boardman to Hemingway options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the Boardman to Hemingway project.

Considerable progress has also been made in regard to the federal and state permitting processes. The federal permitting process is established by NEPA. The Bureau of Land Management (BLM) is the lead agency in administering the NEPA process for the Boardman to Hemingway project. On May 3, 2013, the BLM announced their preliminary environmentally preferred route

to the public. Figure 6.2 shows the proposed transmission line routes with the preliminary environmentally preferred route.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the Oregon Department of Energy (ODOE) as part of the state siting process. The final application is scheduled to be filed in spring 2014. As a result of the current federal and Oregon state permitting process, Idaho Power estimates that a project in-service date prior to 2018 is unlikely.

Additional project information is available at http://www.boardmantohemingway.com.

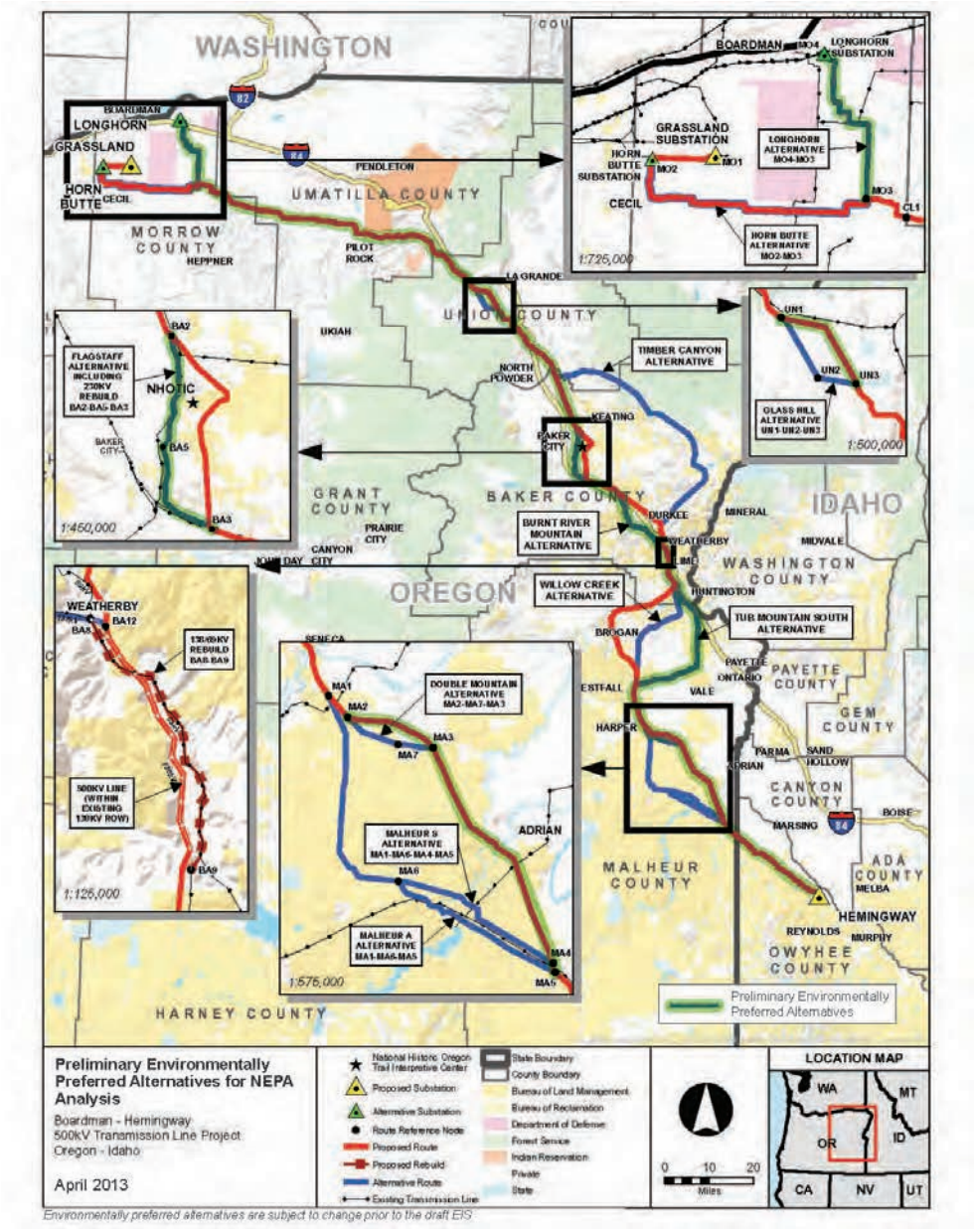



**Figure 6.2 Boardman to Hemingway routes with the BLM preliminary environmentally preferred route**

# Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho. Rocky Mountain Power has been designated as the permitting project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 6.3 shows a map of the project identifying the routes studied in the federal permitting process and depicts the BLM's preferred route. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint, which is constructed as a 500 kV-line presently operating at 345 kV. The 345-kV line will be converted to 500-kV operation in the future.

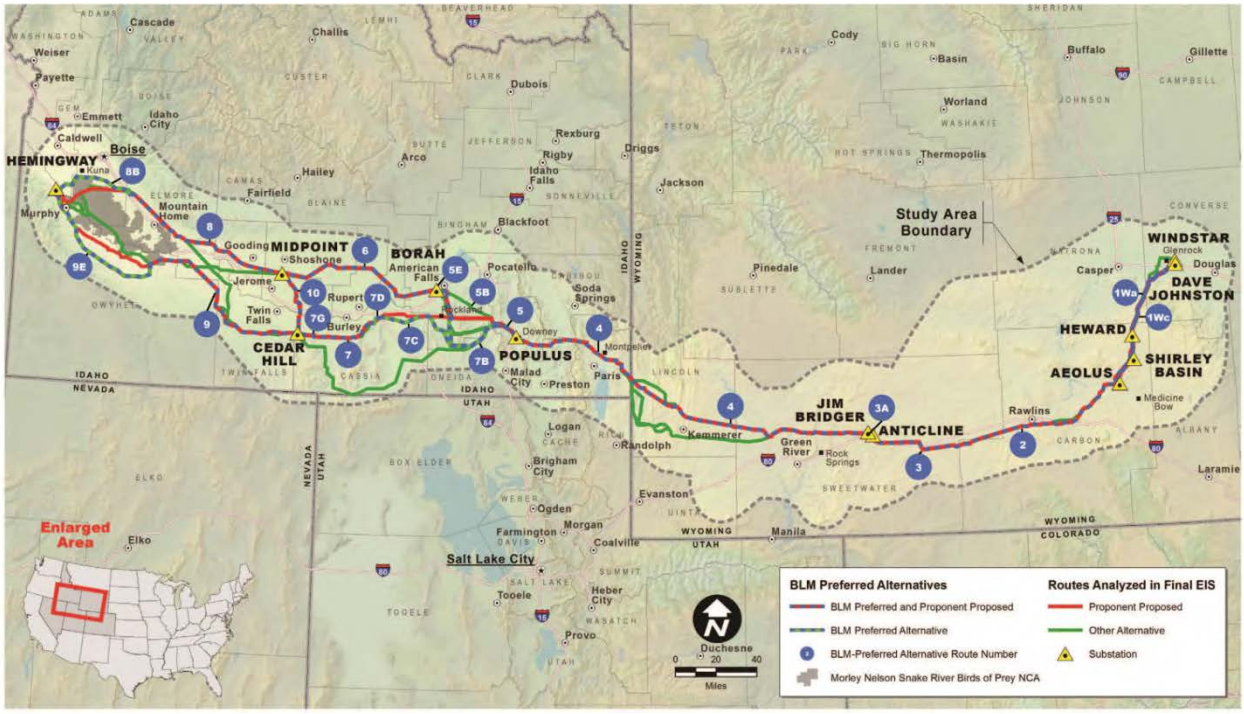



**Figure 6.3 Gateway West Map**

The two transmission projects, Boardman to Hemingway and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah. The new line will provide many benefits to Idaho Power customers, including the following:

- Relieve transmission constraints on the Borah West and Midpoint West paths, allowing Idaho Power to move additional energy between the east and west sides of the system.

- Provide the option to locate future generation resources east of the Treasure Valley load center.

- Provide future load service to the Magic Valley from the Cedar Hill Substation.

Phase 1 of the project is expected to provide up to 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide a total of 3,000 MW of additional transfer capacity.

The Gateway West project is currently undergoing the federal permitting process established by NEPA. The BLM is the lead agency administering the NEPA permitting process. On April 26, 2013, the BLM publically released the Final Environmental Impact Statement (FEIS) for comment. Releasing the FEIS for comment is a significant milestone in the NEPA process. A Record of Decision (ROD) is anticipated before the end of the 2013 calendar year.

The project is scheduled for line segments to be in service between 2019 and 2023. Multiple construction phases are planned to develop the transmission project by segment. The line segments from the Windstar Substation near Glenrock, Wyoming, to the Populus Substation near Downey, Idaho, are a priority for Rocky Mountain Power and are planned to be in service between 2019 and 2021.

Additional information about the Gateway West project can be found at http://www.gatewaywestproject.com.

## Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine the transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 6.3.



The Hemingway Substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

**Table 6.3 Transmission assumptions**

| Resource Type | Geographic Area | Resource Levels (per portfolio) | Additional Transmission Requirements |
|---|---|---|---|
| Boardman to Hemingway Line | Hemingway Substation | 500 MW | New 230-kV line from Hemingway into the Treasure Valley. |
| Gas Turbines[1] | Payette County | 0 MW–170 MW | Upgrade of approximately 9 miles of existing transmission into the Treasure Valley. |
| | Payette County | 170 MW–300 MW | Rebuild an existing 230-kV line. |
| | Elmore County | >300 MW | Additional 230-kV line(s) into the Treasure Valley, possibly requiring different geographic locations for the resources. |
| Combined heat and power (CHP) | Canyon County | 0 MW–100 MW | No transmission upgrades required. |

[1] Coal replacement resources are assumed at or near the existing coal generation facilities.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. An analysis of the transmission capacity required from the new resources to the growing Treasure Valley load center was conducted for each portfolio. The analysis assumed that CCCT gas turbines identified to replace coal resources are located at or near the existing coal generation facilities. The transmission capacity analysis of the portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

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# 7. RESOURCE ALTERNATIVES ANALYSIS

Idaho Power conducted a resource portfolio design workshop with the IRP Advisory Council on November 30, 2012. At the portfolio design workshop, members of the IRP Advisory Council suggested Idaho Power explore a variety of resource alternatives. Members of the IRP Advisory Council commented that the method to compare resources used in earlier resource plans often paired resources, making it difficult to isolate the characteristics of a single resource alternative.

Based on the comments of the IRP Advisory Council at the portfolio design workshop, Idaho Power decided to perform a preliminary resource analysis to isolate the effects of each resource. Idaho Power performed an analysis of the following eight resources:

1. Northwest transmission
2. SCCT
3. CCCT
4. CHP
5. Pumped storage fueled by LL Wind
6. Canal drop hydroelectric
8. Utility solar PV
9. Distributed solar PV

Idaho Power assumed the same time period—2013 through 2022—the same set of existing resources, the same load forecast, the same set of planning criteria, and added the same quantity of 200 MW of on-peak capacity of each resource type. Idaho Power then conducted eight Aurora simulations of the Idaho Power system to isolate the characteristics of each resource type.

Even though the on-peak capacity of 200 MW was selected for the test, 200 MW may not be a feasible generation quantity. The alternative resource portfolios were designed only as a comparison test and were not designed to either meet load or be constructed. For example, the transmission distance to the Northwest energy market requires a greater transfer capacity than 200 MW. In each resource case, the resource costs were scaled using a linear function to estimate the costs of 200 MW of on-peak capacity for the resource alternatives analysis.

Idaho Power uses a 90-percent exceedance value to calculate the nameplate generation necessary to achieve the on-peak capacity contribution. The 90-percent exceedance value means the resource is expected to deliver the on-peak contribution during the peak hours 9 times out of 10. The 90-percent exceedance method was first applied to hydroelectric generation in the 2002 Idaho Power IRP, and it has been the standard since. The nameplate capacity of many of the resource types must exceed 200 MW to achieve 200 MW of on-peak capacity. A summary of the costs is shown in Table 7.1. Figure 7.1 shows the relative costs per delivered on-peak kW; the most cost-effective resource is Northwest transmission, followed closely by natural gas combustion turbines.

**Table 7.1 Resource alternatives to achieve 200 MW of peak-hour contribution in 2018 (NPV years 2013–2022, 2013 dollars, 000s)**

| Resource Alternative | Peak-Hour Capacity (90% exceedance) | 2018 Peak-Hour Deficit Target (MW) | Installed Nameplate Needed to Meet 200 MW Peak | Variable Costs (Aurora) | RECs Sold (reflected in variable costs) | Fixed Costs (plant, transmission, fixed O&M, & rate of return) | New Natural Gas Pipeline Capacity Charge | Total | Lowest Cost Rank | Lowest Cost Relative Difference |
|---|---|---|---|---|---|---|---|---|---|---|
| 1—Northwest transmission | 100% | (200) | 200 | $2,674,610 | N/A | $33,039 | – | $2,707,650 | 1 | $0 |
| 2—SCCT | 95% | (200) | 211 | $2,677,067 | N/A | $79,331 | $7,152 | $2,763,549 | 2 | $55,900 |
| 3—CCCT | 95% | (200) | 211 | $2,646,794 | N/A | $134,786 | $38,377 | $2,819,957 | 3 | $112,308 |
| 4—CHP | 95% | (200) | 211 | $2,644,909 | $5,964 | $192,212 | $34,461 | $2,871,582 | 4 | $163,932 |
| 5—Pumped storage fueled by LL wind | 100% | (200) | 200 | $2,677,703 | $10,332 | $311,842 | – | $2,989,545 | 5 | $281,895 |
| 6—Canal drop hydroelectric | 67% | (200) | 299 | $2,513,007 | $21,104 | $603,920 | – | $3,116,927 | 6 | $409,277 |
| 7—Utility solar PV | 32% | (200) | 625 | $2,514,873 | $17,589 | $882,286 | – | $3,397,159 | 7 | $689,510 |
| 8—Distributed solar PV | 39% | (200) | 513 | $2,542,702 | $14,550 | $1,338,597 | – | $3,881,298 | 8 | $1,173,649 |

Note: Variable costs reflect the existing system plus the resource alternative. Fixed costs are representative of the resource alternative only.

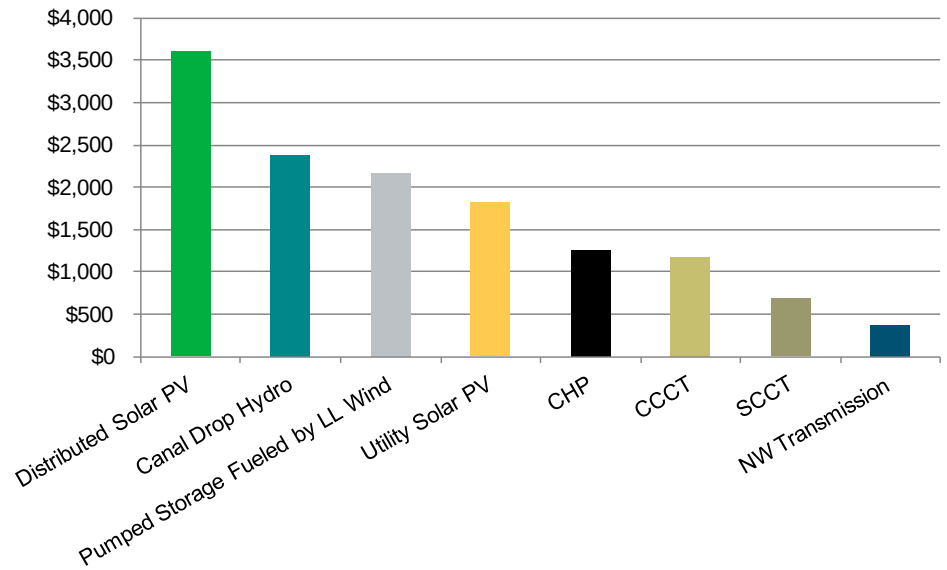


**Figure 7.1 Relative costs per delivered on-peak kW**

The high costs of the solar PV resources require some explanation. The Idaho Power system peak commonly occurs in the late afternoon and early evening on hot July days when A/C and agricultural pumping are near maximum use. Solar gain reaches a maximum at solar noon on the summer solstice in June. By the late afternoon and early evening hours in mid-July when Idaho Power experiences peak demand, solar gain in Idaho is considerably less—especially in the evening hours. The solar characteristics combined with the 90-percent exceedance criteria require a considerable quantity of solar generation to meet peak customer demand.

Distributed solar PV was the subject of several spirited discussions at the IRP Advisory Council meetings. Idaho Power performed a supplemental analysis of distributed PV to determine the time necessary to recover the capital investment from the perspective of an Idaho Power residential customer. Idaho Power estimated the investment recovery time period using a residential energy rate of $0.0855 per kWh, a 3-percent escalation rate, and an annual solar capacity factor of approximately 15 percent (the solar capacity factor is based on solar data from the NREL PVWatts website). The results of the analysis are shown in Figure 7.2. The figure shows the cost recovery with no tax incentives as well as the recovery with federal and state incentives. Until the installed cost with incentives drops below approximately $2 per watt, investment recovery periods exceed 10 years for residential solar PV.

The same general conclusions can be applied to utility solar PV installations. Until annual average wholesale energy prices exceed $85.50 per MWh and until the installed cost with incentives drops below $2,000 per kW, utility solar investment recovery periods are likely to exceed 10 years.

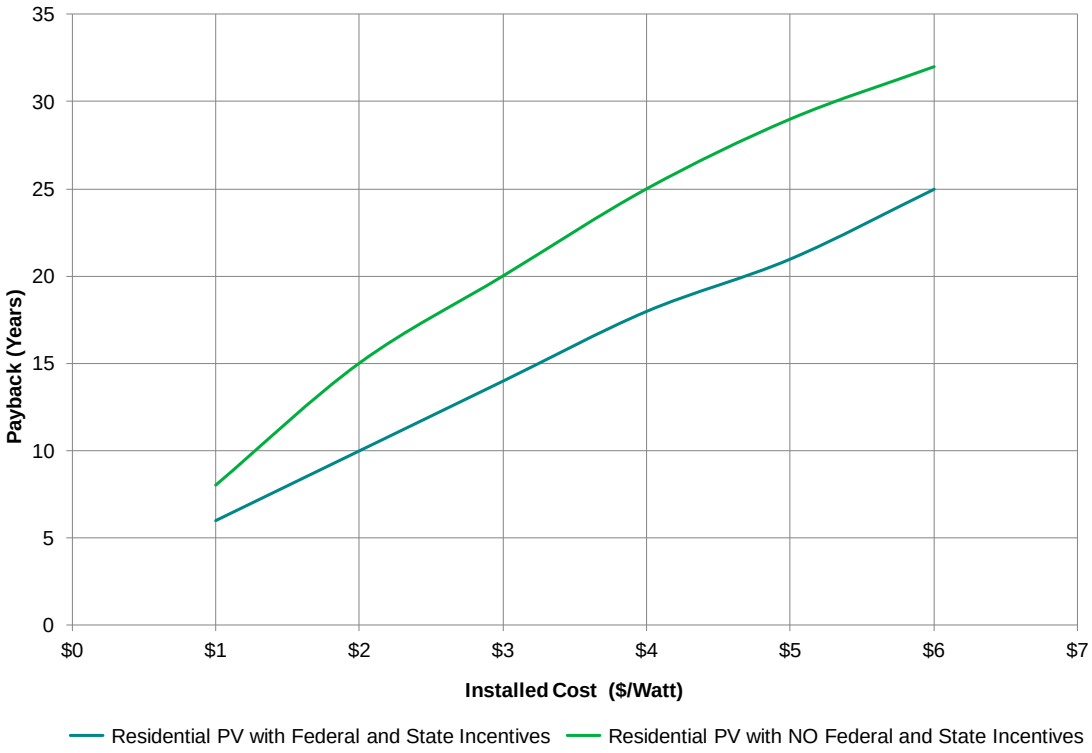


**Figure 7.2 Solar generation recovery period**

Idaho Power proposed a solar demonstration project as part of the 2011 IRP. The proposed project had a nameplate capacity between 0.5 and 1 MW and was initially expected to be on-line by the end of 2013.

Idaho Power is still interested in developing a solar demonstration project. With the recent issues surrounding PURPA in Idaho, the timing has not been suitable for Idaho Power to pursue the construction of a small-scale solar project. Idaho Power is required to comply with the requirements identified in the Oregon Solar Incentive Program, which include building a 500-kW, utility-scale solar facility by 2020 (Oregon House Bill 3039). Idaho Power will continue to evaluate the solar demonstration project and the benefits of receiving double RECs in the Oregon if the project is completed by the end of 2016.

## Solar Parking Lot Lighting Demonstration Project

Idaho Power and Boise-based Inovus Solar have recently entered into an agreement under which Inovus will install a Solar-Enhanced Lighting™ System in the south parking lot of Idaho Power's CHQ (the parking lot is bound by Main Street, Grove Street, 12th Street, and 13th Street). The system is designed to be a grid connected net-zero system, meaning it will generate as much energy during the day as the lights consume at night while illuminating the parking lot. An example of the light is shown in Figure 7.3.

The project provides Idaho Power with insight into the performance, technology, and potential applications of the Inovus state-of-the-art Solar-Enhanced Lighting System. Additionally, the Idaho Power project provides Inovus a local installation to evaluate the performance of individual components, test enhancements, and monitor and evaluate overall system performance.

The system will generate approximately 4 kW, and the new lights are scheduled to be in service by late July 2013.



**Figure 7.3 Inovus solar light**

## Risk Analysis and Results

Idaho Power also performed a risk analysis on the eight resource alternatives. The risk analysis is a quantitative scenario analysis. Idaho Power identified four variables for the risk analysis—the natural gas price, customer load, hydroelectric conditions, and carbon adder. In total, using the four risk variables, the following seven risk scenarios were tested:

1. High carbon adder
2. Low carbon adder
3. High gas prices

4. Low gas prices
5. Low water conditions
6. High gas prices plus low water conditions
7. High gas prices plus low water conditions and a high carbon adder

Scenarios six and seven are combinations of the risk variables designed to test more severe conditions.

The ranking of the resource alternatives under each of the seven scenarios is presented in Table 7.2 (the full costs for the different scenarios are reported in *Appendix C—Technical Appendix*).

**Table 7.2 Risk scenario results**

| | Risk Scenario | | | | | | |
|---|---|---|---|---|---|---|---|
| | Carbon | | Natural Gas Price | | Low | Scenario | Scenario |
| Resource Alternative | High | Low | High | Low | Water | 6 | 7 |
| Northwest transmission | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| SCCT | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| CCCT | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| CHP | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Pumped storage fueled by LL wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Canal drop hydroelectric | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Utility solar PV | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Distributed solar PV | 8 | 8 | 8 | 8 | 8 | 8 | 8 |

Northwest transmission was the lowest-cost resource alternative in all scenarios, and the ranking of the resource alternatives did not change in any scenario; the low cost resources were low cost in all seven risk scenarios, and the high cost resources were high cost in all seven risk scenarios.

Based on the suggestions of the IRP Advisory Council and the results of the resource alternatives analysis, Idaho Power designed resource portfolios using the lowest-cost resource alternatives—Northwest transmission and generation fired by natural gas. The specific resource portfolios are described in the following chapter.

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# 8. PLANNING CRITERIA AND PORTFOLIO SELECTION

## Planning Scenarios and Criteria

Idaho Power conducted a systematic analysis to select the preferred resource portfolio. The planning scenarios can be grouped into three main categories:

1. *Boardman to Hemingway resource portfolios*—Two resource portfolios rely primarily on the Boardman to Hemingway transmission line to meet future resource needs. The two resource portfolios contain the existing and committed Idaho Power generation resources.

2. *Alternative to Boardman to Hemingway resource portfolios*—Three resource portfolios explore alternatives to the Boardman to Hemingway transmission line to meet future resource needs. The Boardman to Hemingway transmission line is not included in the three resource portfolios. The three resource portfolios contain the existing and committed Idaho Power generation resources.

3. *Coal alternative resource portfolios*—Four resource portfolios explore options to reduce coal-fired generation in the Idaho Power resource portfolio. The options to reduce the reliance on coal include replacement with natural gas-fired generation; increased demand-side measures, including demand response; changing the fuel at the North Valmy plant to natural gas; and the Boardman to Hemingway transmission line. The alternatives to coal resource portfolios are an extension of the coal study Idaho Power included with the 2011 IRP Update.

Demand response is included in many of the resource portfolios. Idaho Power applied demand response in 50 MW increments in the resource portfolios. The lines shown on the resource portfolio graphs identify the maximum level of demand response. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The demand response 2016 level was estimated to be 100 MW and the 2017 level was estimated to be 150 MW.

The four resource portfolios that explore options for reducing coal-fired generation at Idaho Power are the first IRP portfolios in which Idaho Power has considered the early retirement of a generating resource in an IRP. Resource retirement raises a few issues unique to the 2013 IRP. Specifically, resource retirement portfolios require Idaho Power to consider the remaining asset value of the resource and to include recovering the asset value in the resource portfolio. In addition, resource retirement also requires Idaho Power to account for any retirement and termination costs when estimating the resource portfolio costs.

Resource retirement also requires Idaho Power to estimate the ongoing capital requirements of the coal-fired resources and to include the ongoing capital requirements in the resource portfolios containing the existing resources. Treatment of the fixed-cost accounting is summarized in Table 8.1.

**Table 8.1 Coal resource fixed-cost accounting**

| Capital Description | Existing Coal Resource Portfolios | Coal Replacement Resource Portfolios |
|---|---|---|
| Coal Emission-Control Equipment | Included | Excluded |
| Existing Coal Resources | Included | Excluded |
| Replacement Resources | Excluded | Included |
| Accelerated Recovery of Existing Coal Plant Investment | Excluded | Included |
| Decommissioning Coal Asset | Excluded | Included |

The word *included* indicates costs must be added to the resource portfolio costs, and *excluded* indicates no additional costs. For example, the cost of the emission-control equipment must be added to the resource portfolios that use the existing coal plants, whereas the resource portfolios that replace coal will not incur the emission-control equipment costs. Each of the nine detailed resource portfolios analyzed are described in the next section.

# Portfolio Design and Selection

The following resource portfolios are described in tables 8.2 through 8.10, which list the resource types, implementation dates, and on-peak capacity. Figures 8.1 through 8.9 show monthly peak-hour deficits under 90$^{th}$-percentile water and 95$^{th}$-percentile load with existing and committed resources and existing energy efficiency programs. When a new resource is added, a horizontal line on the chart shows the capacity contribution of the new resource.

## *Boardman to Hemingway Resource Portfolios*

### Resource Portfolio 1—Boardman to Hemingway plus Demand Response and an SCCT

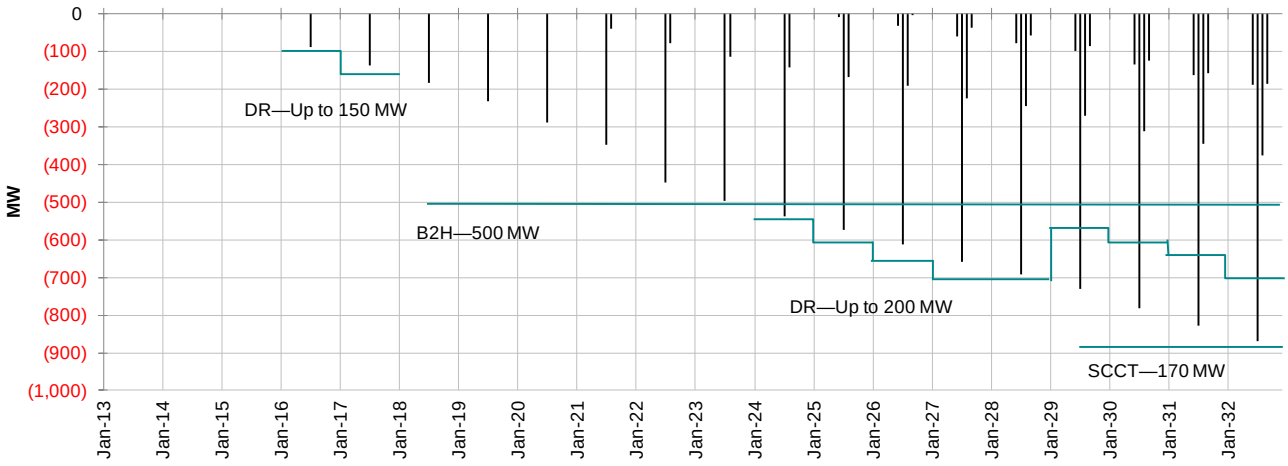


**Figure 8.1 Resource portfolio 1**

**Table 8.2 Resource portfolio 1**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| 2018 | Boardman to Hemingway | 500-MW transfer capacity |
| Summer 2024 | Demand response | Up to 200 MW in 50-MW increments |
| Summer 2029 | SCCT | 170 MW |

## Resource Portfolio 2—Boardman to Hemingway plus Demand Response

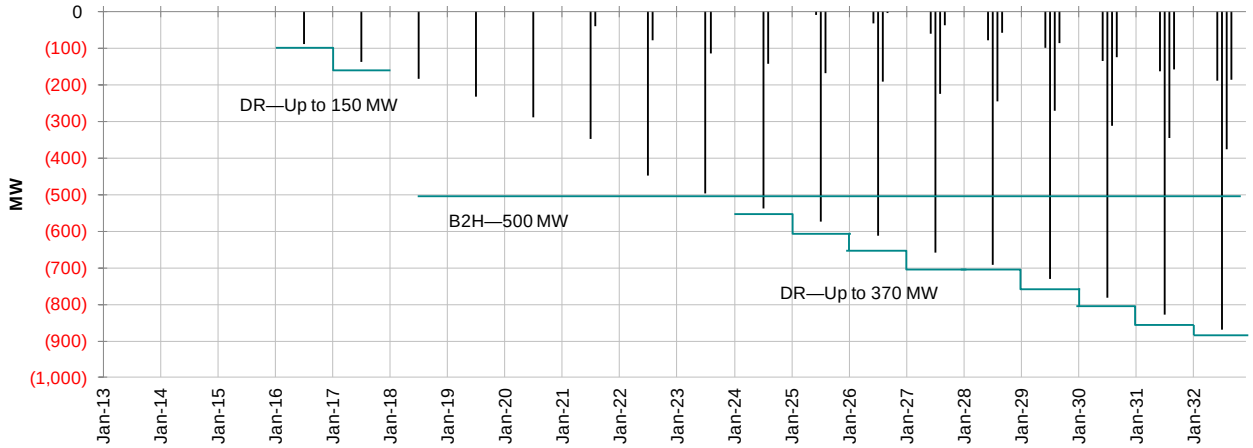


**Figure 8.2 Resource portfolio 2**

**Table 8.3 Resource portfolio 2**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| 2018 | Boardman to Hemingway | 500-MW transfer capacity |
| Summer 2024 | Demand response | Up to 370 MW in 50-MW increments |

# *Alternative to Boardman to Hemingway Resource Portfolios*

## Resource Portfolio 3—Demand Response plus a CCCT and an SCCT

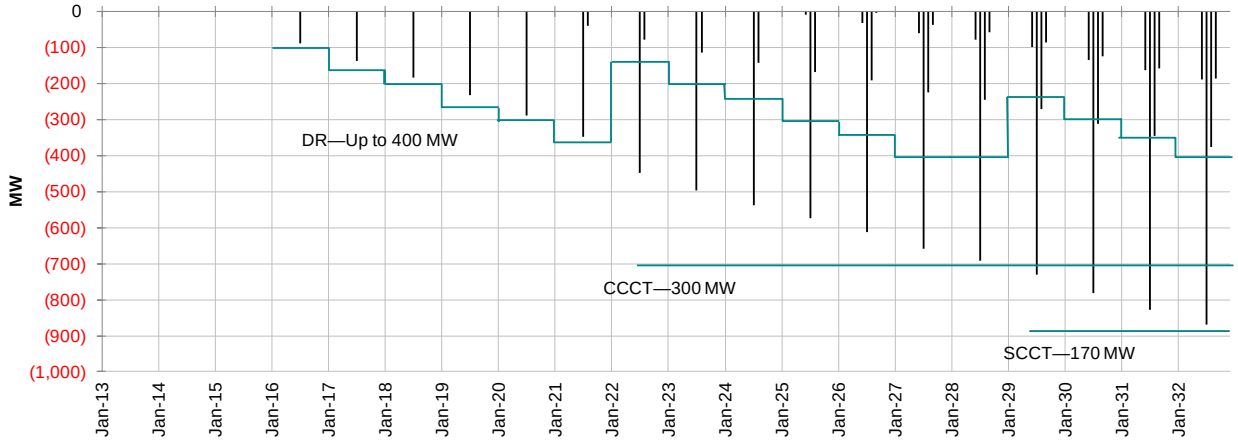


**Figure 8.3 Resource portfolio 3**

**Table 8.4 Resource portfolio 3**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| Summer 2018 | Demand response | Increasing to 400 MW in 50-MW increments |
| Summer 2022 | CCCT | 300 MW |
| Summer 2029 | SCCT | 170 MW |

## Resource Portfolio 4—Demand Response plus Two CCCTs

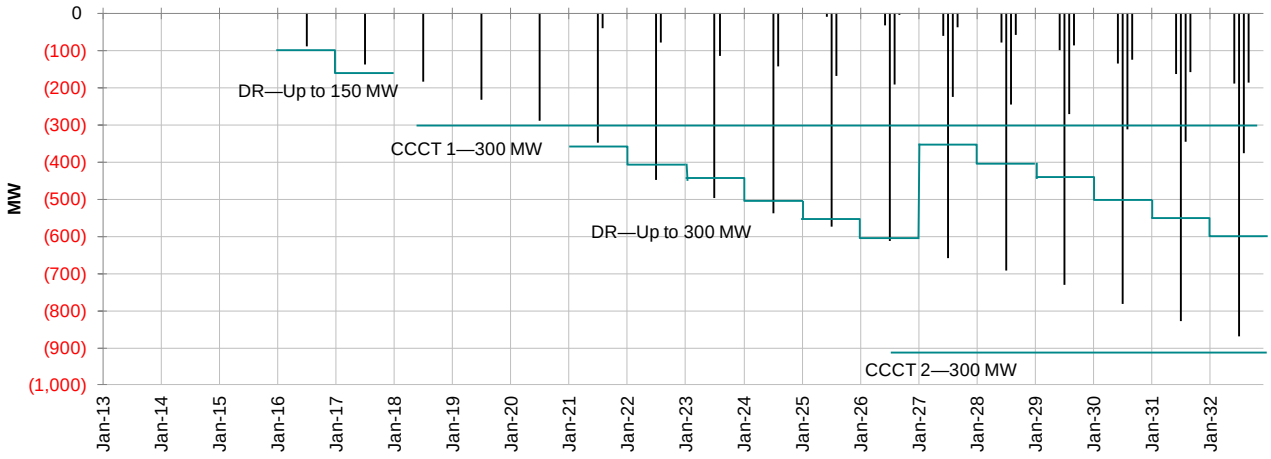


**Figure 8.4 Resource portfolio 4**

**Table 8.5 Resource portfolio 4**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| Summer 2018 | CCCT | 300 MW |
| Summer 2021 | Demand response | Additional 300 MW in 50-MW increments |
| Summer 2026 | CCCT | 300 MW |

## Resource Portfolio 5—Demand Response plus Two Consecutive CCCTs

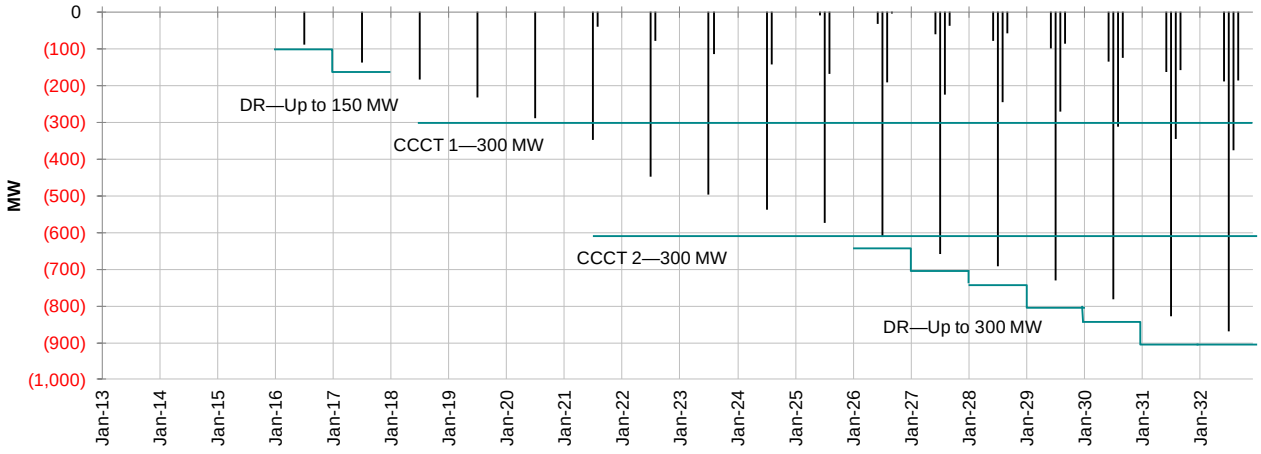


**Figure 8.5 Resource portfolio 5**

**Table 8.6 Resource portfolio 5**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| Summer 2018 | CCCT | 300 MW |
| Summer 2021 | CCCT | 300 MW |
| Summer 2026 | Demand response | Additional 300 MW in 50-MW increments |

## Coal Alternative Resource Portfolios

The coal alternative resource portfolios are shown with a different monthly peak-hour load and resource balance. Figures 8.6 through 8.9 show the anticipated monthly peak-hour resource deficits in black, similar to resource portfolios 1 through 5. However, removing existing generation resources increases the monthly peak-hour capacity deficits, and figures 8.6 through 8.9 show the increased deficits created by removing coal generation in red. Resource portfolios 6 through 9 are designed to meet the increased deficits shown in red. The deficit scale in the coal alternative resource portfolios is different than the scale shown in the resource portfolios containing the existing coal resources. The monthly peak-hour deficits are under 90$^{th}$-percentile water and 95$^{th}$-percentile load with existing and committed resources and existing energy efficiency programs.

### Resource Portfolio 6—ICL–BSU

Resource portfolio 6 was suggested by members of the Idaho Power IRP Advisory Council representing the ICL and BSU. Idaho Power worked with the two IRP Advisory Council members representing the ICL and BSU to refine the resource portfolio.

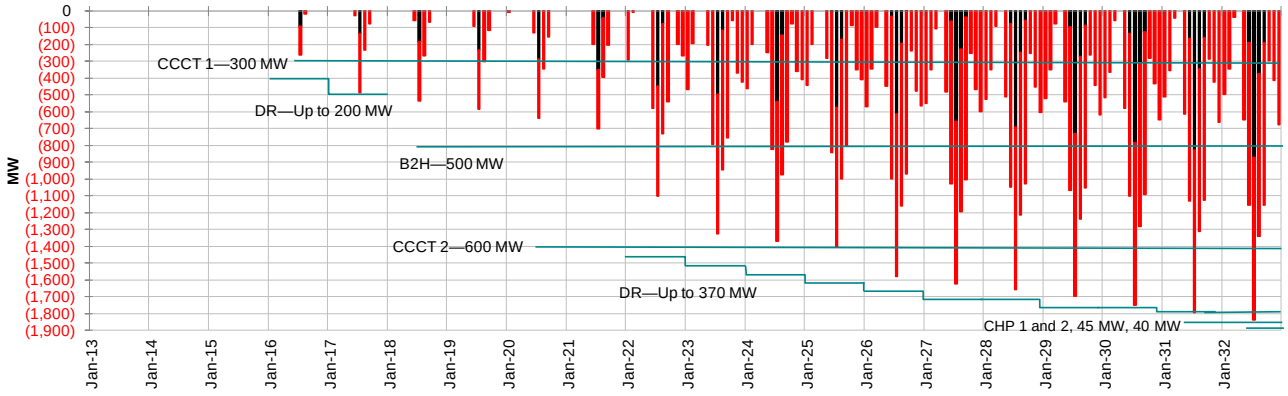


**Figure 8.6 Resource portfolio 6**

**Table 8.7 Resource portfolio 6**

| Date | Resource | Capacity |
|---|---|---|
| Year-end 2015 | Exit Bridger Unit 3 and Valmy Unit 1 | Minus approximately 300 MW |
| Summer 2016 | CCCT | 300 MW |
| Year-end 2016 | Exit Bridger Unit 4 | Minus approximately 170 MW |
| 2016–2017 | Demand Response | Up to 200 MW |
| 2018 | Boardman to Hemingway | 500-MW transfer capacity |
| Year-end 2020 | Exit Bridger Units 1 and 2, Valmy Unit 2 | Minus approximately 370 MW |
| Year-end 2020 | CCCT | 600 MW |
| Summer 2031 | CHP | 45 MW |
| Summer 2032 | CHP | 40 MW |

## Resource Portfolio 7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response

Resource portfolio 7 is based on the Idaho Power coal study presented with the 2011 IRP Update. Resource portfolio 7 replaces coal-fired generation resources with natural gas-fired generation. Specifically, the North Valmy coal plant is modified to burn natural gas and the Jim Bridger plant is replaced with CCCTs fired by natural gas.

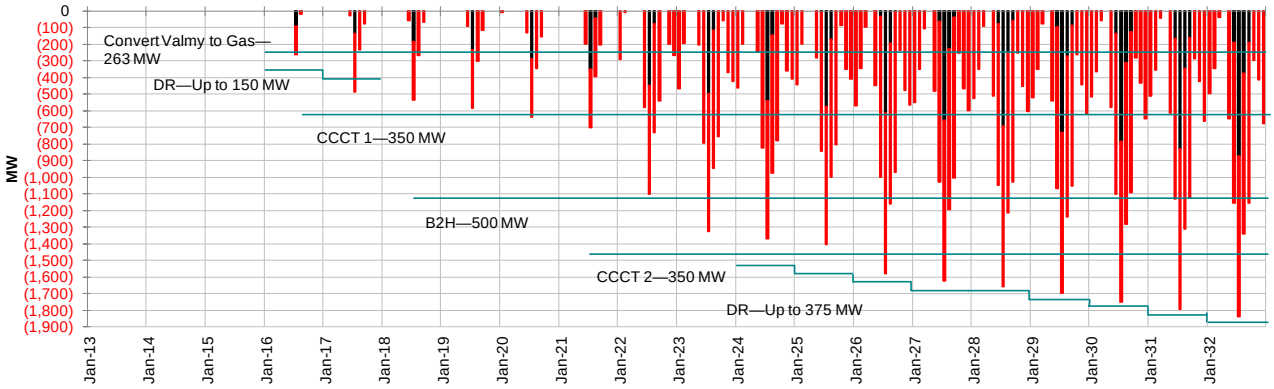


**Figure 8.7 Resource portfolio 7**

**Table 8.8 Resource portfolio 7**

| Date | Resource | Capacity |
|---|---|---|
| January 2015 | Convert Valmy Units 1 and 2 to be fueled by natural gas | No Change |
| Year-end 2015 | Cease coal-fired operation of Bridger Units 3 and 4 | Minus approximately 340 MW |
| Summer 2016 | CCCT | 350 MW |
| 2016–2017 | Demand response | Up to 150 MW |
| 2018 | Boardman to Hemingway | 500-MW transfer capacity |
| Year-end 2020 | Cease coal-fired operation of Bridger Units 1 and 2 | Minus approximately 340 MW |
| Summer 2021 | CCCT | 350 MW |
| 2021–2032 | Demand response | Up to 375 MW |

## Resource Portfolio 8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT

In April 2013, NV Energy announced a schedule to retire the North Valmy Coal Plant. Idaho Power is a one-half owner of the North Valmy coal plant, and NV Energy is the operating partner. Idaho Power has not agreed to the North Valmy plant retirement schedule announced by NV Energy. Resource Portfolio 8 is designed to estimate the effects of retiring North Valmy Units 1 and 2 according to the NV Energy schedule and replacing the lost generation with demand response, Boardman to Hemingway, and a CCCT (North Valmy Unit 1 is retired at year-end 2020 and North Valmy unit 2 is retired at year-end 2025).

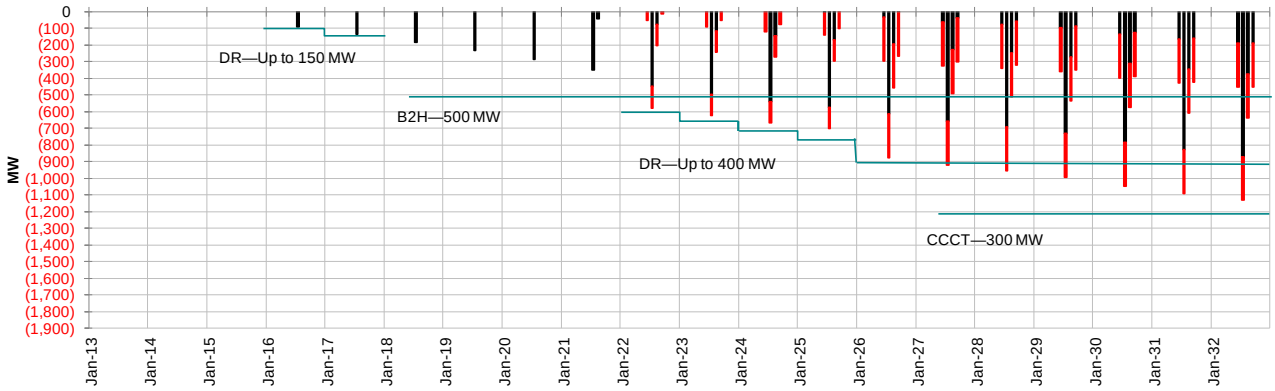


**Figure 8.8 Resource portfolio 8**

**Table 8.9 Resource portfolio 8**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| 2018 | Boardman to Hemingway | 500-MW transfer capacity |
| Year-end 2021 | Valmy 1 retired | Minus approximately 130 MW |
| Summer 2022 | Demand response | Up to 400 MW |
| Year-end 2025 | Valmy 2 retired | Minus approximately 130 MW |
| Summer 2027 | CCCT | 300 MW |

## Resource Portfolio 9—North Valmy Closure, Boardman to Hemingway Alternative

Like resource portfolio 8, resource portfolio 9 is designed to estimate the effects of retiring North Valmy on the schedule announced by NV Energy. Resource Portfolio 9 replaces the lost generation with alternatives to Boardman to Hemingway, including demand response, two CCCTs, and one SCCT.

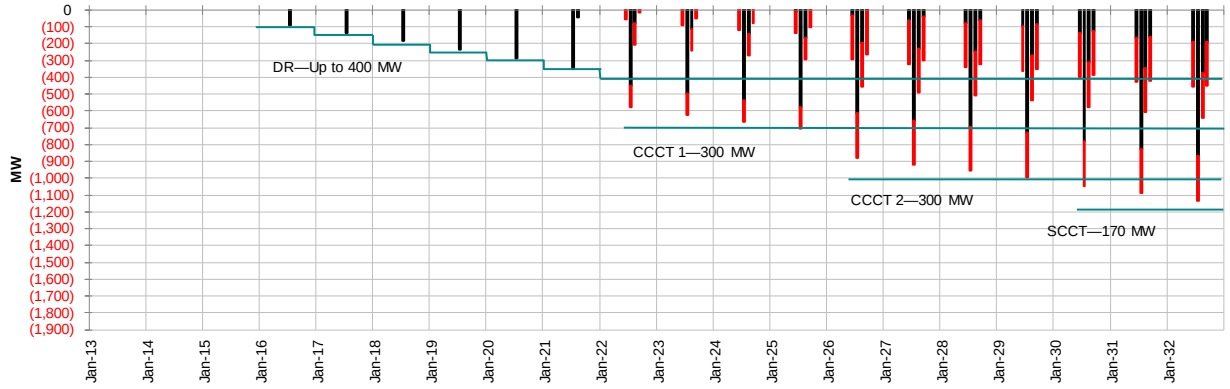


**Figure 8.9 Resource portfolio 9**

**Table 8.10 Resource portfolio 9**

| Date | Resource | Capacity |
|---|---|---|
| 2016–2017 | Demand response | Up to 150 MW |
| 2018 | Expanded demand response | Up to 400 MW |
| Year-end 2021 | Valmy 1 closure | Minus approximately 130 MW |
| Summer 2022 | CCCT | 300 MW |
| Year-end 2025 | Valmy 2 closure | Minus approximately 130 MW |
| Summer 2026 | CCCT | 300 MW |
| Summer 2030 | SCCT | 170 MW |

# 9. Modeling Analysis and Results

## Portfolio Costs

Idaho Power evaluated the costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to meet the customer load using all resources in the portfolio. Resource portfolios 1 through 5 assume the continued operation of the Jim Bridger and North Valmy coal facilities. (The Boardman coal plant ceases coal-fired operations at year-end 2020 in all resource portfolios.) Idaho Power ceases coal-fired operations at the North Valmy and Jim Bridger plants in resource portfolios 6 and 7. Resource portfolios 8 and 9 retire the North Valmy plant on the schedule identified by NV Energy in April 2013. (North Valmy Unit 1 is retired at year-end 2021, and North Valmy Unit 2 is retired at year-end 2025.)

The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

**Table 9.1 Financial assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount rate (weighted average cost of capital) | 7.00% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 3.00% |
| Emissions-adder escalation rate | 2.50% |
| Carbon-adder escalation rate | 5.00% |
| Annual property tax escalation rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premium (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.00% |
| Production tax credit escalation rate | 3.00% |

Table 9.2 reports the total cost of each resource portfolio for the 20-year planning horizon. The total cost is the NPV of the variable operating costs plus the fixed cost of the existing, new, and replacement resources. The variable operating costs include the fuel cost, purchased-power cost, O&M, and other costs.

**Table 9.2 2013 IRP portfolios, NPV years 2013–2032 (2013 dollars, 000s)**

| Portfolio | Variable Costs | Fixed Costs | | | | Summary | | |
|---|---|---|---|---|---|---|---|---|
| | Operating[1] (Aurora) | New Resources[2] | New Natural Gas Pipeline Capacity Charge | Demand Response | Total | Total Portfolio Costs | Lowest Cost Rank | Lowest Cost Relative Difference |
| (1) | (2) | (3) | (4) | (5) | (6) (3)+(4)+(5) | (7) (2)+(6) | (8) | (9) |
| 2—Boardman to Hemingway plus Demand Response | $4,987,003 | $185,028 | $0 | $48,547 | $233,575 | $5,220,578 | 1 | $0 |
| 1—Boardman to Hemingway plus Demand Response and an SCCT | $4,987,143 | $221,699 | $2,300 | $34,818 | $258,817 | $5,245,960 | 2 | $25,382 |
| 3—Demand Response plus a CCCT and an SCCT | $4,940,835 | $351,762 | $80,973 | $105,933 | $538,668 | $5,479,503 | 3 | $258,925 |
| 4—Demand Response plus Two CCCTs | $4,872,870 | $638,016 | $166,043 | $52,744 | $856,803 | $5,729,673 | 4 | $509,095 |
| 8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT | $5,056,695 | $598,447 | $38,902 | $73,927 | $711,276 | $5,767,971 | 5 | $547,394 |
| 5—Demand Response plus Two Consecutive CCCTs | $4,843,988 | $796,666 | $211,320 | $35,067 | $1,043,052 | $5,887,040 | 6 | $666,463 |
| 9—North Valmy Closure, Boardman to Hemingway Alternative | $4,991,277 | $744,041 | $139,722 | $127,677 | $1,011,439 | $6,002,716 | 7 | $782,138 |
| 6—ICL–BSU | $5,688,123 | $650,693 | $336,164 | $57,771 | $1,044,628 | $6,732,751 | 8 | $1,512,173 |
| 7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response | $5,789,525 | $654,534 | $516,133 | $45,965 | $1,216,632 | $7,006,156 | 9 | $1,785,578 |

[1] Variable operating costs reflect the existing system with coal plant shutdowns (when applicable) plus the new portfolio resources, REC sales, and carbon adder.

[2] New plant capital, new plant transmission, stranded asset value, environmental compliance upgrade (when applicable), accelerated recovery of existing coal plant investment, and decommissioning coal asset.

The resource portfolios are sorted from lowest cost to highest cost in Table 9.2. Resource portfolio 2 is the least-cost resource portfolio.

The general ranking of resource portfolios shows resource portfolios that include Boardman to Hemingway cost less than comparable resource portfolios that rely on alternatives to Boardman to Hemingway. The resource portfolios that replace resources—resource portfolios 6 through 9—are generally the most expensive options. However, resource portfolio 8, which replaces North Valmy, costs less because it includes the Boardman to Hemingway transmission line. Figure 9.1 shows the resource portfolio costs.

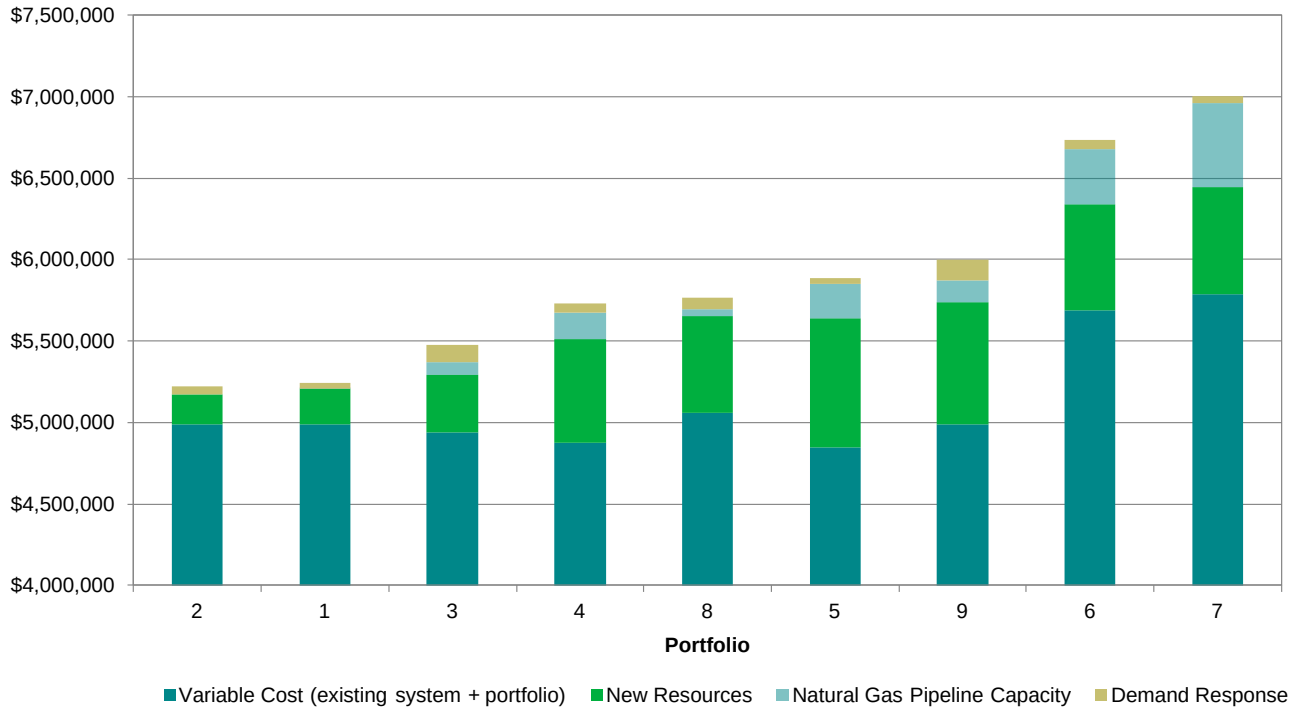


**Figure 9.1 Total portfolio costs, NPV 2013–2032 (2013 dollars, 000s)**

# Portfolio Emissions

For the 2013 IRP, Idaho Power analyzed the total portfolio emissions for the 20-year planning period by the following four emission types:

1. $CO_2$—A greenhouse gas associated with climate change
2. $NO_x$—Contributes to regional haze
3. $SO_2$—Contributes to acid rain formation
4. Hg—A toxic element found in coal deposits

Total emissions by type were calculated using Aurora emissions modeling. All portfolios comply with all known environmental regulations. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing and committed resources.

## *$CO_2$ Emissions*

Figure 9.2 shows the total $CO_2$ emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced $CO_2$ emissions. The reduced emissions are because a CCCT resource emits approximately 37 percent of the $CO_2$ per MWh that Idaho Power coal-fired generation resources emit on average.

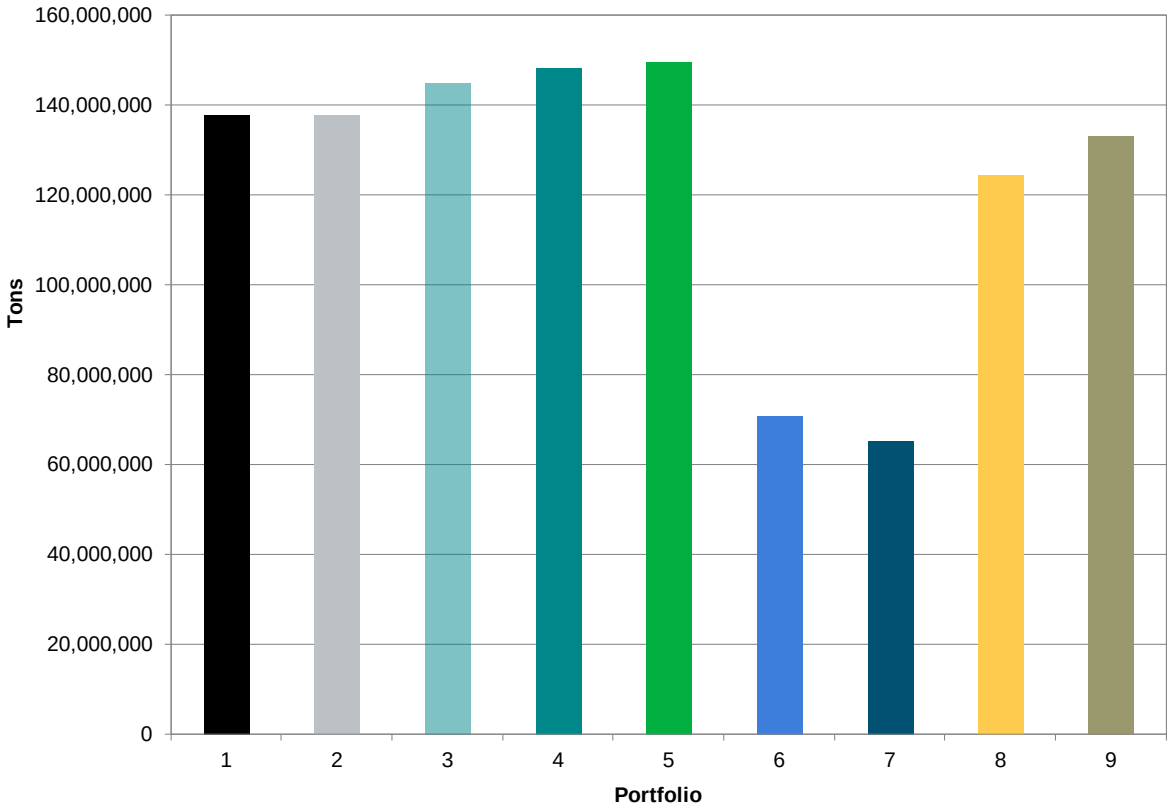


**Figure 9.2 Total $CO_2$ emissions for 2013–2032**

## *$NO_x$ Emissions*

Figure 9.3 shows the total $NO_x$ emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced $NO_x$ emissions. The reduced emissions are because a CCCT resource emits approximately 2 percent of the $NO_x$ per MWh that Idaho Power coal-fired generation resources emit on average.

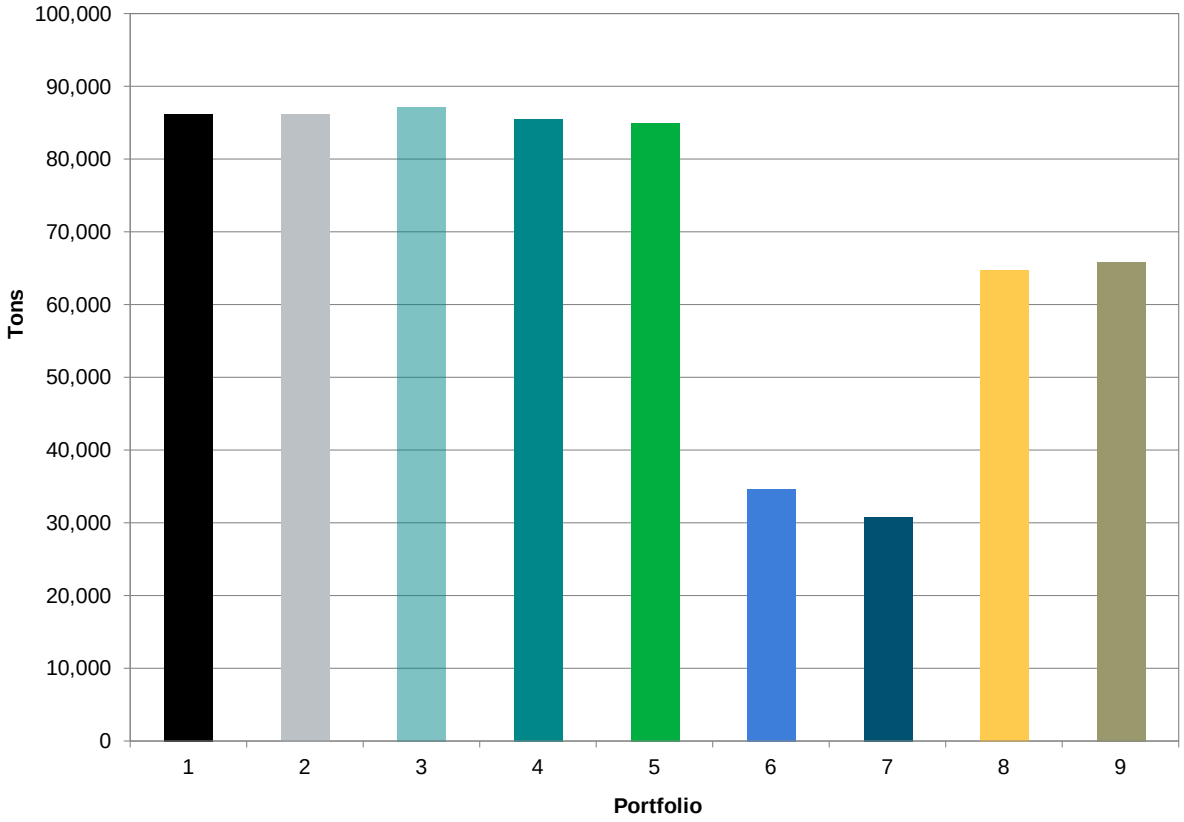


**Figure 9.3 Total $NO_x$ emissions for 2013–2032**

## *$SO_2$ Emissions*

Figure 9.4 shows the total $SO_2$ emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced $SO_2$ emissions. The reduced emissions are because a CCCT resource emits approximately 1 percent of the $SO_2$ per MWh that Idaho Power coal-fired generation resources emit on average.

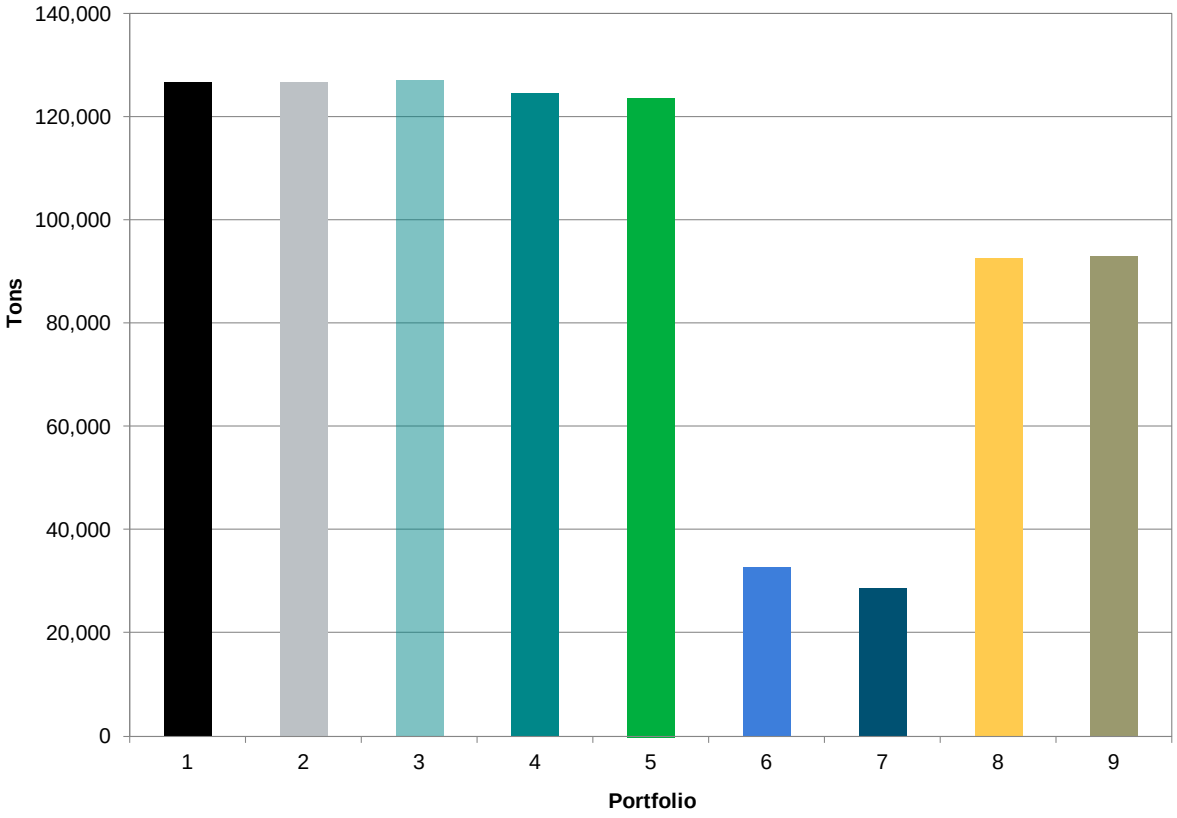


**Figure 9.4 Total $SO_2$ emissions for 2013–2032**

## *Hg Emissions*

Figure 9.5 shows the total Hg emissions for each portfolio analyzed for the 20-year period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced Hg emissions. The reduced emissions are because CCCT resources do not have Hg emissions. Coal fuel contains traces of Hg.

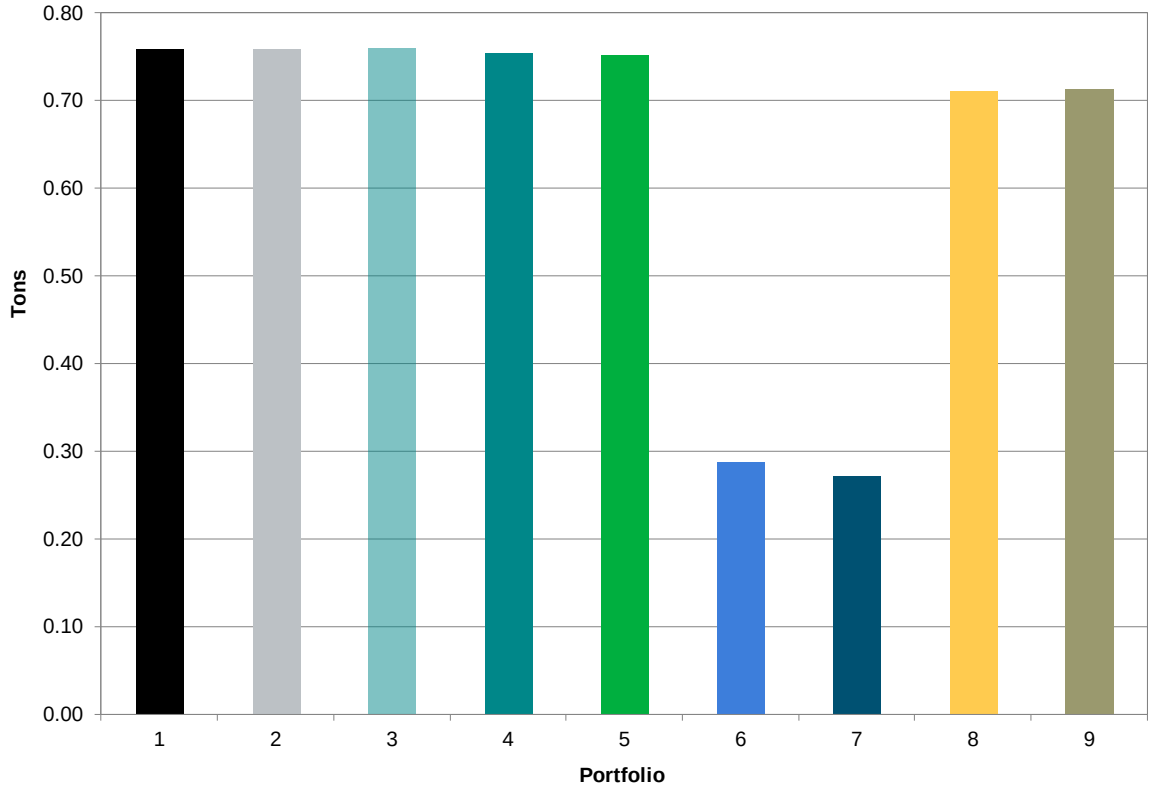


**Figure 9.5 Total Hg emissions for 2013–2032**

## Stochastic Analysis

The stochastic analysis is an extension of the risk analysis of the resource alternatives presented in Chapter 7. The stochastic analysis simulates a variety of possible futures and calculates the resource portfolio performance in each of the futures.

Idaho Power identified the following four variables for the stochastic simulation:

1. *Natural gas price*—The natural gas price follows a log-normal distribution centered on the planning period forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2012. The serial correlation factor is 0.65.

2. *Customer load*—The customer load follows a normal distribution and is correlated with the Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

3. *Hydroelectric variability*—The hydroelectric variability follows a normal distribution. The Idaho Power-owned hydroelectric generation is serial correlated with the Pacific Northwest regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from the 1928 through 2009.

4. *Carbon adder*—Idaho Power and the IRP Advisory Council identified three carbon-adder scenarios: low, planning, and high. Idaho Power stratified the stochastic simulation, and one-third of the stochastic simulations were drawn from each of the three carbon-adder scenarios.

Idaho Power created a set of 102 simulations based on the four stochastic variables. Idaho Power then calculated the TRC of each of the nine resource portfolios for each of the 102 simulations using the Aurora model. Each simulation was reduced to one numerical value—the NPV of the total cost to meet the customer load over the 20-year planning period. Figure 9.6 shows the stochastic simulations.

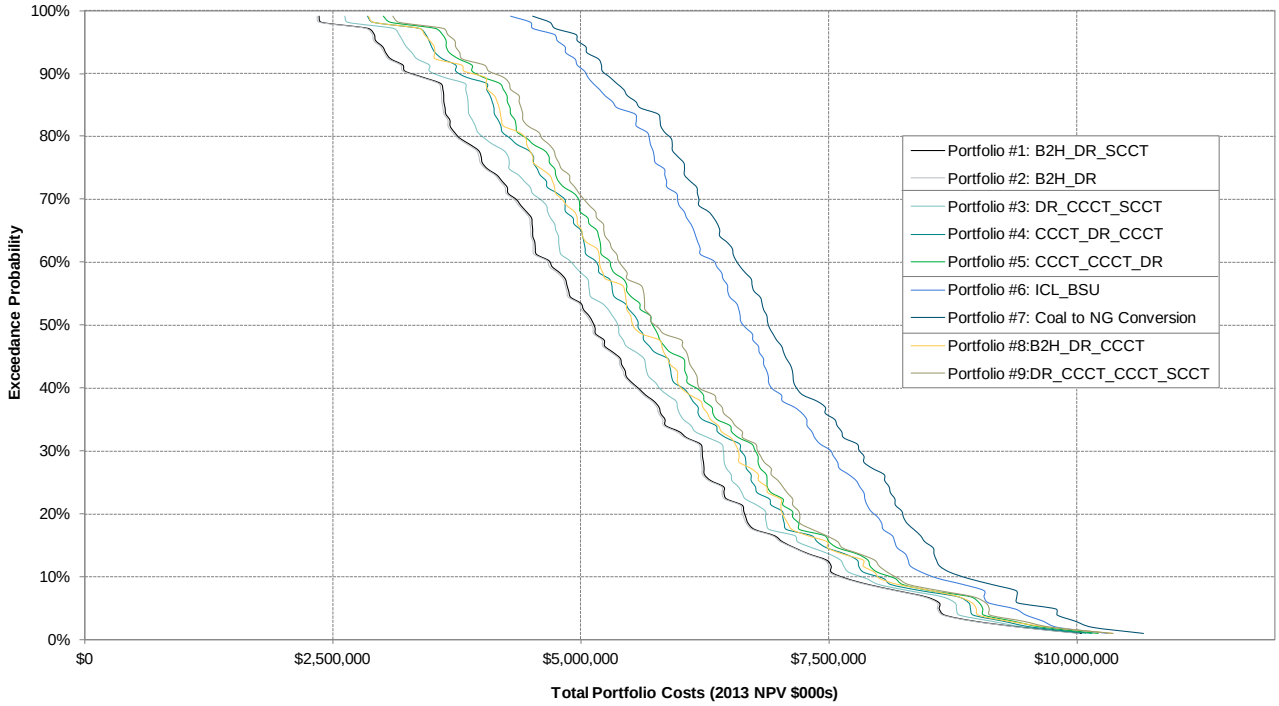


**Figure 9.6 Portfolio stochastic analysis**

Figure 9.6 shows the NPV of the portfolio cost on the horizontal axis and the exceedance probability on the vertical axis. The exceedance probability is the likelihood a resource portfolio will cost more than a certain amount. For example, in 50 percent of the simulations, resource portfolio 2 cost more than approximately $5.2 billion.

Resource portfolio 2, which relies on Boardman to Hemingway and Idaho Power's demand response programs to meet customer load, is the lowest-cost resource portfolio in all the simulations. The resource alternative analysis presented in Chapter 7 indicated that Northwest transmission, such as the Boardman to Hemingway transmission line, is the lowest-cost resource addition. The stochastic analysis confirms the cost-effectiveness of the Boardman to Hemingway line. In general, resource portfolios that contain the Boardman to Hemingway transmission line are less costly than the resource portfolios with alternatives to the Boardman to Hemingway line.

As expected, resource portfolios that replace generation resources cost more than resource portfolios that continue operations at the existing Idaho Power generation facilities. The resource

portfolios replacing all of the coal generation have the highest cost and are represented by the two lines on the right side of the graph.

## Carbon-Adder Analysis

During the IRP Advisory Council meetings in April and May, several IRP Advisory Council members questioned the effect of carbon-adder prices on Idaho Power's resource acquisition decisions. As described previously, the stochastic results demonstrated that resource portfolio 2 is the preferred resource portfolio. The IRP Advisory Council members' question was, "At what carbon adder does Idaho Power choose a different resource portfolio than resource portfolio 2?"

Idaho Power analyzed the IRP Advisory Council's question by increasing the price of the carbon adder beyond the values selected for the high-carbon scenario and extrapolated the trends in resource portfolio costs. The supplemental carbon analysis focuses on two of the resource portfolios: the preferred resource portfolio—resource portfolio 2—and the lowest-cost coal-retirement resource portfolio—resource portfolio 6. (Resource portfolio 6 was suggested by IRP Advisory Council members representing the ICL and BSU.) The results of the analysis are shown in Figure 9.7.

Figure 9.7 shows that at a carbon adder of approximately $45 per ton in 2018, the preferred resource portfolio would change from resource portfolio 2 to resource portfolio 6. (In 2018, the IRP high-carbon scenario has a value of $35 per ton.) The supplemental carbon analysis shows that sufficiently high carbon prices can affect Idaho Power resource acquisition decisions. Much lower carbon-adder values can affect the daily resource dispatch decisions under certain conditions as described previously in the Carbon Adder section.

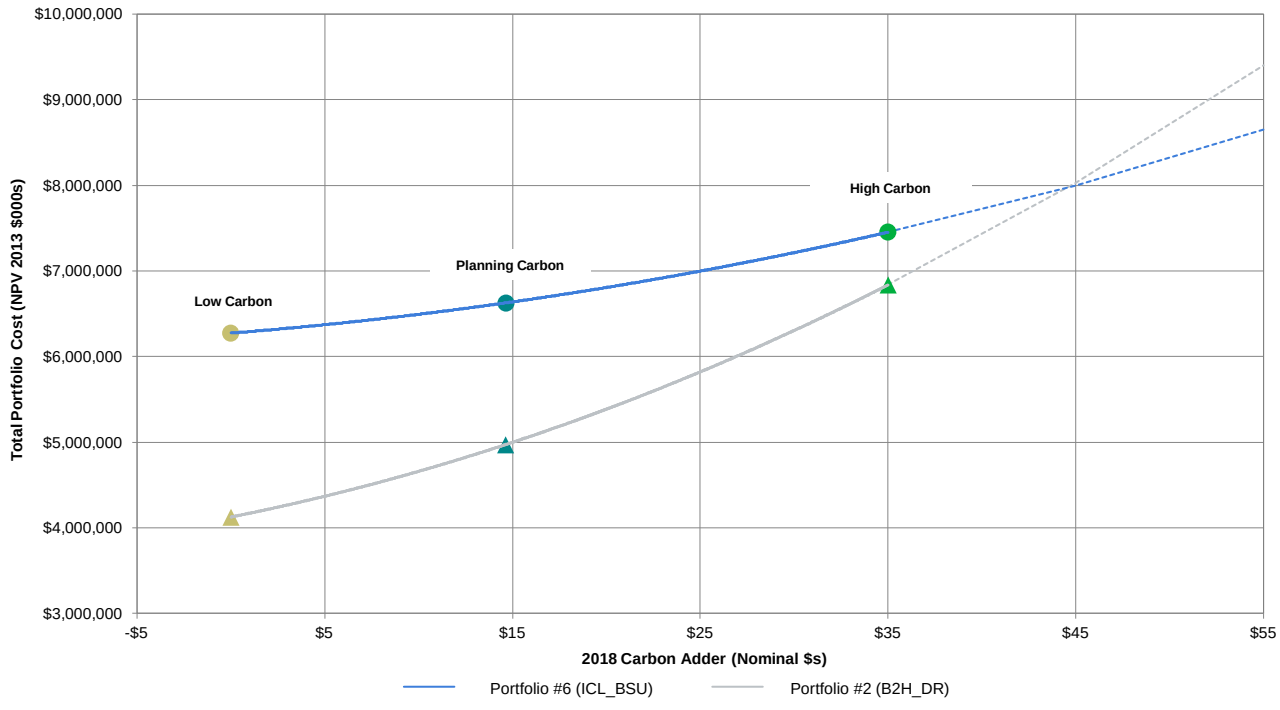


**Figure 9.7 Stochastic-based carbon-adder tipping point**

## Capacity Planning Margin

Idaho Power discussed planning criteria with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2013 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected-case ($50^{th}$-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case ($50^{th}$-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin is also roughly equivalent to a loss-of-load expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.3.

## Table 9.3 Capacity planning margin

| | July 13 | July 14 | July 15 | July 16 | July 17 | July 18 | July 19 | July 20 | July 21 | July 22 | July 23 | July 24 | July 25 | July 26 | July 27 | July 28 | July 29 | July 30 | July 31 | July 32 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | | | | | | | | | | | | | | | | | | | | |
| **Peak-Hour Forecast (50th%)** | (3,189) | (3,245) | (3,294) | (3,335) | (3,387) | (3,437) | (3,489) | (3,544) | (3,601) | (3,651) | (3,701) | (3,748) | (3,790) | (3,836) | (3,888) | (3,936) | (3,984) | (4,045) | (4,097) | (4,147) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | | | | | |
| Jim Bridger | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| North Valmy | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 |
| Boardman | 58 | 58 | 58 | 58 | 58 | 58 | 58 | 58 | – | – | – | – | – | – | – | – | – | – | – | – |
| **Coal Total** | **1,024** | **1,024** | **1,024** | **1,024** | **1,024** | **1,024** | **1,024** | **1,024** | **966** | **966** | **966** | **966** | **966** | **966** | **966** | **966** | **966** | **966** | **966** | **966** |
| **Gas** | | | | | | | | | | | | | | | | | | | | |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **Gas Total** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** | **300** |
| **Hydroelectric** | | | | | | | | | | | | | | | | | | | | |
| Hydroelectric (50th%)—HCC | 1,170 | 1,168 | 1,168 | 1,165 | 1,162 | 1,160 | 1,157 | 1,154 | 1,151 | 1,148 | 1,145 | 1,142 | 1,139 | 1,136 | 1,133 | 1,133 | 1,133 | 1,133 | 1,133 | 1,133 |
| Hydroelectric (50th%)—Other | 311 | 311 | 311 | 311 | 310 | 310 | 309 | 309 | 308 | 307 | 307 | 306 | 306 | 305 | 304 | 304 | 304 | 304 | 304 | 304 |
| Shoshone Falls Upgrade (50th%) | – | – | – | – | – | – | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Shoshone–Bannock Water Lease | 48 | 48 | 48 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| **Hydroelectric Total (50th%)** | **1,529** | **1,526** | **1,527** | **1,476** | **1,473** | **1,470** | **1,468** | **1,465** | **1,461** | **1,458** | **1,454** | **1,450** | **1,447** | **1,443** | **1,440** | **1,440** | **1,440** | **1,440** | **1,440** | **1,440** |
| **CSPP (PURPA) Total** | **177** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** | **189** |
| **PPAs** | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Clatskanie Exchange—Take | 6 | 6 | 6 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Clatskanie Exchange—Return | 0 | 0 | 0 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| **PPAs Total** | **41** | **41** | **41** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** | **35** |

**Table 9.3 Capacity planning margin (continued)**

| | July 13 | July 14 | July 15 | July 16 | July 17 | July 18 | July 19 | July 20 | July 21 | July 22 | July 23 | July 24 | July 25 | July 26 | July 27 | July 28 | July 29 | July 30 | July 31 | July 32 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Pacific Northwest Import Capability Total** | 194 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 290 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 | 237 |
| **Gas Peakers Total** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,681 | 3,733 | 3,733 | 3,676 | 3,673 | 3,670 | 3,669 | 3,665 | 3,657 | 3,601 | 3,597 | 3,593 | 3,590 | 3,586 | 3,582 | 3,582 | 3,582 | 3,582 | 3,582 | 3,582 |
| **Monthly Surplus/Deficit** | 492 | 488 | 439 | 341 | 286 | 233 | 180 | 122 | 56 | (50) | (104) | (155) | (201) | (250) | (306) | (354) | (402) | (462) | (515) | (564) |
| **2013 IRP DSM (Energy Efficiency)** | | | | | | | | | | | | | | | | | | | | |
| Irrigation | 3 | 6 | 8 | 10 | 11 | 13 | 15 | 17 | 20 | 22 | 26 | 29 | 33 | 38 | 43 | 48 | 54 | 56 | 58 | 61 |
| Commercial | 7 | 13 | 20 | 25 | 30 | 36 | 41 | 47 | 53 | 60 | 67 | 74 | 80 | 86 | 92 | 98 | 104 | 109 | 114 | 119 |
| Residential | 0 | 0 | 1 | 2 | 3 | 6 | 9 | 8 | 8 | 8 | 9 | 11 | 14 | 18 | 23 | 29 | 33 | 38 | 42 | 46 |
| **Total New DSM Peak Reduction** | 10 | 20 | 29 | 37 | 45 | 55 | 65 | 72 | 80 | 91 | 101 | 114 | 127 | 142 | 158 | 175 | 191 | 202 | 214 | 226 |
| **Remaining Monthly Surplus/Deficit** | 502 | 507 | 468 | 377 | 331 | 288 | 244 | 193 | 137 | 41 | (3) | (41) | (73) | (108) | (148) | (179) | (211) | (260) | (300) | (338) |
| **2013 IRP Resources** | | | | | | | | | | | | | | | | | | | | |
| 2016 Demand Response | – | – | – | 150 | 150 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| 2018 Boardman to Hemingway | – | – | – | – | – | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2024 Demand Response | – | – | – | – | – | – | – | – | – | – | – | 370 | 370 | 370 | 370 | 370 | 370 | 370 | 370 | 370 |
| **New Resource Subtotal** | 0 | 0 | 0 | 150 | 150 | 500 | 500 | 500 | 500 | 500 | 500 | 870 | 870 | 870 | 870 | 870 | 870 | 870 | 870 | 870 |
| **Remaining Monthly Surplus/Deficit** | 502 | 507 | 468 | 527 | 481 | 788 | 744 | 693 | 637 | 541 | 497 | 829 | 797 | 762 | 722 | 691 | 659 | 610 | 570 | 532 |
| **Planning Margin** | 16% | 16% | 14% | 16% | 14% | 23% | 21% | 20% | 18% | 15% | 13% | 22% | 21% | 20% | 19% | 18% | 17% | 15% | 14% | 13% |

## Flexible Resource Needs Assessment

In Order No. 12-013 issued on January 19, 2012, as part of Docket No. UM 1461 on the "Investigation of Matters related to Electric Vehicle Charging," the OPUC adopted the following staff-proposed guidelines:

1. *Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.*

2. *Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.*

3. *Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.*

Idaho Power relies primarily on its hydroelectric system to meet reserve requirements. Increases in Idaho Power's reserve requirements due to load-growth projections can be adequately handled with the existing hydroelectric generation.

Changes in intermittent resources, such as wind generation, will be the primary driver of future reserve requirements. Idaho Power's *Wind Integration Study Report*[4] details the effects of adding additional wind capacity to the Idaho Power system. The balancing requirements for various levels of wind integration are documented along with an estimated cost for integration at those levels.

Idaho Power has reviewed the guidelines and the preferred resource portfolio—resource portfolio 2. Specifically, resource portfolio 2 proposed to add no new intermittent renewable generation over the 20-year planning horizon. Idaho Power does not forecast a significant increase in intermittent generation from PURPA or a significant increase in intermittent renewable generation from the customer programs. Idaho Power does not forecast a need to increase flexible capacity associated with implementing resource portfolio 2.

Resource portfolio 2 adds two resources—the Boardman to Hemingway transmission line and demand response programs. Resource portfolio 2 is not expected to increase the supply of flexible resources over the 20-year planning horizon.

[4] The *Wind Integration Study Report* can be found on Idaho Power's website at: http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf

Idaho Power does not project a gap between demand and the supply of flexible capacity. Electric vehicles are not expected to significantly affect the Idaho Power load and resource balance over the 20-year planning horizon. The effect of electric vehicles over the 20-year planning period is described in *Appendix A—Sales and Load Forecast*.

## Loss of Load Expectation

Idaho Power used a spreadsheet model[5] to calculate the LOLE for the nine portfolios identified in the 2013 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred portfolio. As mentioned in the previous section, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require the use of the transmission capacity. The 2013 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator and purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load for the 10 peak hours in a given year. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power chose to calculate a LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5 to 1 hour per year.

The results of the LOLE probability analysis are shown in Figure 9.8. Several portfolios result in a LOLE greater than two, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The LOLE in 2031 is high for many portfolios due to the number of high load days and the assumptions made for demand response (only available for 10 peak days). The results indicate that resource portfolios 1 and 2 perform well over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

[5] Based on Roy Billinton's *Power System Reliability Evaluation*, chapters 2 and 3. 1970.

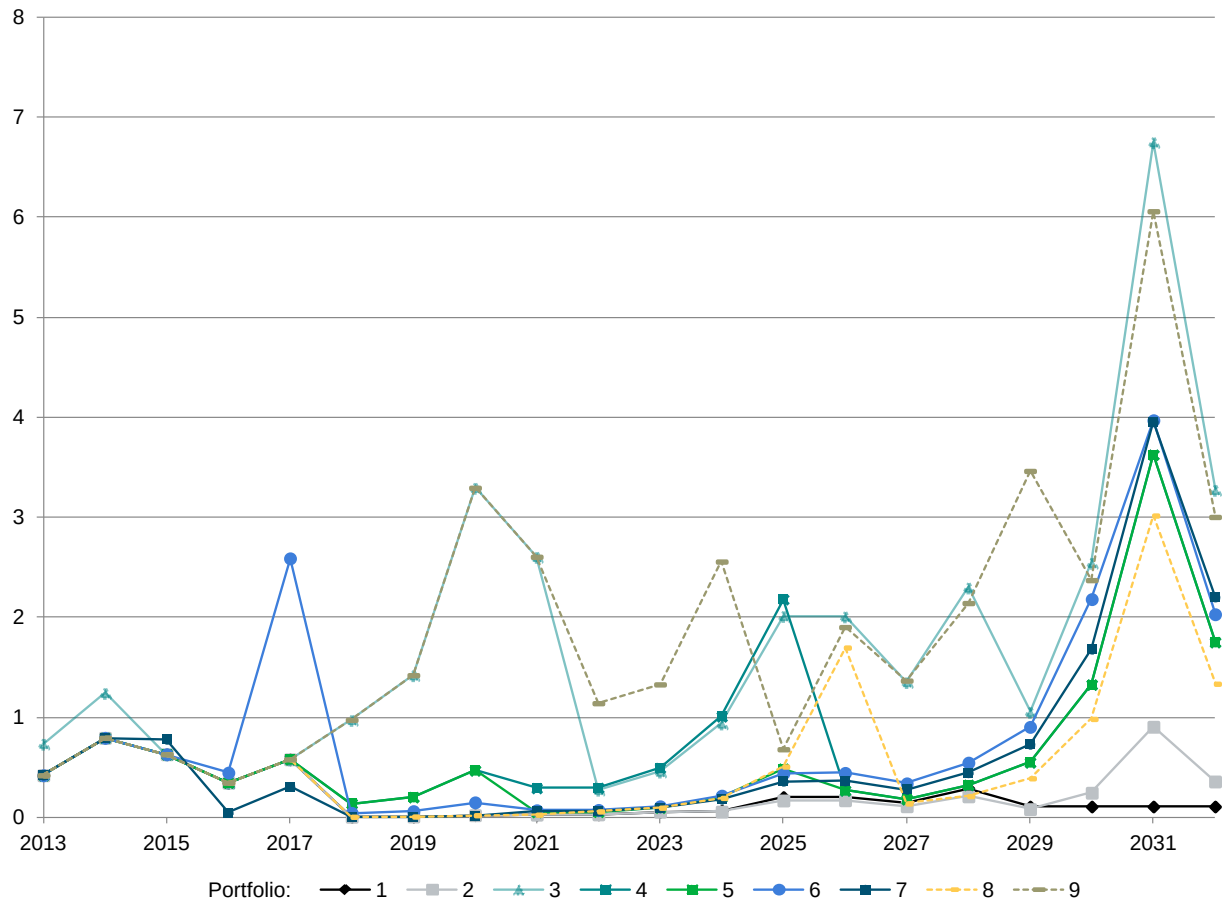


**Figure 9.8 LOLE (hours per year)**

## Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In 2005, the NWPCC and the BPA created the Resource Adequacy Forum and asked the forum develop an adequacy standard for the Pacific Northwest regional power supply (Idaho Power participates as a member of the Resource Adequacy Forum). The purpose of the resource adequacy standard is to provide an early warning should resource development fail to keep pace with demand growth. The analytical information generated with each resource adequacy assessment assists the regional utilities when preparing their individual IRPs.

The NWPCC assesses the adequacy of the regional power supply annually. The latest assessment assumes the existing resources and conservation levels identified in the NWPCC 6th power plan, and the resource assessment shows the regional power supply to be slightly inadequate by 2017 (NWPCC document no. 2012-12). The adequacy assessment notes that adding 350 MW of dispatchable resource capacity brings the Pacific Northwest resource adequacy back within the 5 percent adequacy standard. The adequacy assessment indicates that the majority of potential problems are short-term capacity deficits. The regional resource assessment is available from the NWPCC at:

http://www.nwcouncil.org/energy/resource/2012-12/

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2013 IRP analysis indicates Idaho Power resource deficits occur in the summer months of June, July, August, and September. July is the most critical month for Idaho Power. The Northwest Regional Adequacy Assessment indicates that January, February, and, to a lesser extent, August are the most critical months for the overall Pacific Northwest region. The Boardman to Hemingway transmission line is a regional resource that will assist Idaho Power and the larger Pacific Northwest in addressing their opposing seasonal capacity deficits.

The Idaho Power resource planning process is consistent with the NWPCC resource adequacy studies. The Idaho Power stochastic analysis indicates that even under high load, high electricity prices, and low water conditions, resource portfolio 2 (containing the Boardman to Hemingway transmission project) is the lowest-cost resource alternative.

# 10. ACTION PLAN

## Action Plan (2013–2032)

Resource portfolio 2 is the preferred resource portfolio. The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was mentioned as early as the 2000 IRP, and the upgrade was specifically identified in the 2006 IRP. Idaho Power continues efforts to acquire the necessary regulatory approvals and permits to begin construction. Construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018. The action plan to implement resource portfolio 2 is shown in Table 10.1.

**Table 10.1 Portfolio 2 action plan**

| Year | Resource | Action |
|---|---|---|
| 2013–2018 | Boardman to Hemingway | Ongoing permitting, planning studies, and regulatory filings. |
| 2013– | Gateway West | Ongoing permitting, planning studies, and regulatory filings. |
| 2013 | North Valmy Unit 1 | Commit to the installation of dry sorbent injection emission-control technology. |
| 2013 | Jim Bridger Units 3 and 4 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2016–2017 | Demand response | Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. |
| 2018 | Boardman to Hemingway | Transmission line complete and in service. |
| 2019 | Shoshone Falls | Shoshone Falls upgrade complete and in service. |
| 2019 | Jim Bridger Unit 2 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2020 | Jim Bridger Unit 1 | Commit to the installation of selective catalytic reduction emission-control technology. |
| 2020 | Boardman | Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020. |
| 2024–2032 | Demand response | Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031. |

Idaho Power continues efforts to acquire the necessary regulatory approvals and permits for the Gateway West project. As discussed in Chapter 6, Gateway West will relieve transmission constraints and provide the option to locate future generation resources east of the Treasure Valley load center.

For the purpose of this resource plan, the company's demand response programs are assumed to be used throughout the planning period to meet resource needs. Idaho Power expects to use up to 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission line in 2018. Idaho Power applied demand response in approximate 50-MW steps for the 2013 IRP. In the analysis, Idaho Power tailored the level of demand response to the identified deficit. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The level of demand response projected for 2016 was approximately 100 MW and approximately 150 MW in 2017. Idaho Power plans to have a demand response

capacity available beginning in 2024 of up to approximately 370 MW by 2031. Like the 2016 to 2017 time period, demand response for later time periods was applied in 50-MW increments for the resource portfolio analysis. The level of demand response capacity available will be based on the deficits identified through the IRP process or based on operational needs identified between IRP cycles.

The Boardman to Hemingway transmission line is a significant interstate construction project with federal, state, and local permitting and line routing issues. In addition, the project has multiple business partners, which further complicates project management and scheduling. Idaho Power intends to use the demand response programs to adapt to schedule variations that may occur on the Boardman to Hemingway project.

Resource portfolio 2—the preferred resource portfolio—includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to their installation and operation. The approximate financial commitment dates are identified in the action plan.

Idaho Power can develop and own generation assets, rely on PPA and market purchases to supply the electricity needs of its customers, or use a combination of the two ownership strategies. Idaho Power expects to continue participating in the regional power market and enter into mid-term and long-term PPAs. However, when pursuing PPAs, Idaho Power must be mindful of imputed debt and its potential impact on Idaho Power's credit rating. In the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate-of-return advantages inherent in a regulated electric utility.

## Conclusion

The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission project has outperformed the other resource portfolios in the 2013 IRP. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.



Wild horses near the Hemingway Substation.

The 2013 IRP confirms that the Boardman to Hemingway transmission line is a very cost-effective resource. The Resource Alternatives Analysis section of the 2013 IRP indicates that the Boardman to Hemingway line is more cost effective than the other supply-side resources studied. Chapter 9 of the 2013 IRP indicates that resource portfolios containing the Boardman to

Hemingway line are more cost effective than resource portfolios containing alternatives to the Boardman to Hemingway line.

Idaho Power treated the Boardman to Hemingway Transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates that it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

The company's demand response programs will be used throughout the planning period to meet resource needs. The level of demand response capacity available will be based on the deficits identified through the IRP process or on operational needs identified between IRP cycles. The demand response programs may also be used to adapt to schedule variations that may occur on the Boardman to Hemingway transmission project.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRP Advisory Council members and the public for their contributions to the 2013 IRP. The IRP Advisory Council discussed many technical aspects of the 2013 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to Idaho Power facilities. Idaho Power's resource plan is better because of the contributions from the IRP Advisory Council members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates that the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

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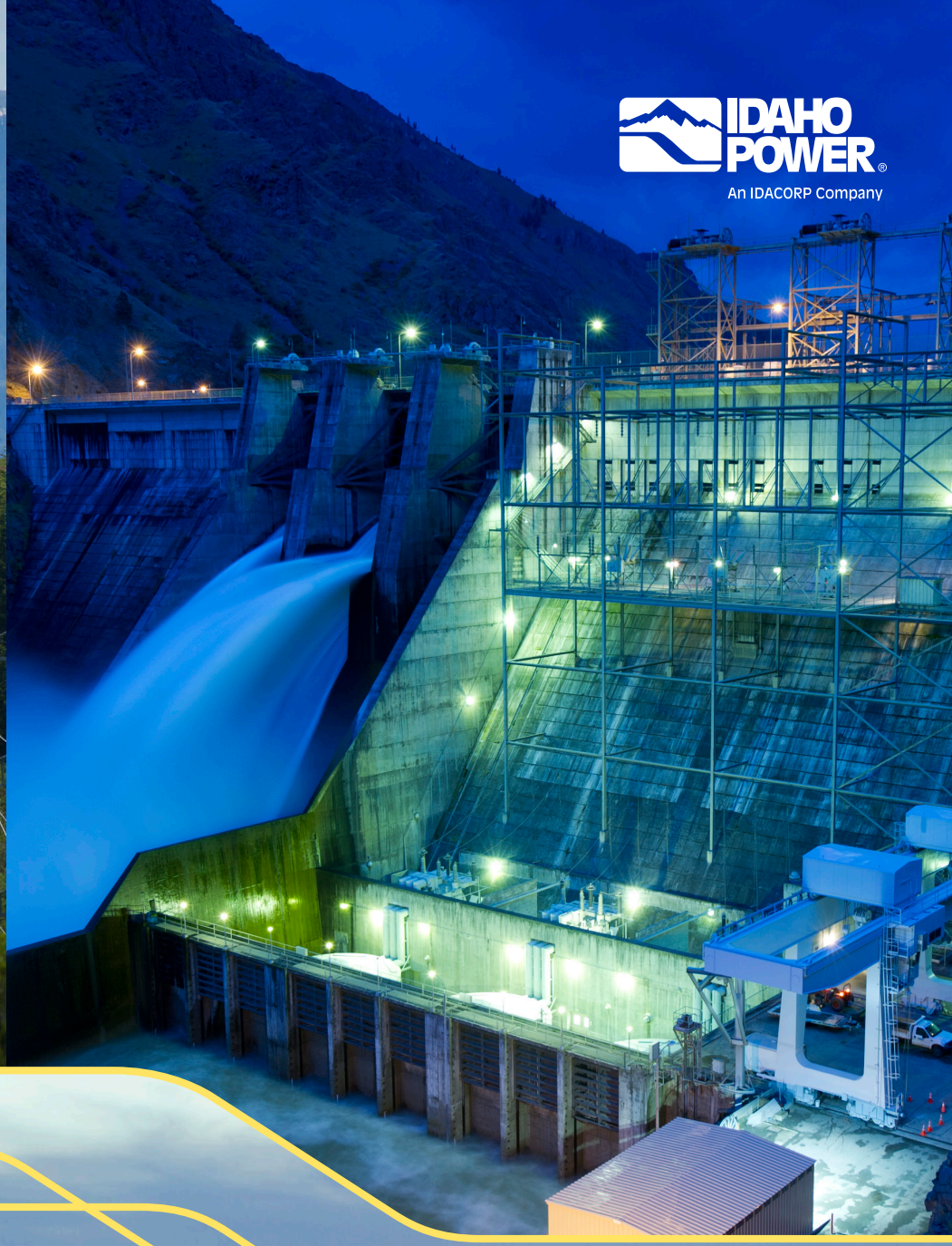

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# 2013 Integrated Resource Plan

## APPENDIX A

# Sales and Load Forecast

June 2013

# 2013

# Integrated Resource Plan

## APPENDIX A

# Sales and Load Forecast

**June 2013**

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## ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the Advisory Council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.


## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.


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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... ii
List of Figures ..... ii
List of Appendices ..... iii
Introduction ..... 1
2013 IRP Sales and Load Forecast ..... 3
Average Load ..... 3
Peak-Hour Demands ..... 4
Overview of the Forecast ..... 7
Fuel Prices ..... 7
Electric Vehicles ..... 10
Forecast Probabilities ..... 11
Load Forecasts Based on Weather Variability ..... 11
Load Forecasts Based on Economic Uncertainty ..... 12
Residential ..... 15
Commercial ..... 17
Irrigation ..... 21
Industrial ..... 25
Additional Firm Load ..... 27
Micron Technology ..... 28
Simplot Fertilizer ..... 28
Idaho National Laboratory ..... 28
Hoku Materials ..... 28
"Special" Contract ..... 28
Company System Peak ..... 29
Company System Load ..... 31
Contract Off-System Load ..... 33
Energy Efficiency and Demand Response ..... 35
Energy Efficiency ..... 35
Demand Response ..... 36

# LIST OF TABLES

Table 1. Residential fuel-price escalation (2013–2032) (average annual percent change) ....8
Table 2. Average load and peak-demand forecast scenarios ....12
Table 3. Forecast probabilities ....13
Table 4. System load growth (aMW) ....14
Table 5. Residential load growth (aMW) ....15
Table 6. Commercial load growth (aMW) ....17
Table 7. Irrigation load growth (aMW) ....21
Table 8. Industrial load growth (aMW) ....25
Table 9. Additional firm load growth (aMW) ....27
Table 10. System summer peak load growth (MW) ....29
Table 11. System winter peak load growth (MW) ....30
Table 12. System load growth (aMW) ....31

# LIST OF FIGURES

Figure 1. Forecast residential electricity prices (cents per kWh) ....9
Figure 2. Forecast residential natural gas prices (dollars per therm) ....10
Figure 3. Forecast system load (aMW) ....14
Figure 4. Forecast residential load (aMW) ....15
Figure 5. Forecast residential use per customer (weather-adjusted kWh) ....16
Figure 6. Forecast commercial load (aMW) ....17
Figure 7. Forecast commercial use per customer (weather-adjusted kWh) ....18
Figure 8. Forecast irrigation load (aMW) ....21
Figure 9. Forecast industrial load (aMW) ....25
Figure 10. Industrial electricity consumption by industry group (based on 2012 figures) ....26
Figure 11. Forecast additional firm load (aMW) ....27
Figure 12. Forecast system summer peak (MW) ....29
Figure 13. Forecast system winter peak (MW) ....30
Figure 14. Forecast system load (aMW) ....31
Figure 15. Composition of system company electricity sales (thousands of MWh) ....32

# LIST OF APPENDICES

Appendix A1. Historical and Projected Sales and Load ....37
Residential Load ....37
Historical Residential Sales and Load, 1972–2012 (weather adjusted) ....37
Projected Residential Sales and Load, 2013–2032 ....38
Commercial Load ....39
Historical Commercial Sales and Load, 1972–2012 (weather adjusted) ....39
Projected Commercial Sales and Load, 2013–2032 ....40
Irrigation Load ....41
Historical Irrigation Sales and Load, 1972–2012 (weather adjusted) ....41
Projected Irrigation Sales and Load, 2013–2032 ....42
Industrial Load ....43
Historical Industrial Sales and Load, 1972–2012 (weather adjusted) ....43
Projected Industrial Sales and Load, 2013–2032 ....44
Additional Firm Sales and Load* ....45
Historical Additional Firm Sales and Load, 1972–2012 ....45
Projected Additional Firm Sales and Load, 2013–2032 ....46
Company System Load (excluding Astaris) ....47
Historical Company System Sales and Load, 1972–2012 (weather adjusted) ....47
Company System Load (including Astaris) ....48
Historical Company System Sales and Load, (1972–2012) (weather adjusted) ....48
Astaris Sales and Load (1972–2002) (weather adjusted) ....48
Projected Company System Sales and Load, 2013–2032 ....49

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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as an appendix to its *2013 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2013 through 2032.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Because actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered: a 70$^{th}$-percentile average load forecast and 90$^{th}$-percentile average load forecast. The 70$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,154 average megawatts (aMW) in the year 2032 from the 2013 forecast load of 1,759 aMW. The expected-case forecast system load growth rate averages 1.1 percent per year over the 20-year planning period (2013–2032). In the more critical 70$^{th}$-percentile load forecast used for resource planning, the system load is forecast to reach 2,201 aMW by 2032. The Idaho Power system peak load (95$^{th}$ percentile) is forecast to grow to 4,418 megawatts (MW) in the year 2032 from the actual system summer peak of 3,245 MW that occurred on Thursday, July 12, 2012, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2013–2032). The number of Idaho Power active retail customers is expected to increase from the December 2012 level of 500,000 customers to over 667,000 customers at year-end 2032.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced *Appendix A—Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service

area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated into the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A—Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2012 Annual Report*. This report is Appendix B to the 2013 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon regulations and subsequent higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high- and low-load growth scenarios previously described. The impact of carbon legislation on the load forecast is reflected in retail electricity prices, which are a driver in the major sector sales forecasting model. The alternative sales and load scenarios of *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for the sales and load forecast is presented in Appendix A1 of this report.

# 2013 IRP Sales and Load Forecast

## Average Load

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery reflected in the economic forecast used for the 2011 IRP was determined too optimistic in terms of a rapid recovery from the recession. The updated variables driving the 2013 forecast reflect this recent performance. The stalled recovery in the national and, to a lesser extent, service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series to date. Longer-term, higher-retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2013 IRP load forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability new customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

## Peak-Hour Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

- As referenced previously, the 2011 IRP sales and load forecast included a new customer referred to as "Special" that failed to materialize. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 60 MW of peak demand originally anticipated is excluded from this sales and load forecast.

- The 2013 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2013 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts to effectively plan for demand response and supply-side resources in meeting peak demand. Demand response programs impacts are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the $50^{th}$, $90^{th}$, and $95^{th}$ percentiles of occurrence for each month of the year.

- Historical peak-demand data is considered in the peak-model regressions. Based on a historical comparison of percentiles, the July 2002, July 2003, June 2005, and July 2005 peak-day temperatures were near the $100^{th}$ percentile, and their addition to the regression models impacted forecast results. More recently, all-time system peaks were reached in July 2007, June 2008, and July 2012 and were incorporated into the peak forecast model regressions.

- Idaho Power continues to use a median peak-day temperature driver in lieu of an average peak-day temperature driver. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1982 to 2011 time period (the most recent 30 years).

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# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); the Idaho National Laboratory (INL); and Hoku Materials. These four special-contract customers are combined into a single forecast category labeled additional firm load. Last, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2013 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space-heating demand that normally occurs in December, January, or February; and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning (A/C) use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

## Fuel Prices

Fuel prices, in combination with service-area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future

demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2013–2032) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2013 IRP | 3.2% | 1.3% |
| Electricity—2011 IRP | 1.5% | (0.1%) |
| Natural Gas | 3.2% | 1.3% |

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1972 to 2012 and over the forecast period 2013 to 2032. Both nominal and real prices are shown. In the 2013 IRP, nominal electricity prices are expected to climb to nearly 17 cents per kilowatt-hour (kWh) by the end of the forecast period in 2032. Real electricity prices (inflation adjusted) are expected to increase over the forecast period at an average rate of 1.3 percent annually. In the 2011 IRP, nominal electricity prices were assumed to slowly climb to nearly 13 cents per kWh by 2032, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of -0.1 percent annually. The impact of the higher real electricity price forecast on the 2013 IRP load forecast serves to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yielded higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

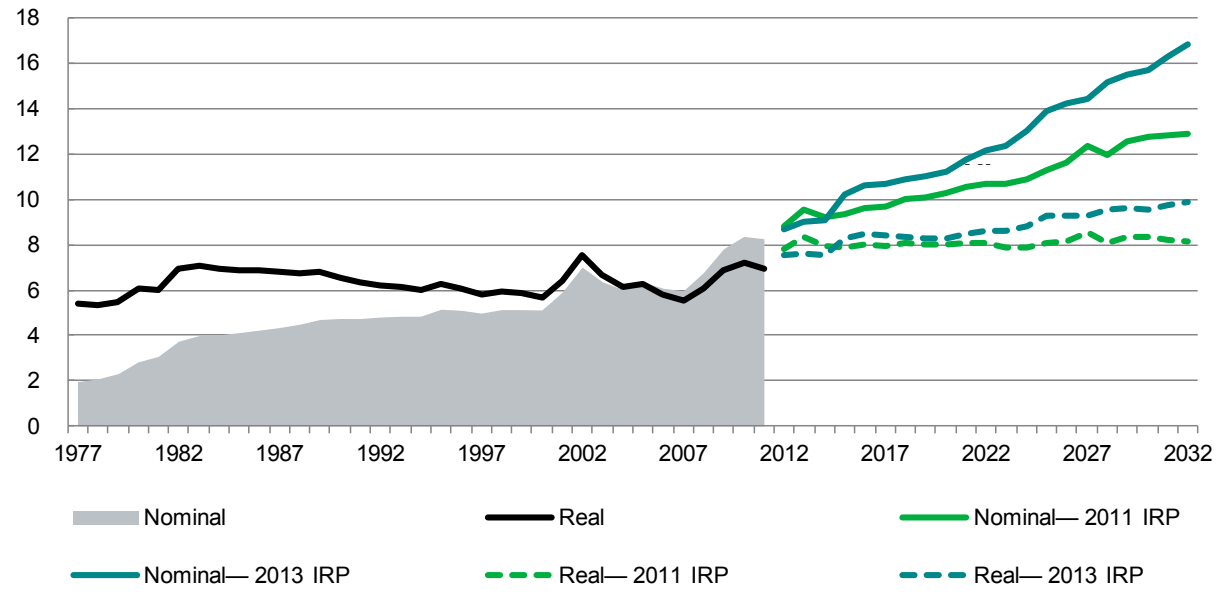


**Figure 1. Forecast residential electricity prices (cents per kWh)**

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970 to 2011 and forecast prices from 2012 to 2032. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. The collapse in natural gas prices that began in 2009 led to much lower prices in 2010 and 2011. Nominal natural gas prices are expected to rise slowly through 2014, then more rapidly throughout the remainder of the forecast period until nearly doubling at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

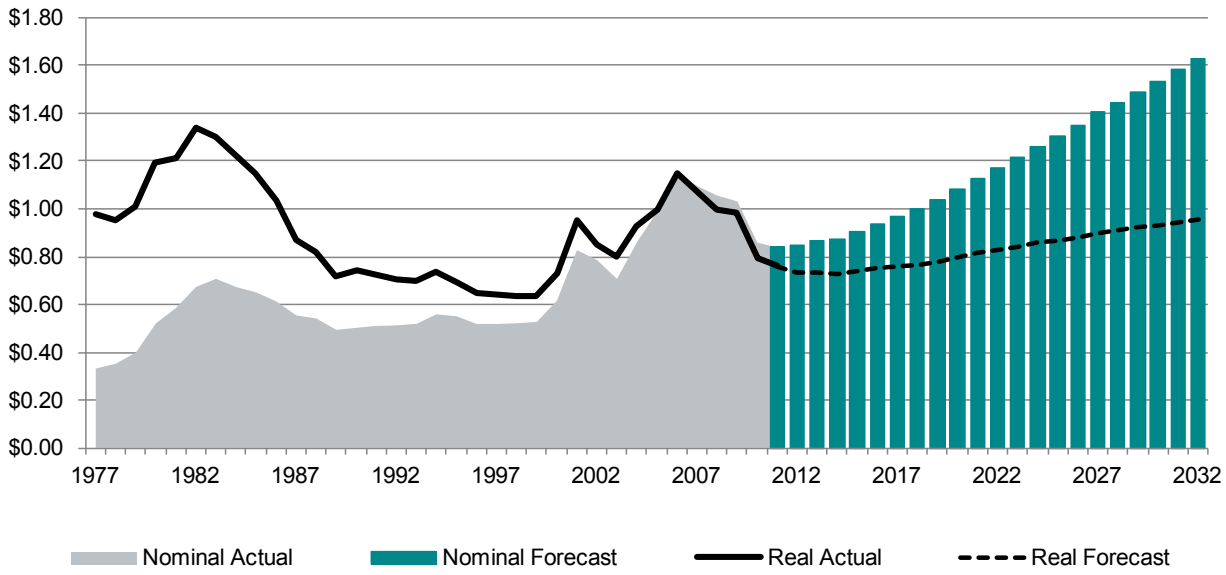


**Figure 2. Forecast residential natural gas prices (dollars per therm)**

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2013 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles on the system load. The 2011 IRP forecast model relied heavily on the forecast methodologies of the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory. At the time, these models did not have actual consumer adoption data or most recent domestic fuel supply impacts of advanced technologies in crude oil production. The 2013 IRP electric-vehicle forecast update integrates service area vehicle registration data with updated technological and economic variables impacting adoption, as well as vehicle charging behavior. This update also integrates the fuel and technology forecasts of the Department of Energy's (DOE) National Energy Model (NEM).

The Idaho Power vehicle share forecast is based on a Bass diffusion model of adoption as informed by actual vehicle registration. Load impacts from adoption are derived from assumptions of battery-only and hybrid plug-in shares evident from historical registration data and informed by NEM forecasts. The combined vehicle forecast represents just over 4 percent of new vehicle sales in the service area at the end of the planning period. Battery-only vehicles represent 15 percent of the total, and the updated forecast model reflects a much slower adoption rate than anticipated in the 2011 forecast. The all-electric share is consistent with the DOE Annual Energy Outlook (AEO) 2013 update that forecasts all-electric vehicles at less than 1 percent of sales in 2040.

The resulting impact on the load forecast is about 1 aMW in 2020, reaching approximately 4 aMW at the end of the forecast period in 2032. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, respectively.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption to improve the forecasting model in future forecasts.

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation (i.e., there is a 50-percent chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1982 to 2011 (the most recent 30 years) was 1,039. The 70$^{th}$-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90$^{th}$-percentile HDD is 1,291 and would be exceeded in 1 out of 10 years. The 100$^{th}$-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$-percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is

important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70th-percentile or 90th-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th-percentile or 90th-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2013 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

| Scenario | Weather Probability | Probability of Exceeding | Weather Driver |
|---|---|---|---|
| **Forecasts of Average Load** | | | |
| 90th Percentile | 90% | 1-in-10 years | HDD, CDD, GDD, precipitation |
| 70th Percentile | 70% | 3-in-10 years | HDD, CDD, GDD, precipitation |
| Expected Case | 50% | 1-in-2 years | HDD, CDD, GDD, precipitation |
| **Forecasts of Peak Demand** | | | |
| 95th Percentile | 95% | 1-in-20 years | Peak-day temperatures |
| 90th Percentile | 90% | 1-in-10 years | Peak-day temperatures |
| 50th Percentile | 50% | 1-in-2 years | Peak-day temperatures |

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

## *Load Forecasts Based on Economic Uncertainty*

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2013 to 2032 planning period due to high and low economic and demographic conditions. The high- and low-economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1987–2011).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1987–2011). The high- and low-case load forecasts also reflect the integration of existing energy efficiency DSM program effects as a reduction to the average load wintertime forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

| Probability of Exceeding | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 90% | 90% | 90% | 90% |
| Expected Case | 50% | 50% | 50% | 50% |
| High Growth | 10% | 10% | 10% | 10% |
| **Probability of Occurrence** | | | | |
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 26% | 26% | 26% | 26% |
| Expected Case | 48% | 48% | 48% | 48% |
| High Growth | 26% | 26% | 26% | 26% |

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser).

Idaho Power system load projections are reported in Table 4 and pictured in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.5 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover

approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Low | 1,738 | 1,760 | 1,826 | 1,949 | 0.6% |
| Expected | 1,759 | 1,842 | 1,956 | 2,154 | 1.1% |
| High | 1,829 | 1,972 | 2,145 | 2,447 | 1.5% |

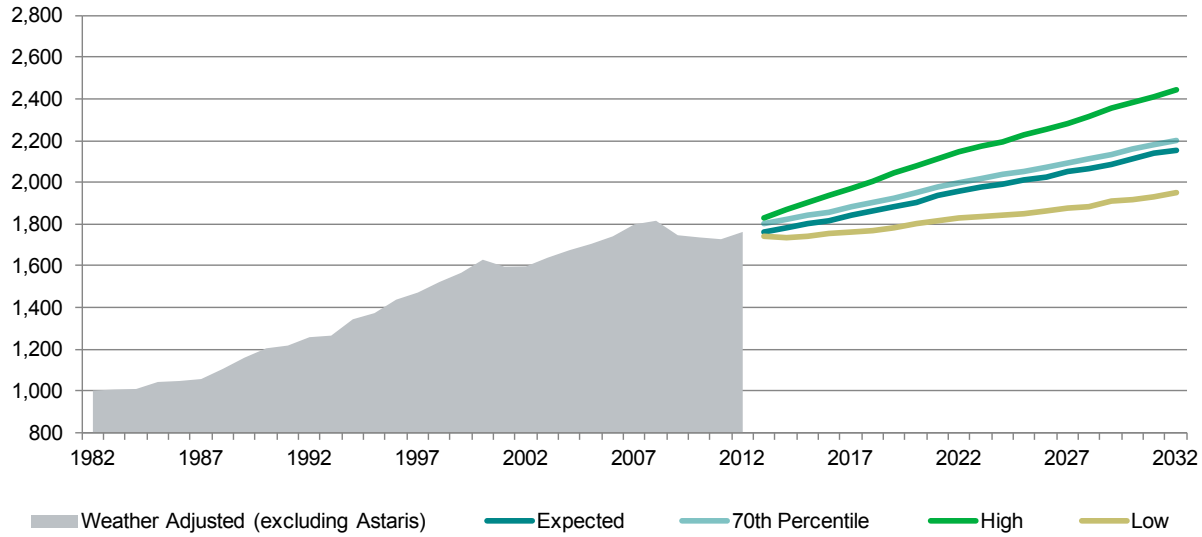


**Figure 3. Forecast system load (aMW)**

# RESIDENTIAL

The expected-case residential load is forecast to increase from 574 aMW in 2013 to 704 aMW in 2032, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 590 aMW in 2013 to 724 aMW in 2032, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

**Table 5. Residential load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90th Percentile | 623 | 649 | 687 | 763 | 1.1% |
| 70th Percentile | 590 | 614 | 650 | 724 | 1.1% |
| Expected Case | 574 | 597 | 632 | 704 | 1.1% |

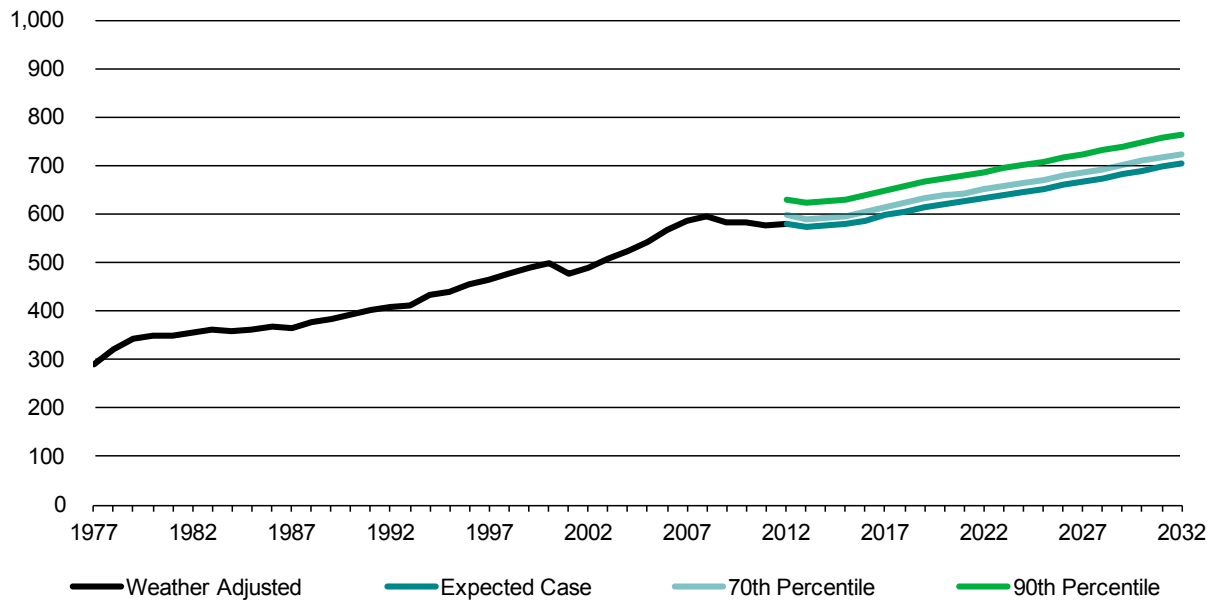


**Figure 4. Forecast residential load (aMW)**

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1982 and 36 percent of system sales in 2012. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2032. There were 416,000 residential customers as of December 2012. The number of residential customers is projected to increase to approximately 554,000 by December 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average sales per residential customer were 13,700 kWh in 1977. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per

customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use served to slow the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2032. Average annual sales per residential customer are shown in Figure 5.

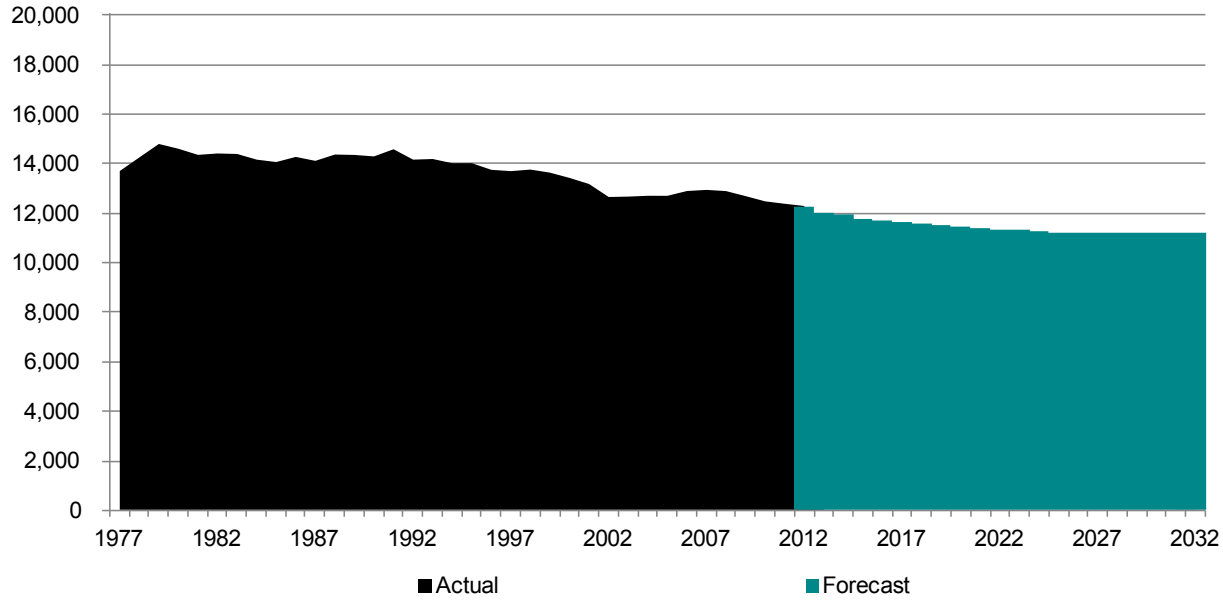


**Figure 5. Forecast residential use per customer (weather-adjusted kWh)**

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 forecast of county housing stock and demographic data. The residential-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.5 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other schedules considered part of the commercial category are unmetered general-service, street-lighting service, traffic-control signal-lighting service, and dusk-to-dawn customer lighting.

In the expected-case scenario, the commercial load is projected to increase from 446 aMW in 2013 to 549 aMW in 2032. The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. As referred to previously, the forecast does not include an assumption for growth from new customers that deviate from historical business failure and startup parameters. As summarized in Table 6, the commercial load in the 70th-percentile scenario is projected to increase from 451 aMW in 2013 to 556 aMW in 2032. The commercial load forecasts are illustrated in Figure 6.

**Table 6. Commercial load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90th Percentile | 463 | 485 | 510 | 572 | 1.1% |
| 70th Percentile | 451 | 472 | 496 | 556 | 1.1% |
| Expected Case | 446 | 466 | 490 | 549 | 1.1% |

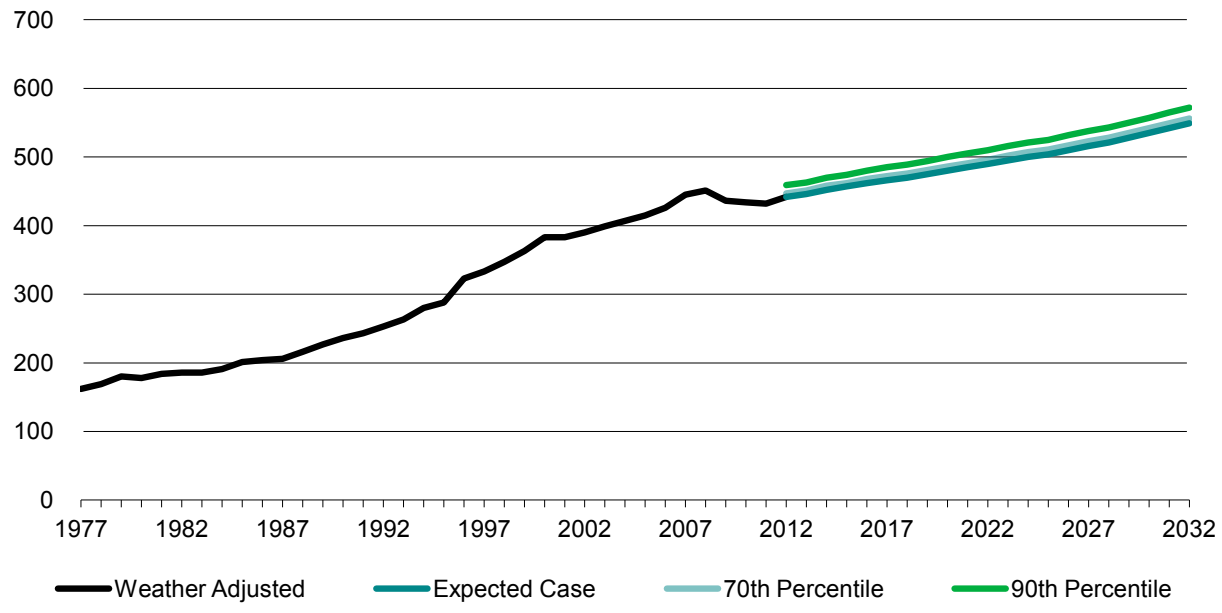


**Figure 6. Forecast commercial load (aMW)**

As of December 2012, Idaho Power had 66,000 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 1.6 percent, reaching 90,200 customers by 2032. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1982 and nearly 28 percent of system sales in 2012.

The commercial customer proportion of system sales is projected to remain at 28 percent of system sales by 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average consumption per commercial customer increased to a record 67,300 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial use per customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial use per customer through 2007. However, a severe recession in 2008 and 2009 caused commercial use per customer to drop considerably. After flattening out from 2010 to 2012, commercial use per customer is projected to rise slowly through 2014 as the economy recovers, then continue its downward trend. The primary reasons for the long-term decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 53,500 kWh in 2032. The forecast average annual use per commercial customer is shown in Figure 7.

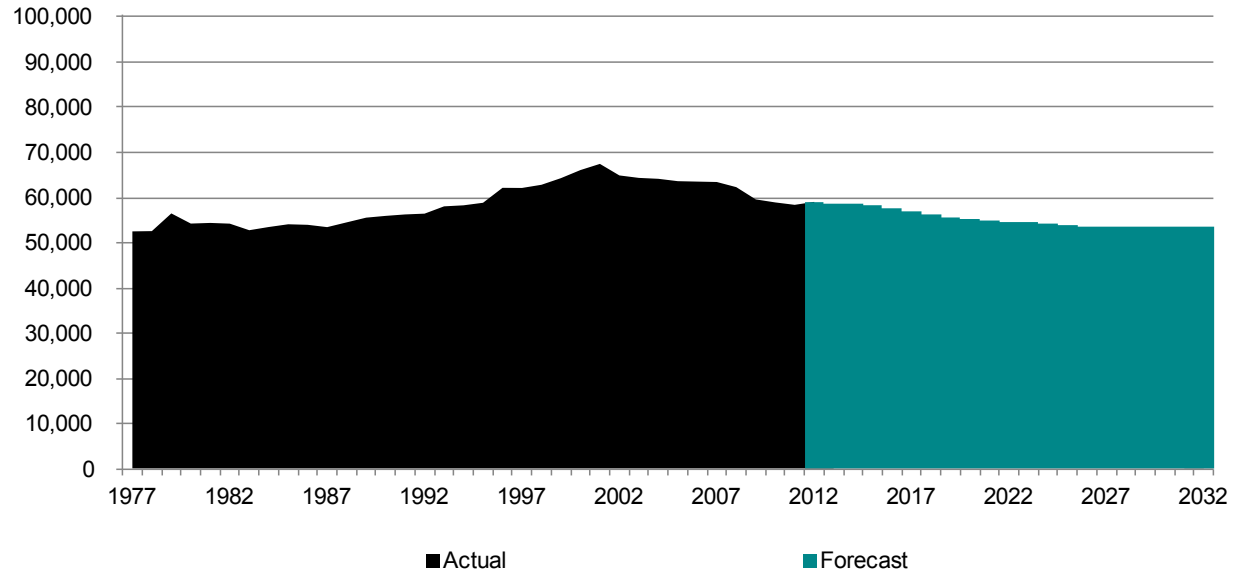


**Figure 7. Forecast commercial use per customer (weather-adjusted kWh)**

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial-sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.6 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households and service-area employment as derived from

Moody's Analytics forecasts; and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecast DSM, by the commercial-customer forecast.

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# IRRIGATION

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecast period, the expected-case irrigation load is forecast to remain flat at 200 aMW from 2013 to 2032, an average annual compound growth rate of 0 percent. The expected-case, 70$^{th}$-percentile, and 90$^{th}$-percentile scenarios forecast no growth in irrigation load from 2013 to 2032. In the 70$^{th}$-percentile scenario, irrigation load is projected to be 215 aMW in 2013 and 215 aMW in 2032. The individual irrigation load forecasts are reported in Table 7 and Figure 8, which illustrates the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

**Table 7. Irrigation load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 235 | 235 | 236 | 235 | 0.0% |
| 70$^{th}$ Percentile | 215 | 215 | 216 | 215 | 0.0% |
| Expected Case | 200 | 200 | 202 | 200 | 0.0% |

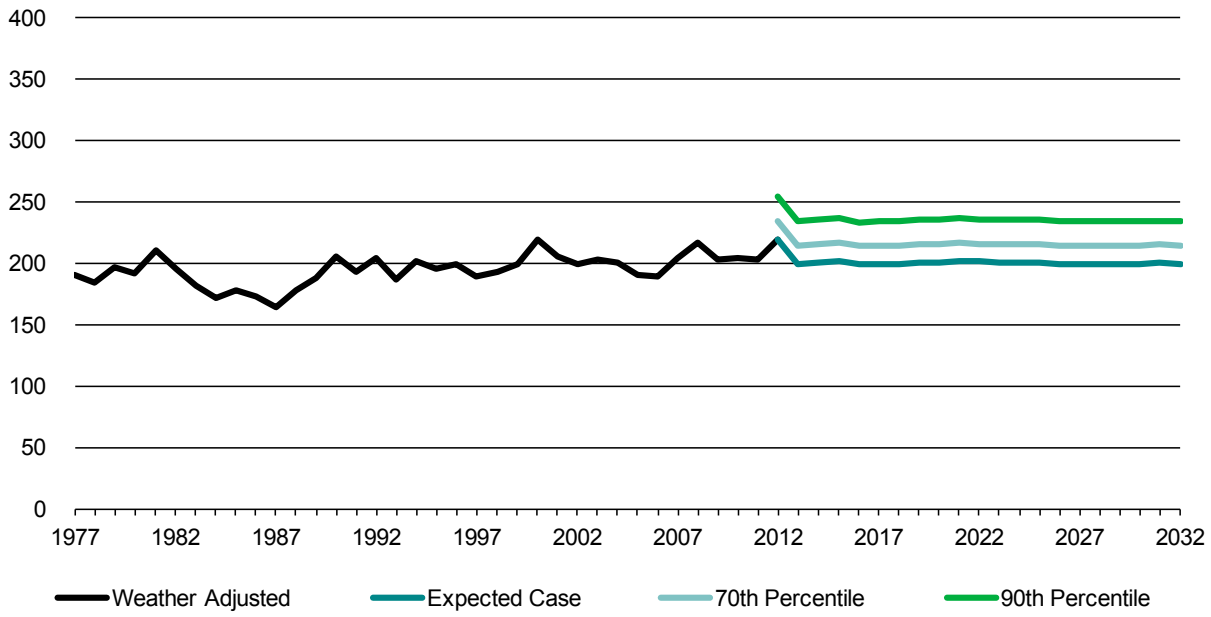


**Figure 8. Forecast irrigation load (aMW)**

It is important to understand that the annual average loads in Table 7 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of

the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 800 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop planting patterns. Farmers have taken advantage of the commodities market by planting increasing levels of acreage. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices influencing demand. The conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2013 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1982 and reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2012, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2032, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 15.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2012, the number of active irrigation accounts had increased to 18,675 and is projected to be nearly 23,000 at the end of the planning period in 2032.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation

customer. This is because water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh annually.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

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# INDUSTRIAL

The industrial category is made up of Idaho Power's large power service (Schedule 19) customers with monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2012, the number of industrial customers had risen to 116, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 267 aMW in 2013 to 367 aMW in 2032, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 9.

**Table 8. Industrial load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Expected Case | 267 | 294 | 319 | 367 | 1.7% |

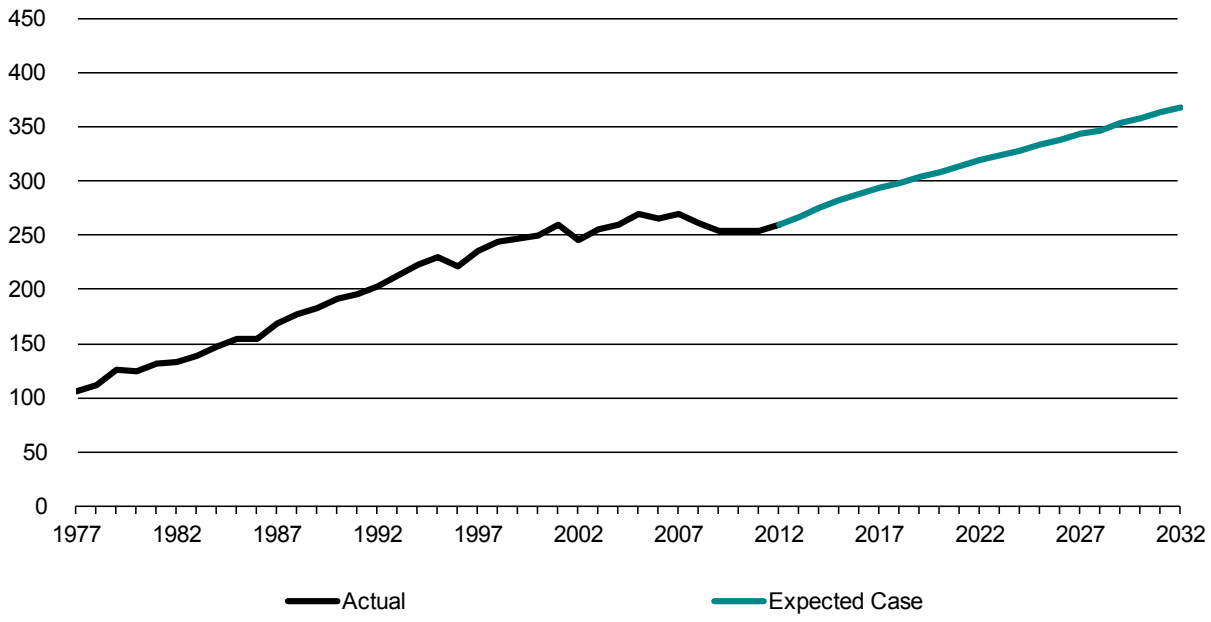


**Figure 9. Forecast industrial load (aMW)**

The industrial energy forecast is based on the most recent (June 2012) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 primary and transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial-sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 16 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2012 industrial electricity consumption by industry group. By far, the largest share of electricity was consumed by the food manufacturing sector (47%); followed by other industry groups (17%); health care (7%); and computer and electronic product manufacturing, education, and other manufacturing (each representing 6%). As Figure 10 shows, several other industry groups make up the remaining share of the 2012 industrial electricity consumption.

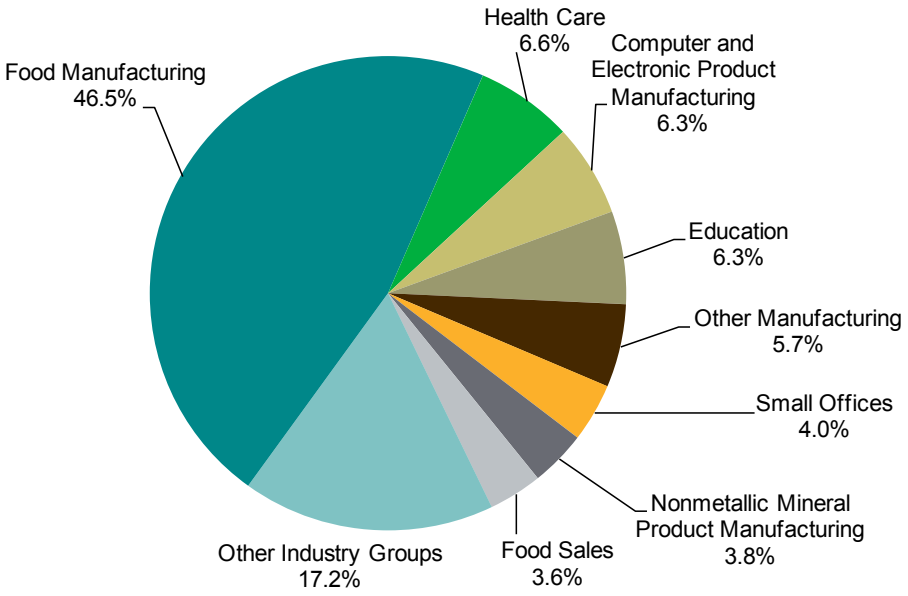


**Figure 10. Industrial electricity consumption by industry group (based on 2012 figures)**

# ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, the INL, and Hoku Materials. The contract with Raft River expired on September 30, 2011.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2013 to 143 aMW in 2032, an average growth rate of 1.1 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

**Table 9. Additional firm load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Expected Case | 115 | 121 | 140 | 143 | 1.1% |

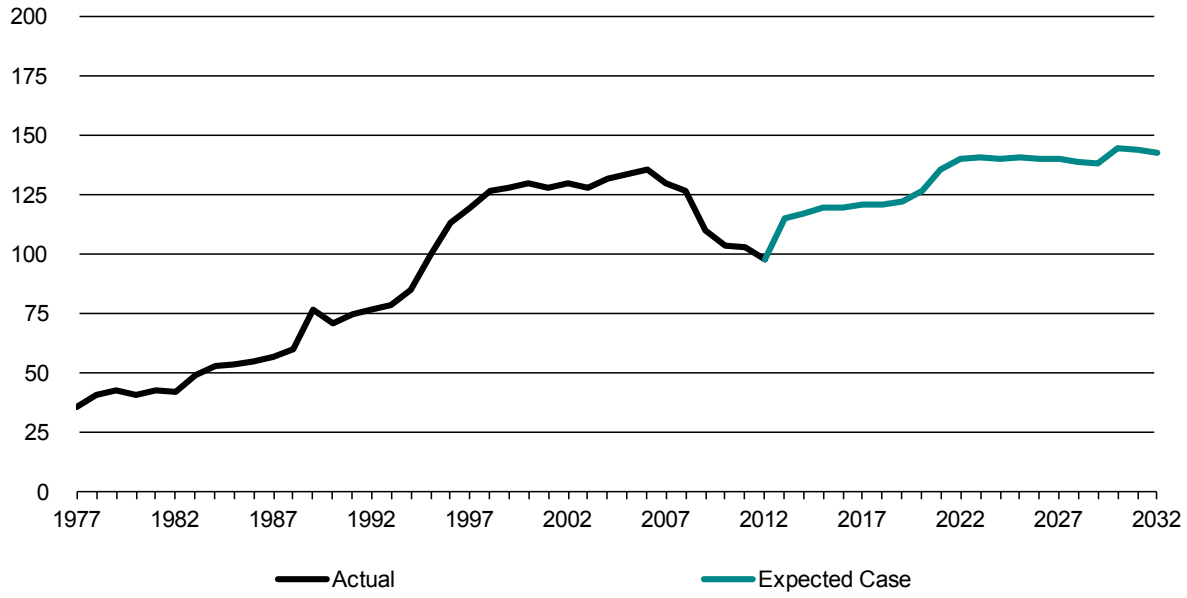


**Figure 11. Forecast additional firm load (aMW)**

## Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly in 2013 and 2014, then stay flat throughout the remainder of the planning. The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

## Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

## Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed that Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

## "Special" Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. It was determined at that time there was a real possibility of the new large load materializing. However, since the 2011 IRP, the likelihood of the new large load diminished. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are excluded from this sales and load forecast.

# COMPANY SYSTEM PEAK

System peak load includes the sum of individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

The all-time system summer peak demand was 3,245 MW, recorded on Thursday, July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,344 MW in 2013 to 4,365 MW in the year 2032, an average growth rate of 1.4 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. The three scenarios of projected system summer peak load are illustrated in Figure 12. The 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth (MW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 95th Percentile | 3,382 | 3,596 | 3,881 | 4,418 | 1.4% |
| 90th Percentile | 3,344 | 3,555 | 3,835 | 4,365 | 1.4% |
| 50th Percentile | 3,189 | 3,387 | 3,651 | 4,147 | 1.4% |

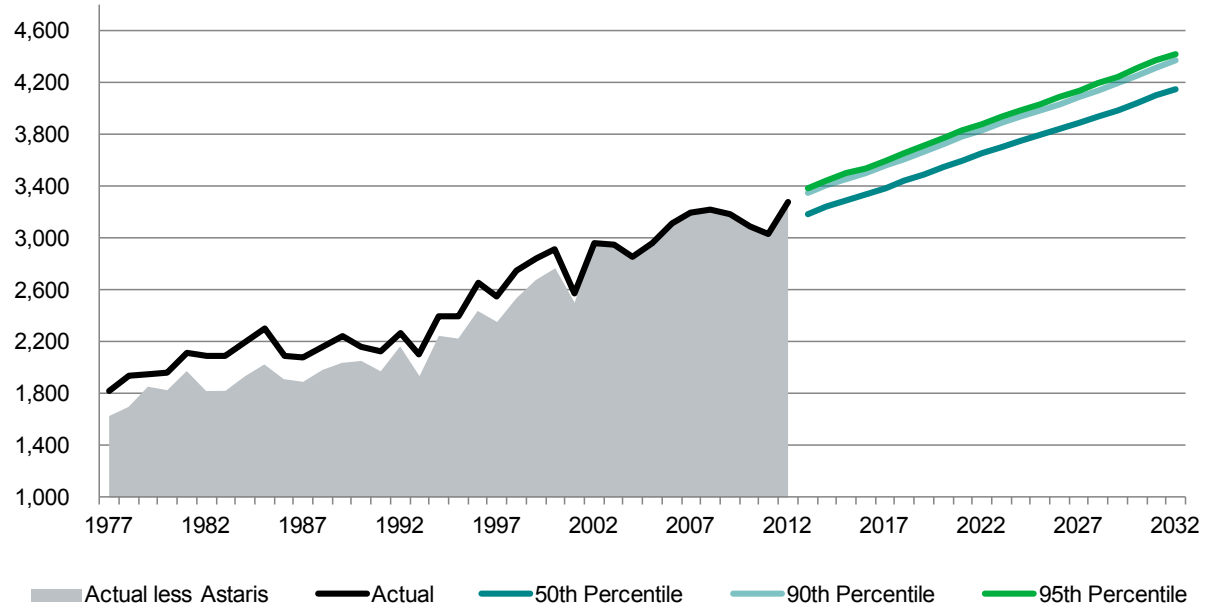


**Figure 12. Forecast system summer peak (MW)**

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is far greater than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,585 MW in 2013 to 3,020 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,683 MW in 2013 to 3,118 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

**Table 11. System winter peak load growth (MW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 95th Percentile | 2,683 | 2,765 | 2,901 | 3,118 | 0.8% |
| 90th Percentile | 2,585 | 2,668 | 2,803 | 3,020 | 0.8% |
| 50th Percentile | 2,301 | 2,384 | 2,520 | 2,737 | 0.9% |

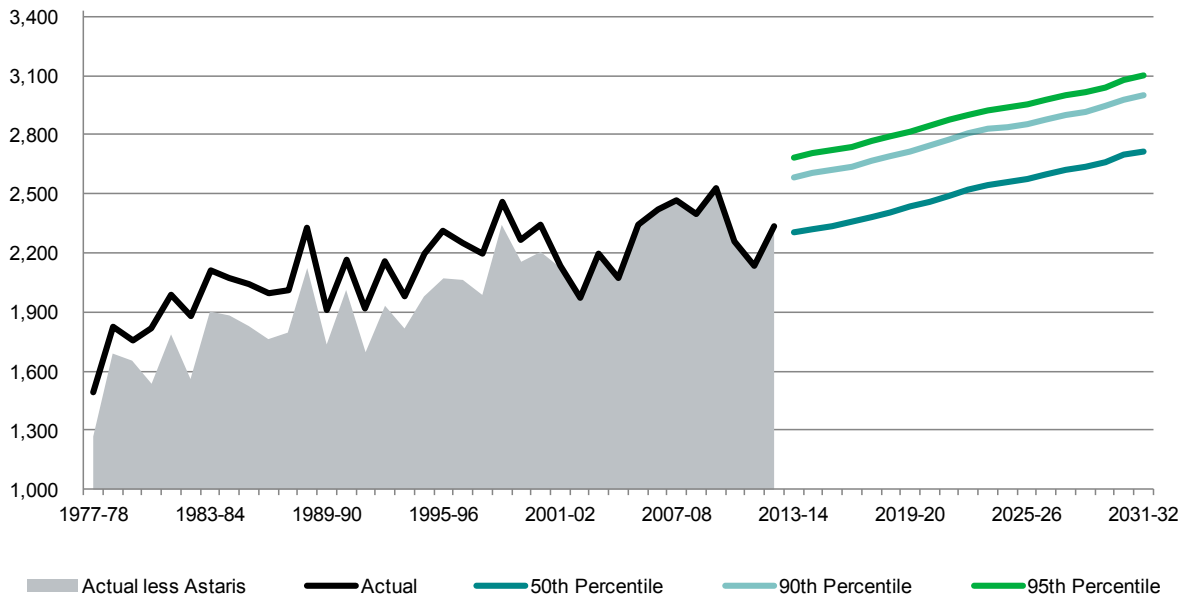


**Figure 13. Forecast system winter peak (MW)**

# COMPANY SYSTEM LOAD

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation, state, MSAs, and counties in the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.1 percent per year from 2013 to 2032. Company system load projections are reported in Table 12 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,759 aMW in 2013 to 2,154 aMW in 2032. In the 70$^{th}$-percentile forecast, the company system load is expected to increase from 1,800 aMW in 2013 to 2,201 aMW by 2032, an average growth rate of 1.1 percent per year over the planning period (Table 12).

**Table 12. System load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,872 | 1,959 | 2,078 | 2,284 | 1.1% |
| 70$^{th}$ Percentile | 1,800 | 1,884 | 2,000 | 2,201 | 1.1% |
| Expected Case | 1,759 | 1,842 | 1,956 | 2,154 | 1.1% |

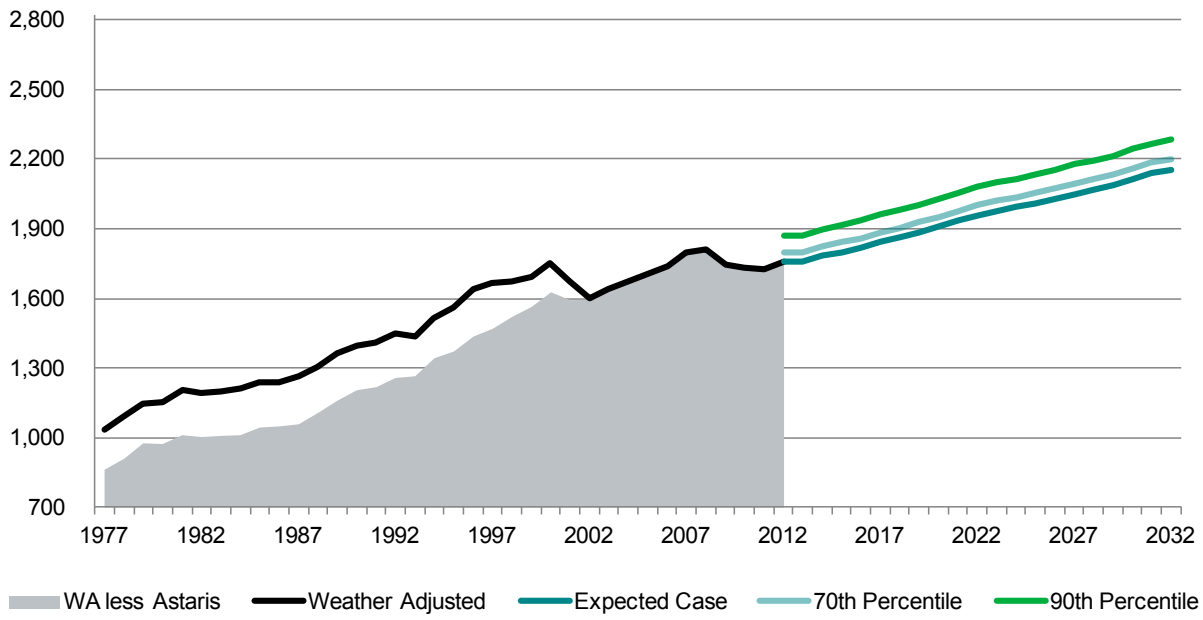


**Figure 14. Forecast system load (aMW)**

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load more accurately portrays the underlying general business growth trend within the service area.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A—Sales and Load Forecast* projects continued growth in Idaho Power's system load. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 23 percent higher in 2032, gaining 1.1 million MWh over 2013. Commercial sales are also expected to be 23 percent higher or 0.9 million MWh above 2013 followed by industrial (38 percent higher or 0.9 million additional MWh) and irrigation (only 0.2 percent higher in 2032 than 2013). Electricity sales to Astaris ended in April 2002.

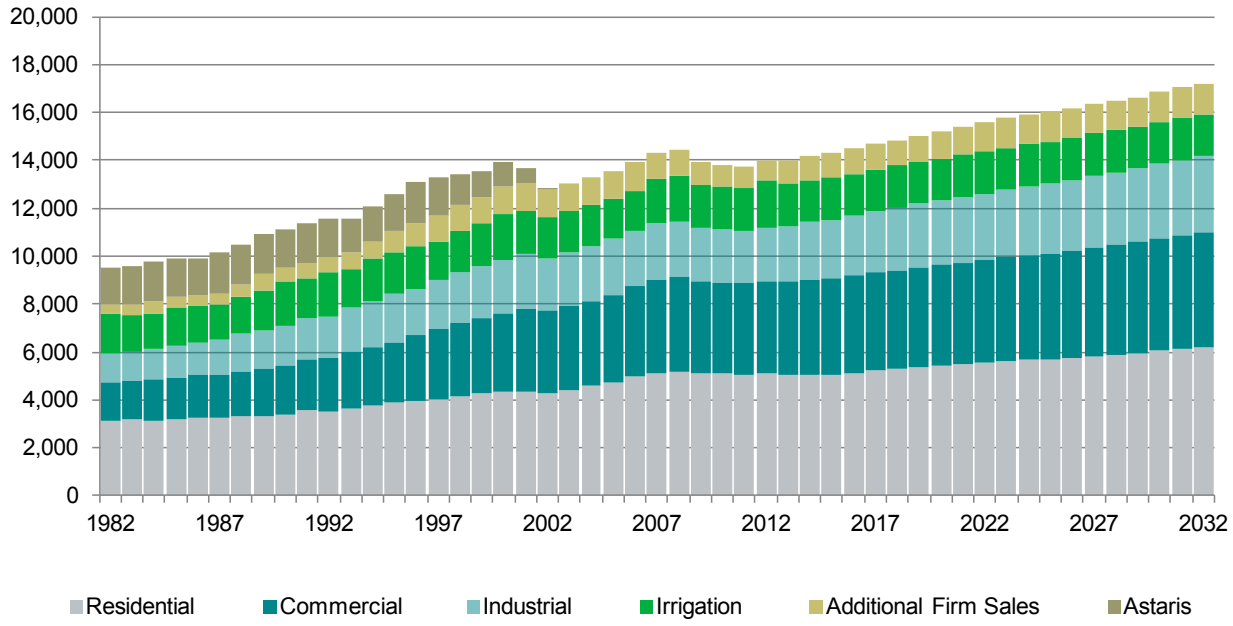


**Figure 15. Composition of system company electricity sales (thousands of MWh)**

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2013 to 2032.

# CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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# ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

## Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for industrial and irrigation customers is not directly surveyed and collected by the DOE; therefore, the models for efficiency impacts have been developed using a methodology established in Itron's white paper, "Incorporating DSM into the Load Forecast".[1] This approach develops statistical methods to recognize efficiency trends from historical utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serves as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical actual energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to sister utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

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[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of the new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

## Demand Response

Beginning with the 2009 IRP, demand response programs have been accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries, are detailed in *Appendix C—Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2013 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction integrated into the sales and load forecast. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2012 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

### Residential Load

**Historical Residential Sales and Load, 1972–2012 (weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 145,208 | – | 10,959 | 1,591 | – | 184 |
| 1973 | 152,957 | 5.3% | 11,537 | 1,765 | 10.9% | 203 |
| 1974 | 160,151 | 4.7% | 12,066 | 1,932 | 9.5% | 223 |
| 1975 | 167,622 | 4.7% | 12,955 | 2,172 | 12.4% | 250 |
| 1976 | 175,720 | 4.8% | 13,455 | 2,364 | 8.9% | 271 |
| 1977 | 184,561 | 5.0% | 13,686 | 2,526 | 6.8% | 290 |
| 1978 | 194,650 | 5.5% | 14,235 | 2,771 | 9.7% | 321 |
| 1979 | 202,982 | 4.3% | 14,779 | 3,000 | 8.3% | 342 |
| 1980 | 209,629 | 3.3% | 14,585 | 3,057 | 1.9% | 348 |
| 1981 | 213,579 | 1.9% | 14,339 | 3,063 | 0.2% | 349 |
| 1982 | 216,696 | 1.5% | 14,395 | 3,119 | 1.9% | 356 |
| 1983 | 219,849 | 1.5% | 14,375 | 3,160 | 1.3% | 363 |
| 1984 | 222,695 | 1.3% | 14,146 | 3,150 | (0.3%) | 357 |
| 1985 | 225,185 | 1.1% | 14,049 | 3,164 | 0.4% | 363 |
| 1986 | 227,081 | 0.8% | 14,256 | 3,237 | 2.3% | 368 |
| 1987 | 228,868 | 0.8% | 14,097 | 3,226 | (0.3%) | 366 |
| 1988 | 230,771 | 0.8% | 14,352 | 3,312 | 2.7% | 378 |
| 1989 | 233,370 | 1.1% | 14,336 | 3,346 | 1.0% | 383 |
| 1990 | 238,117 | 2.0% | 14,277 | 3,400 | 1.6% | 393 |
| 1991 | 243,207 | 2.1% | 14,566 | 3,542 | 4.2% | 402 |
| 1992 | 249,767 | 2.7% | 14,146 | 3,533 | (0.3%) | 408 |
| 1993 | 258,271 | 3.4% | 14,172 | 3,660 | 3.6% | 412 |
| 1994 | 267,854 | 3.7% | 14,002 | 3,750 | 2.5% | 434 |
| 1995 | 277,131 | 3.5% | 14,004 | 3,881 | 3.5% | 438 |
| 1996 | 286,227 | 3.3% | 13,734 | 3,931 | 1.3% | 455 |
| 1997 | 294,674 | 3.0% | 13,682 | 4,032 | 2.6% | 463 |
| 1998 | 303,300 | 2.9% | 13,744 | 4,169 | 3.4% | 476 |
| 1999 | 312,901 | 3.2% | 13,620 | 4,262 | 2.2% | 488 |
| 2000 | 322,402 | 3.0% | 13,407 | 4,322 | 1.4% | 500 |
| 2001 | 331,009 | 2.7% | 13,160 | 4,356 | 0.8% | 476 |
| 2002 | 339,764 | 2.6% | 12,637 | 4,294 | (1.4%) | 488 |
| 2003 | 349,219 | 2.8% | 12,653 | 4,419 | 2.9% | 507 |
| 2004 | 360,462 | 3.2% | 12,686 | 4,573 | 3.5% | 524 |
| 2005 | 373,602 | 3.6% | 12,684 | 4,739 | 3.6% | 543 |
| 2006 | 387,707 | 3.8% | 12,878 | 4,993 | 5.4% | 568 |
| 2007 | 397,286 | 2.5% | 12,924 | 5,135 | 2.8% | 585 |
| 2008 | 402,520 | 1.3% | 12,875 | 5,182 | 0.9% | 594 |
| 2009 | 405,144 | 0.7% | 12,672 | 5,134 | (0.9%) | 584 |
| 2010 | 407,551 | 0.6% | 12,461 | 5,078 | (1.1%) | 582 |
| 2011 | 409,786 | 0.5% | 12,363 | 5,066 | (0.2%) | 577 |
| 2012 | 413,610 | 0.9% | 12,274 | 5,077 | 0.2% | 581 |

**Residential Load**

**Projected Residential Sales and Load, 2013–2032**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 417,852 | 1.0% | 12,025 | 5,025 | (1.0%) | 574 |
| 2014 | 422,850 | 1.2% | 11,954 | 5,055 | 0.6% | 577 |
| 2015 | 429,685 | 1.6% | 11,783 | 5,063 | 0.2% | 579 |
| 2016 | 438,746 | 2.1% | 11,695 | 5,131 | 1.3% | 587 |
| 2017 | 448,379 | 2.2% | 11,644 | 5,221 | 1.8% | 597 |
| 2018 | 457,313 | 2.0% | 11,588 | 5,299 | 1.5% | 606 |
| 2019 | 465,250 | 1.7% | 11,545 | 5,371 | 1.4% | 614 |
| 2020 | 472,652 | 1.6% | 11,480 | 5,426 | 1.0% | 620 |
| 2021 | 479,844 | 1.5% | 11,412 | 5,476 | 0.9% | 626 |
| 2022 | 486,853 | 1.5% | 11,363 | 5,532 | 1.0% | 632 |
| 2023 | 493,741 | 1.4% | 11,342 | 5,600 | 1.2% | 640 |
| 2024 | 500,509 | 1.4% | 11,294 | 5,653 | 0.9% | 646 |
| 2025 | 507,171 | 1.3% | 11,235 | 5,698 | 0.8% | 651 |
| 2026 | 513,749 | 1.3% | 11,230 | 5,769 | 1.2% | 659 |
| 2027 | 520,202 | 1.3% | 11,230 | 5,842 | 1.3% | 667 |
| 2028 | 526,553 | 1.2% | 11,199 | 5,897 | 0.9% | 674 |
| 2029 | 532,781 | 1.2% | 11,197 | 5,966 | 1.2% | 682 |
| 2030 | 538,901 | 1.1% | 11,211 | 6,042 | 1.3% | 690 |
| 2031 | 544,944 | 1.1% | 11,203 | 6,105 | 1.0% | 697 |
| 2032 | 550,883 | 1.1% | 11,189 | 6,164 | 1.0% | 704 |

## Commercial Load

### Historical Commercial Sales and Load, 1972–2012 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 22,585 | – | 46,141 | 1,042 | – | 120 |
| 1973 | 23,286 | 3.1% | 48,145 | 1,121 | 7.6% | 128 |
| 1974 | 24,096 | 3.5% | 49,028 | 1,181 | 5.4% | 136 |
| 1975 | 25,045 | 3.9% | 51,217 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,513 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,416 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,476 | 1,460 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,389 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,145 | 1,559 | (1.6%) | 178 |
| 1981 | 29,567 | 2.7% | 54,286 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,127 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,676 | 1,621 | (0.7%) | 186 |
| 1984 | 31,554 | 2.5% | 53,383 | 1,684 | 3.9% | 191 |
| 1985 | 32,418 | 2.7% | 53,989 | 1,750 | 3.9% | 201 |
| 1986 | 33,208 | 2.4% | 53,869 | 1,789 | 2.2% | 204 |
| 1987 | 33,975 | 2.3% | 53,357 | 1,813 | 1.3% | 206 |
| 1988 | 34,723 | 2.2% | 54,409 | 1,889 | 4.2% | 216 |
| 1989 | 35,638 | 2.6% | 55,451 | 1,976 | 4.6% | 227 |
| 1990 | 36,785 | 3.2% | 55,844 | 2,054 | 3.9% | 236 |
| 1991 | 37,922 | 3.1% | 56,164 | 2,130 | 3.7% | 243 |
| 1992 | 39,022 | 2.9% | 56,339 | 2,198 | 3.2% | 253 |
| 1993 | 40,047 | 2.6% | 57,951 | 2,321 | 5.6% | 263 |
| 1994 | 41,629 | 4.0% | 58,181 | 2,422 | 4.4% | 280 |
| 1995 | 43,165 | 3.7% | 58,742 | 2,536 | 4.7% | 288 |
| 1996 | 44,995 | 4.2% | 62,048 | 2,792 | 10.1% | 323 |
| 1997 | 46,819 | 4.1% | 62,019 | 2,904 | 4.0% | 333 |
| 1998 | 48,404 | 3.4% | 62,722 | 3,036 | 4.6% | 347 |
| 1999 | 49,430 | 2.1% | 64,191 | 3,173 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 65,975 | 3,306 | 4.2% | 383 |
| 2001 | 51,501 | 2.8% | 67,339 | 3,468 | 4.9% | 383 |
| 2002 | 52,915 | 2.7% | 64,788 | 3,428 | (1.1%) | 390 |
| 2003 | 54,194 | 2.4% | 64,243 | 3,482 | 1.6% | 399 |
| 2004 | 55,577 | 2.6% | 64,042 | 3,559 | 2.2% | 407 |
| 2005 | 57,145 | 2.8% | 63,517 | 3,630 | 2.0% | 415 |
| 2006 | 59,050 | 3.3% | 63,425 | 3,745 | 3.2% | 426 |
| 2007 | 61,640 | 4.4% | 63,336 | 3,904 | 4.2% | 445 |
| 2008 | 63,492 | 3.0% | 62,200 | 3,949 | 1.2% | 451 |
| 2009 | 64,151 | 1.0% | 59,488 | 3,816 | (3.4%) | 436 |
| 2010 | 64,421 | 0.4% | 58,820 | 3,789 | (0.7%) | 434 |
| 2011 | 64,921 | 0.8% | 58,285 | 3,784 | (0.1%) | 432 |
| 2012 | 65,599 | 1.0% | 58,941 | 3,866 | 2.2% | 442 |

## Commercial Load

### Projected Commercial Sales and Load, 2013–2032

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 66,489 | 1.4% | 58,657 | 3,900 | 0.9% | 446 |
| 2014 | 67,430 | 1.4% | 58,737 | 3,961 | 1.6% | 452 |
| 2015 | 68,612 | 1.8% | 58,249 | 3,997 | 0.9% | 457 |
| 2016 | 70,122 | 2.2% | 57,661 | 4,043 | 1.2% | 462 |
| 2017 | 71,686 | 2.2% | 56,953 | 4,083 | 1.0% | 466 |
| 2018 | 73,199 | 2.1% | 56,250 | 4,117 | 0.9% | 470 |
| 2019 | 74,579 | 1.9% | 55,754 | 4,158 | 1.0% | 475 |
| 2020 | 75,873 | 1.7% | 55,392 | 4,203 | 1.1% | 480 |
| 2021 | 77,131 | 1.7% | 55,025 | 4,244 | 1.0% | 485 |
| 2022 | 78,357 | 1.6% | 54,730 | 4,288 | 1.0% | 490 |
| 2023 | 79,565 | 1.5% | 54,520 | 4,338 | 1.2% | 495 |
| 2024 | 80,754 | 1.5% | 54,202 | 4,377 | 0.9% | 500 |
| 2025 | 81,925 | 1.4% | 53,864 | 4,413 | 0.8% | 504 |
| 2026 | 83,082 | 1.4% | 53,741 | 4,465 | 1.2% | 510 |
| 2027 | 84,220 | 1.4% | 53,642 | 4,518 | 1.2% | 516 |
| 2028 | 85,343 | 1.3% | 53,466 | 4,563 | 1.0% | 521 |
| 2029 | 86,450 | 1.3% | 53,429 | 4,619 | 1.2% | 528 |
| 2030 | 87,540 | 1.3% | 53,470 | 4,681 | 1.3% | 535 |
| 2031 | 88,619 | 1.2% | 53,491 | 4,740 | 1.3% | 542 |
| 2032 | 89,685 | 1.2% | 53,547 | 4,802 | 1.3% | 549 |

## Irrigation Load

### Historical Irrigation Sales and Load, 1972–2012 (weather adjusted)

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 7,815 | – | 132,292 | 1,034 | – | 118 |
| 1973 | 8,341 | 6.7% | 141,030 | 1,176 | 13.8% | 134 |
| 1974 | 8,971 | 7.6% | 147,698 | 1,325 | 12.6% | 151 |
| 1975 | 9,480 | 5.7% | 153,957 | 1,460 | 10.2% | 167 |
| 1976 | 9,936 | 4.8% | 155,406 | 1,544 | 5.8% | 176 |
| 1977 | 10,238 | 3.0% | 163,266 | 1,672 | 8.3% | 191 |
| 1978 | 10,476 | 2.3% | 154,006 | 1,613 | (3.5%) | 184 |
| 1979 | 10,711 | 2.2% | 161,705 | 1,732 | 7.4% | 197 |
| 1980 | 10,854 | 1.3% | 155,740 | 1,690 | (2.4%) | 192 |
| 1981 | 11,248 | 3.6% | 164,533 | 1,851 | 9.5% | 211 |
| 1982 | 11,312 | 0.6% | 151,369 | 1,712 | (7.5%) | 196 |
| 1983 | 11,133 | (1.6%) | 142,865 | 1,591 | (7.1%) | 182 |
| 1984 | 11,375 | 2.2% | 132,933 | 1,512 | (4.9%) | 172 |
| 1985 | 11,576 | 1.8% | 134,849 | 1,561 | 3.2% | 178 |
| 1986 | 11,308 | (2.3%) | 134,121 | 1,517 | (2.8%) | 173 |
| 1987 | 11,254 | (0.5%) | 128,532 | 1,446 | (4.6%) | 165 |
| 1988 | 11,378 | 1.1% | 137,237 | 1,561 | 7.9% | 178 |
| 1989 | 11,957 | 5.1% | 137,982 | 1,650 | 5.7% | 188 |
| 1990 | 12,340 | 3.2% | 146,128 | 1,803 | 9.3% | 206 |
| 1991 | 12,484 | 1.2% | 135,557 | 1,692 | (6.2%) | 193 |
| 1992 | 12,809 | 2.6% | 140,744 | 1,803 | 6.5% | 205 |
| 1993 | 13,078 | 2.1% | 125,294 | 1,639 | (9.1%) | 187 |
| 1994 | 13,559 | 3.7% | 130,325 | 1,767 | 7.8% | 202 |
| 1995 | 13,679 | 0.9% | 125,349 | 1,715 | (3.0%) | 196 |
| 1996 | 14,074 | 2.9% | 123,944 | 1,744 | 1.7% | 199 |
| 1997 | 14,383 | 2.2% | 115,552 | 1,662 | (4.7%) | 190 |
| 1998 | 14,695 | 2.2% | 114,918 | 1,689 | 1.6% | 193 |
| 1999 | 14,912 | 1.5% | 117,715 | 1,755 | 3.9% | 200 |
| 2000 | 15,253 | 2.3% | 126,625 | 1,931 | 10.0% | 220 |
| 2001 | 15,522 | 1.8% | 116,328 | 1,806 | (6.5%) | 206 |
| 2002 | 15,840 | 2.0% | 110,674 | 1,753 | (2.9%) | 200 |
| 2003 | 16,020 | 1.1% | 110,784 | 1,775 | 1.2% | 203 |
| 2004 | 16,297 | 1.7% | 108,574 | 1,769 | (0.3%) | 201 |
| 2005 | 16,936 | 3.9% | 98,823 | 1,674 | (5.4%) | 191 |
| 2006 | 17,062 | 0.7% | 97,105 | 1,657 | (1.0%) | 189 |
| 2007 | 17,001 | (0.4%) | 105,867 | 1,800 | 8.6% | 205 |
| 2008 | 17,428 | 2.5% | 109,360 | 1,906 | 5.9% | 217 |
| 2009 | 17,708 | 1.6% | 100,337 | 1,777 | (6.8%) | 203 |
| 2010 | 17,846 | 0.8% | 99,895 | 1,783 | 0.3% | 204 |
| 2011 | 18,292 | 2.5% | 97,124 | 1,777 | (0.3%) | 203 |
| 2012 | 18,675 | 2.1% | 103,703 | 1,937 | 9.0% | 220 |

## Irrigation Load

### Projected Irrigation Sales and Load, 2013–2032

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 18,890 | 1.2% | 92,719 | 1,751 | (9.6%) | 200 |
| 2014 | 19,142 | 1.3% | 92,074 | 1,762 | 0.6% | 201 |
| 2015 | 19,396 | 1.3% | 91,204 | 1,769 | 0.4% | 202 |
| 2016 | 19,645 | 1.3% | 89,128 | 1,751 | (1.0%) | 199 |
| 2017 | 19,899 | 1.3% | 87,928 | 1,750 | (0.1%) | 200 |
| 2018 | 20,152 | 1.3% | 87,142 | 1,756 | 0.4% | 200 |
| 2019 | 20,404 | 1.3% | 86,281 | 1,760 | 0.2% | 201 |
| 2020 | 20,655 | 1.2% | 85,477 | 1,766 | 0.3% | 201 |
| 2021 | 20,909 | 1.2% | 84,582 | 1,769 | 0.2% | 202 |
| 2022 | 21,160 | 1.2% | 83,429 | 1,765 | (0.2%) | 202 |
| 2023 | 21,413 | 1.2% | 82,407 | 1,765 | 0.0% | 201 |
| 2024 | 21,664 | 1.2% | 81,620 | 1,768 | 0.2% | 201 |
| 2025 | 21,917 | 1.2% | 80,447 | 1,763 | (0.3%) | 201 |
| 2026 | 22,172 | 1.2% | 79,028 | 1,752 | (0.6%) | 200 |
| 2027 | 22,423 | 1.1% | 78,263 | 1,755 | 0.2% | 200 |
| 2028 | 22,675 | 1.1% | 77,568 | 1,759 | 0.2% | 200 |
| 2029 | 22,926 | 1.1% | 76,458 | 1,753 | (0.3%) | 200 |
| 2030 | 23,180 | 1.1% | 75,656 | 1,754 | 0.0% | 200 |
| 2031 | 23,434 | 1.1% | 75,013 | 1,758 | 0.2% | 201 |
| 2032 | 23,684 | 1.1% | 74,129 | 1,756 | (0.1%) | 200 |

## Industrial Load

### Historical Industrial Sales and Load, 1972–2012 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 56 | – | 10,944,714 | 615 | – | 71 |
| 1973 | 63 | 12.3% | 10,889,056 | 687 | 11.7% | 79 |
| 1974 | 65 | 2.2% | 11,464,249 | 739 | 7.6% | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | (0.3%) | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | (0.1%) | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | (1.0%) | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | (0.6%) | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | (15.9%) | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | (14.4%) | 18,774,093 | 1,934 | (4.3%) | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | (2.3%) | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | (0.8%) | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | (0.1%) | 19,441,876 | 2,156 | (5.8%) | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | (1.1%) | 265 |
| 2007 | 123 | (3.6%) | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | (3.1%) | 19,412,391 | 2,308 | (2.4%) | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | (3.6%) | 254 |
| 2010 | 121 | (2.0%) | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | (1.1%) | 18,586,468 | 2,229 | (0.1%) | 254 |
| 2012 | 115 | (4.2%) | 19,746,525 | 2,269 | 1.8% | 260 |

## Industrial Load

### Projected Industrial Sales and Load, 2013–2032

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 116 | 0.9% | 20,123,969 | 2,334 | 2.9% | 267 |
| 2014 | 117 | 0.9% | 20,531,410 | 2,402 | 2.9% | 275 |
| 2015 | 118 | 0.9% | 20,904,644 | 2,467 | 2.7% | 282 |
| 2016 | 121 | 2.5% | 20,855,283 | 2,523 | 2.3% | 288 |
| 2017 | 121 | 0.0% | 21,229,207 | 2,569 | 1.8% | 294 |
| 2018 | 123 | 1.7% | 21,215,736 | 2,610 | 1.6% | 298 |
| 2019 | 124 | 0.8% | 21,400,507 | 2,654 | 1.7% | 303 |
| 2020 | 125 | 0.8% | 21,591,980 | 2,699 | 1.7% | 308 |
| 2021 | 126 | 0.8% | 21,777,074 | 2,744 | 1.7% | 314 |
| 2022 | 128 | 1.6% | 21,782,963 | 2,788 | 1.6% | 319 |
| 2023 | 130 | 1.6% | 21,787,965 | 2,832 | 1.6% | 324 |
| 2024 | 131 | 0.8% | 21,953,791 | 2,876 | 1.5% | 328 |
| 2025 | 131 | 0.0% | 22,268,240 | 2,917 | 1.4% | 333 |
| 2026 | 133 | 1.5% | 22,264,535 | 2,961 | 1.5% | 338 |
| 2027 | 133 | 0.0% | 22,596,372 | 3,005 | 1.5% | 343 |
| 2028 | 135 | 1.5% | 22,573,943 | 3,047 | 1.4% | 347 |
| 2029 | 136 | 0.7% | 22,727,071 | 3,091 | 1.4% | 353 |
| 2030 | 138 | 1.5% | 22,713,855 | 3,135 | 1.4% | 358 |
| 2031 | 139 | 0.7% | 22,862,159 | 3,178 | 1.4% | 363 |
| 2032 | 140 | 0.7% | 23,014,399 | 3,222 | 1.4% | 367 |

**Additional Firm Sales and Load***

**Historical Additional Firm Sales and Load, 1972–2012**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1972 | 284 | – | 32 |
| 1973 | 291 | 2.3% | 33 |
| 1974 | 282 | (2.9%) | 32 |
| 1975 | 314 | 11.2% | 36 |
| 1976 | 289 | (8.1%) | 33 |
| 1977 | 311 | 7.8% | 36 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.4% | 43 |
| 1980 | 360 | (3.5%) | 41 |
| 1981 | 376 | 4.6% | 43 |
| 1982 | 368 | (2.4%) | 42 |
| 1983 | 425 | 15.6% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 482 | 2.4% | 55 |
| 1987 | 502 | 4.2% | 57 |
| 1988 | 530 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | (6.9%) | 71 |
| 1991 | 661 | 5.8% | 75 |
| 1992 | 680 | 2.9% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | (2.1%) | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | (1.7%) | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,141 | (4.0%) | 130 |
| 2008 | 1,114 | (2.4%) | 127 |
| 2009 | 965 | (13.4%) | 110 |
| 2010 | 907 | (6.0%) | 104 |
| 2011 | 906 | 0.0% | 103 |
| 2012 | 862 | (4.8%) | 98 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2013–2032**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2013 | 1,010 | 17.1% | 115 |
| 2014 | 1,025 | 1.5% | 117 |
| 2015 | 1,053 | 2.7% | 120 |
| 2016 | 1,053 | 0.1% | 120 |
| 2017 | 1,062 | 0.8% | 121 |
| 2018 | 1,060 | (0.3%) | 121 |
| 2019 | 1,068 | 0.8% | 122 |
| 2020 | 1,115 | 4.4% | 127 |
| 2021 | 1,193 | 7.0% | 136 |
| 2022 | 1,229 | 3.0% | 140 |
| 2023 | 1,234 | 0.4% | 141 |
| 2024 | 1,231 | (0.2%) | 140 |
| 2025 | 1,234 | 0.2% | 141 |
| 2026 | 1,228 | (0.5%) | 140 |
| 2027 | 1,228 | 0.0% | 140 |
| 2028 | 1,217 | (0.9%) | 139 |
| 2029 | 1,212 | (0.5%) | 138 |
| 2030 | 1,268 | 4.6% | 145 |
| 2031 | 1,262 | (0.5%) | 144 |
| 2032 | 1,257 | (0.4%) | 143 |

*Includes Micron Technology, Simplot Fertilizer, and the INL

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1972–2012 (weather adjusted)**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1972 | 4,566 | – | 577 |
| 1973 | 5,040 | 10.4% | 635 |
| 1974 | 5,461 | 8.4% | 690 |
| 1975 | 6,012 | 10.1% | 760 |
| 1976 | 6,422 | 6.8% | 810 |
| 1977 | 6,858 | 6.8% | 863 |
| 1978 | 7,174 | 4.6% | 910 |
| 1979 | 7,776 | 8.4% | 977 |
| 1980 | 7,773 | 0.0% | 974 |
| 1981 | 8,043 | 3.5% | 1,012 |
| 1982 | 7,994 | (0.6%) | 1,004 |
| 1983 | 7,991 | 0.0% | 1,009 |
| 1984 | 8,095 | 1.3% | 1,012 |
| 1985 | 8,303 | 2.6% | 1,045 |
| 1986 | 8,382 | 0.9% | 1,050 |
| 1987 | 8,462 | 1.0% | 1,059 |
| 1988 | 8,839 | 4.5% | 1,108 |
| 1989 | 9,237 | 4.5% | 1,161 |
| 1990 | 9,544 | 3.3% | 1,206 |
| 1991 | 9,744 | 2.1% | 1,219 |
| 1992 | 9,985 | 2.5% | 1,259 |
| 1993 | 10,163 | 1.8% | 1,266 |
| 1994 | 10,628 | 4.6% | 1,344 |
| 1995 | 11,030 | 3.8% | 1,373 |
| 1996 | 11,390 | 3.3% | 1,437 |
| 1997 | 11,688 | 2.6% | 1,471 |
| 1998 | 12,151 | 4.0% | 1,522 |
| 1999 | 12,472 | 2.6% | 1,565 |
| 2000 | 12,895 | 3.4% | 1,628 |
| 2001 | 13,037 | 1.1% | 1,594 |
| 2002 | 12,771 | (2.0%) | 1,596 |
| 2003 | 13,030 | 2.0% | 1,637 |
| 2004 | 13,327 | 2.3% | 1,673 |
| 2005 | 13,568 | 1.8% | 1,703 |
| 2006 | 13,909 | 2.5% | 1,739 |
| 2007 | 14,346 | 3.1% | 1,796 |
| 2008 | 14,460 | 0.8% | 1,813 |
| 2009 | 13,917 | (3.8%) | 1,744 |
| 2010 | 13,789 | (0.9%) | 1,734 |
| 2011 | 13,762 | (0.2%) | 1,725 |
| 2012 | 14,011 | 1.8% | 1,760 |

**Company System Load (including Astaris)**

| Historical Company System Sales and Load, (1972–2012) (weather adjusted) | | | | Astaris Sales and Load (1972–2002) (weather adjusted) | | |
|---|---|---|---|---|---|---|
| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) | Astaris Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
| 1972 | 6,385 | – | 794 | 1,819 | – | 207 |
| 1973 | 6,685 | 4.7% | 832 | 1,645 | (9.6%) | 188 |
| 1974 | 7,104 | 6.3% | 887 | 1,643 | (0.1%) | 188 |
| 1975 | 7,569 | 6.6% | 946 | 1,557 | (5.3%) | 178 |
| 1976 | 7,997 | 5.6% | 998 | 1,575 | 1.2% | 179 |
| 1977 | 8,276 | 3.5% | 1,033 | 1,418 | (10.0%) | 162 |
| 1978 | 8,716 | 5.3% | 1,094 | 1,542 | 8.8% | 176 |
| 1979 | 9,170 | 5.2% | 1,144 | 1,395 | (9.6%) | 159 |
| 1980 | 9,286 | 1.3% | 1,155 | 1,513 | 8.5% | 172 |
| 1981 | 9,677 | 4.2% | 1,208 | 1,634 | 8.0% | 186 |
| 1982 | 9,548 | (1.3%) | 1,191 | 1,554 | (4.9%) | 177 |
| 1983 | 9,600 | 0.5% | 1,202 | 1,610 | 3.6% | 184 |
| 1984 | 9,796 | 2.0% | 1,215 | 1,701 | 5.7% | 194 |
| 1985 | 9,917 | 1.2% | 1,239 | 1,614 | (5.1%) | 184 |
| 1986 | 9,935 | 0.2% | 1,236 | 1,554 | (3.7%) | 177 |
| 1987 | 10,154 | 2.2% | 1,262 | 1,692 | 8.9% | 193 |
| 1988 | 10,474 | 3.2% | 1,303 | 1,635 | (3.4%) | 186 |
| 1989 | 10,940 | 4.4% | 1,365 | 1,703 | 4.2% | 194 |
| 1990 | 11,149 | 1.9% | 1,398 | 1,604 | (5.8%) | 183 |
| 1991 | 11,353 | 1.8% | 1,412 | 1,609 | 0.3% | 184 |
| 1992 | 11,555 | 1.8% | 1,446 | 1,570 | (2.4%) | 179 |
| 1993 | 11,600 | 0.4% | 1,438 | 1,437 | (8.4%) | 164 |
| 1994 | 12,048 | 3.9% | 1,514 | 1,420 | (1.2%) | 162 |
| 1995 | 12,597 | 4.6% | 1,561 | 1,567 | 10.4% | 179 |
| 1996 | 13,079 | 3.8% | 1,639 | 1,689 | 7.8% | 192 |
| 1997 | 13,315 | 1.8% | 1,666 | 1,628 | (3.6%) | 186 |
| 1998 | 13,424 | 0.8% | 1,674 | 1,273 | (21.8%) | 145 |
| 1999 | 13,523 | 0.7% | 1,691 | 1,051 | (17.4%) | 120 |
| 2000 | 13,949 | 3.1% | 1,754 | 1,054 | 0.3% | 120 |
| 2001 | 13,695 | (1.8%) | 1,673 | 658 | (37.5%) | 75 |
| 2002 | 12,782 | (6.7%) | 1,597 | 11 | (98.3%) | 1 |
| 2003 | 13,030 | 1.9% | 1,637 | 0 | (100.0%) | 0 |
| 2004 | 13,327 | 2.3% | 1,673 | 0 | 0.0% | 0 |
| 2005 | 13,568 | 1.8% | 1,703 | 0 | 0.0% | 0 |
| 2006 | 13,909 | 2.5% | 1,739 | 0 | 0.0% | 0 |
| 2007 | 14,346 | 3.1% | 1,796 | 0 | 0.0% | 0 |
| 2008 | 14,460 | 0.8% | 1,813 | 0 | 0.0% | 0 |
| 2009 | 13,917 | (3.8%) | 1,744 | 0 | 0.0% | 0 |
| 2010 | 13,789 | (0.9%) | 1,734 | 0 | 0.0% | 0 |
| 2011 | 13,762 | (0.2%) | 1,725 | 0 | 0.0% | 0 |
| 2012 | 14,011 | 1.8% | 1,760 | 0 | 0.0% | 0 |

**Company System Load**

**Projected Company System Sales and Load, 2013–2032**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2013 | 14,020 | 0.1% | 1,759 |
| 2014 | 14,205 | 1.3% | 1,782 |
| 2015 | 14,348 | 1.0% | 1,800 |
| 2016 | 14,502 | 1.1% | 1,818 |
| 2017 | 14,684 | 1.3% | 1,842 |
| 2018 | 14,842 | 1.1% | 1,862 |
| 2019 | 15,011 | 1.1% | 1,883 |
| 2020 | 15,208 | 1.3% | 1,906 |
| 2021 | 15,426 | 1.4% | 1,934 |
| 2022 | 15,603 | 1.1% | 1,956 |
| 2023 | 15,769 | 1.1% | 1,977 |
| 2024 | 15,905 | 0.9% | 1,992 |
| 2025 | 16,025 | 0.8% | 2,009 |
| 2026 | 16,176 | 0.9% | 2,028 |
| 2027 | 16,348 | 1.1% | 2,049 |
| 2028 | 16,483 | 0.8% | 2,065 |
| 2029 | 16,640 | 1.0% | 2,087 |
| 2030 | 16,879 | 1.4% | 2,116 |
| 2031 | 17,043 | 1.0% | 2,137 |
| 2032 | 17,201 | 0.9% | 2,154 |

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IDAHO POWER®
An IDACORP Company

# 2013 Integrated Resource Plan

## APPENDIX B

# Demand-Side Management

## 2012 ANNUAL REPORT

**March 15, 2013**

# 2013

# Integrated Resource Plan

## APPENDIX B

# Demand-Side Management

## 2012 ANNUAL REPORT

**March 15, 2013**

IDAHO POWER®

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## ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the Advisory Council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.


## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.


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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... iii
List of Figures ..... iv
List of Appendices ..... iv
List of Supplements ..... iv
Glossary of Acronyms ..... v
Executive Summary ..... 1
Introduction ..... 3
DSM Programs ..... 4
Demand Response Programs ..... 6
Energy Efficiency Programs ..... 7
Market Transformation ..... 7
Other Programs and Activities ..... 7
Program Performance ..... 8
2012 Activities ..... 9
Energy Efficiency Advisory Group ..... 10
Regulatory Initiatives ..... 12
DSM Expenditures ..... 12
Marketing ..... 15
Program Evaluation ..... 17
Customer Satisfaction ..... 17
Cost-Effectiveness ..... 19
Future Plans ..... 20
DSM Annual Report Structure ..... 21
Residential Sector Overview ..... 23
Description ..... 23
Programs ..... 24
A/C Cool Credit ..... 26
Ductless Heat Pump Pilot ..... 31
Energy Efficient Lighting ..... 35
Energy House Calls ..... 38
ENERGY STAR® Homes Northwest ..... 41

Heating & Cooling Efficiency Program ....44
Home Improvement Program ....48
Home Products Program ....51
Oregon Residential Weatherization ....55
Rebate Advantage ....57
See ya later, refrigerator® ....59
Weatherization Assistance for Qualified Customers ....64
Weatherization Solutions for Eligible Customers ....68
Commercial/Industrial Sector Overview ....73
Description ....73
Programs ....73
Building Efficiency ....77
Custom Efficiency Program ....82
Easy Upgrades ....88
FlexPeak Management ....94
Oregon Commercial Audits ....98
Irrigation Sector Overview ....101
Description ....101
Programs ....102
Irrigation Efficiency Rewards ....103
Irrigation Peak Rewards ....107
Market Transformation ....111
Northwest Energy Efficiency Alliance ....111
Commercial and Industrial NEEA Activities in Idaho ....111
Residential NEEA Activities in Idaho ....112
Other NEEA Activities in Idaho ....114
NEEA Funding ....114
Other Programs and Activities ....117
Residential Energy Efficiency Education Initiative ....117
Easy Savings Program ....121
Commercial Education Initiative ....122
Local Energy Efficiency Funds ....123
Residential Economizer Project Study ....124
Regional Technical Forum ....124

Boise City Home Audit Project ....125
Regulatory Initiatives ....129
Fixed-Cost Adjustment ....129
Custom Efficiency Incentive Recovery ....130
Energy Efficiency Rider—Prudence Determination of Expenditures ....130
Cost-Effectiveness and Funding of Low-Income Weatherization ....131
Demand Response Programs Suspension ....131
Continued Commitment ....133
Continued Expansion and Broad Availability of Energy Efficiency and Demand Response Programs ....133
Building-Code Improvement Activity ....134
Promotion of Energy Efficiency through Electricity Rate Design ....134
Third-Party, Independent Verification ....135
Energy Efficiency Potential Study ....135
Idaho Power's Internal Energy Efficiency Commitment ....136
Appendices ....139

## LIST OF TABLES

Table 1. 2012 DSM, sectors, programs, operational type, and energy savings/demand reduction ....8
Table 2. 2012 program sector summary and energy usage/savings/demand reduction ....9
Table 3. 2012 funding source and energy impact ....13
Table 4. 2012 DSM program expenditures by category ....13
Table 5. 2012 DSM program incentives by segment and sector ....14
Table 6. 2012 residential program summary ....24
Table 7. 2012 weatherization solutions financial breakdown ....69
Table 8. 2012 commercial/industrial program summary ....73
Table 9. 2012 Custom Efficiency annual energy savings by primary project measure ....83
Table 10. 2012 irrigation program summary ....102
Table 11. Option incentives ....108
Table 12. Total program daily MW reduction without distribution losses using realization rates ....109
Table 13. Number of participating homes by size ....126
Table 14. Number of participating homes by zip code and heating source ....126
Table 15. Measures installed in participating homes by heat source ....127

# LIST OF FIGURES

Figure 1. Peak demand-reduction capacity 2004–2012 (MW) ....4
Figure 2. Annual energy savings 2002–2012 (MWh) ....5
Figure 3. DSM expense history 2002–2012 from all sources (millions of dollars) ....5
Figure 4. 2012 DSM program expenditures by category ....14
Figure 5. 2012 DSM program incentives by segment and sector ....15
Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts ....18
Figure 7. How customers heard about See ya later, refrigerator® ....62
Figure 8. NEEA chart of attendees (seats filled) by attendee sponsor ....84

# LIST OF APPENDICES

Appendix 1. Idaho Rider, Oregon Rider, Idaho Custom Efficiency, and NEEA funding balances ....141
Appendix 2. 2012 DSM expenses by funding source (dollars) ....142
Appendix 3. 2012 DSM program activity ....143
Appendix 4. Historical DSM expense and performance 2002–2012 ....145
Appendix 5. 2012 DSM program activity by state jurisdiction ....159

# LIST OF SUPPLEMENTS

Supplement 1: Cost-Effectiveness
Supplement 2: Evaluation
NEEA Market Effects Evaluations (included on CD with Supplement 2)

# GLOSSARY OF ACRONYMS

aMW—Average Megawatt

A/C—Air Conditioning/Air Conditioners

ACB, Inc.—Advertising Checking Bureau, Inc.

ADM—ADM Associates, Inc.

AMI—Advanced Metering Infrastructure

ARRA—*American Reinvestment and Recovery Act of 2008*

B/C—Benefit/Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BCW—Boise Center West

BOMA—Building Owners and Managers Association

BOP—Builder Option Package

BPA—Bonneville Power Administration

CAES—Center for Advanced Energy Studies

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CAIS—Certified Agricultural Irrigation Specialist

CBSA—Commercial Building Stock Assessment

CEERI—CAES Energy Efficiency Research Initiative

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CEU—Continuing Education Unit

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CIS—Customer Information System

COP—Coefficient of Performance

CR—Customer Representative (field staff)

CR&EE—Customer Research and Energy Efficiency Department

CSR—Customer Service Representative (call center)

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

DSR—Demand-Side Resource

EA4—EA4 Energy Audit Program

EA5—EA5 Energy Audit Program

EEAG—Energy Efficiency Advisory Group

EECBG—Energy Efficiency Conservation Block Grant

EISA—*Energy Independence and Security Act of 2007*

EM&V—Evaluation, Measurement, and Verification

EnerNOC Solutions—EnerNOC Utility Solutions Consulting

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

EUAT—Energy-Use Advisory Tool

FCA—Fixed-Cost Adjustment

$ft^2$—Square Feet

GMPG—Green Motors Practice Group

GWh—Gigawatt-hour

H&CE—Heating & Cooling Efficiency Program

HEM, LLC—Home Energy Management, LLC

hp—Horsepower

HPWH—Heat Pump Water Heater

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IDL—Integrated Design Lab (in Boise)

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IOER—Idaho Office of Energy Resources

IP—Internet Protocol

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

IRS—Internal Revenue Service

iSTEM—Idaho Science, Technology, Engineering and Mathematics

IT—Information Technology

JACO—JACO Environmental, Inc.

kW—Kilowatt

kWh—Kilowatt-hour

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

MEF—Modified Energy Factor

MOU—Memorandum of Understanding

MHAFB—Mountain Home Air Force Base

MPER—Market Progress Evaluation Report

MW—Megawatt

MWh—Megawatt-hour

MVBA—Magic Valley Builders Association

NEEM—Northwest Energy Efficient Manufactured

NEEA—Northwest Energy Efficiency Alliance

NEMA—National Electrical Manufacturers Association

NPCC—Northwest Power and Conservation Council

NWRRC—Northwest Regional Retail Collaborative

OPUC—Public Utility Commission of Oregon

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PECI—Portland Energy Conservation, Inc.

PLC—Power-Line Carrier

PSA—Public-Service Announcement

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAP—Resource Action Programs

R&D—Research and Development

RBSA—Residential Building Stock Assessment

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure Test

ROCEE—Refrigerator Operator Coaching for Energy Efficiency

RPAC—*Regional Portfolio Advisory Committee*

RTF—Regional Technical Forum

SCCT—Simple-Cycle Combustion Turbine

SCO—State-Certifying Organization

SEE—Students for Energy Efficiency

SEER—Seasonal Energy Efficiency Ratio

SEM—Strategic Energy Management

SGIS—Smart Grid Investment Grant

SIR—Savings-to-Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

T-5HO—T-5 High Output

TRC—Total Resource Cost

TVP—Time-Variant Pricing

VFD—Variable-Frequency Drive

UC—Utility Cost

UES—Unit Energy Savings

US—United States

USA—Utility Service Agreement

W—Watt

WAQC—Weatherization Assistance for Qualified Customers

# EXECUTIVE SUMMARY

The pursuit of cost-effective energy efficiency is a primary objective for Idaho Power. Energy efficiency and demand response provide economic and operational benefits to the company and its customers. The enhancement of information and programs ensures customers' opportunities to learn about their energy use and participate in programs.

In 2012, Idaho Power focused energy efficiency activities on program analysis, energy savings, demand reductions, and improvements and expansion of its current programs. Idaho Power initiated several impact evaluations conducted by third-party consultants. The company also sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about the company's energy efficiency programs. To identify additional energy-savings measures, Idaho Power conducted a new energy efficiency potential study in conjunction with its *2013 Integrated Resource Plan* (IRP). Also in 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000$^{th}$ unit.

Total expenditures from all funding sources on demand-side management (DSM)-related activities increased about 7 percent, from almost $46.3 million in 2011 to $49.3 million in 2012. This funding now comes from several sources outside the Idaho and Oregon Energy Efficiency Riders. Idaho incentives from the company's demand response programs are recovered through the annual power cost adjustment (PCA), and Idaho incentives for its industrial energy efficiency program, Custom Efficiency, are capitalized similar to a supply-side resource.

Although on target for savings achieved for the IRP, Idaho Power's annual energy savings from its energy efficiency activities slightly decreased in 2012. Reduced energy savings in 2012 were caused partially by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities, which generally reduce savings estimates. The amount of energy saved was enough to power over 13,000 average homes served by Idaho Power. From Idaho Power's energy efficiency programs alone (excluding Northwest Energy Efficiency Alliance [NEEA] savings), the savings decreased 7 percent, from 163,315 megawatt-hours (MWh) in 2011 to 152,486 MWh in 2012. Annual energy savings for 2011, including the revised NEEA savings, were 183,862 MWh. In 2012, these savings decreased slightly to 170,228 MWh.

In 2012, Idaho Power celebrated 10 years of energy efficiency and demand response activity funded under the Idaho Energy Efficiency Rider (Idaho Rider). In those 10 years, the company realized a cumulative annual savings of over 1 million MWh savings. This is enough energy to power a city of 85,000 average residences. The demand-reduction capacity for Idaho Power's demand response programs in 2012 was over 438 megawatts (MW). This represents over 13 percent of Idaho Power's new record system peak of 3,245 MW set in 2012.

The *Demand-Side Management 2012 Annual Report* provides a review of the company's DSM activities and finances throughout 2012 and outlines Idaho Power's plans for DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419, as well as the Memorandum of Understanding (MOU) signed by IPUC staff and Idaho investor-owned utilities in January 2010.

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# INTRODUCTION

Idaho Power's *Demand-Side Management 2012 Annual Report* provides a review of the financial and operational performance of Idaho Power's demand-side management (DSM) activities and initiatives for 2012. In 2012, Idaho Power offered energy efficiency and demand response programs to all customer sectors and sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about reducing their electricity consumption.

Idaho Power's main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. Idaho Power also strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

Customer participation in Idaho Power's energy efficiency and demand response programs continues to remain strong, provide substantial energy savings, and increase demand-reduction capacity. The energy savings exclusively from Idaho Power's energy efficiency programs in 2012 were 152,486 megawatt-hours (MWh). In 2012, the amount of energy saved from its programs was enough to power more than 13,000 average homes served by Idaho Power for one year.

Demand reduction available from the demand response programs increased in 2012. Combined, the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs resulted in an estimated summer peak reduction capacity of 438 megawatts (MW).

Idaho Power uses the same report structure each year in a continuing effort to fulfill the objectives of the Memorandum of Understanding (MOU) signed on January 25, 2010 by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities. The report consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows all of the standard cost-effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category (Table 2). In 2012, the company continued its commitment to third-party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2012 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. In 2012, all Idaho Power energy efficiency programs were cost effective, except the company's weatherization programs for income-qualified customers and 52 individual measures in various programs. The majority of these measures have been discontinued, and the remaining measures will be reviewed in 2013.

The cost-effectiveness analysis of Idaho Power's demand response programs showed all three demand response programs to be cost-effective over the life of each program. This analysis uses a program life of a 20-year planning period for the A/C Cool Credit and Irrigation Peak Rewards programs and a 10-year planning period for the FlexPeak Management program. For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in IPUC Case No. IPC-E-12-29, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The cost-effectiveness analysis for the FlexPeak Management program is still based on a 10-year life. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance.

## DSM Programs

The programs within Idaho Power's energy efficiency and demand response portfolio are offered to all major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either sector.

Idaho Power groups its DSM activities in four categories: energy efficiency, demand response, market transformation, and other programs and activities. The other programs and activities are generally designed to provide customer outreach and education concerning the efficient use of electricity. All of these activities are coordinated to advance Idaho Power's continued commitment to pursue all cost-effective energy efficiency, all prudent demand response, and to enhance customer satisfaction.

Figures 1 through 3 show the demand-reduction capacity, historic energy savings, and DSM expenses.

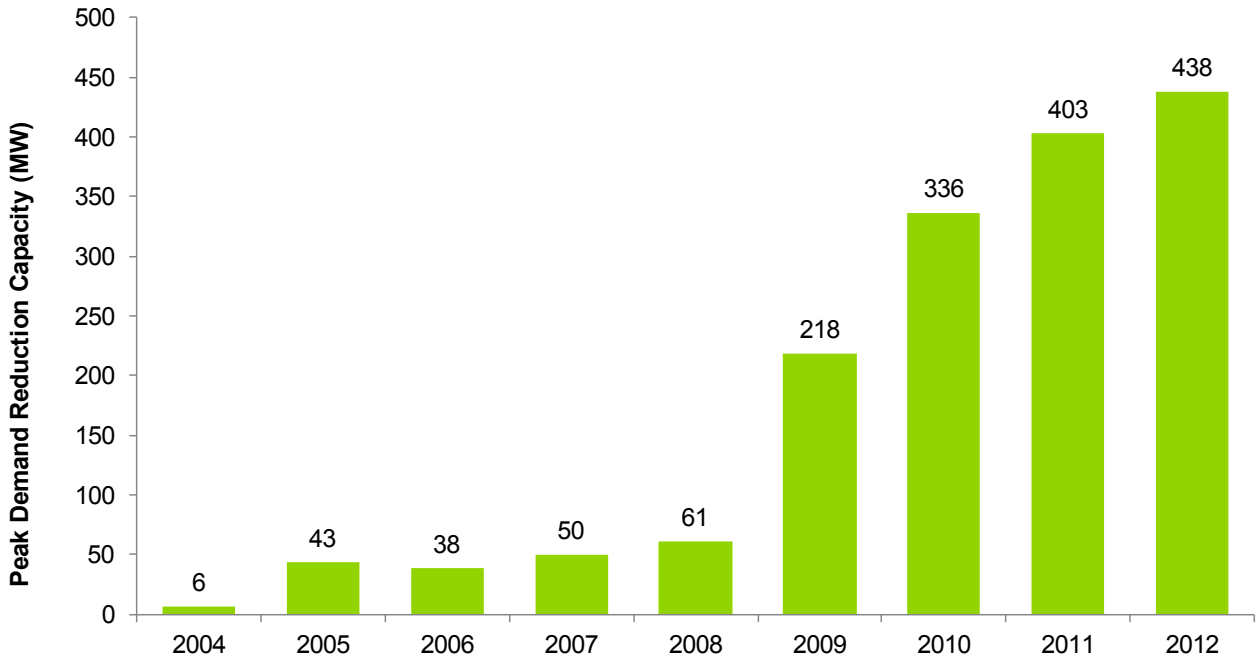


Figure 1. Peak demand-reduction capacity 2004–2012 (MW)

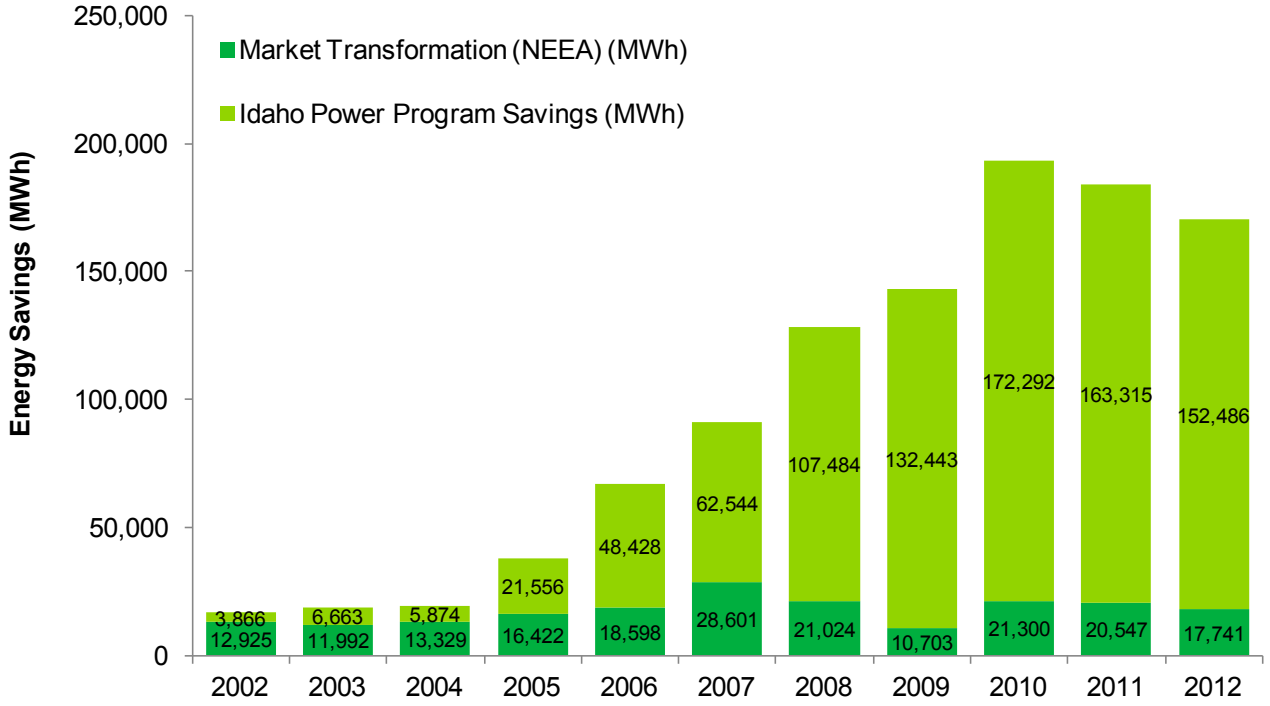


Figure 2. Annual energy savings 2002–2012 (MWh)

Note: 2012 market-transformation savings (NEEA) are preliminary.

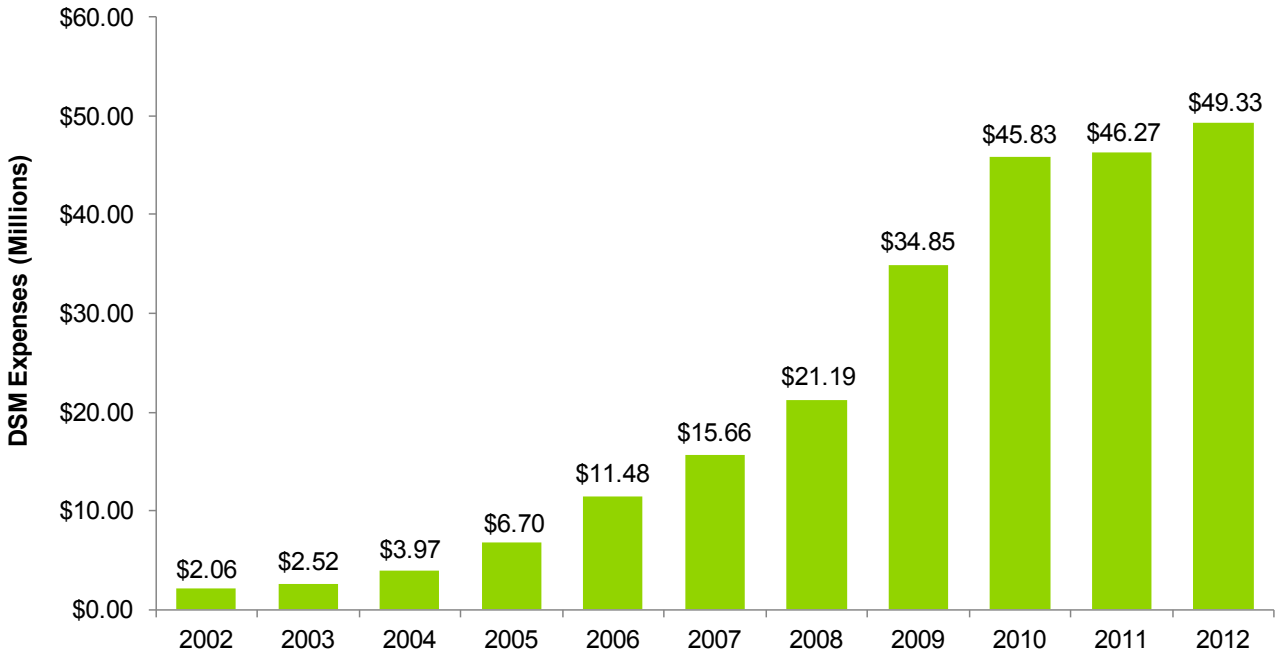


Figure 3. DSM expense history 2002–2012 from all sources (millions of dollars)

## Demand Response Programs

The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side resources. The company estimates future capacity shortfalls through the IRP planning process, then plans programs to mitigate these shortfalls. Demand response programs are measured by the amount of demand reduction, in MW, available to the company during system peak periods. In 2012, Idaho Power operated three demand response programs: the A/C Cool Credit program for residential customers, the FlexPeak Management program for commercial/industrial customers, and the Irrigation Peak Rewards program for irrigation customers.

Research efforts in 2012 included a continued investigation into the need for demand response, as well as how to measure its value. Idaho Power also continued to examine and refine program dispatch criteria. Idaho Power contracted with Portland Energy Conservation, Inc. (PECI), to conduct a research project for the A/C Cool Credit program to optimize the use of this program by more accurately estimating the available demand reduction in advance of dispatching this program. In 2012, the company, based on PECI's research plan, used the A/C Cool Credit program 13 times, with a goal of capturing various cycling strategies at various temperature bins, allowing PECI to create a regression model to estimate demand reduction.

The FlexPeak Management program was used four times during summer 2012. These events did not incur any marginal costs for the company and were successful in keeping the participants familiar and engaged with the program while verifying the accuracy of EnerNOC, Inc.'s, weekly nominations. Although Idaho experienced fairly extreme weather conditions in summer 2012, there was no need to dispatch the Irrigation Peak Rewards program, which was not economical to operate considering the variable payment necessary to use this program. Idaho Power hit a new all-time system peak of 3,245 MW at 4:00 p.m. on July 12, 2012. Both the A/C Cool Credit and FlexPeak Management programs were dispatched at 4:00 p.m. on this day, successfully preventing the system peak from increasing after 4:00 p.m., as it would have otherwise done.

Idaho Power's IRP determines the company's forecasted need for energy resources while balancing reliability, cost, environmental concerns, and efficiency. The plan is developed with the assistance of the company's customers and other stakeholders and is reviewed and updated every two years. In 2012, Idaho Power began the analytical portion of the 2013 IRP and commenced its regular meetings with the Integrated Resource Plan Advisory Council (IRPAC).

In fall 2012, the company's IRP analysis demonstrated there were no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. The Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management programs have been available to meet that need. However, the most recent analysis from the 2013 IRP indicates no peak-hour shortages until 2016. This is primarily due to a slower-than-expected economic recovery, causing slower customer growth than previously forecasted, as well as two previously anticipated large-load customers that did not materialize. Based on the results of this analysis, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC, requesting a temporary suspension of the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.

## Energy Efficiency Programs

Energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components where an energy-efficient design, replacement, or repair can achieve energy savings. These programs are available to all customer sectors in Idaho Power's service area. Project measures range from entire residential or commercial building construction to appliance replacement. Savings from these programs are measured in terms of kilowatt-hour (kWh) or MWh savings. These programs usually supply energy savings throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

## Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improves their energy efficiency. Idaho Power achieves market-transformation savings primarily through its participation in the Northwest Energy Efficiency Alliance (NEEA).

## Other Programs and Activities

Other programs and activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Educational Initiative, Local Energy Efficiency Funds (LEEF), Residential Economizer Project Study, and Boise City Home Audit Project. These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a list of the DSM programs and their respective sectors, operational category, the state each was available in 2012, and associated energy savings.

Table 1. 2012 DSM, sectors, programs, operational type, and energy savings/demand reduction

| Program by Sector | Operational Type | State | Savings |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 44.9 MW |
| Ductless Heat Pump Pilot | Energy Efficiency | ID/OR | 445 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 16,709 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 1,192 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 537 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 689 MWh |
| Home Improvement Program | Energy Efficiency | ID | 457 MWh |
| Home Products Program | Energy Efficiency | ID/OR | 887 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | 12 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 187 MWh |
| Residential Energy Efficiency Education Initiative | Other Programs and Activities | ID/OR | n/a |
| See ya later, refrigerator® | Energy Efficiency | ID/OR | 1,576 MWh |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 648 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 258 MWh |
| **Commercial/Industrial** | | | |
| Building Efficiency | Energy Efficiency | ID/OR | 20,450 MWh |
| Commercial Education Initiative | Other Programs and Activities | ID/OR | n/a |
| Easy Upgrades | Energy Efficiency | ID/OR | 41,569 MWh |
| FlexPeak Management | Demand Response | ID/OR | 52.8 MW |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| Custom Efficiency | Energy Efficiency | ID/OR | 54,253 MWh |
| **Irrigation** | | | |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 12,617 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 339.9 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 17,741 MWh |

## Program Performance

In 2012, annual energy savings slightly decreased compared to 2011. The saving difference varied by sector. Energy savings for the residential sector decreased by 24 percent to 23,597 MWh. The commercial sector energy savings increased by 23 percent to 62,019 MWh, and the industrial sector energy savings decreased by 20 percent to 54,253 MWh. Energy savings for the irrigation sector decreased by 10 percent to 12,617 MWh. The reduction in savings in the residential sector was due, in part, to new lower deemed-savings amounts approved by the Regional Technical Forum (RTF) and Idaho Power making some programs available only for electrically heated homes. Some of the energy-savings reduction in the industrial sector and the increase in the commercial sector were due to programmatic changes. The overall reduced energy savings in 2012 may be caused, in part, by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities. Additional energy savings continue to be realized through market-transformation partnership activities with NEEA.

Customer participation remained strong in most of the existing programs during the year. The number of projects completed under the Building Efficiency and Easy Upgrades programs increased by 33 percent

and 6 percent, respectively. Participation in Rebate Advantage increased by 40 percent, from 25 homes in 2011 to 35 homes in 2012. The number of homes completed under the ENERGY STAR® Homes Northwest program increase by 33 percent. The projects completed under the Irrigation Efficiency Rewards program increased slightly by 3 percent, from 880 projects in 2011 to 908 projects in 2012.

A few programs were big contributors to overall energy savings. Although the Custom Efficiency program had reduced savings compared to 2011, the program accounted for 32 percent of Idaho Power's energy savings from programs, resulting in an estimated 54,253 MWh of savings. The Easy Upgrades program in the commercial sector provided 24 percent, or 41,569 MWh, of estimated energy savings. In the residential sector, the Energy Efficient Lighting program saved 16,709 MWh, accounting for 10 percent of overall energy savings.

Table 2 shows the 2012 annual energy savings, percent of energy usage, number of customers, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2012 contribution of each sector in terms of energy usage and its respective size in the number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

Table 2. 2012 program sector summary and energy usage/savings/demand reduction

| | Energy Efficiency Program Impacts[a] | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (kWh) | Average Energy (aMW) | Peak Load Reduction (MW)[b] | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $ 6,337,777 | 23,597,363 | 2.7 | 44.9 | 5,052,302 | 35.83% | 416,020 |
| Commercial | 6,954,795 | 62,018,709 | 7.1 | 7.1 | 3,869,314 | 27.44% | 65,920 |
| Industrial | 7,092,581 | 54,253,106 | 6.2 | 60.4 | 3,131,650 | 22.21% | 116 |
| Irrigation | 2,373,201 | 12,617,164 | 1.4 | 343.0 | 2,048,435 | 14.53% | 19,045 |
| Market Transformation | 3,379,756 | 17,741,430 | 2.0 | n/a | n/a | n/a | n/a |
| Other Programs and Activities | 692,062 | n/a | n/a | n/a | n/a | n/a | n/a |
| **Total Direct Program Expenses** | **$26,830,172** | **170,227,773** | **19.0** | **455.0** | **14,101,701** | **100.00%** | **501,101** |

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] This includes peak load reduction from both demand response and energy efficiency programs.

## 2012 Activities

In 2012, Idaho Power continued to expand its DSM programs to increase participation and energy savings. Many activities in 2012 revolved around evaluation and research to make DSM programs more effective and the savings gained from these programs more reliable. The company also completed a third-party energy efficiency potential study and a non-participant survey for the residential, commercial, and irrigation sectors.

Although not directly related to Idaho Power's DSM activities, the company has continued to install and configure its new Customer Information System (CIS), made possible under a matching grant from the Smart Grid Investment Grant (SGIG). This project should be complete with migration to the new CIS by mid-2013. This installation has and will affect some of the company's DSM program activities because any changes related to the company's billing system cannot occur until the system is implemented. Information technology (IT) resources for other projects have also been dramatically constrained during the conversion.

Idaho Power collaborated with the City of Boise to finalize the Boise City Home Audit Project. Additionally, the company continued to fund and collaborate with the Integrated Design Lab (in Boise) (IDL) and participate with NEEA's Ductless Heat Pump (DHP) Pilot.

During 2012, Idaho Power continued its contractual participation in NEEA under the 2011 to 2014 agreement. NEEA's efforts in the northwest impact Idaho Power's customers by encouraging regional market transformation. Idaho Power representatives participated in several NEEA committees and in several NEEA events.

Idaho Power also continued to help fund and participate in the RTF and used the results from the RTF's research in program development and cost-effectiveness analyses. Beginning in 2012, a representative from Idaho Power was a member of the RTF Policy Advisory Committee. This committee provides policy recommendations on how to best meet the needs of stakeholders while maintaining the independent technical model of the RTF. Additionally, Idaho Power staff participated in numerous sub-committees.

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15, a request for the IPUC to designate Idaho Power's expenditure of $35,623,321 in Idaho Energy Efficiency Rider (Idaho Rider) funds and $7,018,385 in Custom Efficiency incentive expenses as prudently incurred expenses in 2012. Through the discovery process, Idaho Power found that $345 had been inadvertently charged to the Idaho Rider that should have been charged to the Oregon Energy Efficiency Rider (Oregon Rider). The company subsequently modified its request for prudency to $35,622,976 in Idaho Rider expenses, for a total request of $42,641,361. The company included copies of the *Demand-Side Management 2011 Annual Report* along with *Supplement 1: Cost-Effectiveness* and *Supplement 2: Evaluation* in its filing. On October 22, 2012, the IPUC issued Order No. 32667. In this order, the IPUC found that the company had prudently incurred $41,942,123.50, including $34,923,738.50 in Rider expenses and $7,018,385 in Custom Efficiency incentive expenses in 2011. The commission declined to decide the reasonableness of $89,601 of Idaho Power labor-related expense increases for Rider funded employees and denied Rider funding for $82,855.50 in A/C Cool Credit incentive payments to customers. On November 13, 2012, Idaho Power filed a petition for reconsideration in Case No. IPC-E-12-15. In this filing and subsequent filings, the company asked for reconsideration on an accounting adjustment of $526,781 and $89,601 in labor-related expenses. On December 11, 2012, the commission issued Order No. 32690, in which they found it reasonable to grant the company reconsideration of the accounting-related adjustment but again declined to decide the reasonableness of the company's labor-related expense increase until the company provided evidence from which the commission might better assess the reasonableness of those expenses. As a result of these orders, the company has credited the Idaho Rider account 254201 by $82,855.50 and placed $89,601 in reserve account 253000 until prudency can be determined. These prudency filings and Idaho Power's DSM activities are designed to comply with the agreed principles set forth in the MOU for Prudency Determination of DSM Expenditures.

## Energy Efficiency Advisory Group

Formed in 2002, the Energy Efficiency Advisory Group (EEAG) provides input on formulating and implementing energy efficiency and demand-reduction programs funded by the Rider. Currently, the EEAG consists of 14 members from Idaho Power's service area and the Pacific Northwest. Members represent a cross section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power.

The EEAG met three times in 2012: February 22, July 19, and November 6. Additionally, a webinar was held on December 5 and a conference call was held on December 14. During these meetings, Idaho Power discussed and requested recommendations on new program proposals, marketing methods, and specific measure details; provided a status of the Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues. Idaho Power relies on input from the EEAG to provide a customer and public interest review of energy efficiency and demand response programs and expenses. The minutes from the 2012 EEAG meetings, the webinar on December 5, and the December 14 conference call are included in *Supplement 2: Evaluation*.

During the July 19 EEAG meeting, EEAG members and Idaho Power staff engaged in an interactive session to review the structure and content of EEAG meetings. A summary of this discussion and suggestions was provided in a memo dated August 3, 2012, and sent to all members. In subsequent meetings, and after review of the original order by the IPUC that created EEAG, the members affirmed their desire to meet quarterly for all-day, in-person sessions to review DSM activities. Additional teleconferences and/or webinars may supplement the quarterly meetings. The members also requested that time be allocated for the audience to ask questions throughout the presentations and discussions and that guest speakers be used when appropriate to the subject matter. Finally, members will be given an opportunity to suggest agenda items and will receive presentation materials one week in advance of the meeting. The company has implemented many of the EEAG members' recommendations to increase the effectiveness of EEAG meetings. Additionally, Idaho Power continues to address recommendations from the IPUC received in Case No. IPC-E-12-15 and confirmed by Order No. 32667. A copy of the revised memo can be found in *Supplement 2: Evaluation*.

At the November 6 EEAG meeting, Idaho Power presented and discussed four residential initiatives: Home Energy Audits, Shade Tree Pilot, Student Energy Efficiency Kits, and Solar Thermal Hot Water measure. All initiatives except the Solar Thermal Hot Water measure received positive feedback and support from EEAG. Idaho Power plans on launching the following three initiatives in 2013.

The new Home Energy Audits program is based, in part, on the Boise City Home Audit Project that Idaho Power and the City of Boise undertook previously using *American Recovery and Reinvestment Act of 2008* (ARRA) funding. This new program will allow all-electric residential customers to select a home performance specialist (HPS) from a list of preferred providers and have the HPS perform an audit of their home. The audit will include a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Homeowners will receive a report with specific recommendations for their home and information on programs that may help with the cost of energy efficiency improvements. Preparations are underway for a program launch during third quarter 2013.

Idaho Power, along with local stakeholders, is exploring a shade-tree program for the Treasure Valley. Using results from a state-sponsored urban tree-canopy study and online planting resources developed by the Arbor Day Foundation, the Shade Tree Pilot will encourage strategic planting of trees to reduce residential energy use. Properly planted shade trees save energy in the summer by reducing cooling costs. Trees provide measureable economic and environmental benefits, including enhanced air quality, storm water quality, and property values. Utility shade-tree programs throughout the country report energy savings, high participant satisfaction, and enhanced public images related to environmental stewardship. The Shade Tree Pilot is being developed for implementation in fall 2013, and results will be reviewed for full program development in 2014.

Idaho Power plans to build on the success of its previous Students for Energy Efficiency (SEE) Program (2009–2011) by implementing a new Student Energy Efficiency Kits program. The new

program will target elementary school students in grades four through six. The project plan includes the delivery of 2,500 kits to students attending schools in Idaho Power's service area during spring semester 2013 and another 2,500 kits in the fall. Participating classrooms will be identified by Idaho Power's community education representatives. Once enrolled, one of two vendors selected through a competitive request for proposal (RFP) process will facilitate the delivery of the curriculum, take-home energy kits, and feedback materials directly to the school. Spring kit delivery will begin on approximately April 1, 2013, and reporting for the spring enrollment will be complete in July 2013. Fall kit delivery will begin in September 2013, with reporting complete in early 2014. At the end of 2013, Idaho Power intends to gather feedback from all stakeholders to capture lessons learned and determine whether or not to continue the program in 2014.

In addition to EEAG, Idaho Power solicits further customer input through meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

## Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27, which was filed with the IPUC on October 22, 2010.

Since 2002, Idaho Power has recovered most DSM program costs through the Rider, with the intended result of providing a more timely recovery of DSM costs. To address the removal of financial disincentives, Idaho Power has tested the effects of a fixed-cost adjustment (FCA) mechanism in a five-year pilot initiative. In 2011, the FCA pilot completed year five and the company filed Case No. IPC-E-11-19 with the IPUC requesting to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC approved the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company filed its Compliance Filing in response to the IPUC's directive. On January 31, 2013, the IPUC issued Final Order No. 32731, directing that the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for customer incentives paid through the Custom Efficiency program as a regulatory asset beginning on January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in demand-side resources (DSR). As of December 31, 2012, proceedings relating to this case are ongoing.

## DSM Expenditures

Funding for DSM programs in 2012 came from several sources. The Rider funds are collected directly from customers on their monthly bills. For 2012, the Idaho Rider was 4 percent of base-rate revenues. The 2012 Oregon Rider was 3 percent of base-rate revenues. Beginning in 2011, Idaho Power was

allowed to account for incentives paid through the Custom Efficiency program as a regulatory asset in Idaho. Additionally beginning in 2012, Idaho related demand response program incentives were paid through the power cost adjustment (PCA) mechanism. Other energy efficiency and demand response-related expenses not funded through the Rider, including costs for administration and overhead, are included as part of Idaho Power's ongoing operation and maintenance costs.

Total DSM expenses funded from all sources were $49.3 million in 2012. At the beginning of 2012, the Idaho Rider negative balance was about $5.3 million, and by January 1, 2013, the positive balance was $4 million. This reduction in the Idaho Rider negative balance and accrual of a positive balance was accomplished through the filings described in the Regulatory Initiatives section. At the beginning of the year, the Oregon Rider negative balance was approximately $3.5 million, and by year-end, the negative balance was $3.9 million.

Table 3 shows the total expenditures funded by the Idaho Rider ($25,739,189); the Oregon Rider ($1,382,330); and Idaho Power base rates ($22,205,341). The Idaho Power base rates category includes Idaho Custom Efficiency program incentives, Idaho Power demand response incentives, and operation and maintenance costs, separated by expense category.

Table 3. 2012 funding source and energy impact

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider | $ 25,739,188 | 164,781 |
| Oregon Rider | 1,382,330 | 4,771 |
| Idaho Power Base Rates | 22,205,341 | 676 |
| **Total** | **$ 49,326,859** | **170,228** |

Table 4 and Figure 4 indicate 2012 DSM program expenditures by category. The expenses in the Materials & Equipment category are primarily for A/C Cool Credit ($3,300,000). The Other Expense category includes marketing ($397,800), program evaluation ($214,000), and program training ($115,800). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs, such as M2M Communication Corp. for Irrigation Peak Rewards; EnerNOC for FlexPeak Management; JACO Environmental, Inc. (JACO), for See ya later, refrigerator®; Honeywell for A/C Cool Credit; Evergreen Consulting for Easy Upgrades; and contractors for Weatherization Assistance for Qualified Customers (WAQC) and Weatherization Solutions for Eligible Customers.

Table 4. 2012 DSM program expenditures by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $ 30,848,941 | 62% |
| Labor/Administrative Expense | 3,490,392 | 7% |
| Materials & Equipment | 3,308,304 | 7% |
| Other Expense | 532,733 | 1% |
| Purchased Services | 11,146,489 | 23% |
| **Total 2012 DSM Program Expenditures by Category** | **$ 49,326,859** | **100%** |

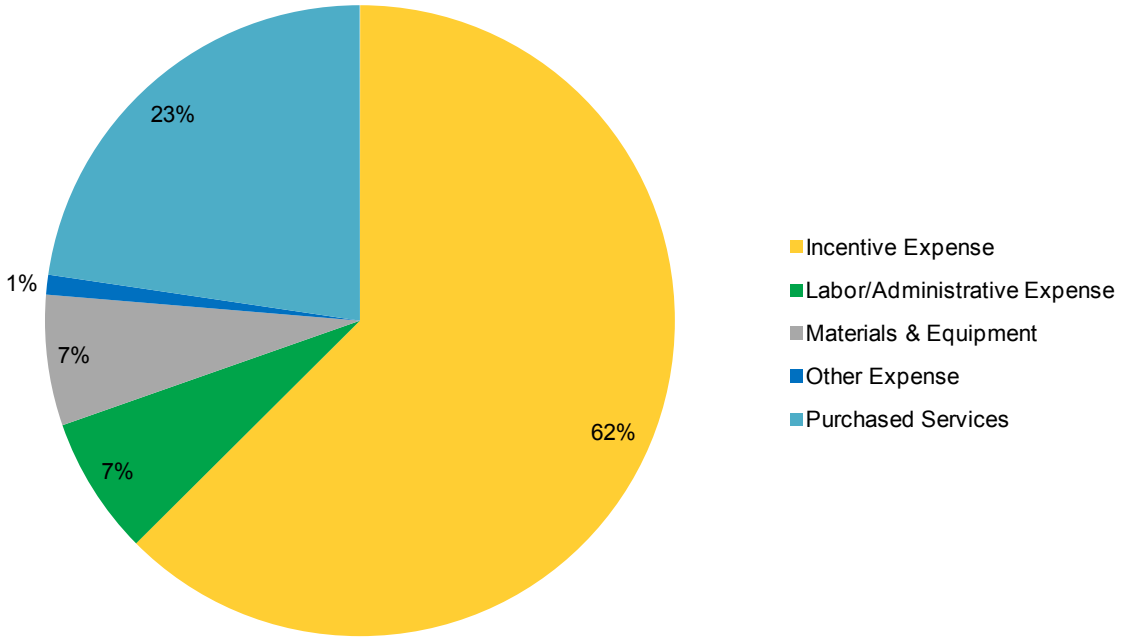


Figure 4. 2012 DSM program expenditures by category

Table 5 and Figure 5 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments—demand response (DR) and Energy Efficiency (EE)—and three sectors—Residential, Commercial/Industrial, and Irrigation. The incentives listed are funded by the Idaho Rider, Oregon Rider, the Custom Efficiency regulatory asset, the Idaho PCA mechanism, and Idaho Power base rates. Market transformation-related payments made to NEEA and payments made to third-party community action partners under the WAQC program are not included in the incentive amounts.

Table 5. 2012 DSM program incentives by segment and sector

| | Sector Total | % of Total |
|---|---|---|
| DR—Residential | $ 759,544 | 2% |
| DR—Commercial/Industrial | 2,905,642 | 9% |
| DR—Irrigation | 11,011,193 | 36% |
| EE—Irrigation | 2,043,829 | 7% |
| EE—Residential | 2,143,235 | 7% |
| EE—Commercial/Industrial | 11,985,498 | 39% |
| **Total Incentive Expense** | **$ 30,848,941** | **100%** |

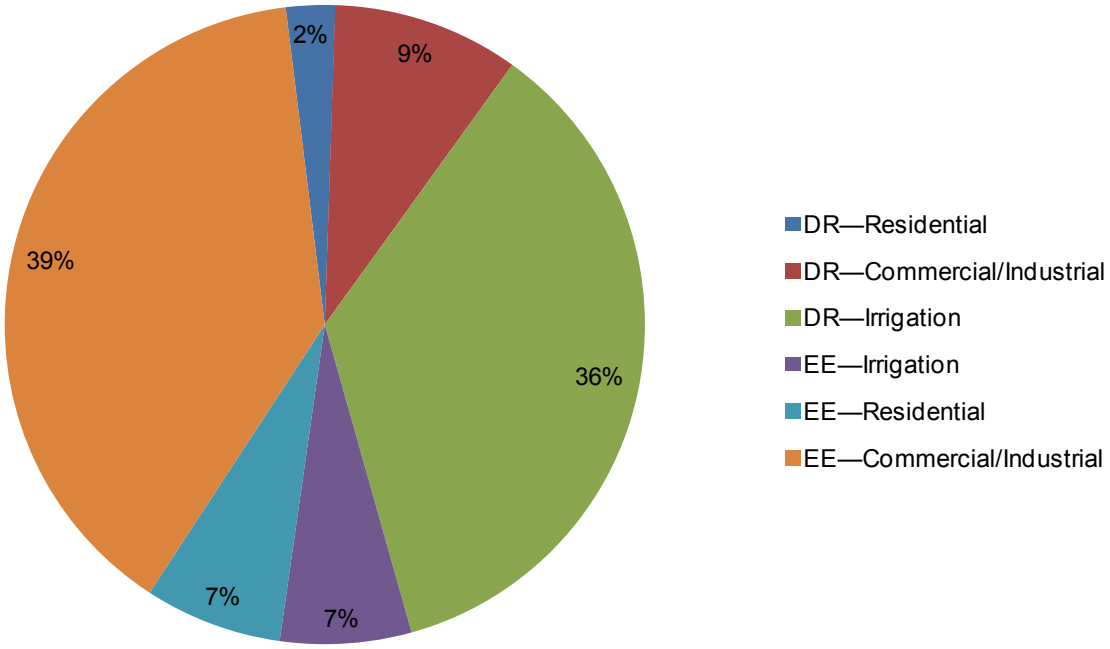


Figure 5. 2012 DSM program incentives by segment and sector

## Marketing

With technology rapidly advancing, marketing choices are no longer as simple as placing a print advertisement or distributing a press release. Now marketing is a mosaic that also includes social media, multimedia, community events, online advertising, and owned media.

To meet the demands, a new marketing specialist was added to the energy efficiency team at Idaho Power in April 2012. Adding this position allowed for new marketing ideas and a more balanced workload for two specialists.

Idaho Power marketing staff continually research academic and industry best practices to stay current on marketing theory and tactics. Successful marketing approaches from inside and outside the utility industry are studied and evaluated to determine if they are appropriate for marketing Idaho Power's energy efficiency programs.

Below is a high-level summary of new marketing communication tactics developed and implemented during 2012.

To increase Idaho Power's communication with small and medium commercial customers, the company launched the first biannual *Energy at Work* commercial newsletter. The goal of this newsletter is to provide pertinent and useful information to a customer segment with limited time. The summer 2012 edition is available to download on Idaho Power's business energy efficiency web page. Topics in this edition include the following:

- Energy Efficiency: Good for Business and Your Health
- T-12 Lamps are So Yesterday

- 2011 Commercial Energy Efficiency Program Recap
- Planning for a Successful Energy Efficiency Project
- Four Steps to An Energy-Saving Business Strategy

A video about the DHP Pilot was produced in the first half of 2012 using customer testimonials to explain why people choose DHPs and the benefits for electrically-heated homes. This video is available on Idaho Power's DHP Pilot's web page http://www.idahopower.com/EnergyEfficiency/Residential/Programs/ductlessHeatPumps/default.cfm. The video also was uploaded to YouTube and received 5,200 views in approximately one year.

Planning for an Easy Upgrades program online advertising campaign began in the fall and winter of 2012 to increase participation in the program. An animated advertisement was developed to target commercial businesses, with a planned launch date of January 2, 2013. The advertisement targets specific professions and industries within Idaho Power's service area. Idaho Power staff will review weekly reports to monitor click-through rates (the number of times a user clicks on the advertisement, taking them to a corresponding web page) and make adjustments as needed over the course of the three-month campaign.

Two movie theater advertisements, one for the Home Improvement Program and one for both ducted and DHPs, were produced using in-house resources and shown at Regal Cinema theaters in Nampa and Boise. The advertisements ran for eight weeks during June and July 2012. The number of individual advertisements shown totaled 12,544, and the number of total projected impressions was 695,376; total projected impressions are the anticipated number of times an advertisement will be displayed or viewed, giving customers a certain number of potential exposures to a message or an "opportunity-to-see." The more times a message is viewed, particularly within a shorter time frame, the more likely customers will take action. To maximize the usability of the two movie theater advertisements, both advertisements were uploaded to YouTube and the Home Improvement Program advertisement was posted on the program's Idaho Power web page.

At the November 6 EEAG meeting, an Idaho Power Corporate Communications department representative solicited information from EEAG regarding changes to the company's monthly customer newsletter, *Connections*. Discussions covered reducing the number of energy efficiency bill inserts and instead creating energy efficiency-focused *Connections* editions. EEAG members offered suggestions and support for adding more energy efficiency information in the newsletter. In July 2013, *Connections* will specifically focus on the company's energy efficiency programs.

In January 2013, Idaho Power produced a print advertisement campaign featuring a New Year's theme and a number of Idaho Power's energy efficiency programs. The advertisement ran for two weeks in daily and weekly newspapers throughout Idaho Power's service area.

Facebook and Yahoo! behavioral-targeted advertisements are being used to expand Idaho Power's online presence. Idaho Power staff track these online marketing campaigns through reports that show the number of impressions (number of times a person is exposed to a message), click-through rates, and reach (geographic dispersion of the message). These reports will help inform subsequent marketing decisions.

The following additional metrics are used to determine if marketing tactics are successful.

- Trade ally/contractor feedback
- Customer comments via the Idaho Power call center, email, and customer representatives (CR)
- Qualitative and quantitative survey results
- Customer inquiries and customer awareness of programs
- Web Trends data reports

## Program Evaluation

Evaluation of the company's DSM programs is integral in providing accurate and transparent program savings results and is a key component in Idaho Power's commitment to continuous program improvement.

Most program evaluations and primary research is contracted through third-party entities by means of a competitive bid process managed by Idaho Power's Procurement department. When appropriate, an internal analysis is conducted and managed by Idaho Power's Energy Efficiency Research and Analysis team.

In 2012, Idaho Power completed third-party impact evaluations on the following six programs: Heating & Cooling Efficiency (H&CE) Program; See ya later, refrigerator®; WAQC; Weatherization Solutions for Eligible Customers; Building Efficiency; and Easy Upgrades. Additionally, a third-party process evaluation of the A/C Cool Credit program and a 20-year all-sector energy efficiency potential study were completed.

Two third-party primary research projects were conducted in 2012. The A/C Cool Credit research project delivered a predictive model for future use in determining the value of curtailments at various temperatures and cycling strategies. The Irrigation Efficiency Rewards research project determined the estimated unit energy savings for measures deemed out of compliance by the RTF.

Internal program impact reports were completed by Customer Relations and Energy Efficiency staff for the FlexPeak Management and Irrigation Peak Rewards programs. The *Weatherization Assistance for Qualified Customers 2011 Annual Report* was completed in 2012 and filed with the IPUC on April 1, 2012.

Copies of the final reports from evaluations and research performed in 2012 and the *Weatherization Assistance for Qualified Customers 2011 Annual Report* are included in *Supplement 2: Evaluation*.

## Customer Satisfaction

In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*. In 2013, based on surveys conducted in 2012, Idaho Power's satisfaction among business customers decreased by 6 percent overall. Fifty-five percent of the business customer respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than the

customers who are unaware of the programs. The awareness of Idaho Power's energy efficiency programs not only affects the customer's overall satisfaction with the company but also his/her satisfaction with corporate citizenship.

Since 1995, Idaho Power has employed an independent third-party research vendor to conduct customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The survey measures the satisfaction of a number of aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, the intent of this survey is not to measure all aspects of any or all energy efficiency programs offered by Idaho Power.

The 2012 results of Idaho Power's quarterly customer relationship survey continued to show slight but steady improvement. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003, when energy efficiency-related questions were added to the survey, to 60 percent in late 2012. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for improvement. Figure 6 depicts quarterly growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

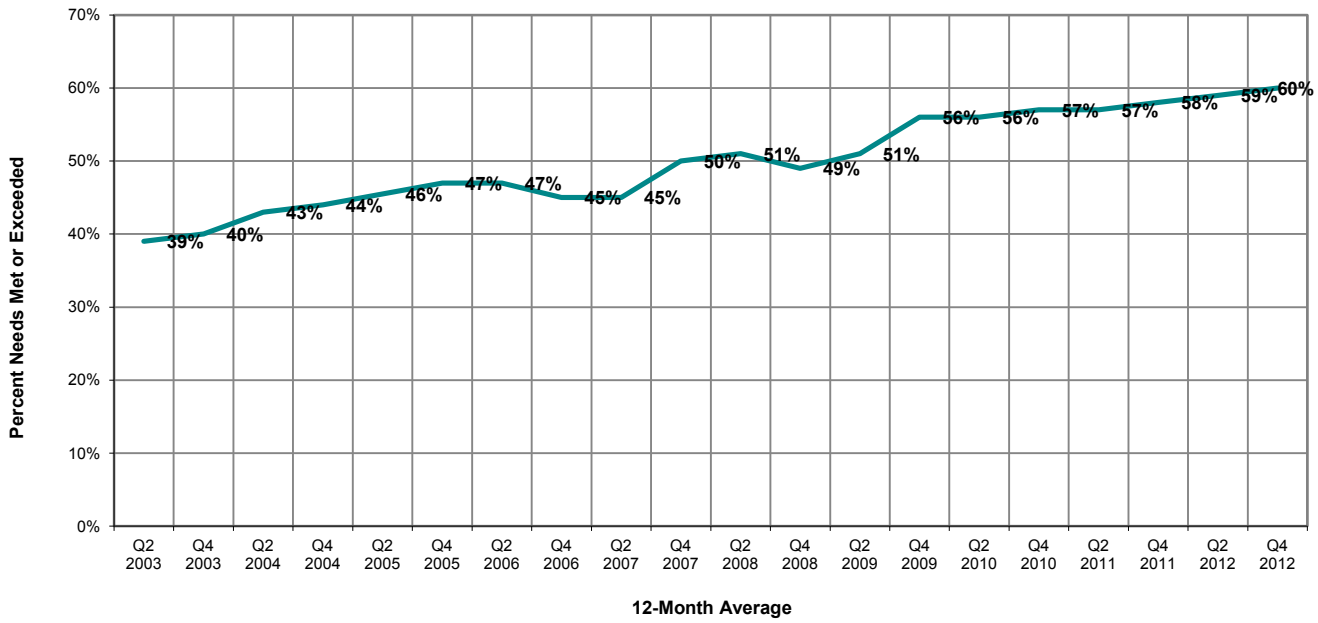


Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

Three questions related to energy efficiency programs in the general relationship survey were added in 2010 and continued in the 2012 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs?, 2) Which energy efficiency program did you participate in?, and 3) Overall, how satisfied are you with the energy efficiency program? In 2012, overall, 35 percent of the survey respondents across all sectors indicated they have participated in at least one Idaho Power energy efficiency program. Of survey respondents who have participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program.

Qualitative research in the form of focus groups and one-on-one customer interviews measured customer satisfaction with the Building Efficiency program in 2012. This research provided guidance for

program modification and marketing. Results from this research are presented in the program descriptions in this report under Building Efficiency.

Due to a concern of over-surveying program participants or "survey fatigue," and because the measures and specifics of most program designs do not change annually, Idaho Power has determined it is in the best interest of customers and program operations not to survey most program participants annually. To ensure meaningful research in the future, Idaho Power has determined that program research will be done periodically (every two to three years), unless there have been major program changes. If aspects of the program change significantly, a satisfaction survey will likely be warranted subsequent to the change.

## Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. In the past, most of Idaho Power's energy efficiency and demand response programs were preliminarily identified through the IRP process. Because of Idaho Power's diversified portfolio of programs, in the 2011 IRP, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to programs rather than new programs. The process in the IRP remains the same for determining if measures should be adopted as it was for program inclusion. Specific cost-effective programs or energy-saving measures are screened by sector to determine if the levelized cost of these programs or measures is less than supply-side resource alternatives. If they are shown to be less costly than supply side resources from a levelized-cost perspective, the hourly shaped energy savings is subsequently included in the IRP as a resource.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models are inputs from various sources in order to use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other utilities in the region or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than 1 for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program level and the measure level where appropriate. An exception to the measure level cost-effectiveness is when there is interaction between measures. Idaho Power may launch a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following the implementation of a program, cost-effectiveness analyses are reviewed as new inputs from the actual program activity become available, such as actual program expenses, savings, or participation levels. If measures or programs are determined not to be cost effective after implementation, the program or measures are reexamined, including input provided from the company's EEAG.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2012. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. As done in 2011, the actual historic savings and expenses were not discounted; only the value of the ongoing savings going forward are discounted to reflect today's dollars. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

In 2012, all three of the company's demand response programs were cost effective from a long-term perspective. Since this report is focused on cost-effectiveness for 2012 and with the final order pending on IPC-E-12-29, Idaho Power did not change the forecast of future expenses and program performance of its demand response programs. The Irrigation Peak Rewards and FlexPeak Management programs were shown to be cost effective from the one-year perspective for 2012. The A/C Cool Credit program was determined not to be cost-effective on a one-year perspective for 2012 because of the additional expense of replacing the paging switches with Advanced Metering Infrastructure (AMI)-compatible switches. All but two of Idaho Power's energy efficiency programs were cost effective from the UC, TRC, and PCT perspectives. WAQC and Weatherization Solutions for Eligible Customers programs are shown to be not cost-effective from the TRC and UC perspective. This was due to the lower estimated savings per home that resulted from the impact evaluation conducted by D&R International, Ltd. Fifty-two measures within programs were not cost effective from the UC or TRC perspective. Of those 52 measures, 40 were measures that were removed from the program offerings in 2012. Eleven measures will be reviewed and possibly modified in 2013. One measure will be removed in 2013. The specific cost-effectiveness ratios are included in *Supplement 1: Cost-Effectiveness*.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found that 10 incentives out of 410 were paid to builders who submitted applications for ENERGY STAR gas-heated homes that were initiated in 2011. Since non-electrically heated ENERGY STAR Homes Northwest applicants with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The total incentives paid for the 10 homes were $4,000. Gas-heated homes were excluded from the program because, as shown in *Supplement 1: Cost-Effectiveness*, gas-heated ENERGY STAR homes are not cost effective from the TRC perspective; however, they are cost-effective from the UC perspective, and the program remains cost-effective with the inclusion of the costs and savings from the gas-heated homes. In 2013, the fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. The code was changed on the incentive field to reflect electrically heated homes. These changes will prevent gas-heated homes from being given incentives in the future. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

## Future Plans

Many of Idaho Power's DSM programs are selected for implementation through Idaho Power's biennial IRP planning process. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency in developing a preferred portfolio of future resources that meets the specific energy needs of Idaho Power's customers. In 2013, Idaho Power plans to increase participation in, and energy savings from, existing energy efficiency programs and initiatives. The company will continue to explore new potential, such as efficient measures for multiple-family dwellings. The company will continue to modify programs and measures and update energy savings and cost data to ensure all of its programs remain cost effective. With the filing and acknowledgement of the 2013 IRP, Idaho Power will have a new set of commission-acknowledged DSM alternative costs with which to analyze its energy efficiency programs. The company will conduct research and analysis to determine the effects of these new costs on the cost-effectiveness of its programs. Additionally, the company will continue to expand and enhance its research and EM&V projects included in the evaluation plan in *Supplement 2: Evaluation*.

## DSM Annual Report Structure

The structure of Idaho Power's *Demand-Side Management 2012 Annual Report* remains mostly unchanged from the 2011 report. It aligns with the reporting requirements included in the MOU with the IPUC staff and Idaho's other investor-owned utilities.

This main *Demand-Side Management 2012 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a chart containing 2012 and 2011 program metrics in tabular format, followed by a general description, 2012 activities, cost-effectiveness, customer satisfaction/evaluation, and 2013 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. Appendices 1 through 5 following the written sections contain tabular information on 2012 expenses and savings and supply historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions: 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams, Valley, and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot, and Salmon areas.

Idaho Power currently divides its service area into three geographic regions: 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the five historical regions are often referred to throughout this report.

Appendices 1 through 5 remain generally unchanged in form and contain financial, energy savings, demand reduction, levelized costs, and program life B/C ratios from the UC and the TRC perspectives. Appendix 5 contains detailed financial and energy-savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Included again this year are two supplements and an attached CD. *Supplement 1: Cost Effectiveness* contains detailed annual cost-effectiveness information by program and energy-saving measures, as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, ratepayer impact measure test (RIM), and PCT perspectives. As of 2011, Idaho Power is using the alternate DSM costs and other financial inputs from Idaho Power's 2011 IRP. These inputs are used in cost-effective analyses for 2011 and forward.

*Supplement 2: Evaluation* contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) and other reports provided by NEEA is attached to Supplement 2.

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# RESIDENTIAL SECTOR OVERVIEW

## Description

Idaho Power serves a population of slightly over one million people. Of this overall population, at the end of 2012 the company was serving 416,020 residential customers in its Idaho and Oregon service areas. During 2012, Idaho Power added 4,533 residential customers, a significant increase of residential customers compared to 2,733 in 2011. The growth in residential customers is the largest increase of residential customers over the past five years. This positive trend points towards a decrease in economic uncertainty, with more housing starts occurring in the company's service area. However, it is important to keep this growth rate in perspective from the standpoint that at its highest growth rate, Idaho Power was adding over 15,000 residential customers per year. In 2012, the residential segment represented 35.8 percent of Idaho Power's total electricity usage.

During 2012, after three consecutive years without hitting a system peak, Idaho Power hit its new system peak of 3,245 MW on July 12 at 4:00 p.m. The previous system peak of 3,214 MW was on Monday, June 30, 2008, at 3:00 p.m. In 2012, the Idaho Power service area experienced higher than normal summer temperatures and a summer high temperature of 108 degrees on July 12, 2012. A/C Cool Credit and FlexPeak Management demand response programs were dispatched on July 12, helping reduce what would have been a higher system peak. The company also had a low system winter peak during 2012. The all-time winter peak for Idaho Power of 2,528 MW occurred on Thursday, December 10, 2009, at 8:00 a.m. The winter system peak during 2012 was only 2,133 MW on Wednesday, December 19, at 8:00 a.m. All of these factors contributed to a of 1.4-percent decrease in residential system sales from 2011 to 2012. However, when the system sales data is weather adjusted, this decrease is only 0.2 percent. Idaho Power continued its education and promotion of energy efficiency programs and information to all residential customers. These tasks and activities contributed to increased program participation and continued strong customer satisfaction results.

# Programs

Table 6. 2012 residential program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| A/C Cool Credit | 36,454 homes | $ 5,727,994 | $ 5,727,994 | n/a | 44.9 |
| **Total** | | **$ 5,727,994** | **$ 5,727,994** | | **44.9** |
| **Energy Efficiency** | | | | | |
| Ductless Heat Pump Pilot | 127 homes | $ 159,867 | $ 617,833 | 444,500 | |
| Energy Efficient Lighting | 925,460 bulbs | 1,126,836 | 2,407,355 | 16,708,659 | |
| Energy House Calls | 668 homes | 275,884 | 275,884 | 1,192,039 | |
| ENERGY STAR® Homes Northwest | 410 homes | 453,186 | 871,310 | 537,447 | |
| Heating & Cooling Efficiency Program | 141 projects | 182,281 | 676,530 | 688,855 | |
| Home Improvement Program | 840 homes | 385,091 | 812,827 | 457,353 | |
| Home Products Program | 16,675 appliances/fixtures | 659,032 | 817,924 | 887,222 | |
| Oregon Residential Weatherization | 5 homes | 4,516 | 11,657 | 11,985 | |
| Rebate Advantage | 35 homes | 37,241 | 71,911 | 187,108 | |
| See ya later, refrigerator® | 3,176 refrigerators/freezers | 613,146 | 613,146 | 1,576,426 | |
| Weatherization Assistance for Qualified Customers | 238 homes/non-profits | 1,370,141 | 1,819,945 | 648,304 | |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 1,070,556 | 257,466 | |
| **Total** | | **$ 6,337,777** | **$10,066,879** | **23,597,363** | |

Notes:
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.

Programs available to residential customers include 1 demand response program, 12 energy efficiency programs, and 1 energy efficiency educational initiative. Residential efficiency programs include Energy House Calls; Rebate Advantage; ENERGY STAR® Homes Northwest; Home Products Program; Home Improvement Program; Energy Efficient Lighting; WAQC; Weatherization Solutions for Eligible Customers; DHP Pilot; Oregon Residential Weatherization; H&CE Program; and See ya later, refrigerator®.

Idaho Power markets its residential energy efficiency programs through many promotional methods including, but not limited to, bill inserts, bill messages, print advertisements, radio and television commercials, billboards, retail events, customer visits, and participation in home and garden shows as well as fairs.

Presentations to community groups and businesses continued to be a major emphasis during 2012. Idaho Power customer and community education representatives made hundreds of presentations in communities served by the company.

Idaho Power conducts the Burke Customer Relationship survey each year. This survey showed 53 percent of residential survey respondents in 2012 indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill.

Sixty-one percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 45 percent of Idaho Power residential customers surveyed in 2012 indicated Idaho Power is meeting or exceeding their needs in offering

energy efficiency programs, while 26 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 83 percent are “very” or “somewhat” satisfied with the program.

# A/C Cool Credit

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants) | 36,454 | 37,728 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 44.9 | 24.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $4,804,566 | $2,781,553 |
| Oregon Energy Efficiency Rider | $92,810 | $114,989 |
| Idaho Power Funds | $830,618 | $0 |
| Total Program Costs—All Sources | $5,727,994 | $2,896,542 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.33 | |
| Total Resource Benefit/Cost Ratio | 1.33 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners (A/C) or heat pumps off and on via a direct-load control device installed on the A/C unit. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high. Idaho Power may cycle participants' A/C for up to 40 hours each month in June, July, and August. In return, participants receive a $7 per-month credit on their Idaho Power bill during July, August, and September.

Customers' A/Cs are controlled using two types of switches that communicate either by power-line carrier (PLC) or radio paging signals. A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C during a cycling event. AMI switches use PLC communication, which provides the communication backbone for these switches. Since the implementation of Idaho Power's AMI project, the company installed the AMI switches wherever possible on new A/C Cool credit participants' A/C units in an effort to eliminate the use of radio paging signal switches.

In 2012, Idaho Power decided to replace existing radio-controlled paging switches with AMI switches due to declining radio paging coverage. There were approximately 23,500 paging switches in the field at the start of 2012. The company successfully negotiated with its third-party installation vendor to reduce the cost to replace the switches and worked with the switch supplier, Aclara®, to reduce the lead time to secure the necessary switches. This switch replacement project began in spring 2012. The project was originally planned to take approximately 18 months beginning in March 2012 and finishing in

June 2013. Switches in areas where paging coverage had been discontinued were replaced first and were replaced by June 15, 2012. Due to Idaho Power's filing of IPUC Case No. IPC-E-12-29 to temporarily suspend the program, the switch replacement project was discontinued in December 2012. At the end of 2012, approximately 7,640 radio-controlled paging switches were still on the system and 28,539 AMI switches were in the program.

## 2012 Activities

In 2012, Idaho Power contracted with PECI to conduct a research project for the A/C Cool Credit program. PECI's goals were to: 1) verify that savings can be estimated using AMI data, 2) verify that the adaptive algorithm embedded in the switches was working as designed, 3) create a predictive model for planning purposes, 4) estimate the kW reduction at various temperature and cycling strategies, and 5) test customer comfort impacts of higher cycling strategies to find optimum curtailment strategies that maximize kW results while minimizing customer comfort impacts.

To obtain the necessary data to complete this research and develop a predictive model, PECI needed observations of different curtailment strategies at different temperatures with corresponding baseline days where no curtailments occurred. The baseline days provided comparative information to ensure the impact on a curtailment day was fully attributed to the program. Overall, this curtailment research approach was a departure from previous years, where resources were called based on the perceived system need and value.

Based on PECI's research strategy and available days where the temperature matched the research design, there were 13 cycling events in 2012. One cycling event was in June, six events were in July, and six events were in August. Most events lasted from 4:00 p.m. to 7:00 p.m. For two events, participants were divided into two groups, with one group cycling from 4:00 p.m. to 7:00 p.m. and the second group cycling from 5:00 p.m. to 8:00 p.m. One hundred percent cycling, where the paging switches completely turn off the A/C units, was tested twice for one hour each time from 5:00 p.m. to 6:00 p.m.

Prior to the 2012 cycling season, the program specialist convened a working group to manage the complex nature of the cycling events required by the study. This working group included leaders and staff from the Customer Research & Energy Efficiency (CR&EE) department and representatives of Idaho Power's Metering department, who are responsible for configuring the dispatch software used by the AMI switches. The variables that needed configuration included three geographic areas, eight cycling percentages, and four time intervals that needed to be developed for two types of AMI switches.

This working group monitored the events and acted to address cycling issues as they occurred throughout the summer. After the cycling season, this group updated program process flow charts and provided input to PECI's Start-Up Checklist provided in their process evaluation report.

In 2012, due to the low switch inventory and the lead-time necessary to obtain switches, the company determined it would be best to use the available switches to replace paging switches and reduce marketing activities. The limited marketing methods used included a bill insert, follow-up letters for a cause-related effort, and a few small direct-mail campaigns.

The cause-related marketing approach used the last few years, consisting of partnering with the Idaho Foodbank and the Oregon Food Bank–Southeast Oregon Services, was updated and expanded to offer more choices for potential participants. The promotion started in mid-October 2011 and continued

through February 2012. Customers enrolling during this limited-time offer and having a switch installed chose between a $20 contribution made to the participant's local food bank and a $20 gift card to a retailer or restaurant of their choice. For 2012, this marketing approach yielded 315 new A/C Cool Credit enrollments. Gift card fulfillment was administered by a third party.

The criteria used for creating new participant solicitation lists were further refined in 2012 as part of a continuing endeavor to focus targeting efforts. Previous criteria included July energy use over 500 kWh; July use 15 percent or greater than April use; Idaho and Oregon residential customers in Ada, Bannock, Bingham, Canyon, Elmore, Gem, Gooding, Jerome, Malheur, Payette, Power, Twin Falls, and Washington counties; an active Utility Service Agreement (USA); "receive marketing" indicator yes; not an existing program participant; premise type is a house; no known landlord; and no duplicates. In 2012, a criterion was added to include 5 kW of demand, or more, for July. The mailing list was further refined to remove any miscellaneous accounts that met the above criteria but did not make sense to include, such as outbuildings, wells, religious facilities, estate accounts, or those managed by a third party.

Since the paging provider discontinued paging service to the Mountain Home Air Force Base (MHAFB), the company could not cycle the switches located in this area in 2012. The financial incentives previously paid to the MHAFB were discontinued. The company explored the option of partnering with the MHAFB to add additional paging equipment at the MHAFB; however, it was not possible to complete the contracts in time for the 2012 cycling season. As of the date of this publishing, a solution to use the paging switches on the MHAFB has not been determined.

## Cost-Effectiveness

The B/C analysis for the A/C Cool Credit program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW simple-cycle combustion turbine (SCCT) is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation agreed to in that settlement workshop was filed on February 14, 2013. Idaho Power will meet with stakeholders and interested parties in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in the IPC-E-12-29 case, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit program for its cost-effective analysis. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance. Under these assumptions, the A/C Cool Credit program had a lifecycle TRC ratio of 1.33 and a one-year TRC ratio of 0.68. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

As mentioned earlier, in 2012, Idaho Power contracted with PECI to conduct research on the A/C Cool Credit program to determine optimal curtailment strategies to meet cost-effectiveness targets and develop a predictive model that correlates weather forecasts with achievable kW load shifts from curtailment events. The results of this research showed that: 1) AMI data for evaluation is more reliable, accurate, and cost-effective than data loggers; 2) the embedded adaptive algorithm is operating as intended, although was only used once during the research period; 3) customer comfort is only minimally affected by higher cycling strategies and indoor temperature increase during events within the range expected for load control programs; and 4) the data from this research enabled PECI to create a predictive model that can be used for planning purposes.

The PECI research also demonstrated that the A/C Cool Credit program can achieve 1.09 kW per participant demand reduction when the weather is sufficiently hot and the cycling strategy is set appropriately. The research noted that on the July 2 event, one set of switches did not respond as expected. The event was intended to be a one-hour curtailment at 100 percent at a temperature of less than 90 degrees. The temperature rose above 90 degrees, which was outside the parameters recommended by PECI, thus the event was canceled. The paging switches and one set of the AMI switches responded; however, the other set of the AMI switches did not stop cycling when the event was cancelled. A change had been made to the scheduling software on Friday, June 29, and the Monday, July 2 event was the first event that occurred after this change was made. Upon investigating and working with the vendor, a coding error was found in the third-party software. Idaho Power developed an interim solution for future use. The vendor is aware of the situation and is working to develop a more permanent solution. The report also makes note that for the event on July 11, only one set of the AMI switches received the signal to dispatch. Idaho Power investigated and found a configuration setting that needed to be changed. This setting was corrected and tested before the event on the following day, July 12. All the switches responded correctly for that event.

Idaho Power also contracted with PECI to provide a process evaluation and program readiness plan. The objective of this evaluation was to document and evaluate the current program processes, identify best practices, and provide recommendations for improvement where applicable. The readiness plan was created to ensure interdepartmental coordination and program readiness prior to the 2012 curtailment season.

The process evaluation report indicated that the program has a high customer satisfaction rate, low churn rate, and a successful relationship with the delivery partner, Honeywell, Inc. PECI also noted that the program has operated successfully due to the continuity in program knowledge from the program specialist and the diligence of internal stakeholders.

PECI recommends: 1) determine appropriate metrics for measuring response rates to marketing campaigns; 2) more focus on customer retention; 3) clearly define roles, responsibilities, and accountability to increase collaboration between marketing and program staff; 4) incorporate pre-season testing of field equipment; and 5) more consistent messaging regarding program guidelines. Copies of both of these reports are included in *Supplement 2: Evaluation*.

## 2013 Strategies

The 2013 activities for this program hinge on the results of the company's proposal in IPC-E-12-29 to temporarily suspend the A/C Cool Credit program for the 2013 season and upcoming workshops on how to proceed with demand response programs for 2014 and beyond. The proposed suspension will

provide Idaho Power an opportunity to work with stakeholders to determine how this program might best serve customers and the company in the future. The company believes the filing is a prudent step to avoid expenses associated with the program until the company's planning process determines the future of the A/C Cool Credit program and the demand response programs in general. Because of this pending proposal, switch replacements were discontinued in December 2012. Approximately 15,564 paging switches have been replaced, and approximately 7,640 remain in the field.

# Ductless Heat Pump Pilot

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 127 | 131 |
| Energy Savings (kWh) | 444,500 | 458,500 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $153,017 | $183,260 |
| Oregon Energy Efficiency Rider | $6,850 | $7,923 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $159,867 | $191,183 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.024 | $0.028 |
| Total Resource Benefit/Cost Ratio | $0.094 | $0.081 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.22 | |
| Total Resource Benefit/Cost Ratio | 1.44 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area. The company extended the project as an Idaho Power DHP pilot through 2012. A main goal of the Northwest DHP Pilot project is to promote DHP technology as an energy-saving alternative for customers who primarily heat their homes with electricity. In 2012, Idaho Power offered customers a $750 incentive payment to participate.

The program targets homes heated with electric zonal systems. Typically, these homes do not have air ducting and therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboards, ceiling cables, and wall-mounted units. Homes heated with fossil fuel forced-air systems or electric forced-air systems do not qualify. Qualifications include having one DHP indoor unit installed in the main living area of the home, since this is where most occupants spend the majority of their time.

Other Northwest DHP Pilot goals are to identify how much energy this technology saves to determine an RTF deemed-savings amount and to obtain customer satisfaction and behavior patterns regarding the units.

Field monitoring of selected homes throughout the Pacific Northwest, an analysis of billing data, and other evaluations occurred from 2009 through mid-2011. Data was analyzed during the second half of 2011 and continued through 2012. An impact and process evaluation field metering report was published in 2012 by NEEA. NEEA will complete a billing analysis report, cost-effectiveness report,

and the final summary report in early 2013. Details about the regional DHP effort can be found at the project website at www.goingductless.com and www.neea.org.

## 2012 Activities

Idaho Power used several marketing methods during 2012 to promote the pilot. Examples include participating in trade shows with a working demo unit, advertising in 10 newspapers, sending direct-mail letters, and adding bill inserts. The use of social-media websites continued in 2012 to increase DHP Pilot awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on the Idaho Power website. Copies of the two DHP Pilot 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Expanding the network of participating contractors remained a key growth strategy for the DHP Pilot. The goal was to support contractors currently in the DHP Pilot while adding new contractors. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation training sessions to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22 percent increase over 2011.

To hasten the residential adoption of the DHP technology in the Idaho Power service area, a key strategy was to communicate with other tiers of the supply chain. In the Idaho Power service area, there are several wholesalers supplying DHPs to the contractors. The program specialist met with several of these wholesalers to provide them the ability to promote DHPs to their contracting customers and to share helpful information. NEEA provided additional marketing and contractor training support for the DHP Pilot.

Idaho Power and other northwestern utilities participated in a 2012 NEEA-sponsored marketing campaign for DHPs conducted from September through December. Residents in the Idaho Power service area were targeted for the campaign using radio, television, and social-media website advertisements.

## Cost-Effectiveness

In 2012, the RTF reaffirmed support for a provisional annual-savings estimate based on the installation of one indoor-unit installation until the full pilot analysis is completed in early 2013. The qualifying unit should be installed consistent with the pilot guidelines, including at least one ton of heating capacity and using an inverted driven compressor. The deemed savings per unit is estimated at 3,500 annual kWh until the pilot analysis is completed. Regardless of prior cooling, the type of electric-resistance heat the DHP was displacing, or the climate zone in which the unit is located, the RTF has only deemed one savings amount. Participant costs for the TRC estimate were calculated by averaging one-unit installations that occurred in Idaho Power's service area in 2012. The average installation cost was $4,358, which was an increase over the 2011 average cost of $3,407. Using the RTF-deemed savings, this program is shown to be cost effective. For details see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the DHP Pilot, Idaho Power conducted on-site verifications (OSV) at completed installations in Idaho Power's service area to ensure the installations complied with program requirements. The OSVs were beneficial for customers and the contractors. The inspector provided information to customers regarding maximizing the benefits of their DHP. The contractors received feedback from the

inspector and reviewed the installation requirements of the DHP Pilot. Ten percent of the installations received on-site verifications in 2012.

In 2012, NEEA provided two reports to update the DHP pilot. The following are report highlights. These reports are included on the CD accompanying *Supplement 2: Evaluation*.

### Report E12-237, released May 2012

This report focuses on the detailed metering portion of the evaluation. Ecotope, Inc., installed metering equipment on a total of 95 homes selected from the participants in the DHP Pilot project. The metered sites were analyzed to develop the determinants of energy savings of the DHP systems as they operated across a variety of climates and occupants. The results of this report contribute to a more comprehensive understanding of DHP performance and its applicability as an energy efficiency measure in the Northwest. The metering results indicate supplemental heat from other fuels has less overall impact on savings than originally expected. The analysis also strongly indicates that increased indoor temperatures result in lower savings. The use of a DHP in place of baseboard heaters is far less sensitive to the characteristics of the home than would be expected in a conventional heating system. Other findings suggest the occupant's acceptance of this equipment is good and their satisfaction is uniform.
The amount of DHP cooling energy measured in the study was about 7 percent of the total value of heating savings. The cooling energy value was considered insignificant when compared to the heating savings value. Therefore, the cooling energy usage was not factored into the net impact of the equipment.

### Report E12-245, released October 2012

This report is the second MPER of NEEA's Northwest DHP Initiative. The report presents evaluation findings based on 1) telephone surveys of households that purchased DHPs through the initiative, 2) telephone surveys of other general-population households, and 3) in-depth interviews with Northwest utilities that support the initiative, DHP manufacturers/distributors, and installers. The report includes current data on the DHP market in the Northwest. The report findings suggest that multimedia marketing should be continued. Word-of-mouth marketing is a tactic that should be incented as well.
The distributors should also be encouraged to promote DHPs that can perform well in extremely low outdoor temperatures. The report also suggests that banks and financial institutions be encouraged to offer financing for DHPs.

## *2013 Strategies*

Idaho Power will sponsor and provide training sessions and orientations to the DHP Pilot program for new and existing contractors to assist them in meeting program requirements and further their product knowledge.

Expanding the network of participating contractors remains a key strategy for the DHP Pilot. The goal is to support contractors currently in the DHP Pilot while adding new contractors. Performance of the DHP Pilot is substantially dependent on the success of the contractor's ability to promote and leverage the DHP Pilot. Frequent individual contractor meetings will be held in 2013. The program specialist, along with Idaho Power CRs, will arrange these meetings.

To promote the residential adoption of the DHP technology in Idaho Power's service area, the strategy includes communicating with the complete supply chain. To accelerate the wholesaler's ability to increase contractor awareness of DHPs and the DHP Pilot, the program specialist will meet with the wholesalers and share helpful information.

Traditional and new marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the DHP Pilot program, as well as the H&CE Program. Specifically, Idaho Power will discuss the helpfulness and usability of a contractor portal housed on Idaho Power's website. The portal will provide contractors with access to predesigned and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their specific business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces targeted to customers who have high electric winter usage, as well as customers who have moved into a new home, which research has shown have a higher likelihood to make home upgrades. Behavioral advertisements refer to advertisements posted on websites based on an individual's recent web behavior. For example, if someone views a major automobile company's website, automobile advertisements will pop up on other unrelated websites viewed because the Internet Protocol (IP) address of the viewer's searches is tracked.

# Energy Efficient Lighting

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 925,460 | 1,039,755 |
| Energy Savings (kWh) | 16,708,659 | 19,694,381 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,110,329 | $1,668,328 |
| Oregon Energy Efficiency Rider | $16,507 | $50,805 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $1,126,836 | $1,719,133 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.015 |
| Total Resource Benefit/Cost Ratio | $0.025 | $0.024 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.47 | |
| Total Resource Benefit/Cost Ratio | 3.05 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy Efficient Lighting program strives for residential energy savings through the replacement of less-efficient lighting with more-efficient technology. According to the *NEEA 2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study, the average Idaho home has 63 bulb sockets. The *2010 Idaho Power End Use* study shows 88 percent of customers have less than 20 compact fluorescent bulbs installed, indicating there is still potential to install more energy-efficient bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR® qualified compact fluorescent lamps (CFL) are an alternative to standard incandescent light bulbs that result in saved money, energy, and time. Bulbs come in a variety of wattages, colors, and styles, including bulbs for three-way lights and dimmable fixtures. ENERGY STAR bulbs use up to 75 percent less energy and last up to 10 times longer than incandescent bulbs.

## *2012 Activities*

In 2012, the Energy Efficient Lighting program provided more than two-thirds of all energy savings derived from residential energy efficiency customer programs. This contribution is expected to decline in future years as CFL penetration rates increase and more efficient lighting standards are enforced.

The Energy Efficiency Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers with savings passed onto the customer at the point of purchase. The benefits of this model are low administration costs, the availability of products to the customer, and the ability to provide an incentive for specific products.

In 2012, Idaho Power again participated in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings™ promotion focusing on ENERGY STAR specialty and spiral bulbs. Fluid Market Strategies managed the promotion. Fluid Market Strategies is responsible for retailer and manufacturer contracts, marketing materials at the point of purchase, and for providing support and training to retailers. Additional marketing by Idaho Power included the utility website, events, and presentations to customers.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power dropped light fixtures from the Home Products Program and added them as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales of fixtures were reported in 2012 under this promotion.

Additional 2012 program activities included direct distribution and retailer education events. Idaho Power has a small, direct-distribution program where bulbs are given directly to customers at appropriate venues. The idea is, if given a free bulb, customers might try CFLs for the first time or be encouraged to replace additional lamps. Guidelines for approved venues and the direct distribution effort have been developed to ensure customer fairness.

During 2012, Idaho Power participated in six retailer events with large national retailers. Retailer events were designed to communicate directly to customers at the point of sale. Idaho Power staff set up tables with light displays at the entrances of stores and answered questions about CFLs.

The Energy Efficient Lighting program was one of three Idaho Power programs that sponsored the local, semi-professional basketball team, the Idaho Stampede, at the team's Green Week games in April. As part of the promotion, Idaho Power ran a 30-second public-service announcement (PSA) on energy-efficient lighting that aired at two Idaho Stampede home games. The announcement was posted to Idaho Power's website and to YouTube. At the two Idaho Stampede games, the promotion included a light bulb demonstration using a bicycle to power incandescent and CFL bulbs. Sixty-eight people rode the bike at the games and learned firsthand how much less electricity CFL blubs use compared to incandescent bulbs.

Three presentations were developed for use by Idaho Power staff focusing on lighting basics, outdoor lighting, and holiday lighting. A lighting-basics presentation was given at the Ada County Extension office and the Idaho Green Expo.

In 2012, Idaho Power began participating in the Northwest Regional Retail Collaborative (NWRRC) facilitated by NEEA and following work by the Western Regional Utility Network. Both the NWRRC and the Network seek to develop collaborative approaches to working with manufactures and retailers to increase the uptake of energy-efficient products in the retail market.

In 2012, Idaho Power began researching the transition of the Energy Efficient Lighting program to a more comprehensive retailer markdown program that would include additional product categories. Barriers include retailer point-of-sale system limitations. Groups like the NWRRC provide a forum to identify and work toward addressing these types of barriers.

## Cost-Effectiveness

In 2012, the RTF updated several assumptions for specialty CFL bulbs. The change to baseline and efficient wattage assumptions, though minimal, did contribute to the decrease in savings. The RTF reviewed studies and took into consideration the changes in bulb efficiency standards from the

*Energy Independence and Security Act of 2007* (EISA), as well as regional sales data. Additionally, there was a change to the hours-of-use assumptions for various lamp types and storage rates that further contributed to the decrease in savings. Despite the change, the measures still remain cost effective. The savings for spiral bulbs remained unchanged. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

## 2013 Strategies

Idaho Power will continue to participate in Simple Steps, Smart Savings through 2013. Marketing for this program will continue to include point-of-purchase signs at the retailer managed by Fluid Market Strategies. Idaho Power will also promote the program through its website, events, and presentations.

Idaho Power will continue to distribute limited quantities of bulbs directly to customers at appropriate public energy efficiency events and continue to participate in retailer educational events. An evaluation will be made based on the cost to put CFLs in new-customer welcome packets. Customer education regarding savings of time and energy from these improved products will continue.

The company will monitor the market and emerging technologies. Light-emitting diode (LED) light bulbs are on display at many major retailers. As of December 2012, there were over 1,300 products on the ENERGY STAR criteria list for LED replacement bulbs. Seventy-five percent are reflectors. Market prices for LED products are significantly higher than CFLs and EISA-compliant halogens.[1] Idaho Power will continue to evaluate the price, availability, savings, and technology of LED lighting to determine if it should be included in the future.

Idaho Power will also participate in the NWRRC. Participation in the NWRRC will help facilitate research into transitioning the Energy Efficient Lighting program to a more comprehensive retailer-markdown program with additional product categories.

In 2013, Idaho Power plans to do a third-party process evaluation of the Energy Efficient Lighting program.

[1] Example: An ENERGY STAR qualified, 60-watt (W) equivalent A-lamp LED equivalent by Phillips retails between $25.45 and $38.50 according to Consumer Reports at http://www.consumerreports.org/cro/home-garden/home-improvement/lightbulbs/lightbulb-ratings/models/overview/philips-ambientled-12-5w-12e26a60-60w-409904-99040398.htm.

# Energy House Calls

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 668 | 881 |
| Energy Savings (kWh) | 1,192,039 | 1,214,004 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $272,666 | $447,229 |
| Oregon Energy Efficiency Rider | $3,217 | $36,146 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $275,884 | $483,375 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.027 |
| Total Resource Benefit/Cost Ratio | $0.016 | $0.027 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.05 | |
| Total Resource Benefit/Cost Ratio | 3.05 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program helps manufactured and mobile homeowners with electric heating reduce electricity use by improving the home's efficiency. This program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing a CFL bulb; providing two furnace filters, along with replacement instructions; testing water heater temperatures for the proper setting; and distributing energy efficiency educational materials for manufactured home occupants. The value of the service to the customer is dependent on the complexity of the repair, although services are provided free to participants. The typical cost range of the average service call is $325 to $550. Idaho Power provides the customer with the sub-contractor contact information. Customers access the service and schedule an appointment by directly calling one of the recognized, certified sub-contractors specially trained to provide these services in their region.

## *2012 Activities*

Energy House Calls serviced 592 manufactured homes during 2012, resulting in 1,192,039 kWh savings. Seventy-six percent of the homes serviced were located in the Treasure Valley. Twenty-four percent were outside the Treasure Valley, with 11 percent in Eastern Idaho and 13 percent in Southern Idaho. Quality-assurance (QA) checks were conducted on 5 percent of the homes serviced in the program. Idaho Power coordinates the sub-contractors performing local weatherization and

energy efficiency services, processes sub-contractor paperwork, and pays sub-contractors directly for work performed.

Marketing campaigns included a bill insert sent to all Idaho Power residential customers, a program brochure used by Idaho Power representatives in the field and at Idaho Power-sponsored events, and a direct-mail postcard. The direct-mail postcards were sent to all customers identified as living in a manufactured home. Feedback from Idaho Power sub-contractors indicated the direct-mail postcards yielded the most amount of interest in the program. This was the most effective form of marketing.

During summer 2012, Idaho Power employees marketed the Energy House Calls program to managers and residents of mobile home parks in Twin Falls, Pocatello, and Chubbuck. Marketing efforts included distributing marketing material, leaving door hangers, and answering customer questions and inquiries. Marketing materials informed customers their inquiries would be forwarded to the appropriate contractor.

Idaho Power field staff CRs and call-center customer service representatives (CSR) are educated about the program and will continue to promote it to qualified customers.

## Cost-Effectiveness

Duct-sealing deemed savings for manufactured homes were revised in spring 2012 by the RTF to bring the measure into compliance with current guidelines. The measure definition was also updated to reflect different manufactured home styles.

The baseline pre- and post-supply duct leakage were analyzed by the RTF as part of the comprehensive measure review during 2012, and the results were reported at the October 2012 RTF meeting. The baseline duct leakage increased from a previous 15 percent to 20 percent, which corresponds to more duct leakage being found in existing homes, resulting in increased savings from duct sealing. The increased baseline leakage is consistent with data collected from Idaho Power projects. The updated savings were provided along with new measure definitions splitting out savings by either single-wide manufactured homes and double-wide or triple-wide manufactured homes. Annual savings reported for 2012 were assigned by the home's heat source, the existence of central A/C (electric furnace with and without A/C) or a heat pump, and the home's climate zone. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

To monitor QA in 2012, third-party verifications were conducted by Momentum, LLC on approximately 5 percent of the participant homes, resulting in 33 home inspections. The final round of QA results is being analyzed during first quarter 2013 and appears to be consistent with those conducted earlier in the year, which were very positive. Verifications were selected at random. The verification included a visual review of the reported information, as well as a blower door test to verify the results submitted by the sub-contractor.

## 2013 Strategies

Plans for the upcoming year include continuing the direct-mail campaign throughout the Idaho Power service area to increase market penetration. Based off low response rates in the Eastern and Southern regions, there are concerns the market may be reaching saturation. Possible reasons for the lack of participation include an imperfect mailing list and the difficulty in identifying manufactured homes on the Idaho Power billing system. Idaho Power updated the mailing list used for the direct-mail letters in

2012 and plans to do the same in 2013. The list is generated from homes designated as manufactured or mobile on Idaho Power's CIS and is analyzed for homes that appear to use electric heat, based on kWh use during winter and summer months. The company will also continue to explore low-cost and effective methods of marketing this program to all residential customers believed to have electrically heated manufactured homes. This form of marketing may yield additional word-of-mouth promotion to potential program participants. Less broad-based outreach efforts will continue via CRs and limited-income outreach entities.

# ENERGY STAR® Homes Northwest

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 410 | 308 |
| Energy Savings (kWh) | 537,447 | 728,030 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $450,727 | $255,405 |
| Oregon Energy Efficiency Rider | $2,458 | $4,357 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $453,186 | $259,762 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.046 | $0.020 |
| Total Resource Benefit/Cost Ratio | $0.089 | $0.051 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.77 | |
| Total Resource Benefit/Cost Ratio | 2.51 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA to improve and promote the construction of energy-efficient homes using guidelines set forth by the United States (US) Environmental Protection Agency (EPA). This program targets the lost-opportunity energy savings and summer-demand reduction that results by increasing the efficiency of the residential-building envelope and air delivery system above current building codes and building practices. An ENERGY STAR certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR rater to meet the stringent ENERGY STAR requirements. This third-party rater is hired by the builder to perform these duties.

The ENERGY STAR Homes Northwest residential construction program promotes homes that are electrically heated and are at least 15 percent more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes Northwest are verified by independent, third-party HPS and are certified by the Washington State University Extension Energy Program, an organization that conducts the certification inspections throughout the state of Idaho and for the EPA. The homes are more efficient, comfortable, and durable than standard homes constructed according to Idaho building codes.

Homes that earn the ENERGY STAR label include six required specifications. The specifications found in all ENERGY STAR certified homes are 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

In 2012, builders involved in ENERGY STAR Homes Northwest received a $1,000 incentive per home built to the Northwest Builder Option Package (BOP) electrically heated homes standard. Builders who entered their homes in a Parade of Homes received the standard $1,000 incentive plus an additional $500 incentive to encourage builders to construct ENERGY STAR homes.

The Idaho Power program collaborates with many local entities for program promotion, including ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2012 was to provide marketing materials and conduct education and training activities for residential new construction industry partners.

## 2012 Activities

As the housing market slowly started to improve throughout the Idaho Power service area in 2012, the ENERGY STAR Homes Northwest program showed an increase in ENERGY STAR Homes certified from 308 in 2011 to 410 in 2012.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2012. The company presented energy efficiency awards at the Building Contractors Association of Southwestern Idaho (BCASWI) Parade of Homes awards banquet. In addition, the company maintained a presence in the building industry by supporting many of the building contractors associations (BCA) throughout Idaho Power's service area. Specifically, the company participated in the BCASWI Builder's Expo, the Snake River Valley Building Contractors Association (SRVBCA) Builder's Expo, the Magic Valley Builders Association Parade of Homes (MVBA), the BCASWI Parade of Homes, SRVBCA Parade of Homes, the Building Contractors Association of Southeast Idaho (BCASEI) Parade of Homes, and the Idaho BCA Convention. Idaho Power joined with Northwest ENERGY STAR for a minor sponsorship of the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home. Northwest ENERGY STAR secured the donation of the heat pump. Idaho Power produced a bill insert, sent to all residential customers in the Idaho Power service area, promoting ENERGY STAR homes and highlighting the 2012 Dream Home.

Other marketing projects involved adding a message about this program to residential customers' electric bills. These bill messages encouraged Idaho Power customers to visit ENERGY STAR certified homes in their local Parade of Homes events.

## Cost-Effectiveness

There were no changes to RTF deemed-savings values for single family ENERGY STAR homes during 2012. In fall 2012, the RTF produced deemed annual savings for multi-family ENERGY STAR homes using a blended prototype of low-rise, multi-family dwelling types that included a townhome design. The modeled multi-family ENERGY STAR home prototype included a range of homes sizes between 950 to 1,500 square feet ($ft^2$). The average size of a townhome in the program in 2012 was 925 $ft^2$, which falls within the RTF-modeled prototype range. The annual deemed savings for the townhome are approximately one-third the annual savings of a traditional detached single-family home and vary depending on the climate zone between 599 and 770 kWh annual savings. Since 396 out of 410 ENERGY STAR homes given incentives by Idaho Power in 2012 were townhome style homes and did not fit the traditional single-family home, the company applied the new updated savings to all townhomes.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found 10 incentives, out of a total of 410, that were inadvertently paid to builders who submitted applications for ENERGY STAR gas-heated homes. Since non-electrically heated ENERGY STAR Homes Northwest homes with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The costs and savings are included in the cost-effectiveness analysis, and although the company has determined that gas-heated homes are not cost-effective, the program remains cost-effective. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

The HPS works with builders to ensure the ENERGY STAR homes are compliant with the Northwest electric-only BOP. Along with verifying the installation of building components and equipment through on-site inspections, prior to being certified, the home must pass a blower door test, air-duct leakage test, and combustion back-draft tests.

The state-certifying organization (SCO) performs QA. The Washington State University Energy Extension Program is under contract with NEEA to perform QA and technical assistance duties within Idaho. For QA purposes, 10 percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed by the Washington State University Energy Extension Program. This is a technical verification of the homes. All of the homes randomly chosen for QA in Idaho Power's service area passed the QA inspection process.

## 2013 Strategies

As in 2012, builders involved in ENERGY STAR Homes Northwest during 2013 will receive a $1,000 incentive per home built to the Northwest BOP, electric-only standards in Idaho Power's service area. Builders showcasing their electric-only home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive.

Idaho Power plans to continue marketing efforts to help sell ENERGY STAR homes, including educating consumers, Realtors, and appraisers about the benefits and features of ENERGY STAR homes. Results will be influenced by the housing market's potential improvements. These marketing efforts include Parade of Homes advertisements in parade magazines for the BCASWI, SRVBCA, MVBA, and the Building Contractor Association of Eastern Idaho. Bill inserts will be sent to all residential customers in April and May. In addition, bill messaging is planned in June, July, and August to support the various BCA Parade of Homes events throughout Idaho Power's service area.

In 2013, changes were made in Idaho Power's database and payment review process to prevent incentives to be paid for gas-heated ENERGY STAR homes. The fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. Also, the code was changed on the incentive field to reflect electrically heated homes. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the ENERGY STAR Homes Northwest program.

# Heating & Cooling Efficiency Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 141 | 130 |
| Energy Savings (kWh) | 688,855 | 733,405 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $175,483 | $188,876 |
| Oregon Energy Efficiency Rider | $6,798 | $6,894 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $182,281 | $195,770 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.018 | $0.018 |
| Total Resource Benefit/Cost Ratio | $0.066 | $0.056 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.49 | |
| Total Resource Benefit/Cost Ratio | 1.78 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The H&CE Program provides incentives for the purchase and proper installation of qualified heating and cooling equipment to residential customers.

The objective of the program is to acquire energy savings by providing customers with energy-efficient alternatives for electric space heating. Incentive payments are provided to residential customers and heating, ventilation, and air conditioning (HVAC) participating contractors who install eligible equipment. The eligible measures in 2012 included air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Heating and A/C companies authorized by Idaho Power as participating contractors for the program are required to perform all installations, with the exception of evaporative coolers, which can be self-installed. The program continued through 2012 with the same portfolio of incentives as in 2011.

## *2012 Activities*

The H&CE Program's list of measures and incentives during 2012 included the following:

- Air-source heat pump customer incentives for replacing an existing air-source heat pump with a new air-source heat pump were $200 for minimum efficiency 8.2 heating seasonal performance factor (HSPF) and $250 for minimum efficiency 8.5 HSPF.

- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump were $300 for minimum efficiency 8.2 HSPF and $400 for minimum

efficiency 8.5 HSPF. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.

- Incentives for customers or builders of new construction installing an air-source heat pump in a new home were $300 for minimum efficiency 8.2 HSPF and $400 for minimum efficiency 8.5 HSPF.

- The open-loop water-source heat pump customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump was $500 for minimum efficiency 3.5 coefficient of performance (COP).

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump was $1,000 for minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.

- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home was $1,000 for minimum efficiency 3.5 COP.

- The evaporative-cooler customer incentive was $150.

The expanding of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal was to support contractors currently in the program, while adding new contractors. The company held meetings with several prospective contractors to support this strategy. Six companies were added in 2012 to Idaho Power's list of participating contractors, doubling the number added from 2011.

Idaho Power held training sessions for contractors in September that provided general instructions on heat pumps and program guidelines. For a company to be eligible to join the program as a participating contractor, they must have attended this training. Fourteen technicians from eight companies attended the sessions in 2012. These training sessions remain an important part of the program because the training creates opportunities to invite additional contractors into the program.

Several marketing tactics were used during 2012 to reach customers. Examples include print advertising in newspapers, direct-mail, bill inserts, and trade shows. The use of social-media websites continued in 2012 to increase program awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on Idaho Power's website. Copies of the two H&CE Program 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

To increase contractor participation in the program, stronger relationships with the equipment wholesalers was necessary. In Idaho Power's service area, there are several major wholesalers supplying heat pumps to the contractors. The program specialist met with such wholesalers to provide them with the ability to promote the program with their contracting customers and share helpful information.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review the incentive applications and perform OSVs. This contractor provides direct support to participating contractors and the residential program participants. Honeywell offers local assistance through representative visits to contractors at their businesses as needed. Using a program database via a portal developed by Idaho Power, Honeywell reviews and submits incentive applications for Idaho Power payment. This allows

Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor.

On the national level, a 2011 federal tax credit for heat pumps contained in section 25C of the Internal Revenue Service (IRS) tax code was not renewed for 2012.

## Cost-Effectiveness

The savings for heat pumps installed under the H&CE Program consists of both savings for the increased efficiency of the equipment and savings resulting from quality installation, including proper unit sizing, controls settings, and commissioning. While the core savings of air-source heat pumps were not updated or changed by the RTF during 2012, other measures currently not deemed by the RTF, including lower-tier savings heat pumps, evaporative A/Cs, and geothermal heat pumps savings sources were reviewed to ensure they were consistent with the current regional work done by the RTF. For 2012, participant costs' averages used for the cost-effectiveness analysis were calculated using Idaho Power-specific project data instead of relying on regional averages.

There were no changes in 8.5 HSPF air-source heat pump annual savings for 2012 when customers were displacing electric furnaces. Additional equipment savings were claimed in 2012 in cases were customers' equipment performance exceeded an HSPF rating of 9. An additional 115 to 128 annual kWh were claimed depending on the customer's climate zone.

The previous savings for evaporative coolers (swamp cooler) were based on the 2009 potential study and on a generic prototype evaporative cooler that was not differentiated between a direct or indirect cooler design. Indirect cooler designs have specialized equipment that pre-cools the air before the evaporation process occurs, which substantially increases the savings and equipment costs. The few incentives that Idaho Power paid for evaporative coolers were for the direct-cooler design that pushed direct outside air into the cooler with no pre-treatment. The savings were reduced from an annual savings rate 1,300 kWh over a seasonal energy efficiency ratio (SEER) 13 code central A/C to between 300 and 400 annual kWh depending on whether the cooler was installed in a multi-family manufactured home or single-family home. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power contracted with The Cadmus Group, Inc., to conduct an impact evaluation of 2011 savings results. The evaluation report indicated that most measures were installed in compliance with PTCS commissioning, controls, and sizing standards. Tracked data was complete and accurate, and ex-ante energy savings were a reasonable but needed refinement. The program ex-post realized savings rate was 94 percent as compared to ex-ante estimates.

The Cadmus Group, Inc., recommends the following: 1) program staff continue to collect detailed data on each project to refine individual project savings estimates, 2) perform a saturation study to determine intent to convert to all-electric heating and cooling, and 3) consider the promotion of on-bill financing to make a heat pump more attractive to customers. A copy of the complete report is included in *Supplement 2: Evaluation*.

The program performed random OSVs on 14 completed installations in the Idaho Power service area, resulting in 10 percent of the total applicants. These OSVs verified the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with

respect to the contractors. The program specialist continues to work with contractors to help them understand the importance of accurate documentation.

## 2013 Strategies

There will be two changes to the program in 2013. The first change is the removal of measures involving air-source heat pumps below 8.5 HSPF. The measures include replacing an existing air-source heat pump, electric resistance, oil, or propane heating system with a new minimum 8.2 HSPF air-source heat pump. The primary reason for removing these measures is that the heat pump market has been slowly transforming to more efficient, higher HSPF heat pumps. In the last several years, only about 3.5 percent of all applications received in this program have been for units below 8.5 HSPF, rendering an incentive unnecessary.

The second change is to increase the incentive from $400 to $800 when replacing an electric-resistance heating system with an air-source heat pump having a minimum of 8.5 HSPF. Idaho Power made this change to increase the participation of this measure and to focus the program on higher efficiency measures. The incremental installed cost of a new heat pump is approximately $3,000. Idaho Power has evaluated the cost-effectiveness of this measure with an $800 incentive, and this measure continues to be cost effective.

Idaho Power will sponsor and provide training to new and existing contractors in the program to assist them in meeting program requirements and further their product knowledge. Sessions will be held at both local wholesaler and Idaho Power facilities.

Expanding the network of participating contractors remains a key strategy for the program. The goal is to support contractors currently in the program while adding new contractors. The performance of the program is substantially dependent on the success of the contractors' abilities to promote and leverage the measures offered in the program. Frequent individual meetings will be held with contractors in 2013. The program specialist, along with Idaho Power CRs, will arrange the discussions.

To increase participation in the program in the Idaho Power service area, the program specialist will work to strengthen relationships with equipment wholesalers. To accelerate the wholesalers' abilities to increase contractor awareness of the program, the program specialist will meet with the wholesalers and share information.

Numerous marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the H&CE Program, as well as the DHP Pilot. During the visits with contractors, the marketing specialist and the program specialist will specifically discuss the helpfulness and usability of a new contractor portal housed on Idaho Power's website. The portal will provide contractors access to pre-designed and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces to targeted customers who have high electric winter usage and who have moved into a new home. Research has shown new home buyers are more likely to make home upgrades in the first two years of ownership.

In 2013, Idaho Power plans to do a third-party process evaluation of the H&CE Program.

# Home Improvement Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 840 | 2,275 |
| Energy Savings (kWh) | 457,353 | 917,519 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $385,091 | $666,041 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $385,091 | $666,041 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.044 | $0.038 |
| Total Resource Benefit/Cost Ratio | $0.093 | $0.155 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.15 | |
| Total Resource Benefit/Cost Ratio | 1.21 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Home Improvement Program offers incentives to homeowners for upgrading insulation in electrically heated homes. The program's list of measures and incentives in 2012 consisted of the following:

- Customer incentives for attic insulation, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing.
- Customer incentives to Idaho residential customers in the Idaho Power service area for additional insulation professionally installed was 15 cents per square foot for attic insulation, 50 cents per square foot for wall and under-floor insulation, and 30 cents per linear foot for air- and duct-sealing.
- Existing attic insulation must be an R-20 or less to qualify, and the final R-Value must meet the local energy code. Idaho Power's service area consists of climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-Value must be R-19.
- The existing insulation level of under-floor must be R-5 or less, and the final R-Value must be R-30.

On April 1, 2012, the program transitioned from an open contractor program to a participating contractor program. Participating contractors must successfully complete a two-day contractor training

course administered by Fluid Market Strategies. Customers must use a participating contractor to qualify for the Idaho Power incentive.

Also on April 1, 2012, the program transitioned from being a fuel-neutral program to an electrically heated home program. To qualify for an incentive under this program, the home must be a single-family home, including duplexes and townhomes. The home must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system. Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor. On April 1, 2012, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing were added to the program.

## 2012 Activities

Due to the increased complexity of the program requirements, Idaho Power brought the outsourced, third-party incentive processing back in house. All Home Improvement Program incentive applications are now processed by Idaho Power staff.

Various marketing techniques were employed in 2012. Movie theater advertising ran during June, July, and August in the Boise, Nampa, Pocatello, and Cascade markets. A small-market print advertising campaign ran in November and December. An informational bill insert ran in October, and a direct-mail letter targeted to electrically heated customers was sent out in November. All of these marketing activities resulted in increased customer inquiries regarding program details and provided opportunities for customer education.

## Cost-Effectiveness

*Supplement 1: Cost-Effectiveness* contains cost-effectiveness information for attic, wall, and floor insulation measures broken out by customers' electric heating source equipment type, R-value change, climate zone, and presence of central A/C if applicable. Additionally, the cost-effectiveness results in *Supplement 1: Cost-Effectiveness* are shown for the Home Improvement Program attic insulation measures phased out in the first trimester of 2013. These measures included previously available incentives for customers with central A/C, regardless of heating fuel type.

Although the RTF reviewed 2011 attic insulation measures for compliance and RTF guidelines during 2012, no changes were made to deemed annual savings values. Deemed-savings values specific to Idaho Power's climate zones were published by the RTF in October 2011, including cooling savings based on the RTF's deemed savings for single-family home weatherization published in July 2011.

A change in the Idaho Power cost-effectiveness analysis for 2012 was the inclusion of the RTF specifications requiring homes to be adequately air-sealed, including air ducts, prior to the installation of attic and floor insulation. Idaho Power included the costs of the $0.30-per-linear-foot incentive offered to program participants who needed to have air- and duct-sealing done to align with the updated guidelines. When calculating the TRC, the installed costs were averaged across attic and floor insulation projects, including costs to air- and duct-seal to assess cost-effectiveness. The additional project costs had minimal impacts to participant costs and the overall cost-effectiveness of project costs per square foot, staying consistent with the RTF deemed participant cost estimates. For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

For QA purposes, third-party contractors randomly reviewed 10 percent of all insulation jobs completed in the Home Improvement Program. With the addition of the new program requirements in April 2012, these QA contractors also performed in-progress QA to assist and educate the contractors on the new program requirements, particularly the air- and duct-sealing requirements. Of the 80 QA inspections completed in 2012, two issues concerning post-insulation depth were reported and corrected.

One voluntary marketing question, inquiring how the customer heard about the program, was added to the program incentive application form. Of the 840 applications, 196 customers answered the marketing question. Ninety-two customers (47%) heard about the program from an insulation contractor, while 66 customers (34%) heard about the program from an Idaho Power bill insert. Twenty-six customers (13%) received a referral from a friend or acquaintance, eight customers (4%) heard about the program from the Idaho Power website, and four customers (2%) heard about the program from a newspaper advertisement.

## 2013 Strategies

In February 2013, Idaho Power plans to add an energy-efficient-windows measure to the Home Improvement Program. Windows being replaced must be single-pane wood frame, single-pane metal frame, or double-pane metal frame. As with all other Home Improvement Program measures, only electrically heated homes qualify for an incentive.

In addition, beginning in February 2013, manufactured homes meeting all program qualifications will be eligible for all Home Improvement Program incentives.

Numerous marketing activities are planned for 2013. A new program brochure and web page update are planned for February 2013, in conjunction with program additions and updates. Informational bill inserts are planned for February and April. Targeted direct-mail letters are planned for April and October. Facebook advertisements in high-electric-usage areas are planned for January and September. Print advertisements in select rural areas are planned for February.

# Home Products Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances/fixtures) | 16,675 | 15,896 |
| Energy Savings (kWh) | 887,222 | 1,485,326 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $640,098 | $619,764 |
| Oregon Energy Efficiency Rider | $18,829 | $18,559 |
| Idaho Power Funds | $105 | $0 |
| Total Program Costs—All Sources | $659,032 | $638,323 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.061 | $0.034 |
| Total Resource Benefit/Cost Ratio | $0.075 | $0.080 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.26 | |
| Total Resource Benefit/Cost Ratio | 1.40 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards. In 2012, the measures and related incentives included ENERGY STAR qualified clothes washers ($50), refrigerators ($30), and freezers ($20). Program participation is a simple process for customers, who have two options to submit their application: They may complete a mail-in incentive application and submit it with an itemized copy of the sales receipt or submit an online application, offered through Idaho Power's processing vendor's website, and upload or mail in the receipt. If the purchase qualifies, the customer receives an incentive check by mail.

The Home Products Program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point of purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products at the retail level. This mid/upstream incentive model is potentially anticipated to be powerful in changing markets when incentive dollars are small per product but the product category has a high volume of sales. "Upstream and midstream incentives offer the advantage that incentive amounts can sometimes be lower, as market partners may need less 'convincing' to make or sell efficient technologies."[2]

[2] http://www.epa.gov/cleanenergy/documents/suca/program_incentives.pdf.

One measure offered through the retailer markdown model is low-flow showerheads. Low-flow showerheads are part of the Simple Steps, Smart Savings™ markdown promotion administered by the BPA. Simple Steps, Smart Savings is coordinated by Fluid Market Strategies.

Idaho Power works in collaboration with NEEA on the Consumer Electronics Energy Forward Campaign program. This program provides a direct incentive to manufactures for producing the most energy-efficient televisions available. NEEA manages advertising, sales support, and in-store promotions for the program.

## 2012 Activities

Marketing the Home Products Program to customers occurs primarily through retail outlets. Idaho Power provides information to store managers and employees through training sessions at store staff meetings and through periodic visits by various Idaho Power representatives. In addition to brochures, fixture hang-tags and static clings—small, sticky decals—were distributed to nearly 80 retailers for placement on qualifying products. The prominent focus for using hang-tags and clings was to highlight the respective incentive amounts and eligible products.

In 2012, Idaho Power continued outsourcing the processing of applications for the Home Products Program to Advertising Checking Bureau, Inc. (ACB, Inc.), a third-party vendor. Participants have the option of online or paper applications. Both methods require the customer submit a copy of the sales receipt to confirm the product purchase. If submitting the application online, customers have the option of uploading their receipt, or mailing it in, along with a copy of their web page confirmation.

Idaho Power promoted the program to residential customers via retail store salespeople, bill stuffers, community promotions, Idaho Power field staff, and other outreach activities. During 2012, two bill inserts detailing the program were mailed to all residential customers. The spring (April) insert was shared with the Rebate Advantage program. The holiday bill insert (November) was shared with the DHP Pilot program.

As a result of findings from the 2011 impact evaluation completed by ADM Associates, Inc. (ADM), it was determined that ceiling fans, ceiling fan light kits, and LED light fixtures no longer met cost effectiveness requirements. Thus, these three products, along with CFL fixtures, were removed from the list of eligible products, effective March 1, 2012.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power evaluated including CFL fixtures in its administration of the Simple Steps, Smart Savings promotion. Due to different incentive structures and lower administration costs, CFL light fixture incentives are cost effective if delivered under the Simple Steps, Smart Savings markdown model. Therefore, in March 2012, light fixture incentives for select fixtures were added as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales for fixtures were reported in 2012 under this promotion.

An option on the application allows customers to donate their entire incentive to Project Share, an energy assistance program where Idaho Power partners with the Salvation Army. In 2012, Home Products Program participants donated $190 to this cause. A Project Share donation thank-you card created specifically for the Home Products Program was sent to customers who donated their incentive.

NEEA created a marketing campaign for the Energy Forward campaign in fall 2012 to promote energy-efficient televisions. The campaign objectives were to drive sales of Energy Forward televisions at partner retail stores, provide retailers, utilities, and manufacturers with additional channels of promotion; increase retailer and utility engagement and partnership in the promotion of Energy Forward televisions; and increase consumer awareness and adoption of Energy Forward televisions.
The campaign included a sweepstakes hosted through the Energy Forward Facebook page located at www.Facebook.com/EnergyEfficientElectronics. Northwest residents could win Energy Forward televisions, tickets to college football games, and a grand prize of a VIP tailgate party in each of the four Northwest states—Idaho, Montana, Oregon, and Washington.

The campaign in Idaho generated 218 contest entries. Best Buy and Sears stores participated as full campaign partners, which included additional sales associate trainings and educational and campaign-related point of purchase material in all Best Buy and Sears stores. NEEA also secured discounted rates for in-store broadcasts of the *Energy Forward Most Efficient* video on televisions screens in the consumer electronics sections of Best Buy, Costco, Sam's Club, Sears, and Wal-Mart.

Through the Home Products Program, Idaho Power paid 16,675 incentives during 2012, resulting in 887,222 kWh savings. Incentives were issued for approximately 6,338 clothes washers, 4,497 refrigerators, 461 freezers, 285 light fixtures, 7 ceiling fans, 2 ceiling fan light kits, and 5,085 showerheads.

## Cost-Effectiveness

In 2011, ADM reviewed the savings for each measure. ADM reduced the annual savings estimate for ceiling fans from 159.36 kWh to 59 kWh. The savings for ceiling fan light kits were based on the number of CFLs in each kit. In 2011, the RTF reduced the annual savings for CFLs from 24 kWh to 16 kWh. Additionally, ADM confirmed the RTF's assumptions and lower savings regarding LED light fixtures. As a result of these changes, the measures were determined not to be cost effective and were removed from the program in March 2012.

In 2012, the RTF updated the savings for clothes washers and freezers. For clothes washers, the RTF looked at the impact of the new federal standards and the efficiency levels of clothes washers readily available in the Pacific Northwest market. The RTF also updated the savings assumptions on annual loads of laundry using the research from the recent Residential Building Stock Assessment (RBSA) conducted by NEEA. As a result of this work, the baseline efficiency for clothes washers increased and the savings decreased. For programs like Idaho Power's that do not restrict the modified energy factor (MEF), the annual savings decreased from 122 kWh to 37 kWh, which has made the measure not cost effective. In the 2011 impact evaluation, ADM recommended applying the RTF's breakouts for clothes washer savings by MEFs; however, due to a measure definition change by the RTF, Idaho Power has applied the wide-ranging ENERGY STAR clothes washer savings for any type of domestic hot water heating system and any dryer type. As before, Idaho Power adjusted the savings downwards to reflect the electric hot-water heater and electric dryer saturation in the Idaho Power service area. The adjustment is based on information from the *2010 Home Energy Survey*.

The RTF updated the baseline for freezers based on sales data from the region and data from the California Energy Commission database. As a result of the review, savings for freezers decreased slightly; however, the measure life was extended from 20 years to 22 years. Freezers remain cost effective.

Due to the lower savings attributed to clothes washers, the program's overall administrative costs per kWh increased from $0.118 to $0.342 per kWh. As a result, two refrigerator measures are shown to have a TRC of 0.99. Idaho Power expects to incur lower administrative costs in 2013 once clothes washers are removed from the program, which will increase the cost-effectiveness of the measures within the program. There were no changes to the savings assumptions that drive the cost-effectiveness of refrigerators and low-flow showerheads. For detailed information for all measures within the Home Products Program, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Information gathered from a question on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. Ninety-one percent of the responses indicated customers learned about the incentive program through salespeople. Three percent learned from in-store materials (brochures); 3 percent from one of two Idaho Power bill inserts sent to all residential customers; and 3 percent from the Idaho Power website, newspaper/radio, or referral.

A customer satisfaction survey is scheduled for the Home Products Program in 2013.

## 2013 Strategies

Due to changes in the baseline threshold used to calculate energy savings, clothes washers will be discontinued, effective March 31, 2013. On February 15, 2013, Idaho Power filed Oregon Advice No. 13-03 with the Public Utility Commission of Oregon (OPUC) to remove clothes washers from the list of eligible appliances offered to Oregon customers through the Home Products Program. With the removal of the clothes washer incentives, several methods will be used to notify customers. Letters were mailed to all retailers in January 2013 to alert them of the changes. New table tents were created for distribution to all retailers in early February for display. These will inform customers of the removal of the clothes washer incentive and that they need to purchase their clothes washer before March 31, 2013, to qualify for the incentive. To announce the changes to the program, the Idaho Power website home page will be updated for February and March and an online advertising campaign will target potential purchasers. Idaho Power staff will visit retailers during February and March to discuss the changes and answer questions. Idaho Power will continually review potential products for addition to the program during 2013 and beyond.

The marketing strategy for 2013 will remain similar to 2012, with only minimal adjustments and updates as needed. Bill stuffers, in-store brochures, hang-tags, and clings will be the primary marketing avenues. Online banner advertisements and keyword search terms will be added as a new media effort. Idaho Power will research if company billboards would be effective for the program. As a result of the removal of clothes washers, new brochures will be created and distributed to all retailers before April 1, 2013.

The company expects participation for 2013 to decrease significantly with the removal of clothes washers from the list of eligible products. In 2012, clothes washers accounted for more than half of applications received. In 2013, Idaho Power will explore transitioning the light fixtures and showerheads to a more comprehensive retailer markdown program and explore additional product categories for this type of program model.

# Oregon Residential Weatherization

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 5 | 8 |
| Energy Savings (kWh) | 11,985 | 21,908 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $4,051 | $6,690 |
| Idaho Power Funds | $465 | $1,236 |
| Total Program Costs—All Sources | $4,516 | $7,926 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.021 |
| Total Resource Benefit/Cost Ratio | $0.056 | $0.027 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.88 | |
| Total Resource Benefit/Cost Ratio | 1.55 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1980 | |

## *Description*

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program offered under Oregon Schedule 78. Upon a customer's request, an Idaho Power CR visits the home to analyze it for energy efficiency opportunities. An estimate of costs and savings for specific measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

## *2012 Activities*

During May, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. Eight Oregon customers responded. Each customer returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Eight audits and responses to customer inquiries to the program were completed, with five incentives paid.

Idaho Power issued five rebates totaling $1,722 for 11,985 kWh savings. All rebates and related savings were attributed to the addition of new windows, ceiling insulation, and floor insulation. There were no loans made through this program during 2012.

## *Cost-Effectiveness*

The Oregon Residential Weatherization program is a statutory program as provided for in Oregon Schedule 78. The cost-effectiveness of this program is defined within this schedule. Pages 3 and 4 of the schedule list the measures determined to be cost effective and the required measure-life cycles for

specific measures. This schedule also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years.

Five projects were completed under this program in 2012. Projects consisted of increasing attic and floor insulation and putting in new windows. The projects combined for an annual energy savings of 11,985 kWh at a levelized TRC per kWh of 5.6 cents over the 30-year measure life as defined by the Oregon Schedule 78. The CEL for insulation (30-year measure life) is $1.09 per annual kWh saved and $0.95 per annual kWh for new windows (25-year measure life) is. Since the actual levelized cost of energy savings for the 2012 projects was 3.4 cents from the TRC perspective, these projects are considered cost effective.

## 2013 Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective rebate and loan applications.

# Rebate Advantage

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 35 | 25 |
| Energy Savings (kWh) | 187,108 | 159,325 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $34,926 | $59,241 |
| Oregon Energy Efficiency Rider | $2,316 | $4,228 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $37,241 | $63,469 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.024 |
| Total Resource Benefit/Cost Ratio | $0.024 | $0.033 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 8.71 | |
| Total Resource Benefit/Cost Ratio | 3.87 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

Idaho Power residential customers who purchase a new, all-electric ENERGY STAR® qualified manufactured home in 2012 and sited it in Idaho Power's service area were eligible for a $500 rebate through the Rebate Advantage program. Salespersons received a $100 incentive for each qualified home they sold.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured (NEEM) housing program establishes quality-control (QC) and energy efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

The Rebate Advantage program helps Idaho Power customers with the initial costs associated with purchasing a new, energy-efficient ENERGY STAR qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. In addition, Idaho Power encourages sales consultants to discuss energy efficiency with their customers during the sales process.

## *2012 Activities*

During 2012, Idaho Power paid 35 incentives on new manufactured homes, which accounted for 187,108 annual kWh savings. Despite three dealerships closing in 2012, the number of incentives processed increased by 40 percent over 2011.

Marketing strategies used in 2012 included maintaining the Google AdWords campaign, a billboard campaign, and one bill insert. The program specialist, marketing specialist, and Idaho Power field staff visited numerous dealerships throughout the company's service area over the summer to answer any questions and notify them of a planned incentive increase, effective 2013.

Idaho Power continued to support dealerships in 2012 by providing them with Rebate Advantage brochures and applications as needed. CRs visited these dealerships to distribute material, promote the program, and answer salespersons' questions.

## Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness for ENERGY STAR manufactured homes. All cost-effective analyses were based on the January 2011 approval decision by the RTF. The measures remained cost-effective for 2012. The measure is currently under review by the RTF and will be updated in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

## 2013 Strategies

The Rebate Advantage incentive amounts for customers and salespeople will double in 2013. Customers who purchase an all-electric ENERGY STAR manufactured home will receive a $1,000 incentive. Salespersons will receive a $200 incentive for each qualified home they sell. This new rebate offsets the cost of the ENERGY STAR enhancements and is designed to offset a greater portion of the cost differential between these homes and non-ENERGY STAR homes. This program remains cost effective with the increased incentive levels.

In early 2013, a bill insert will be mailed to all residential customers to inform them of the change in the incentive amount. The new posters and brochures that were created and distributed in 2012 to all local dealerships to promote the increase in the incentive amount will continue to be used throughout 2013. Idaho Power continues to explore new marketing methods and promote the program using internal resources and externally at the dealership level. CRs will enhance relationships with dealerships by visiting each dealership, offering program support, answering questions, and distributing materials. The interaction of local Idaho Power staff with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

Idaho Power will continue to examine additional marketing strategies directed at the end consumer. These will include the continuation and revision, as needed, of the Google AdWords campaign and additional bill inserts sent to all residential customers. This strategy may be shared with the Home Products Program, as done in 2012. Strategies may include other banner-type promotional materials at the physical dealerships. Participation in this option will be determined by direct contact with the dealerships to determine how many show interest in having the banner displayed at their dealership. In addition, new research from the upcoming *2013 Manufactured Home Market Facts Report* by Foremost® Insurance will be used to determine the best marketing strategies.

# See ya later, refrigerator®

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (refrigerators/freezers) | 3,176 | 3,449 |
| Energy Savings (kWh) | 1,576,426 | 1,712,423 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $596,167 | $634,967 |
| Oregon Energy Efficiency Rider | $16,979 | $19,426 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $613,146 | $654,393 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.046 | $0.046 |
| Total Resource Benefit/Cost Ratio | $0.046 | $0.046 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.70 | |
| Total Resource Benefit/Cost Ratio | 1.70 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

The See ya later, refrigerator® program acquires energy savings through the removal of qualified refrigerators and stand-alone freezers in residential homes throughout Idaho Power's service area. Each application is screened upon enrollment by Idaho Power to determine whether each refrigerator or freezer unit under consideration meets all program eligibility requirements, including the requirement that a unit must be residential-grade, a minimum of 10 cubic feet as measured using inside dimensions, no larger than 30 cubic feet, and in working condition. Customers receive a $30 incentive check mailed after the removal of the unit. The program targets older, extra units for maximum savings.

Idaho Power contracts with JACO to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Idaho Power provides participant confirmation, supplemental marketing, and internal program administration.

## *2012 Activities*

In July 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000$^{th}$ unit. Idaho Power invited local media to watch the unit get unloaded from the collection truck to a trailer used to haul units to the recycling facility in Salt Lake City, Utah. The story was picked up by several television stations.

Idaho Power continued to offer See ya later, refrigerator® participants, upon enrollment, the option to receive their $30 incentive or donate it to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army. The program helps customers who need help paying for energy

services, including fuel bills and furnace repairs. In 2012, 2.7 percent of Idaho Power's See ya later, refrigerator® participants chose this option, raising $2,610 for Project Share.

In 2012, program staff visited the JACO recycling facility in Salt Lake City. According to the contract terms, JACO is responsible for dismantling and properly recycling or disposing of parts of each unit. This trip confirmed the contract conditions were being met.

The program continued to use a variety of marketing channels including bill inserts, direct mail, Valpak®, and promotion at events. In 2012, the program tested a new marketing avenue, cinema advertising at a theater in Nampa, ID. Idaho Power developed a 30-second spot that aired 5,824 times.

The See ya later, refrigerator® program was one of three programs that sponsored the Idaho Stampede's Green Week games. The promotion included highlighting Idaho Power's energy efficiency programs at two home games through announcements, posters, and staffed displays providing attendees the opportunity to talk with Idaho Power employees about energy efficiency. As part of the promotion, Idaho Power ran a 30-second PSA regarding See ya later, refrigerator®, which aired at both home games. Idaho Power posted the PSA to its website and YouTube.

The program also tested different types of direct-mail in 2012. In January and April, letters were sent to customers encouraging enrollment in the program. In June, a magnet mailer was sent. All mailings used market segmentation to create the mailing list. In the April and June mailings, the lists were further refined using total energy use and length-of-time as customers. By evaluating energy use, homes with extremely low use (and therefore unlikely to have a secondary appliance) were removed. By evaluating length-of-time as customer, the mailing targeted those customers identified by market research as more likely to participate in this program.

## Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness of the two measures that are part of this program, which include the decommissioning of secondary freezers and refrigerators. All cost-effective analyses are based on the RTF's approval decision dated July 2010. Both program measures remained cost effective in 2012.

Refrigerator and freezer recycling measures were reviewed by the RTF during the year as part of the comprehensive review of most residential measures and RTF guideline updates. Savings and measure-life estimates were updated by the RTF late in 2012 and will be included in the claimed savings in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2012, Idaho Power considered the recommendations provided by the 2011 process evaluation conducted for the program by ADM. The evaluation included two recommendations. The first recommendation was to continue researching "existing retailer involvement in the program." Idaho Power continues to track referrals through retailers. The goal of the program is to collect secondary units and remove them from customer homes. Energy savings are maximized when the unit is removed and not replaced. In 2012, 67 percent of participants that reported hearing about the program through retailers also indicated they intended to replace the unit. This is compared to 49 percent of all program participants that indicated they intended to replace the unit. Since retailer referrals have a higher replacement rate, resulting in lower energy savings, marketing through retailers is not a preferred approach at this time.

The second recommendation was to monitor customer understanding of program requirements. Anecdotal comments in the evaluation suggested some participants may not always understand the purpose of the program or eligibility requirements. Idaho Power continues to include major program requirements on its marketing materials to enhance customers' understanding of program parameters. Idaho Power also emphasizes the energy-saving benefits of the program on its marketing materials. In addition, JACO's call center and online enrollment process include screening to ensure program requirements are met.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. ADM noted the program appears to be running smoothly with an ex-post realization rate of 95 percent as compared to ex-ante estimates.

The ADM report also indicated the JACO screening process is mostly preventing ineligible units from entering the program. Also, the current RTF-approved unit energy savings (UES) values were correctly applied as ex-ante estimates, and the parameters supporting those values appear applicable to the Idaho Power program.

ADM recommended Idaho Power continue to actively monitor the RTF UES list of measures for deemed-savings updates since, although appliance decommissioning measures are RTF approved, they were listed as "under review" at the time of the publication of the evaluation. These measures are subject to change as updates to the estimation procedures and/or data sources are made. A copy of the complete report is included in *Supplement 2: Evaluation*.

JACO tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2012 unit data showed that 22 percent of units the program picked up were stand-alone freezers, and 78 percent of the units were refrigerators. Fifty-seven percent of the units were secondary, 28 percent were primary, and 14 percent were unknown. This shows slight improvement in the collection of secondary units over 2011. The average vintage of units collected was 1986, with 57 percent of the units manufactured from 1965 to 1990, generally the least efficient years of manufacture. In 2011, 64 percent of units were of this vintage, suggesting the program is still collecting older units.

The program reclaims or recycles up to 95 percent of the components of each unit collected. In 2012, this translated into over 417,676 pounds of materials. Reclaimed materials may include oils or refrigerants that can be distilled, then reused.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 49 percent of customers reported learning of the program through bill inserts that ran in February, May, August, and October 2012. A portion of these customers reporting bill inserts may refer to the article that appeared in the *Customer Connection* newsletter in the September bill. Eighteen percent of customers reported learning of the program through a friend or neighbor. Other word-of-mouth activities, such as events, account for an additional one percent of signups.

In 2012, direct-mail was used three times and resulted in 6 percent of the enrollments. Direct-mail is sent to a subset of customers. Idaho Power market-segmentation data and national research show participants in utility refrigerator recycling programs are likely to have common characteristics, including older, empty-nesters, smaller households, homeowners, single-family homes, and higher

incomes. Nielsen's PRIZM segmentation software was used to identify customers with these characteristics. In addition to the segmentation software, two other criteria were applied to list: energy use and length of time in the home. As older refrigerators can use up to 1,400 kWh per year, homes with very low energy use were considered unlikely to have a second unit and removed from the list. Second, the length of time in the home may correlate to age. As likely participants are older, the length of time in the home was applied on top of the segmentation criteria.

Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel. The program focuses on the removal of secondary units rather than replacing existing units. Retailers sell new units to replace older units. In addition, a retailer selling a new unit will usually pick up and recycle the old one.

Newspaper advertisements comprise 3 percent of enrollments. Newspaper advertisements ran one to two times per month for seven months in regional publications throughout the Idaho Power service area. Eighty-one percent of customers who enrolled used the toll-free telephone number, and 19 percent used the online enrollment form. Idaho Power uses the customer information that JACO collects and the surveys from Idaho Power evaluations to target future marketing efforts and increase the effectiveness of marketing while reducing the cost.

Figure 7 indicates information sources and the percentage of customers reporting hearing about the program through particular sources. The Other category includes sources such as community event, repeat customer, truck advertisement, and unknown sources.

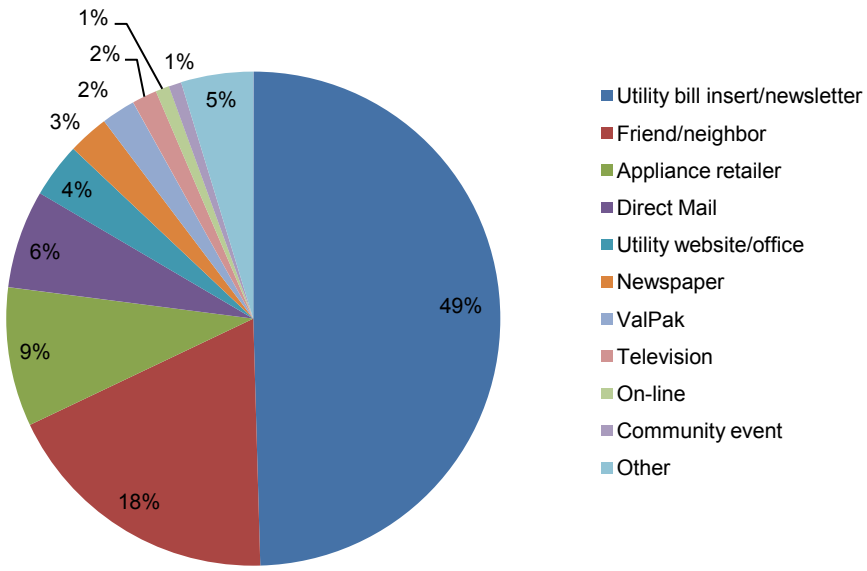


Figure 7. How customers heard about See ya later, refrigerator®

## 2013 Strategies

Idaho Power plans to continue implementing the program and managing the contract with JACO.

The marketing plan for 2013 includes a continued focus on a variety of channels, including bill inserts, newspaper advertisements, and customer newsletters. Digital media pay-per-click advertisements will be

on Google all year. The company will continue promotions at energy efficiency and community outreach events and on the Idaho Power website. A program process evaluation conducted by ADM in 2011 indicated that 52 percent of program participants reported convenience was the aspect of the program that provided them the most value. Therefore, new messaging will be developed and tested with a group of Idaho Power customers, focusing on the convenience aspect of the program as a motivation.

# Weatherization Assistance for Qualified Customers

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 238 | 287 |
| Energy Savings (kWh) | 648,304 | 2,783,648 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,370,141 | $1,324,415 |
| Total Program Costs—All Sources | $1,370,141 | $1,324,415 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.129 | $0.029 |
| Total Resource Benefit/Cost Ratio | $0.172 | $0.042 |
| **Program Life Benefit/Cost Ratios**[a] | | |
| Utility Benefit/Cost Ratio | 4.39 | |
| Total Resource Benefit/Cost Ratio | 2.84 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

[a] The 2012 one-year B/C ratios are 0.84 for the UC and 0.71 for the TRC.

## *Description*

The WAQC program provides funding to install weatherization measures in qualified owner-occupied and rental homes that are electrically heated. In 2012, qualified households included those with incomes up to 200 percent of the federal poverty-level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house non-profit organizations who serve special-needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the Community Action Partnership (CAP) agencies to administer the WAQC program in its service area.

WAQC is modeled after the US Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. While Idaho Power funds the WAQC program, CAP agencies in Idaho Power's service area serve as the administrators of the WAQC program. Federal funds are allocated to the Idaho Department of Health and Welfare (IDHW) and Oregon Housing and Community Services, then to CAP agencies based on US Census data of qualifying household incomes within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. WAQC funding allows these state agencies to leverage their federal weatherization dollars and serve more residents by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. The Idaho Weatherization Assistance Program calculates savings with the EA5 energy audit program (EA5). Idaho implemented the upgrade from the EA4 energy audit program (EA4) to the EA5 in September 2011. By January 2012, all agencies began using the EA5 to report savings. Consistent with the Idaho Weatherization Assistance Program, WAQC offers several measures that have costs but do not save energy or for which savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a household's existing indoor air quality. Other non-energy-savings measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Non-profit building measures that have costs but do not save energy or for which savings cannot be measured are health and safety, vents, furnace repair, and energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2011 Annual Report*, April 1, 2012, located in *Supplement 2: Evaluation*.

## 2012 Activities

During 2012, CAP agencies weatherized 224 electrically heated homes in Idaho and 10 in Oregon, totaling 234 weatherized homes. Four Idaho buildings housing non-profit organizations that serve special-needs populations were weatherized in 2012.

On February 15, 2012, IPUC staff filed Case No. GNR-E-12-01, Cost-Effectiveness and Funding of Low Income Weatherization Programs. As part of this case, IPUC staff sponsored workshops from March 19 to 20, 2012, to discuss investor-owned utility weatherization programs. Also discussed at the workshops was the need for an appropriate funding level for low-income weatherization programs and an overall program design. IPUC staff filed a report on October 23, 2013, providing recommendations on funding, cost-effectiveness, and the low-income energy conservation education programs. Notice of the IPUC decision meeting on January 28, 2013, reports that the IPUC took this case into private deliberation, and Idaho Power is awaiting an order.

## Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation under contract with Idaho Power. This study resulted in significantly lower realized energy savings for the WAQC program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 2,684 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,103-kWh annual savings as reported by the EA4 in 2011. Since the D&R International report did not give a per-unit savings amount for non-profit building weatherized under the WAQC program, these four project savings were adjusted by applying the overall program 29-percent realization rate from the evaluation. Even though the WAQC program used the EA5 in 2012, the company believes the average annual saving per home estimate provided by D&R International is applicable because the

weatherization activities have not changed and the reported savings from the EA5 are similar to the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the WAQC program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.71 and a UC ratio of 0.84. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power used independent third-party verification companies across its service area to randomly check 5 percent of the weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers, as well as discuss the program with these customers. Home verifiers visited 39 homes for feedback about the program. When asked how much customers learned about saving electricity, 26 answered they learned "a lot" or "some." When asked about how many ways they tried to save electricity, 29 responded "a lot" or "some."

The Idaho Power program specialist participates in the Idaho state peer-review process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and the IDHW reviewing homes weatherized by each of the CAP agencies. Results show that all CAP agency weatherization departments are weatherizing in accordance with federal guidelines.

Additionally, the DOE audits the state agencies each year. The DOE audits include field work, as well as paperwork and billing audits and show that the Idaho State Weatherization Assistance Program is in compliance with DOE standards.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology, as used in 2011, for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates resulting in a 29-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load while not calculating cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of the DOE-approved EA5, which ranks heating measures and duct improvements by the savings-to-investment ratio (SIR) and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the CAP agencies to administer the WAQC program. The company hopes to compare the savings estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power will also require the contractor to compare the modeled savings estimates to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in the GNR-E-12-01 case from the IPUC, will help

determine future modifications to the company's low-income weatherization programs. In 2013, Idaho Power also plans to conduct a third-party process evaluation of the WAQC program.

The company will continue its involvement with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho. The council will continue to review state grant applications.

Idaho Power plans to selectively market WAQC throughout 2013. The program is promoted at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions in an attempt to reach customers who may benefit from the program. The Idaho Power web page for WAQC will be updated with new graphics and expanded copy. Marketing for this program is conducted in cooperation with weatherization managers to ensure a manageable response level at the agencies.

# Weatherization Solutions for Eligible Customers

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 141 | 117 |
| Energy Savings (kWh) | 257,466 | 1,141,194 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,048,461 | $774,254 |
| Oregon Energy Efficiency Rider | $0 | $(2,306) |
| Idaho Power Funds | $22,094 | $16,200 |
| Total Program Costs—All Sources | $1,070,556 | $788,148 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.254 | $0.042 |
| Total Resource Benefit/Cost Ratio | $0.254 | $0.042 |
| **Program Life Benefit/Cost Ratios**[a] | | |
| Utility Benefit/Cost Ratio | 1.47 | |
| Total Resource Benefit/Cost Ratio | 1.47 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

[a] The 2012 one-year B/C ratios are 0.43 for the UC and 0.47 for the TRC.

## *Description*

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are slightly above poverty level and, therefore, do not financially qualify for the company's weatherization assistance program, WAQC. The measures in the program and the methods of delivery mirror WAQC. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a SIR of 1 or higher. The amount spent on each home is limited to an annual average per home. Homes considered for this program are electrically heated and either owned or rented. If rented, the landlord's permission is needed, along with an agreement to maintain the unit's current rent for a minimum of one year.

Idaho customers eligible for this program earn income just above the federal poverty level. They typically do not have expendable income to participate in other residential energy efficiency programs, and they live in similar housing as WAQC customers.

## *2012 Activities*

The 2012 program ended the year with 141 weatherization jobs completed. Qualifying customers for the year earned an income between 175 percent and 250 percent of the federal poverty level. The program served customers in Idaho Power's Southern, Western, Eastern, and Capital service areas.

Table 7 shows the number of jobs and costs associated with measures installed in homes called production costs. Also shown are job average costs and total payments to contractors for the year.

Table 7. 2012 weatherization solutions financial breakdown

| Contractor | Number of Jobs | Production Costs | Average Job Cost* | Administrative Payment to Contractor | Total Payment |
|---|---|---|---|---|---|
| Energy Zone | 63 | $ 454,545 | $ 7,215 | $ 45,455 | $ 500,000 |
| Home Energy Management | 41 | 272,900 | 6,656 | 27,290 | 300,190 |
| Power Savers | 20 | 106,461 | 5,323 | 10,646 | 117,107 |
| Savings Around Power | 17 | 87,450 | 5,144 | 8,745 | 96,195 |
| **Total** | **141** | **$ 921,356** | **$ 6,534** | **$ 92,136** | **$ 1,013,492** |

* Average Job Cost is calculated based on the direct cost of installed measures without the administration adder.

Marketing of the program was done several ways in 2012. All four contractors advertised the program in their regions with program flyers and door hangers distributed by contractors throughout mobile-home parks and at specific property-management offices. Flyers were also left with previous customers to spread information about the program to families and friends who might qualify. Word of mouth continued to be an effective marketing tool for the program in 2012. Several articles about the program were featured in various local publications and at an Idaho Power booth at weatherization conferences.

## Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation of the Weatherization Solutions for Eligible Customers program under contract with Idaho Power. This study resulted in significantly lower energy savings estimates for this program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 1,826 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,754-kWh annual savings per home as reported by the EA4 in 2011. This is a realization rate of 19 percent of the savings reported under the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the Weatherization Solutions for Eligible Customers program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.47 and a UC ratio of 0.43. Since the evaluation did not calculate an average measure level saving or realization rate by measure for this report, Idaho Power is not including measure level cost-effectiveness in this report, a change from previous reports. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2012, the program contractors conducted a customer satisfaction survey. Questionnaires were given to customers after the contractor completed the job. Of the 141 participants, 89 customers provided written feedback about the work done and about energy conservation in their home. Each response complimented the work crew and expressed thanks for the program. These contractor surveys include high-level questions and are administered by the contractors, not by Idaho Power.

Idaho Power hired independent third-party verification companies across its service area to randomly check weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers and discuss the program with these customers. Of the 141 jobs completed in 2012, verifiers visited 25 homes for feedback about the program. When these 25 customers were asked how much they learned about saving electricity during weatherization, 16 answered from the choices offered that they learned "a lot" or "some." When asked about how many ways they tried to save electricity in their home, 21 responded "a lot" or "some." This customer

feedback is collected as a part of the actual job verification. The documents containing individual customer information include these two questions.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology currently used for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates, resulting in a 19-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load and does not calculate cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of DOE-approved EA5, which ranks heating measures and duct improvements by the SIR and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the contractors to administer the Weatherization Solutions for Eligible Customers program. The company hopes to compare the saving estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power also will require the contractor to determine per-measure savings for this program and compare them to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in Case No. GNR-E-12-01 from the IPUC, will help determine future modifications to the company's low-income weatherization programs. Additionally, Idaho Power plans to conduct a third-party process evaluation of the Weatherization Solutions for Eligible Customers program in 2013.

In 2013, Idaho Power plans to offer this program to Idaho Power customers in the Southern, Eastern, Western, and Capital regions. Weatherization Solutions for Eligible Customers anticipates weatherizing 165 homes through the program in 2013.

Home Energy Management, LLC (HEM, LLC) is under contract to weatherize approximately 40 homes in Idaho Power's Southern region; Energy Zone, LLC is under contract to weatherize approximately 50 homes in Idaho Power's Western region; and Savings Around Power is contracted to weatherize approximately 25 homes in the Eastern region. Power Savers, serving Idaho Power's Capital region, is under contract to weatherize approximately 50 homes.

An annual allowable average cost of $7,200 per home will be used again in 2013. Contractors will be paid 10 percent of the production costs per home as an administrative fee. All measures that provide energy savings will meet the minimum SIR when applied through the state-approved energy audit. Each total job will also meet the minimum SIR requirements.

Eligible customers will include Idaho Power customers who heat their homes electrically and earn an income between 175 percent and 250 percent of the federal poverty level. Customers who are either

purchasing or renting their homes may be eligible. As in 2011 and 2012, the identification of potential participants will be made through several means. Energy Assistance/LIHEAP applicants at CAP agencies who do not meet WAQC income qualifications are sent denial letters. Program contractors will use this list of denied customers at CAP agencies to market the Weatherization Solutions for Eligible Customers program. Contractors will distribute flyers and door hangers explaining the program and qualifying guidelines to customers heating their homes electrically.

Idaho Power's plans to market the Weatherization Solutions for Eligible Customers program throughout 2013. Direct-mail letters proved successful in 2012, and these targeted mailings will continue along with bill inserts and online advertisements. The web page for the program will be updated with new graphics and expanded copy. Marketing for this program is conducted in close cooperation with contractors to ensure the marketing activity is done at a level each contractor is able to service in a timely manner.

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# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

Idaho Power's commercial and industrial sector consists of over 65,857 customers. In 2012, the commercial sector's number of new customers increased by 683, an increase of 1 percent over 2011. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 27.4 percent of Idaho Power's total electricity usage.

The industrial customers and special-contract sector are Idaho Power's largest individual energy consumers. There are approximately 116 industrial customers. These customers can use millions of kWh a month and account for 22.2 percent of Idaho Power's total electricity usage.

The Custom Efficiency program continued to represent the highest total energy savings among commercial and industrial programs in 2012, with a total savings of 54,253 MWh. The Building Efficiency program saw the highest percentage increase among commercial and industrial programs, with annual savings increasing by 105 percent over 2011. Combined, the programs experienced a 4.54 percent increase in the number of completed projects over 2012. Overall, energy savings decreased less than 1 percent compared to 2011. Table 8 shows a summary of savings and expenses from the three commercial and industrial energy efficiency programs and one demand response program.

## Programs

Table 8. 2012 commercial/industrial program summary

| | | Total Cost | | Savings | |
|---|---|---|---|---|---|
| **Program** | **Participants** | **Utility** | **Resource** | **Annual Energy (kWh)** | **Peak Demand (MW)** |
| **Demand Response** | | | | | |
| FlexPeak Management | 102 sites | $ 3,009,822 | $ 3,009,822 | n/a | 52.8 |
| **Total** | | **$ 3,009,822** | **$ 3,009,822** | | **52.8** |
| **Energy Efficiency** | | | | | |
| Building Efficiency | 84 projects | $ 1,592,572 | $ 8,204,883 | 20,450,037 | 2.3 |
| Easy Upgrades | 1,838 projects | 5,349,753 | 9,245,297 | 41,568,672 | 4.7 |
| Custom Efficiency | 126 projects | 7,092,581 | 12,975,629 | 54,253,106 | 7.6 |
| **Total** | | **$ 14,034,906** | **$ 30,425,809** | **116,271,815** | **14.6** |

Note: See Appendix 3 for notes on methodology and column definitions.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, the building shell, plug loads, and food-service equipment. These energy-saving measures give customers the option of choosing the best selections for incorporating energy efficiency into their business. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost-opportunity savings. This program continues to be successful, incorporating qualified energy-saving improvements for lighting, cooling, building shells, and energy control options. Participants in the Easy Upgrades program can receive incentives of up to $100,000 per site per year for approved, completed projects. There are no incentive caps on Building Efficiency- and Custom Efficiency-approved and completed projects. The Custom Efficiency

program offers financial incentives for large commercial and industrial energy users undertaking more complex projects to improve the efficiency of their electrical systems or processes.

Incentive levels are 70 percent of the project cost or 12 cents per kWh for first-year savings, whichever is less. Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

FlexPeak Management, a demand response program, is offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracts directly with Idaho Power's commercial and industrial customers to achieve demand reduction.

2012 proved to be another challenging, rewarding, and successful year for Idaho Power's commercial and industrial energy efficiency programs. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Building Efficiency experienced substantial growth in both the number of completed projects and energy savings. Easy Upgrades also experienced growth in both the number of completed projects and energy savings. These are remarkable accomplishments considering the economic environment Idaho Power's business customers continue to navigate. The commercial and industrial programs continued to develop and strengthen Idaho Power's strategic partnerships. These partnerships include the IDL, engineering and architectural firms, a vast network of trade allies, and most importantly, Idaho Power customers. Training and education continued to be an important aspect of the company's programs in 2012. Trade ally meetings included training on lighting design and technologies. Custom Efficiency continued to offer a host of industrial training sessions that were well attended. Finally, Building Efficiency sponsored a number of outreach training sessions conducted by the IDL.

The Green Rewind offering is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 42 Green Rewind motors achieved a total annual savings of 84,193 kWh in 2012, with 19 commercial/industrial sector motors contributing 54,154 kWh per year and 23 irrigation sector motors contributing 30,039 kWh per year.

Twenty-one service centers in Idaho Power's service area have the necessary equipment and training to participate in the Green Rewind offering. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, eight service centers have signed on as Green Motors Practice Group (GMPG) members. The GMPG also will expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA) Standard hp-rated motor between 15 and 5,000 hp for industrial uses and 25 to 5,000 hp for agricultural uses that receive a verified Green Rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with a quality check and QA.

In 2012, Idaho Power entered into the third year of a three-year contract with the IDL to meet the following objectives:

- Educate architects, engineers, and other design and construction professionals about energy efficiency topics through an in-firm summer series. This series was expanded in 2011 and 2012 to include firms outside the Treasure Valley.

- Facilitate the Idaho Building Simulation Users' Group to improve the energy efficiency-related simulation skills of local design and engineering professionals.

- Support Idaho Power employees in promoting energy efficiency and providing Idaho Power's customers with up-to-date and accurate information regarding energy efficiency technologies and best practices.

- Create a hands-on demonstration and training area for electrical contractors to learn the necessary skills to successfully install and commission daylight-harvesting lighting control systems.

- Review daylight photo-control incentives to improve the quality and performance of installed systems.

- Develop and maintain a measurement equipment tool loan library, including a web-based equipment tool loan-tracking system.

- Stimulate market awareness of energy use in buildings to promote energy efficiency by working with commercial real estate brokers or owners in the development of metrics to be used in the sale or lease of commercial property.

- Promote aggressive energy efficiency on new construction and major renovation projects in the Idaho Power service area.

- Promote improved energy efficiency in existing convenience stores in the Idaho Power service area.

- Provide measurement and verification services to investigate actual energy savings compared to computer simulation modeled savings or pre- and post-renovation/retrofit conditions.

Expanding on some of the prior year's results, the following objectives were added in 2012:

- Conduct a review of documents associated with the Building Efficiency program's application for incentives along with site inspections on a random percentage of projects to validate whether noted systems and components have been installed.

- Provide the design community with additional spreadsheet-style calculation tools to analyze the feasibility and capacity of various passive cooling design strategies (an expansion of prior climate design resource efforts.)

- Increase both the general public and design community literacy about how different classifications of commercial buildings consume energy and the metrics associated with these data.

- Investigate multi-family new construction and retrofit best practices for utility incentive programs and to investigate the potential for new program incentives.

Phase I of the Idaho Office of Energy Resources (IOER) K–12 Energy Efficiency Project for public schools in Idaho Power's service area concluded December 2012. The project invested federally provided funds into energy efficiency projects in public school buildings within Idaho Power's service

area. In July 2011, Idaho Power entered into an agreement with the IOER that provided for the accumulation and reinvestment of energy efficiency incentive payments from Idaho Power's qualified energy efficiency programs for K–12 projects. These accumulated incentives will be used for additional cost-effective energy efficiency projects that meet current Idaho Power program requirements implemented in public school buildings within Idaho Power's service area and will be referred to as Phase II projects. The agreement will result in achieving a higher level of energy efficiency in public school buildings than either Idaho Power or the IOER could achieve with their individual programs. Phase II projects are anticipated to begin in mid-2013 and conclude in late 2014.

During the November 6 EEAG meeting, the Idaho Power commercial/industrial energy efficiency program leader discussed how the Building Efficiency program is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and the cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research is favorable and measures are cost effective, new measure offerings could be added to the program in 2013. EEAG was generally supportive of researching multi-family measure offerings.

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. Fifty-six percent of Idaho Power's large commercial and industrial customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 79 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 93 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated 42 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 21 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

In 2013, Idaho Power is anticipating adding at least two new initiatives within the Custom Efficiency program. Impact evaluations conducted on Building Efficiency and Easy Upgrades will be finalized in early 2013. Program specialists will be analyzing the findings from these reports and will adjust programs as needed. Training, education, and outreach will continue to be a focus aimed at driving projects. Additionally, the company will analyze ways to improve Idaho Power programs based on customer and trade ally feedback, as well as internally driven research.

# Building Efficiency

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 84 | 63 |
| Energy Savings (kWh) | 20,450,037 | 11,514,641 |
| Demand Reduction (MW) | 2.3 | 0.9 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,579,121 | $1,277,422 |
| Oregon Energy Efficiency Rider | $13,451 | $14,003 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $1,592,572 | $1,291,425 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.007 | $0.010 |
| Total Resource Benefit/Cost Ratio | $0.036 | $0.026 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 6.50 | |
| Total Resource Benefit/Cost Ratio | 2.56 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions are eligible to receive incentives. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special-contract customers are eligible to participate. Program marketing is targeted toward architects, engineers, and other design professionals.

Fourteen measures are offered through this program and include interior-light load reduction, exterior-light load reduction, daylight photo controls, occupancy sensors, high-efficiency exit signs, premium-efficiency HVAC units, additional HVAC-unit efficiency bonuses, efficient chillers, air-side economizers, a reflective roof treatment, high-performance windows, energy- management control systems, demand-controlled ventilation, and variable-frequency drives (VFD).

Idaho Power is a primary sponsor of the IDL, which provides technical assistance and training seminars to local architects, engineers, and designers. Some of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the biannual BetterBricks awards held in Boise. The BetterBricks awards recognize leaders whose work supports the design and operations of high-performance buildings and their commitment to energy efficiency. The Building Efficiency program also sponsors technical lunch-and-learn sessions geared to educate design

professionals and the Idaho Building Simulation Users' Group. The Idaho Building Simulation Users' Group is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

## 2012 Activities

The Building Efficiency program completed 84 projects, resulting in 20,450,037 kWh in annual energy savings in Idaho. Overall, the program increased kWh savings almost 78 percent over 2011. The dramatic increase in energy savings for 2012 was impacted by some large, multi-year construction projects being completed for qualified program incentives. Examples include regional hospitals in Twin Falls and Pocatello. Additionally, design professionals have become more familiar with the program in recent years. In 2012, vinyl construction banners were produced for the first time and installed at a building site to publicly showcase the building was being "built with energy efficiency in mind."

The Building Efficiency program was last modified in 2011, although the cap of $100,000 on Idaho projects was removed in 2012. Also in 2012, an impact evaluation was completed, focus groups were held with architects and engineers, and in-depth interviews were conducted with building owners to gain feedback on the program. Based on the outcome of these activities, minor changes will be made to the program in mid-2013 once all recommendations have been evaluated thoroughly. New construction and major renovation project design and construction life is much longer than small retrofits and requires consistency in program measures and operation. Program consistency reduces confusion for customers with long construction and project timelines.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Twenty-one technical training lunches were completed in 2012, with 235 attendees, including architects, engineers, interior designers, and project managers. Technical training sessions were held in Boise, Twin Falls, Pocatello, Idaho Falls, and Ketchum. Topics included Integrated Design Principals, Energy Benchmarking and Energy Goal Setting, Daylight In Buildings: Schematic Design Methods, Daylighting: Getting the Details Right, Multi-Zone Demand Control Ventilation Systems, Climate Responsive Design: Tools and Methods, Advanced Envelope Construction, Radiant System Design Considerations, High-Performance Classrooms, Role-of-Life Cycle Cost Assessment in Integrated Design, Center for Advanced Energy Studies and Integrated Design, and Commissioning. The Building Efficiency program, in conjunction with the Custom Efficiency program, sponsored 12 training sessions, with 145 attendees for the Building Simulations User Group through the IDL. Additionally, Idaho Power was a sponsor of the American Institute of Architects 2030 Challenge held in Boise. The 2030 Challenge was a 10-session learning course designed to educate architects, engineers, and other design professionals on integrated design practices in new construction. Approximately 40 design professionals were enrolled in the program. The 10 sessions started in fall 2011 and concluded in spring 2012.

Additional *Success Stories* were added to the Idaho Power website in 2012, with one specific to new construction titled *Idaho Power Helps Motorcycle Parts Manufacturer Keep Jobs at Home*. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Building Efficiency has teamed up with the Building Owners and Managers Association (BOMA) and NEEA to offer a Kilowatt Crackdown™ competition for office buildings over 15,000 $ft^2$ located in the Treasure Valley. The initial sign-up closed on December 31, 2012. Over 40 buildings signed up to participate in the year-long competition, which includes benchmarking their building in

ENERGY STAR® Portfolio Manager—an interactive energy-management tool that allows tracking and assessing of energy and water consumption—and implementing low-cost and no-cost efficiency measures in their building throughout 2013. Participating buildings have access to an energy coach, scoping audit of their building, and education opportunities. The purpose of this commercial building energy competition is to facilitate and educate businesses on wise energy use. The competition will continue through the beginning of 2014. Idaho Power is contributing marketing and technical expertise to help ensure the success of the competition. At the November 6 EEAG meeting, Idaho Power provided an update on the Kilowatt Crackdown competition in the Treasure Valley market. Idaho Power also sponsors the American Society of Architects Honor awards, the BetterBricks awards, the Smart Growth awards, and the Association of Idaho Cities Annual Conference.

At the November 6 EEAG meeting, Idaho Power also discussed the work being done regarding multi-family dwellings. Building Efficiency is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research shows the measures are cost effective, new measure offerings could be added to the program in 2013.

## Cost-Effectiveness

For 2012, the Idaho Power incentive structure remained consistent with the 2011 program.

To calculate energy savings, the Building Efficiency program verifies the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters for both the measure at code and at efficiency. The other method for calculating savings in the program is based on industry standard assumptions when precise measurements are unavailable. Since Building Efficiency is a prescriptive program and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry standard assumptions from the International Energy Conservation Code (IECC) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures. In 2012, ADM conducted an impact evaluation of the 2011 program savings. The report recommended a revision to the prescriptive formulas used to estimate the reported savings in three measures. The revised formula has been applied to the 2012 savings results. The program remains cost effective.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kW reduction as the unit being used. For 2012, Idaho Power's incentive structure remained consistent with the 2011 program. Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. The evaluation report indicates that, overall, the Building Efficiency program does a good job ensuring rebated energy efficiency equipment efficiencies are above those mandated by applicable building code. The 2011 program savings realization rate was estimated to be 73 percent as compared to ex-ante estimates.

The report identified two areas that contributed to over 40 percent of the reduction in the ex-post savings adjustment, which included 1) errors in ex-ante prescriptive formulas used to estimate savings for some HVAC equipment and controls and 2) baseline definition issues that redefined subsets of measures as baseline equipment. Some equipment installed as upgrades were actually required as part of code.

ADM recommends 1) the revision of prescriptive formulas used to estimate savings for air-side economizers, energy-management system building controls, and demand-control ventilation; 2) making prescriptive algorithms more rigorous; 3) making each algorithm more specific to the application for which it is applicable; 4) select a larger number of HVAC controls and VFD projects for detailed application review to screen for potential code or baseline issues; and 5) update the application to include specific applications for which VFDs will not qualify for incentives. A revised version of the impact evaluation report was received after the printing of *Supplement 2: Evaluation*. These revisions do not materially change the results of the evaluation. A copy of the complete report is included in *Supplement 2: Evaluation*. A copy of the revised report is available on request.

In 2012, Idaho Power contracted with Market Decisions Corporation to provide participant focus groups with architects, engineers, and designers and to conduct phone interviews with building owners and operators to gain feedback on the Building Efficiency program. Two in-person two-hour focus groups were held with 14 architects, engineers, or designers in attendance. Ten 30-minute in-depth phone interviews were conducted with building owners and operators. Participants were asked a series of questions by a Market Decisions Corporation moderator and asked to candidly share their experience and satisfaction with the Building Efficiency program.

As a qualitative study, the following key findings only reflect the general thoughts of those that participated in the research groups and are not representative of the entire program. Overall, the research participants are "highly satisfied" with the program. Architects and engineers are familiar with all program incentives and owners are familiar with the incentives applicable to their projects. The architects and engineers typically bring the Building Efficiency program to the owner's attention during the project's design phase. All research participants also expressed a high level of satisfaction with the pre-application process and Idaho Power staff engagement during their projects. A copy of the report can be found in *Supplement 2: Evaluation*.

Building Efficiency continued random installation verification on 10 percent of projects in 2012. The purpose of these verifications was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 9 of the 84 projects, which encompasses approximately 10 percent of the total completed projects in the program. Out of the nine projects verified, eight projects were installed with only minor or no discrepancies compared to how they were declared. The minor discrepancies resulted in a total increase of energy-efficient measures. Only one project was installed with less energy-efficient measures than were declared. Random project installation verification will continue in 2013.

## 2013 Strategies

The Building Efficiency program will make program updates in mid-2013 once the impact evaluation and focus group research has been evaluated. Research is currently being conducted on multi-family construction. The outcome of the research may lead to additional Building Efficiency offerings in the multi-family sector. A future filing with the OPUC regarding mid-2013 program changes would include the removal of the $100,000 cap on Building Efficiency projects in Oregon. The Building Efficiency

program will continue to perform random post-project verifications on a minimum of 10 percent of completed projects.

The Building Efficiency program will continue to sponsor technical training through the IDL. Technical trainings will continue to address the energy efficiency education needs of design professionals in the Boise, Pocatello, Twin Falls, and Sun Valley markets. Additionally, the program will continue to support organizations focused on promoting energy efficiency in commercial construction. Idaho Power hopes to replicate the vinyl construction banners publicly showcasing buildings as "built with energy efficiency in mind" across a number of energy-efficient buildings in the coming year. The feasibility and value of advertising in specific trade publications will be determined in 2013.

In 2013, Idaho Power plans to contract with a third-party to conduct a research project for the Building Efficiency program that will evaluate existing and new measures for the program.

# Custom Efficiency Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 126 | 166 |
| Energy Savings (kWh)[a] | 54,253,106 | 67,979,157 |
| Demand Reduction (MW) | 7.6 | 7.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $923,050 | $413,959 |
| Oregon Energy Efficiency Rider | $115,866 | $1,385,613 |
| Idaho Power Funds | $6,053,665 | $6,984,239[b] |
| Total Program Costs—All Sources | $7,092,581 | $8,783,811 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.012 |
| Total Resource Benefit/Cost Ratio | $0.021 | $0.026 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.48 | |
| Total Resource Benefit/Cost Ratio | 3.31 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind.
[b] Capitalized incentive payments per IPUC Order No. 32245.

## *Description*

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy efficiency projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education regarding energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power, or by the customer as applicable to the facility. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application and an agreement finalizing the terms and conditions of the applicant's and Idaho Power's obligations. In some cases, large, complex projects may take as long as two years to be completed. Often, Idaho Power conducts follow-up or post-inspection validation via third-party engineering firms on projects of this nature. Every project is verified post-completion by Idaho Power staff or an Idaho Power contractor. All lighting projects are pre- and post-inspected by an Idaho Power contractor or an Idaho Power representative. Incentive levels for the Custom Efficiency program remained at 70 percent of the project cost, or 12 cents per kWh for first-year savings, whichever is less.

## 2012 Activities

Custom Efficiency experienced another successful year in 2012. A total of 126 projects were completed by 110 customers, including four Oregon projects from four customers. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Program energy savings decreased in 2012 by 20 percent over 2011, from 67,979 MWh to 54,253 MWh. The decrease in program energy savings was a result of several factors: 2012 was a presidential election year and customers mentioned they were hesitant to move forward with large projects until after the election was determined. This, along with general economic uncertainty, impacted the 2012 numbers. Also, the program may have reached some saturation through maturation, as nearly 90 percent of the large-power service customers have submitted an application for a project through 2012. Finally, with the high percentage of industrial customers that have completed projects in the program, deeper energy savings with be challenging to achieve. There were 137 approved applications for active projects at the end of 2012, representing 64,034 MWh of savings. Table 9 indicates the program's 2012 annual energy savings by primary project measures.

Table 9. 2012 Custom Efficiency annual energy savings by primary project measure

| Program Summary by Measure | Number of Projects | KWh Saved |
|---|---|---|
| Lighting | 63 | 20,107,218 |
| HVAC | 6 | 11,885,602 |
| CFL | 19 | 5,321,048 |
| Refrigeration | 15 | 5,319,400 |
| Motors | 3 | 2,289,748 |
| Compressed Air | 4 | 2,228,709 |
| Pump | 2 | 1,425,757 |
| Fan | 9 | 1,380,649 |
| VFDs | 3 | 951,665 |
| Green Rewind | 19 | 54,154 |
| Other | 2 | 3,289,155 |
| **Total** | **126**[a] | **54,253,106** |

[a] Does not include Green Rewind projects.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. Because the link between energy audits and the completion of projects is historically significant, Idaho Power reevaluated its current offerings and strengthened them where appropriate. It is anticipated, effective by the second quarter of 2013, that detailed audits will go from 50 percent reimbursement or $10,000, whichever is less, to 75 percent reimbursement or $12,500. Scoping audit details did not change in 2012.

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. The training is coordinated by the NEEA Industrial Training Project, and Idaho Power is a co-sponsor. Idaho Power also co-funds the trainings, which allows twice the trainings in Idaho Power service area. Additionally, Idaho Power covers the cost of each customer's subsidized attendance in the classroom-based training sessions. A total of nine technical classroom-based training sessions were completed in 2012. Four of these classes were two-day classes, and the rest were one-day classes. Topics included compressed air, chilled water systems and cooling towers, pump systems, VFDs,

data-center efficiency, energy management, and industrial refrigeration. A schedule of training events is posted on Idaho Power's website.

The level of attendance remained high in 2012, with 171 Idaho Power-sponsored seats filled with 146 end-use customers and various Idaho Power staff, consultants, and trade allies. Customer feedback indicated average overall satisfaction levels over 97 percent.

There were two training sessions outside of the Idaho Power service area attended by Idaho Power customers. One was a pump certification training in Eugene, Oregon, attended by two Idaho Power customers. The second was a conveyance systems training in Portland, Oregon, attended by one customer. The conveyance system training is planned to be offered within Idaho Power's service area in 2013.

Additionally, 2012 encompassed Phase II of the Webinar Pilot Plan coordinated by NEEA. Twelve webinars were presented free to all attendees. Topics included VFDs; lighting; data centers; energy-management topics, including developing an energy plan, investment analysis energy management for industrial customers, and energy auditing and troubleshooting. There were 50 Idaho Power region seats filled with end-use customers and multiple Idaho Power personnel and consultants attending the webinar recordings. Idaho Power posted the recordings and PDFs on the newly established training page on the Idaho Power website.

Figure 8 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the 2012 in-class NEEA industrial trainings. This figure uses data from ECOVA™'s summary of the trainings provided in the *NEEA Regional Industrial Training Update, December 2012*, included in *Supplement 2: Evaluation*.

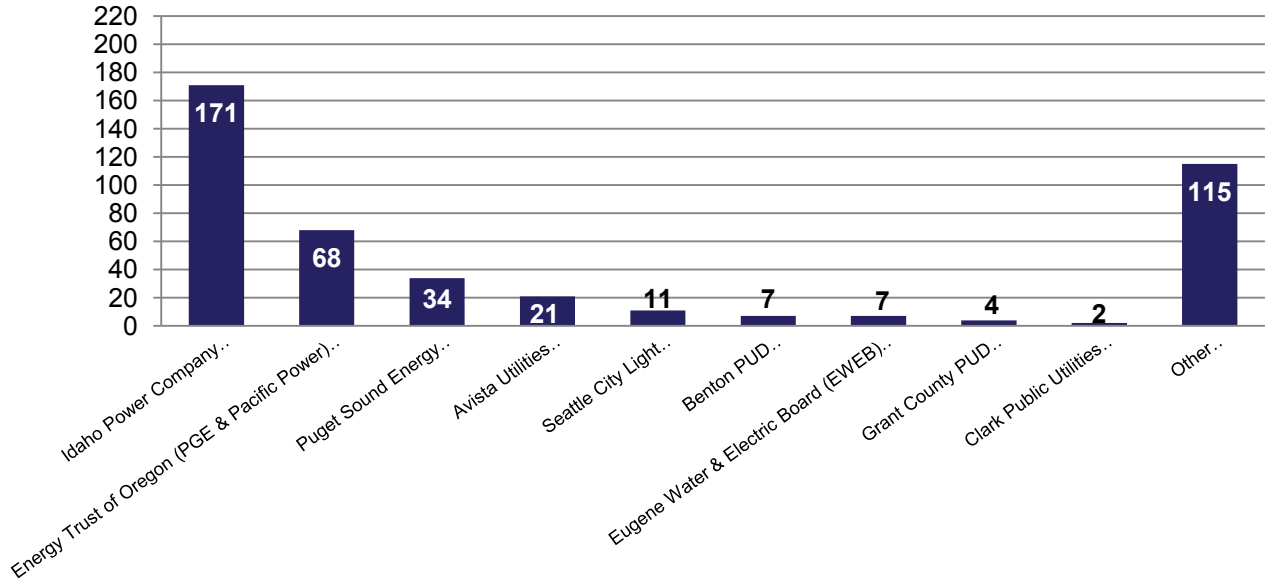


Figure 8. NEEA chart of attendees (seats filled) by attendee sponsor[3]

[3] Data source: *NEEA Regional Industrial Training Update, December 2012*.

As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency and ensures an efficient use of electricity to run the motor. There were 19 Green Rewind motors in the commercial/industrial sector in 2012, contributing 54,154 kWh in annual savings.

The Custom Efficiency program has achieved a high service-area penetration rate. As stated previously, through 2012, nearly 90 percent of the large-power service customers have submitted applications for a project. Idaho Power engineers have met with the remaining viable Rate 19 and special-contract customers to discuss energy efficiency programs and opportunities within customer facilities.

In 2012, the Idaho Power CR&EE department filled a summer internship position with a Boise State University mechanical engineering student. A Custom Efficiency engineer served as the intern mentor. The intern was involved with many aspects of the day-to-day program operation including, but not limited to, measurement and verification of energy efficiency aspects related to Custom Efficiency program lighting projects, attendance at customer meetings related to energy efficiency, familiarization, and communication of all three commercial incentive programs, calculation and review of energy-saving projects, exposure to program marketing and planning activities, and administrative work related to the Custom Efficiency program. Another internship will be offered in summer 2013 and will involve activities similar to the 2012 internship. These internships are important mechanisms that help drive work-force development in the energy efficiency profession.

Early in 2012, the Custom Efficiency staff noticed that program energy savings were trending downward with respect to the prior few years. Several utilities in the region started to implement behavioral, strategic energy management, maintenance-related, energy coaching, resource conservation manager, and other non capital-intensive programs. Thus, Custom Efficiency engineers investigated the potential of bringing some of these offerings to Idaho Power as part of the Custom Efficiency program offerings. Three separate offerings were developed in 2012 and have been budgeted for in 2013. These include 1) Refrigeration Operator Coaching for Energy Efficiency (ROCEE), 2) Small Industrial or Custom Efficiency Express, and 3) Strategic Energy Management (SEM).

## Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement, and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is thoroughly reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculates the energy savings. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, and especially larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or major customer representatives solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to participate in the Custom Efficiency program posting the customers' *Success Stories* on the Idaho Power website. In 2012, six new *Success Stories* describing 2012 projects were posted on the company's website. An example of a *Success Story* posted in 2012, titled *Idaho Power incentives help Ballard Dairy and Cheese bring the kids back to their family operation*, refers to a project Ballard Dairy and Cheese completed early in 2012. Idaho Power provided $28,604 in incentives for energy efficiency upgrades that reduced costs and is expected to save over $12,000 in annual utility bills. The owner said, "We had help from the Small Business Administration and the USDA, too, but we really couldn't have done it without Idaho Power's assistance." Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

## 2013 Strategies

Both the Custom Efficiency and Easy Upgrades programs offer lighting incentives to commercial and industrial customers. In 2013, Idaho Power will continue to make program changes to lighting projects within both Custom Efficiency and Easy Upgrades to be as consistent with each program as possible. Better alignment of the incentives between the two programs will lessen program confusion and potentially increase participant satisfaction. One significant change occurring to lighting projects in 2013 will be the addition of allowing incentives for existing T-8 lighting to more efficient technology, T-8 to LED case lighting, and T-8/T-5HO to reduced wattage T-8/T-5HO.

Early in 2013, detailed audits will go from a 50 percent reimbursement or $10,000, whichever is less, to a 75 percent reimbursement or $12,500, while scoping audits will be revised to have a $3,500 maximum, up from $3,000 in 2012.

In 2013, Idaho Power will conduct customer satisfaction research on the Custom Efficiency program. The actual methodology for the research is under review. Research will be conducted late in the year.

Custom Efficiency plans to launch three new program offerings in 2013 aimed at expanding support for customers implementing energy efficiency within their facilities. The first program, tentatively titled Small Industrial or Custom Efficiency Express, is planned for launch in the third quarter of 2013. It is designed to address the smaller compressed air, pump and fan VFDs (other than HVAC and irrigation), cold storage doors, and small refrigeration projects that do not justify the study costs associated with a typical large and/or complex custom project. The program offering will be administrated by Cascade Energy Engineering and will leverage vendor relationships, incorporate simplified analysis tools, and streamline the incentive process. This offering has not officially been named yet. The second Custom Efficiency program offering anticipated for launch in March 2013 is the ROCEE. This offering will provide highly relevant hands-on energy efficiency training to key individuals whose actions have a

direct bearing on the energy performance of energy-intensive systems. Using services provided by NEEA and Cascade Energy Engineering, this offering will engage 6 to 10 large customer facilities to reduce energy associated with their refrigeration systems. The third program offering under development, SEM, will provide training and incentives to program-offering participants focused on low-cost or no-cost measures that may be more behavioral or operations and maintenance-related. Due to concerns with the persistence of savings and/or measure life, these types of projects have historically not been eligible for incentives. However, with a new SEM program offering, these concerns can be addressed appropriately, leading to an increased energy savings potential within the program. The Small Industrial, ROCEE, and SEM program offerings were described to EEAG at the November 6 meeting, resulting in favorable comments from EEAG members.

In 2013, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities and through continued development of strategic partnerships. These activities will include direct marketing of the Custom Efficiency program by Idaho Power major CRs to further educate customers on Idaho Power energy efficiency programs, identify potential ways the customer can reduce energy costs, and drive program participation. Idaho Power will continue to provide site visits and energy audits for project identification; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored energy improvement practices to customers. Additionally, program staff will continue to engage and support the Center for Advanced Energy Studies (CAES), the IDL, and the Industrial Assessment Center.

Each year, the company designs and pays for a "Top 10" advertisement that appears in the *Idaho Business Review*. This advertisement publicly congratulates companies that had the most energy savings throughout the year. *Success Stories* will continue to be written and produced throughout 2013. These stories focus on businesses that took advantage of Idaho Power's Custom Efficiency program and the resulting benefits. *Success Stories* are posted on Idaho Power's website as PDFs so the highlighted businesses can print and use them to publicize their energy-efficient projects. In addition to these success stories, Idaho Power assists with public-relations opportunities, creating certificates for display within the building and having an Idaho Power representative speak at press events.

# Easy Upgrades

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,838 | 1,732 |
| Energy Savings (kWh) | 41,568,672 | 38,723,073 |
| Demand Reduction (MW) | 4.7 | 4.4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $5,150,422 | $4,598,019 |
| Oregon Energy Efficiency Rider | $199,331 | $121,447 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $5,349,753 | $4,719,466 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.011 |
| Total Resource Benefit/Cost Ratio | $0.020 | $0.022 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.57 | |
| Total Resource Benefit/Cost Ratio | 3.29 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The Easy Upgrades program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering customer incentives. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shells, VFDs, plug loads, and food-service equipment. Easy Upgrades is one of the company's largest programs. A complete list of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial and industrial customers taking service under Rate Schedule 7 (Small General Service), Rate Schedule 9 (Large General Service), Rate Schedule 19 (Large Power Service), and special-contract customers are eligible. For projects with expected incentive payments of more than $1,000 or that contain VFDs or non-standard lighting measures, applicants must submit a pre-approval application prior to initiating the project. In those cases, the customer or contractor completes the pre-approval application and submits it with the required documentation. For projects not requiring pre-approval, customers may elect to skip the pre-approval application process and submit their payment application and accompanying documentation. Under the Easy Upgrades program, customers may assign their incentive payment to a third party (e.g., their contractor or supplier), as approved by Idaho Power.

## *2012 Activities*

Easy Upgrades experienced strong program participation in 2012. The number of completed projects increased by 6 percent over 2011, and energy savings increased by 7 percent.

Several process-improvement activities were implemented in 2012. A written program procedures manual was developed, a non-lighting verification protocol was put in place, and work was undertaken to expand program reporting capability. To provide quicker project turnaround, and in anticipation of an increase in project applications submitted to the program, Idaho Power hired an additional contract employee to assist with application processing. Trade allies experienced and appreciated the improved turnaround.

The program conducted eight lighting trade ally program information workshops across the Idaho Power service area. In addition, three technical lighting classes were offered to trade allies and two lighting classes were given for Idaho Power CRs. Two of the three technical classes qualified for continuing education credits for eligible, licensed trade allies. For the first time, the program held technical and program information classes in McCall. The program was well received, resulting in increased project submissions from that area. A total of 362 people received lighting information/education from the Easy Upgrades program in 2012.

In addition to the formal training classes held, program staff and Idaho Power CRs visited trade allies in the field, at the trade ally's business, or at a customer location to further educate them on program criteria and to respond to their inquiries.

Significant field time was spent visiting lighting trade allies throughout the Idaho Power service area. The program experienced a lull in application submissions mid-year, and trade ally outreach was used to help ameliorate that issue. Over 75 visits were made for the purposes of strengthening relationships; encouraging program participation; increasing knowledge of the Easy Upgrades program; receiving trade ally feedback about the market, the program, and their experiences; and learning how the program can better support trade allies (including where to focus training efforts in the future). Visits targeted electrical supply businesses and electrical contractors who were fairly new to the Easy Upgrades program. The upswing in project submissions post trade ally visits was noticeable.

An Easy Upgrades program specialist participated as a member of the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency development group. This group formed through collaboration with stakeholders to identify opportunities and strategic needs to support the region's success in commercial lighting. This strategic report will be finalized and presented to the NEEA Regional Portfolio Advisory Committee (RPAC) in January 2013. Implementation of the approved regional strategy is proposed to begin shortly thereafter.

Idaho Power continued to contract with Evergreen Consulting Group, LLC to provide ongoing lighting specialist expertise, project support, and trade ally training. Two lighting specialists provided support in trade ally outreach, as well as trade ally training. Idaho Power contracted with Honeywell, Inc., to perform non-lighting project reviews and pre- and post-project inspections.

To ensure projects participating in the program met program specifications and to verify conditions in the field were as stated on the program application, the Easy Upgrades program conducted pre- and post-inspections on numerous projects throughout 2012. The majority of inspections performed (1,030) were for lighting projects and consisted of 453 pre-inspections and 577 post-inspections. Seventy-three non-lighting projects received inspections, of which 19 were pre-inspections and 54 were post-inspections.

Program site inspections resulted in a variety of findings. The field conditions proved an exact match to the information on the application in many instances. For projects where discrepancies were found, incentive payments were adjusted to reflect actual field conditions, anywhere from lowering or

increasing the incentive amount to denying the project incentive altogether. Examples of lighting discrepancies included fixture count and fixture type differences. Examples of non-lighting inspections not matching the project applications included facility square-footage differences; projects not meeting program criteria, such as insulating an unconditioned space; and projects that applied for one measure, but the actual project pertains to a different measure. Program management used inspection findings to identify areas for program improvement and modification and for trade ally training opportunities.

In addition to verifying that the information provided on the incentive application matched conditions in the field, the inspections provided an opportunity for Easy Upgrades to receive feedback from customers and trade allies about their projects and the program. Customers shared how their energy-efficient upgrade benefited their business. They also appreciated the inspections and viewed them as value added. In many cases, inspections resulted in identifying additional retrofit opportunity that resulted in increased energy savings for customers and Idaho Power. A frequent comment heard from trade allies was that knowing Idaho Power had inspectors verifying projects randomly in the field increased the accuracy of project information submitted to the program.

To advance energy savings and quality lighting design, Idaho Power was one of four utilities that participated with NEEA in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. The purpose of the pilot was to provide valuable information regarding the program design, level of incentives, and program support needed to achieve success in securing projects with increased energy savings using a comprehensive approach. Easy Upgrades program staff await NEEA's evaluation report of the pilot expected February 2013.

## Cost-Effectiveness

In 2012, Idaho Power made several small adjustments to the measure offerings in the program. The lighting tool was updated to accept electronic T-12 ballasts. An initial analysis was conducted to see if the lighting measures shown in the tool would remain cost effective with the addition of the electronic T-12 ballasts. While the savings decreased slightly, it was shown to still be cost effective based on the average input watts and hours of operation. The actual savings for each lighting project are calculated based on existing light fixtures, the replacement light fixtures, and hours of operation.

NEMA Premium Efficiency general purpose motors were removed from the program in 2012. The motors are now the federal standard. The VFD measures listed on the Motors and HVAC worksheets were moved to one new worksheet.

In the *Demand-Side Management 2011 Annual Report*, Idaho Power listed several measures it planned to remove, change, or update in 2012. The company anticipated making these changes to the non-lighting measures of the program after the completion of the impact evaluation. However, due to the timing of results from the impact evaluation, the changes to the program have been postponed to 2013. Additionally, Idaho Power is currently working with a contractor to review selected non-lighting measures in the program and to provide updated deemed values to use going forward. Currently, most deemed-savings values for non-lighting measures come from the *Demand-Side Management Potential Study* conducted by Nexant, Inc., in 2009; however, Idaho Power uses data from the RTF for a dozen measures.

As part of a comprehensive review of all deemed measures, the RTF reviewed and updated the savings for commercial ENERGY STAR® refrigerators and freezers in October 2012. Because of the change in federal efficiency standards and the very high level of ENERGY STAR market penetration, the baseline changed and the savings decreased causing the measures to no longer be cost-effective. Five incentives

for solid or glass door ENERGY STAR refrigerators and freezers of varying sizes were paid an Easy Upgrades program incentive in 2012. Idaho Power will review the measure in 2013 and determined what changes needed to be made. The remaining RTF measures have either not been updated or have not changed significantly to impact cost-effectiveness.

For current, detailed cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

An example of a satisfied customer is indicated in a *Success Story* posted on Idaho Power's website in 2012, *Upgrading its lighting gives Dominick's Quick Print whiter whites, brighter colors, and more cheerful employees*. This story describes how Joe Dominick, owner/manager/president of Dominick's Quick Print in Ontario, Oregon (and mayor of Ontario), was considering a lighting upgrade for his print shop. His electrician told him about the Idaho Power Easy Upgrades incentive program to help ease his worries about potential expenses. "I gulped when he first told me the cost," Joe said, "but when he told me that Idaho Power's incentive program could cut the cost by 65 percent, that got my attention. That made the project possible." Through Idaho Power's Easy Upgrades program, this small business owner changed out all 41 of his T-12 light fixtures to efficient T-8 fixtures, resulting in an estimated 7,586 kWh savings per year. A copy of this *Success Story* is provided in *Supplement 2: Evaluation*.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. This evaluation showed that lighting projects, which represented approximately 57 percent of 2011 savings, had a realization rate of 101 percent, while non-lighting projects had a realization rate of 33 percent. The overall realization rate was 72 percent as compared to ex-ante estimates.

The performance of VFD and HVAC controls (specifically programmable thermostat measures), accounted for approximately 80 percent of the reduction in ex-post savings due to the high volatility in savings potential and difficulty in estimating measure savings using deemed estimates.

ADM recommends the use of a partially deemed approach using a stipulated formula with site-specific inputs along with tables of deemed inputs to reduce the variance in realized savings for all VFD measure savings estimates. In addition, they recommend increasing the volume of projects receiving a detailed review of the project scope and measure applicability for both VFD and HVAC controls. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

Several measure changes will be implemented in 2013. The program expects to offer incentives for qualifying T-8 lamps to reduced wattage T-8 lamps, T-5 High Output (T-5HO) lamps to reduced-wattage T-5HO lamps, screw-in metal halide lamps, and T-8 to LED refrigeration/case lighting. Incentives for permanent fixture decommissioning will also be offered as a way to encourage proper lighting design.

The program expected to undertake an evaluation of the non-lighting measures in 2012 similar to the extensive review of lighting measures conducted in 2011. However, with the program impact evaluation slated for mid-year 2012, Idaho Power postponed the non-lighting measure review until after receipt of the impact evaluation to incorporate its findings. Based on the results of the impact evaluation, the following recommendations were provided:

- Use custom calculations for large projects involving VFDs or for projects involving VFDs in process applications.
- Perform a thorough review of the project scope and affected equipment. This recommendation has particular applicability to the energy-management system controls and economizer measures.
- Consider applying interactive factors to lighting savings.
- Consider adopting a concurrent evaluation paradigm.

A review of these recommendations and a plan of action (or reason for no action) are targeted for completion in the first quarter of 2013.

Increased trade ally and customer training will be a focus for the program in 2013. Lighting 101 and lighting controls classes, both with continuing education credits, will be offered throughout the company service area. These classes will be offered in Salmon, a first for that area. Additionally, Easy Upgrades will secure American Institute of Architects CEUs and promote the lighting classes to the design community.

The program will expand beyond its lighting classes and offer technical training for trade allies and customers with in-house technical staff in the areas of VFDs and HVAC/controls.

Due to the success of the focused trade ally visits in 2012 and because the majority of customers participating in the program first learned about the program from trade allies, Easy Upgrades will continue to invest time and effort in trade ally visits across the Idaho Power service area. The purposes for these trade ally visits is noted in the previous 2012 Activities section.

Marketing outreach efforts targeted at small to medium customers will increase in 2013 to better inform/educate customers of the Easy Upgrades program and the various incentives offered. This marketing outreach will include a variety of strategies: direct-mail letters, articles in the company monthly customer newsletter, internet banner advertisements, articles and advertorials in local papers and/or local chamber of commerce newsletters, biannual commercial newsletters, and other tactics as identified throughout the year.

Results from the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency group will be evaluated, and Idaho Power will participate in the various aspects of the strategy it determines to be applicable to Idaho Power's market, program strategy, and goals.

Results from the NEEA Comprehensive Lighting Pilot evaluation will be reviewed, and opportunities for program implementation will be evaluated.

Idaho Power participated in regional discussions regarding the Standards for General Service Fluorescent Lamps protocol that became effective July 14, 2012. Due to the extensive T-12 lamp inventory and manufacturers continuing to produce T-12 lamps that meet the exception clause of the new ruling, Idaho Power will continue offering T-12 to T-8 incentives throughout 2013. Idaho Power discussed this at the July 19, 2012, EEAG meeting. Members were unanimously supportive of continuing to offer incentives for T-12 retrofit projects.

Idaho Power is aware of the RTF Lighting Protocols being drafted and will monitor these protocol outcomes to determine their applicability to the Easy Upgrades program.

In 2013, Idaho Power plans to contract with a third-party consultant to evaluate existing and new measures for the program.

# FlexPeak Management

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (sites) | 102 | 111 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 52.8 | 58.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $98,973 | $1,954,850 |
| Oregon Energy Efficiency Rider | $150,489 | $102,880 |
| Idaho Power Funds | $2,760,360 | $0 |
| Total Program Costs—All Sources | $3,009,822 | $2,057,730 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.22 | |
| Total Resource Benefit/Cost Ratio | 1.22 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

FlexPeak Management is a voluntary demand response program available in Idaho and Oregon service areas designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak days. The program objective is to reduce the demand on Idaho Power's system during peak times through customers' voluntary electrical-use reduction. The program is active June 1 to August 31 between 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand-reduction event two hours prior to the start of the event, and events last between two and four hours. Reduction events may be called a maximum of 60 hours per season.

In November 2008, EnerNOC, Inc., was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805. In June 2010, the program was approved by the OPUC in Order No. 10-206.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours with minimal impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring

equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week during the active season, EnerNOC commits a demand-reduction level in MW to Idaho Power that EnerNOC is obligated to meet during a demand-reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand-reduction event in aggregate. Customers can also continuously monitor their demand-reduction performance using their individual, near real-time energy-usage data through EnerNOC's proprietary software. This metering data and software is available to participating customers throughout the year.

## 2012 Activities

There were no changes to the program in 2012. During the first week of the program, EnerNOC committed to provide a meter-level reduction of 30.5 MW. This weekly commitment, or nomination, was comprised of 99 facility sites, of which 96 participated in the program in 2011 and 3 facility sites were added in 2012. The weekly nomination at the end of the season was 38.8 MW and comprised of 101 facility sites.

EnerNOC was contractually obligated to commit to provide at least 35 MW of reduction for each week in 2012. Their weekly commitments ranged from 29.6 MW to 38.8 MW. Four of the first five weekly commitments were below the 35 MW minimum; therefore, EnerNOC was subject to a penalty for those weeks. The remaining 10 weeks of the season they were above the 35 MW minimum and did not receive a penalty. Their commitment peaked in August at 38.8 MW.

Idaho Power called four demand response events for the FlexPeak Management program in 2012. One event occurred in June, two in July, and one in August. EnerNOC successfully exceeded the committed MW reduction in two of the four events. For the other two events, EnerNOC did not reach their committed MW reduction; performances were 91 percent and 87 percent of the committed levels. The highest hourly reduction achieved was in July at 54.2 MW (47.9 MW at the meter), which exceeded the target reduction of 35 MW for summer 2012.

## Cost-Effectiveness

The B/C analysis for the FlexPeak Management program is based on a 10-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The settlement workshop led to a stipulation that was filed on February 14, 2013. FlexPeak Management was not included in the original filing due the company's contractual obligation to EnerNOC; however, Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond. At the time this

report was written, Idaho Power was negotiating with EnerNOC on potential contract amendments aimed at reducing overall program costs for 2013. Because these negotiations are ongoing, the company conducted the cost-effectiveness analysis using the same cost and benefit assumptions it has in the past and used the 2013 budgeted expenses and forecasted performance, only updating 2012 actual demand reductions and costs.

Because demand response programs are analyzed over their program life, the analysis includes historical program demand reduction and expenses, as well as forecasted program activity. The program is analyzed over a 10-year program life because the 5-year contract with EnerNOC includes an option to extend the contract for another five years.

This analysis is updated annually with actual B/Cs. For the FlexPeak Management program, the benefits are based on measured demand reduction at the participant's meter. The costs include the fees paid to EnerNOC and Idaho Power administration for the program. The 2012 cost-effective analysis demonstrated the FlexPeak Management program has a TRC ratio of 1.22 from a long-term perspective and a TRC ratio of 1.21 for 2012. *Supplement 1: Cost-Effectiveness* contains details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

EnerNOC sent a post-event survey via email after the first event in June 2012 to 195 participants representing all the sites enrolled in the event. Eighteen participants responded, for a 9-percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8.6. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.3.

EnerNOC sent a second post-event survey via email after the August 2012 event to 201 participants, again representing all the sites enrolled in the event. Twenty-one participants responded, for a 10 percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was again 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.1. A summary of the results is in *Supplement 2: Evaluation*. Also included in the supplement is the *FlexPeak Management Annual Report*.

## 2013 Strategies

The 2013 peak season will be the final season of Idaho Power's current contract with EnerNOC. EnerNOC is contractually obligated to commit to provide at least 35 MW of reduction for each week of the active season in 2013. EnerNOC plans to conduct a post-season customer satisfaction survey for the 2012 season during the first quarter of 2013. The results will be made available to Idaho Power. Idaho Power will continue to evaluate the best use of the program to meet the program objectives,

maximize the benefit to Idaho Power's system, and refine internal criteria to call demand-reduction events.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the FlexPeak Management program and produce an internal report, including 2013 activities, demand reduction, and a cost-effectiveness analysis summary.

# Oregon Commercial Audits

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 14 | 12 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $12,470 | $13,597 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $12,470 | $13,597 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program offered under Oregon Rate Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2012 Activities*

Idaho Power sent out its annual mailing to approximately 3,400 Oregon commercial customers in August 2012. Customers were notified of the availability of no-cost energy audits and were provided with the Idaho Power publication *Saving Energy Dollars*. Fourteen customers requested an audit, with five audits completed by Idaho Power and nine completed by a third-party contractor.

Idaho Power contracts with EnerTech Services to perform the third-party portion of requested audits. Energy audits include a review of the customers past billing data and an inspection of the building shell, HVAC equipment, operating schedules if available, and lighting systems. Additionally, specific business operating practices that can be incorporated to improve energy use are discussed. During the audits, customers receive Idaho Power energy efficiency program information.

## *Cost-Effectiveness*

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82. Since the required parameters of the Commercial Energy Audit Program are

specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost effective. Idaho Power claims no energy savings from this program.

## Customer Satisfaction and Evaluations

The value of an audit is the identification of actual savings opportunities in the customer's facility. Audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Both activities can lead to energy efficiency projects being undertaken. Customers are generally pleased with the audit process. This is especially true when the business owner is fully engaged in the audit. Business owners can make the decisions to change operating practices or make capital improvements designed to use energy wisely. Additionally, the audits help identify energy-saving opportunities that may not be obvious to the business owner.

## 2013 Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities. The audits help pinpoint favorable energy-saving actions that customers may pursue through customer behavioral changes or potential capital projects, such as replacing inefficient lighting. Additionally, the audit process will be used to introduce customers to Idaho Power's energy efficiency incentive programs. The program will be marketed through the annual customer notification.

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# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is composed of agricultural customers operating water pumping or water delivery systems to irrigate agricultural crops or pasturage. The end-use equipment primarily consists of agricultural irrigation pumps and center pivots. This customer group does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2012, the active and inactive irrigation service locations totaled 19,045 system-wide. This was an increase of 1 percent compared to 2011, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow-irrigated to sprinkler irrigation systems. Irrigation customers accounted for 2,048,435 MWh of energy usage in 2012, which was up from 2011 by 22.4 percent due to the hotter, dryer summer. This sector represented 14.5 percent of Idaho Power's total electricity usage and about 25 percent of peak demand in the summer. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to provide a system peak resource, and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind offering in which motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 hp and 5,000 hp for agricultural uses that receives a verified Green Rewind. Participation in Green Rewind ensures the motor's original efficiency is maintained if it is rewound at an approved service center.

The Irrigation Peak Rewards program had 340 MW of available demand-reduction capacity for summer 2012, an increase of almost 20 MW, or a 6.2-percent increase over 2011 summer's program capacity. For the 2012 season, 2,433 service points were enrolled, compared to 2,342 in 2011, representing a 3.9-percent increase.

The Irrigation Efficiency Rewards program, in operation since 2003, saw its annual savings decrease by 1,363 MWh to 12,617 MWh compared to 2011 reported savings. The savings decrease in 2012 was primarily due to fewer larger projects being done in 2012. During 2012, irrigation customers contributed 30,039 kWh per year of energy savings from 23 motors participating in Green Rewind.

Table 10 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

# Programs

Table 10. 2012 irrigation program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| Irrigation Peak Rewards | 2,433 service points | $12,423,364 | $12,423,364 | n/a | 339.9 |
| **Total** | | **$12,423,364** | **$12,423,364** | **n/a** | **339.9** |
| **Energy Efficiency** | | | | | |
| Irrigation Efficiency Rewards | 908 projects | $ 2,373,201 | $11,598,185[a] | 12,617,164 | 3.1 |
| **Total** | | **$ 2,373,201** | **$11,598,185** | **12,617,164** | **3.1** |

[a] See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 54 percent of Idaho Power irrigation customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-five percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 29 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 88 percent are “very” or “somewhat” satisfied with the program.

# Irrigation Efficiency Rewards

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 908 | 880 |
| Energy Savings (kWh)[a] | 12,617,164 | 13,979,833 |
| Demand Reduction (MW) | 3.1 | 3.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,978,729 | $2,153,613 |
| Oregon Energy Efficiency Rider | $360,689 | $176,619 |
| Idaho Power Funds | $33,782 | $30,072 |
| Total Program Costs—All Sources | $2,373,201 | $2,360,304 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.020 |
| Total Resource Benefit/Cost Ratio | $0.110 | $0.113 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.66 | |
| Total Resource Benefit/Cost Ratio | 1.76 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind.

## *Description*

The Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help customers recover a portion of the costs of installing a new, more efficient irrigation system and energy-efficient improvements to existing systems.

Two options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per the first year of kWh saved above standard installation methods, not to exceed 10 percent of the total project cost. For existing system upgrades, the incentive is 25 cents per the first year of kWh saved, or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh usage of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in most situations, post-usage demand data are available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which

small maintenance upgrades provide energy savings from 11 separate measures. These measures include the following:

- New flow-control nozzles
- Replacement of worn brass or plastic nozzles
- Rebuilt or new impact sprinklers
- Rebuild kits for wheel-line levelers
- New low-pressure or rotating-type sprinklers
- New low-pressure regulators
- New drains, riser caps, and gaskets
- New wheel line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on predetermined average kWh savings per component.

Participation in Green Rewind is an opportunity that enables customers to maintain the motor's original efficiency and ensures an efficient use of electricity to run the motor. Motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 and 5,000 hp that receives a verified Green Rewind. The RTF approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings for industrial and agricultural applications.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power agricultural representatives sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits conducted by Idaho Power agricultural representatives evaluate prospective customers' potential savings. Agricultural representatives from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing their awareness of the program and promoting it through the irrigation equipment distribution channels. Marketing efforts include direct mailings, advertisements in agricultural publications, and participation in agricultural workshops and conferences. Idaho Power's agricultural representatives are funded approximately 30 percent by the Idaho and Oregon Riders and 70 percent from base rates.

## 2012 Activities

Of the 908 irrigation efficiency projects completed in 2012, 790 were associated with the Menu Incentive Option, providing an estimated 7,015 MWh of energy savings and 1.37 MW of demand reduction. The Custom Incentive Option had 118 projects, of which 65 were new irrigation systems and 53 were on existing systems. This option provided 5,572 MWh of energy savings and 1.7 MW of

demand reduction for the year. Also during 2012, irrigation customers contributed 30,039 kWh of energy savings from 23 motors participating in the Green Rewind opportunity.

In June 2012, with approval from the EEAG and OPUC (Tariff Advice No. 12-09), Idaho Power changed the Menu Incentive Option for new or rebuilt wheel-line levelers to only rebuilt wheel-line levelers or rebuild kits. This change came about because the cost of a new wheel-line leveler made this measure not cost effective.

Idaho Power agricultural representatives, the program specialist, and the agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2012, Idaho Power provided six workshops promoting the Irrigation Efficiency Rewards program throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference.

## Cost-Effectiveness

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. To estimate the effectiveness of a project, Idaho Power uses a service point's previous five years of electricity usage history and, based on the specific equipment to be installed, calculates the estimated post-installation energy consumption of the system. The company also verifies the completion of the system design through aerial photographs, maps, and field visits by Idaho Power agricultural representatives to ensure the irrigation system is used in the manner the documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure savings are achieved. Payments are calculated on predetermined average kWh savings per measure. In some cases, the energy savings estimated in the Menu Incentive Option are adjusted downward to reflect how the components are actually being used. No changes occurred to the assumptions that drive the cost-effectiveness of the measures that are part of this program.

All cost-effective analyses were based on the savings approved by the RTF in January 2010. The measures were reviewed for compliance with the new RTF savings guidelines in 2011 and were determined to be out of compliance. In 2012, the RTF approved of a plan to bring the measure back into compliance with the guidelines. Idaho Power will meet with the RTF in early 2013 to evaluate the research done by the University of Idaho to study the savings impacts of the measures provided in the Menu Incentive Option.

Based on the available deemed savings from the RTF, nearly all the measures offered under the Menu Incentive Option are cost effective. The rebuilt and new wheel-line levelers were shown not to be cost effective in 2010. After reviewing the measure, it was determined that the cost of the new

wheel-line levelers was negatively impacting the cost-effectiveness of the measure. In 2012, the measure was modified to include only rebuilt wheel-line levelers in the program's offerings.

For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

At the February 2012 EEAG meeting, Idaho Power discussed the plan of partnering with the University of Idaho to research the Menu Incentive Option measures of the Irrigation Efficiency Rewards program to gather more information about menu measures. A sub-committee of the RTF will review the research and present aspects of the study to the RTF in 2013.

In 2012, Idaho Power contracted with the University of Idaho to conduct research regarding the Irrigation Efficiency Rewards program Menu Incentive Option. This research evaluated energy savings associated with the repairing of leaks and worn components listed in the Menu Incentive Option. The final report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

Marketing plans for 2013 include conducting 7 to 10 customer-based irrigation workshops. Additionally, Idaho Power program specialists, agriculture representatives, and an agriculture engineer will attend five regional trade shows. These workshops and trade shows enable discussions between Idaho Power representatives, the company's customers, irrigation dealers, and trade allies while continually educating them about irrigation best practices, the program, and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power is reviewing the program regarding measures offered in the Menu Incentive Option. The research provided by the University of Idaho will be presented to the RTF in early 2013. The results of this research project will help determine changes to the program in future years and validate energy savings attributed to the replacement of irrigation components offered in the Menu Incentive Option.

A 2013 media plan has been created aimed at increasing the impact of advertising on this program. In addition, the effectiveness of online advertisements will be evaluated with this target audience. A database of irrigation dealers and vendors is also being developed for direct-mail purposes. Irrigation dealers and vendors are a key component to the successful marketing of the program; therefore, direct mailings containing the most up-to-date program information, brochures, and dealer specific meetings ensure correct program promotion.

# Irrigation Peak Rewards

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 2,433 | 2,342 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 339.9 | 320.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,309,107 | $11,790,216 |
| Oregon Energy Efficiency Rider | $95,863 | $254,013 |
| Idaho Power Funds | $11,018,394 | $41,993 |
| Total Program Costs—All Sources | $12,423,364 | $12,086,222 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.79 | |
| Total Resource Benefit/Cost Ratio | 1.72 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

Idaho Power's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to minimize or delay the need to build new supply-side resources. The program pays irrigation customers a financial incentive for the ability to turn off specified irrigation pumps with the use of one or more load control devices during the program season of June 15 through August 15.

In 2012, all Idaho Power irrigation customers taking service under Schedule 24 in both Idaho and Oregon were eligible, and participants chose between three options: 1) the Electric Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn off participants' pumps, or 3) a Manual Dispatch Option designed for large-service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during a load control event.

Participants in the Manual Dispatch Option are required to nominate the amount of kW they are enrolling in the program by June 1 of the program year. Participants in the Electronic Timer Option can choose to have all irrigation pumps on a single, metered service point turned off one, two, or three times per week. Interruptions occur from 4:00 p.m. to 8:00 p.m., and Idaho Power determines the specific weekday or weekdays to schedule the interruption of all pumps at each service point. Installation fees between $250 and $500 are applied to participating service locations less than 75 hp. For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. For 2012, dispatchable load control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday. Customers who choose to

participate until 9:00 p.m. receive a higher variable incentive for events. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. Installation fees between $500 and $1,000 were applied to participating service points with less than 50 hp depending on the option customers chose.

The incentive structure includes a fixed and variable incentive payment. A customer's fixed incentive appears as a bill credit that sums the demand credit and energy credit for the interruption option selected and applies to a customer's monthly bills. The variable incentive is a summary of all load control event kWh multiplied by the variable incentive credit paid in the form of a check within 45 days of the end of the program season. Credits are prorated for periods when reading/billing cycles do not align with the program season dates from June 15 to August 15. All customer incentives participating in the Electric Timer Option, Automatic Dispatch Option, or Manual Dispatch Options are calculated using Idaho Power meter billing data. In addition, Manual Dispatch Option customers' incentives are calculated using interval metering data and nominated kW. Installation fees and opt-out penalties are completed through manual bill adjustments. Incentives, determined from interval meter data for service points classified as large-service locations, are completed through a manual process, and customers received the incentives in the form of a check in 2012. The incentives offered are listed in Table 11.

Table 11. Option incentives

| Dispatchable Interruption Option Incentives | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Fixed Incentive Payment | | | | Variable Incentive Payment | | |
| Dispatchable Option | Demand Credit ($/billing kW) | | Energy Credit ($/billing kWh) | | Standard Interruption Variable[a] | | Extended Interruption Variable[b] |
| **Options 1, 2, and 3** | $5.00 | **and** | $0.019 | **plus** | $0.159 | **or** | $0.209 |

[a] Energy Credit: 4 hours between 1–8 p.m. ($/event kWh)
[b] Energy Credit: 4 hours between 1–9 p.m. ($/event kWh)

| Electronic Timer Option Incentives | | | |
|---|---|---|---|
| Option | Demand Credit ($ per billing kW) | | Energy Credit ($ per billing kWh) |
| **Timer Option Incentives** | | | |
| One weekday | $3.15 | | |
| Two weekdays | $4.65 | **plus** | $0.002 |
| Three weekdays | $4.65 | **plus** | $0.007 |

Under the rules of the Automatic and Manual Dispatch Options, participants have the ability to opt out of dispatch events five times per service point. Each opt-out incurs a fee of $1 per kW based on the current month's billing kW, which may be prorated to correspond with the dates of program operation and are completed through manual bill adjustments.

## 2012 Activities

Participation in this program was strong in 2012. Service points increased by 91, a 3.9-percent increase over 2011. Most of the challenges surrounding communication with some dispatch devices that occurred in prior years were resolved. In 2012, the program had the potential to achieve a maximum peak load reduction of approximately 340 MW. This represents a 6-percent increase from 2011, even though the company did not solicit new participants. Of all eligible irrigation service locations, approximately 13 percent participated in the program. In 2012, there were 2,433 metered service points enrolled in the program, with approximately 3.4 percent enrolled in the Electric Timer Option, 95.1 percent enrolled in the Automatic Dispatch Option, and 1.5 percent in the Manual Dispatch Option.

Idaho Power attempted to distribute the Electric Timer Option participating service points evenly throughout each weekday based on cumulative demand-reduction potential. However, due to service-point size variability, enrollment opt-outs, and other variables, the load reduction could not be exactly balanced. All participants in the Automatic and Manual Dispatch Options were grouped into five regional areas to be dispatched on each scheduled event day. Table 12 shows the MW reduction achieved daily on a week-by-week basis.

Table 12. Total program daily MW reduction without distribution losses using realization rates

| Measure | Monday | Tuesday | Wednesday | Thursday | Friday |
|---|---|---|---|---|---|
| June 15 | n/a | n/a | n/a | n/a | 3.1 |
| June 18–22 | 4.2 | 4.0 | 3.9 | 4.2 | 3.3 |
| June 25–29 | 4.2 | 4.0 | 3.9 | 339.9[a] | 3.3 |
| July 2–6 | 4.0 | 3.8 | 3.7 | 3.9 | 3.1 |
| July 9–13 | 4.0 | 3.8 | 3.7 | 320.7[b] | 3.1 |
| July 16–20 | 3.5 | 3.3 | 3.2 | 3.5 | 2.7 |
| July 23–27 | 3.5 | 3.3 | 3.2 | 3.5 | 2.7 |
| July 30–August 3 | 3.2 | 3.1 | 3.0 | 3.2 | 2.5 |
| August 6–10 | 3.2 | 3.1 | 3.0 | 3.2 | 2.5 |
| August 13–15 | 3.2 | 3.1 | 3.0 | n/a | n/a |

[a] The shaded cell reflects the estimated MW load reduction capacity available through the program.
[b] The shaded cell is Idaho Power's peak load day and reflects the estimated MW load reduction capacity available through the program.

Although the load reduction provided by the Irrigation Peak Rewards program was available to Idaho Power throughout the 2012 program season, dispatching the program was unnecessary. This was due to resources being able to meet system peak demands, low energy prices, and lack of system emergencies during the summer. Under the program's variable incentive design, taking into account both the extended interruption incentive and program realization rates, the program had an approximate dispatch price of $240 per MWh, which would total about $300,000 per event if all customers were interrupted for four hours. The program would be used if the company could not meet its peak needs with other resources, if hourly energy prices were greater than the dispatch cost of the program, or to avert a system emergency.

In February 2012, a customer mailing was sent to irrigation customers who participated in the program in 2011. The mailing included a program explanation, a program application, contract agreement, the program's incentive structure, a list of the customer's eligible service points, and an incentive estimate for each program option. Customers that had not participated in the program and did not receive the initial mailing but requested to participate were sent the same information.

Idaho Power did not market the program in 2012 but did provide program information at six workshops throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. The company also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths, where company representatives were available to answer questions, were displayed at regional agricultural trade shows, including the Eastern and the Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. Additionally, numerous one-on-one conversations with Idaho Power agriculture representatives familiarized customers with the technology and program details.

At the July 2012 EEAG meeting, Idaho Power presented the concept of changing the Irrigation Peak Rewards program to have three or four interruption events included in the fixed portion of the incentive customers receive. This would mean the program would not have to pay the variable incentive for these events. The events would be used primarily for customer awareness of what happens when events are called. It was discussed that without these included events the program could go multiple years without initiating any load control events. EEAG members were generally accepting of the concept.

## Cost-Effectiveness

The B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation was filed on February 14, 2013. Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

Demand response programs are analyzed over the program life, this includes historical program demand reduction and expenses, as well as forecasted program activity. Because of the uncertainty of the program costs and because an order in the IPC-E-12-29 case is pending, for this report, the company conducted its cost-effectiveness analysis using the information know prior to the filing to temporarily suspend the Irrigation Peak Rewards program in 2013. The costs and demand capacity for 2012 were included with the forecast demand reduction and costs based on the 2013 budget and expected results. The Irrigation Peak Rewards program had a TRC ratio of 1.72. From a one-year perspective, the Irrigation Peak Rewards program had a TRC ratio of 2.4. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load reduction analysis, cost-effectiveness, and program changes. A copy is included in *Supplement 2: Evaluation*.

## 2013 Strategies

As referenced previously, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC to temporarily suspend the Irrigation Peak Rewards program for the 2013 season. The 2013 IRP is under development, and the IRP analysis indicates there will not be a need for demand response programs like the Irrigation Peak Rewards program during 2013. The proposed temporary suspension of Irrigation Peak Rewards will allow Idaho Power to work with stakeholders to determine the future course of action for its demand response programs. Idaho Power has proposed to continue to maintain the load control devices currently in place until further direction indicates otherwise.

Idaho Power plans to also file with the OPUC to suspend the program for 2013.

# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market-transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates the marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. 2012 was the third year of NEEA's current, five-year plan.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

In 2012, Idaho Power energy efficiency staff served on NEEA's Board of Directors, attended advisory meetings, served on sub-committees, and participated in NEEA-sponsored studies and research.

### *Commercial and Industrial NEEA Activities in Idaho*

NEEA continued to provide support for commercial energy efficiency activities in Idaho in 2012. This included partial funding of the IDL and local BetterBricks® trainings and workshops. Idaho Power's commercial sector programs Building Efficiency and Easy Upgrades are designed to leverage NEEA, the IDL, and BetterBricks activities.

In the industrial sector, NEEA continued its efforts to embed Continuous Energy Improvement (CEI) in small- to medium-sized businesses defined as less than 250 employees per site. CEI is a multi-year strategic effort designed to improve energy efficiency in the industrial sector. Prior CEI efforts focused on two regional industries considered heavy energy users: 1) the food processing industry and 2) the pulp and paper industry. Participants achieve cost savings through the adoption of energy-efficient business practices. CEI provides expert support, resources, and services, supplying companies with the training and tools for making energy efficiency a core business value. This effort is supported by providing technical knowledge to organizations and to Idaho Power customers collaborating on energy efficiency implementation. NEEA has a demonstration project for the agricultural sector taking place in Idaho. The project will provide information on control systems and variable-rate irrigation to improve overall efficiency.

Technical training and education continue to be important in helping Idaho Power's industrial customers identify where they may have energy efficiency opportunities within their facilities. Nine technical training classes were completed in 2012. Topics included compressed air, chilled water systems and cooling towers, pumping systems, VFDs, industrial refrigeration, data-center efficiency, and energy-management systems. The level of attendance at these classes remains high, with 171 participants attending the workshops.

In the commercial sector, NEEA has been working with utilities and lighting trade allies to develop a comprehensive lighting program. Idaho Power was one of four utilities that participated in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. NEEA has also been working to secure a pilot project in Idaho for their Existing Building Renewal initiative. This initiative is

aimed at developing and testing new industry tools for commercial property owners engaging in deep energy retrofits.

## Residential NEEA Activities in Idaho

NEEA supported a variety of residential programs and associated activities in Idaho Power's service area in 2012.

Among Idaho Power's programs, NEEA is directly involved in providing additional funding and support for ENERGY STAR® Homes Northwest, the DHP Pilot, the Residential Economizer study, and the Consumer Electronics Energy Forward campaign.

NEEA provides ENERGY STAR Homes Northwest builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates the various building specifications and requirements with the EPA and utilities in Idaho, Montana, Oregon, and Washington. Most of these activities are managed through a third-party implementer hired by NEEA.

In June, Idaho Power partnered with NEEA to promote the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home featuring a state-of-the-art DHP. NEEA secured the donation of the DHP from the manufacturer. An Idaho Power bill insert promoted the ENERGY STAR qualified Dream Home, and NEEA donated an ENERGY STAR flat-screen television to be used as a raffle prize.

NEEA has coordinated the DHP pilot research project since 2009, which includes data collection, design, results analysis, savings calculations, and ongoing promotional activities. The goal of the pilot is to encourage the adoption of these products while displacing the use of existing electric-resistance zonal heating systems in homes. NEEA created and launched a regional marketing program in 2012, conducted from September through December. The goal of the program was to increase consumer awareness of DHPs. The promotion included the use of social media, as well as radio, television, and newspaper advertising. Idaho Power currently offers a $750 cash incentive for qualified homeowners who install a qualified DHP system.

NEEA coordinated a residential Heat Pump Water Heater (HPWH) research project in the Northwest region that started approximately three years ago. A goal of the project is to promote the adoption of higher-efficiency water heaters over units built with only electric-resistance heat. Another goal is to provide a business case to the DOE by April 2016 encouraging the DOE to modify the 2020 federal standards and test methods for domestic electric water heaters. Water heaters built with only electric-resistance heat will not meet the proposed modified standard. The research project includes data collection, design, analysis, savings calculations, and marketing activities. NEEA's promotion offers a $1,000 rebate through June 2013 to residential homeowners who have certain HPWHs installed. The promotion requires the HPWH to be installed by a contractor trained by NEEA. In 2012, NEEA trained 18 contractors in the Idaho Power service area. NEEA also arranged for a HPWH discount program to be offered through Sears, a national appliance retailer, using 30 of their stores in the Northwest. Discounts were made available to homeowners who purchased certain HPWHs. Idaho Power participated in a HPWH summit in Portland in June 2012. The goal of the summit was to increase collaboration and cohesion with all regional utilities and other stakeholders.

In 2012, an Idaho Power residential program specialist participated on the selection committee for the HPWH Model Validation & Process Evaluation. This study strives to provide energy-savings data through the installation of HPWHs and data-logging equipment in residential homes. The committee

scored contractor bids and selected the contractor Evergreen Economics to provide the HPWH Model Validation and Process Evaluation. Evaluation data will be compared to energy-savings data generated by the RTF's computer modeling created specifically for this study.

Idaho Power's partnership with NEEA's Consumer Electronics Energy Forward Campaign continued in 2012. The Energy Forward campaign highlighted the most energy-efficient televisions available. Retailers who represent more than 80 percent of televisions sold in the Northwest partnered with NEEA to promote Energy Forward televisions, including Best Buy, Costco, Kmart, Sam's Club, Sears, and Wal-Mart. Although final 2012 numbers are not yet available, as of late 2012, approximately 37 percent of televisions sold in the region were Energy Forward-qualified.

NEEA developed and launched a number of marketing tactics, including a fall marketing campaign to drive sales of qualifying televisions and engage national retailers in the promotion of these televisions. The campaign was a sweepstakes in which consumers could enter to win one of four "VIP tailgates" at a home game (one in each state of Idaho, Montana, Oregon, and Washington) or a chance to win weekly sub-prizes like Energy Forward televisions. Best Buy, Sears, and ENERGY STAR were campaign sponsors, and NEEA conducted public relations, advertising, social media, and online promotional tactics, including promotional packages with universities.

NEEA also launched a marketing campaign on October 1 with Best Buy, Sears, and ENERGY STAR as campaign sponsors. The primary objectives of the campaign were to increase retailer participation in promoting Energy Forward Most Efficient televisions, increase sales associates' awareness of them, and increase sales associates' ability to communicate qualifying television benefits to consumers leading into Black Friday. Mass consumer outreach via public relations, paid media, social media, community events, and partner outreach enticed retail partners to participate in the campaign and also helped increase consumer awareness and demand leading into the busiest shopping season of the year. NEEA representatives maintained retail partnerships by visiting each store at various times throughout the year, setting up point-of-purchase materials, and educating the sales staff.

Idaho Power has also participated in NEEA's Residential Advisory Committee meetings and activities throughout 2012 and served on the advisory team to contribute to ongoing improvements of Conduit, a regional online community for energy efficiency program managers in the Pacific Northwest. The goal of Conduit is to expedite the delivery and adoption of energy efficiency programs and activities. NEEA launched the website in May 2011. Conduit houses a library, discussion forums, and collaboration space. Similar to Facebook in features and benefits, Conduit is a space for energy efficiency professionals to congregate and share ideas, concerns, and questions. It is open to trade allies, state agencies, regulators, research institutions, and utility professionals. Additionally, two members of the residential programs team attended NEEA's annual conference, Connections Northwest, which provided updates on NEEA-sponsored programs and research, as well as valuable networking opportunities with other utility program managers.

An Idaho Power residential program specialist participated on the Regional Emerging Technologies Advisory Committee (RETAC) during 2012. The committee reviewed and updated the RETAC charter to effectively integrate the charter with other committees such, as the RPAC. Another RETAC committee purpose was to develop a 2013 plan to support the charter and member needs. The 2012 portfolio of emerging technologies under review at NEEA was discussed. Idaho Power and other utilities participating in RETAC reported on the energy efficiency projects the utility companies were interested in or had investigated.

In 2012, an Idaho Power residential program specialist participated on the National Energy Efficiency Technology Road Mapping Summit committee. The purpose of the committee was to revise current technology characteristics and the research and development (R&D) associated with the individual residential and commercial technology roadmaps contained in the Roadmap Portfolio. The Roadmap Portfolio helps guide and prioritize the regional investigation of technologies. The portfolio contains many technologies, along with the specific drivers, capability gaps, characteristics, and R&D programs associated with each technology. Idaho Power participated in revisions to the HVAC technology roadmap. The prioritization of all residential and commercial roadmaps is to be completed by March 2013.

An Idaho Power residential specialist was involved in 2012 with the NWRRC. This collaborative is a forum to evaluate and coordinate regional retail strategy. The first official meeting as a collaborative was held on November 27, 2012, at the Puget Sound Energy office in Olympia, Washington. Activities included a presentation to NEEA's Portfolio Committee, approval and adaption of Charter and Working Agreements, and the development of a scoping process for 20 potential measures identified for review at subsequent meetings.

## Other NEEA Activities in Idaho

Over the last two years, Idaho Power's energy efficiency analysts participated in two committees to collect basic information on building stock and energy use of buildings throughout the Pacific Northwest. The results of the studies help form the future regional planning efforts. In 2011, NEEA moved forward with the RBSA. With the RBSA, customers from households in Washington, Oregon, Idaho, and parts of Montana were selected randomly to participate in a phone survey. A subset of those customers was then selected to participate in an on-site survey and, in some cases, a more in-depth energy review of the home. The *Single-Family Characteristics and Energy Use Report* was released in September 2012. The *Manufactured Home Characteristics and Energy Use Report* was published in January 2013. The multi-family report is expected to be released in 2013. Organizations, such as the RTF, have begun to revise measure saving using updated assumptions from the RBSA.

In addition to the RBSA, NEEA began work on the Commercial Building Stock Assessment (CBSA). An Idaho Power energy efficiency analyst participated in the RFP selection committee and the Sampling Priorities Working Group. Work on the CBSA will continue throughout 2013, with a final report expected in 2014.

Idaho Power is a participant in NEEA's Cost Effectiveness Advisory Committee. This committee meets three to four times a year to review NEEA cost-effectiveness models, assumptions, and, ultimately, energy-savings estimates. Idaho Power also participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally.

## NEEA Funding

In 2012, Idaho Power began the third year of the 2010 to 2014 Regional Energy Efficiency Initiative Agreement with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market-transformation programs in Idaho Power's service area. Of this amount in 2012, 100 percent was funded through the Idaho and Oregon Riders.

In 2012, Idaho Power paid $3,379,756 to NEEA. The Idaho jurisdictional share of the payments was $3,210,768, while $168,988 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

For this report, NEEA provides Idaho Power an early estimate of its annual savings for the previous year. In the *Demand-Side Management 2011 Annual Report*, the NEEA savings reported were 16,109 MWh. The revised estimate included in this report for 2011 NEEA savings is 20,547 MWh. Preliminary estimates reported by NEEA for 2012 indicate that Idaho Power's share of regional market-transformation MWh savings for 2012 is 17,741 MWh, or 2 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at www.nwalliance.org.

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# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative's goal is to promote energy efficiency to the residential sector. This goal is achieved by creating and delivering educational materials and programs that increase Idaho Power's energy efficiency program participation and result in wise and informed choices regarding energy use.

The Residential Energy Efficiency Education Initiative continued to lead the production and distribution of the 2012 energy efficiency guides.

The first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313 due to additional newspaper subscriptions, insertion into the *Boise Weekly* magazine, and an extra 800 copies for hand delivery by Idaho Power representatives to locations, such as senior centers. The *Summer Energy Efficiency Guide*, inserted into newspapers on May 20, focused on ways to save money and make wise use of electricity during the cooling season. To get information out well in advance of the heating season, a third energy efficiency guide was published and distributed on November 11. This guide introduced tools and checklists to assist customers in getting the most savings per dollar invested in energy-related upgrades. It also suggested low and no-cost ways to increase comfort and manage bills while maintaining equipment and planning for future improvements.

During 2012, Idaho Power changed the style of the energy efficiency guides and incorporated a more consistent look and feel, including a catalog identification number to facilitate subsequent in-house printings. These process improvements allowed the company to increase the shelf-life and begin to build a library of flexible resources at a minimal cost. In 2012, 1,405 additional guides were distributed as educational handouts at energy efficiency presentations and events. About 10 percent of customers who requested *30 Simple Things You Can Do To Save Energy* also requested one or more of the energy efficiency guides.

In 2012, Idaho Power continued to build its social-media presence. Compared to this time last year, Facebook fans nearly doubled to just over 3,600, and Idaho Power's Twitter following quadrupled to 800 users. The company continued to leverage both channels to communicate information about Idaho Power energy efficiency programs, incentives, and events. Idaho Power's YouTube channel also saw increased activity; the 45 videos currently posted generated 13,500 views, of which 5,500 came from Idaho Power's educational video on DHPs. Across all channels, content was timed to align with print and broadcast campaigns so as to reinforce the message and heighten customer awareness. Additionally, Idaho Power's Energy Efficiency Program managers responded to 362 web inquiries with detailed written answers.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of other communication methods during 2012. Increased customer awareness of energy-saving ideas was accomplished via continued distribution of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. During the year, 8,707 English and 1,008 Spanish copies were distributed directly to customers via community events and local libraries; by CRs during in-home visits; by participating contractors in the

Home Improvement Program, Energy House Calls, H&CE Program, Boise Home Audit Project, and See ya later, refrigerator® program; through direct web requests; and in response to inquiries received by Idaho Power's customer service center. Of the books distributed in 2012, 1,106 were mailed directly to customers at their request, including 1,087 sent to customers who contacted Idaho Power's Customer Service Center with questions about how to reduce energy use and 19 in response to direct requests received through Idaho Power's website. Idaho Power also mailed 876 copies of the informational brochure *Practical Ways to Manage Your Electricity Bill* to customers who called specifically with concerns about high bills.

Idaho Power continues to recognize that educated employees are effective advocates for Idaho Power's energy efficiency programs. To keep employees informed and up to date, Idaho Power conducted its annual energy efficiency awareness campaign in March. Activities during 2012 included weekly articles in internal publications to engage employees in learning more about Idaho Power's programs and wise energy use. A texting competition was implemented and employees were encouraged to text answers to weekly questions focused on energy efficiency. Posters for display in Idaho Power's offices and distribution of wearable buttons encouraging employees to become "Energy Efficiency Rock Stars" rounded out the month.

Although the formal partnership with the Idaho Commission for Libraries expired in June 2011, the Kill A Watt™ Meter Program remained active in 2012. With this commitment complete, Idaho Power reached out to local libraries to assist with the continued promotion of the program. Idaho Power developed a travelling, interactive table display for individual library use to create buzz and interest around the Kill A Watt kits. All participating libraries received an invitation to schedule the display. Eight libraries responded and three displays moved amongst the libraries throughout the summer and fall.

Idaho Power took the lead in strengthening the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2012, twenty teachers completed the 3-day, 2-credit professional development seminar facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Lab (INL).

Other energy education partnerships included working with the IDL in late autumn to offer two residential-focused training seminars in the BetterBricks® series. Twenty-four participants attended the session titled "Advanced Insulation Techniques" and 16 attended "The People Side of Sustainability." Both sessions had two off-site participants that attended via live video streaming. Videotapes of the seminars are available for download from the IDL's website. The workshops averaged 15 post-lecture downloads in 2012. Idaho Power continued its co-sponsorship of the "Sustainable Energy Sustainable Homes" lecture series. The eight workshops, facilitated by local trade experts, provided information and expertise to encourage energy efficiency upgrades. Attendance increased from an average of 12 participants per session in 2011 to an average of 18 participants per session in 2012. Idaho Power continued to partner with the City of Hailey on the educational portion of their Hailey Community Climate Challenge grant by participating in the delivery of seven workshops during the year.

In addition to these activities, Idaho Power continued sponsorship of the fifth annual Idaho Green Expo in June. As part of Idaho Power's commitment to the Expo, the company sponsored a direct-mail effort to increase participation and publicize the new location. Data from Idaho Power's 2010 and 2011 Green Expo Surveys was mined to determine the best Treasure Valley homeowners to include. Two-for-one coupons were provided the week prior to the Expo to 26,000 targeted participants. The Idaho Power Expo booth consisted of a "Summer of '78" theme, where participants were encouraged to set their

summertime thermostats to 78 degrees and given other stay-cool tips. In addition to sharing this message at the booth, Idaho Power partnered with six other sustainably minded organizations to sponsor a broad educational activity that used text messaging to engage attendees and their families for the length of their expo visit. The activity exceeded expectations with 186 unique individuals, representing 6 percent of total expo attendees, choosing to play. Together, they texted 3,093 correct answers to the specified telephone number. On average, these 186 players texted 17 correct answers each and thus received 34 pieces of valuable information during their expo visit. The regional director for the vendor, who processed the text messages, stated, "These results are quite fantastic. In a typical setting I would estimate 1.5 percent to 2 percent participation. You all have tripled that. Great effort!"

For the third year running, Idaho Power partnered with GreenWorks Idaho to develop and administer an exit survey, resulting in 342 completed surveys. The Green Expo participant profiles will be used to further improve messaging and goals and increase an understanding of Idaho Power's return-on-investment for future sponsorship of this event. It will also be used for tracking energy efficiency-related trends among expo attendees. Thirty percent of this year's survey participants reported having received an energy efficiency incentive payment from Idaho Power, up from 21 percent in 2011. The survey summary is provided in *Supplement 2: Evaluation*.

In September 2012, Idaho Power participated in the St. Luke's Women's Show for the fifth consecutive year. The event continues to be important due to the size of the audience and because its demographic component aligns with Idaho Power's residential energy efficiency target audience. Numerous marketing research studies have shown the people most likely to participate in energy efficiency programs tend to be females with higher education and income levels than the general population. This target audience aligns well with individuals who attend this event.

Idaho Power requested booth visitors complete an in-depth survey. The survey was redesigned in 2012 based on results from the previous two years' surveys to gather key market data and establish a baseline regarding attitudes toward energy-efficient and sustainable behaviors. Another improvement with the 2012 survey was that participants were given the opportunity to complete an online survey prior to the show through the show sponsor. This resulted in a more positive experience in completing the survey for many, since there were frequently waiting lines in previous years. In total, the company collected 670 completed surveys, exceeding the target of 400. The opportunity to complete the survey online shortened the waiting line at the booth and resulted in 274 of the 670 survey respondents completing the survey from a remote location.

Although the respondents are not a random sample, key findings from the Women's Show survey indicated Idaho Power's ENERGY STAR® Homes Northwest continues to be the most recognized energy efficiency program, with most respondents (77%) indicating they were "aware of" the program. Respondents also indicated awareness of other ENERGY STAR branded programs and the See ya later, refrigerator® program. Energy House Calls was the least recognized program, with a majority of respondents (65%) indicating they had "never heard of" the program. The Home Products Program and A/C Cool Credit program were most identified by participants as a program they had participated in.

Of the Women's Show participants that completed the survey (98% female), the majority said they review and pay the monthly bills in their home and are the primary decision makers for managing thermostats, purchasing light bulbs and fixtures, and making appliance and electronics purchases. However, less than half of respondents indicated they are the primary decision maker for home upgrades, such as adding insulation.

When asked if they had plans to reduce their electricity consumption, less than 8 percent indicated they had no plans to do so. Forty-three percent indicated they were already taking some action, while 49 percent indicated they were either currently exploring ways or starting to take some action to reduce electricity use. Of the actions presented, turning lights off when leaving the room, adjusting thermostats up two degrees in the summer, and replacing incandescent light bulbs with CFLs were the most likely behavioral changes respondents would take to save money and to positively impact the environment. Respondents were slightly more inclined to reduce their water heater temperature 10 degrees and participate in the A/C Cool Credit program for positive environmental benefits than cost savings.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 171 outreach activities, including events, presentations, trainings, and other outreach activities. As part of process improvement accomplishments, the Outreach Tracking System, the database that records educational and outreach activities, again received some enhancements for additional metrics. In 2012, a special effort was made to increase the quantity and quality of post-event feedback recorded in the database. At the conclusion of 2012, 71 percent of events taking place during the year had some post-event documentation recorded in the system.

In addition to the outreach activities noted previously, Idaho Power field staff throughout Idaho Power's service area delivered another 176 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2012, the Community Education team provided 92 presentations on *The Power to Make a Difference* to 2,690 people. More specifically, 53 of these presentations were to students, and 29 of them were community presentations. The breakdown of attendance was 1,539 students and 1,151 community members. The community education representatives and other staff members also completed 42 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 1,473 seniors in the company service area.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and other needs of Idaho Power's Corporate Communications department. The initiative staff supplied information for various Idaho Power publications, such as *News Scans, Green Power Newsletter*, *A/C Cool Credit Newsletter*, *Customer Connections*, and Idaho Power's Facebook page. Additionally, the initiative worked with the Energy-Use Advisory Tool (EUAT) team to provide appropriate tips and suggestions for the account manager enhancements implemented in March. One of the major goals of this web enhancement was to educate customers and encourage behavioral change by linking specific energy-related behaviors and choices to their monetary consequences. Time-of-Day promotional materials and calculators were also created with energy efficiency suggestions from the initiative.

During 2013, the initiative's goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. Based on guidance from EEAG, plans for 2013 include more opportunities to educate and influence young people regarding wise energy use and continued work with Idaho Power program specialists, partners, and participating contractors to influence behavioral change, particularly when energy efficiency upgrades are made. Energy efficiency educational materials and channels will continue to be evaluated and either developed or revised, as necessary, to increase customer reach, improve distribution, and enhance presentation opportunities. Beginning in 2013, two issues of *Customer Connections* (the monthly newsletter included in customer bills) will be devoted entirely to energy efficiency. Idaho Power will continue to actively evaluate existing data to determine how future research and data collection may be improved to further the Residential Energy Efficiency Education Initiative's goals.

## Easy Savings Program

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP and provides $125,000 to be paid to CAP agencies in the Idaho Power service area on a prorated basis. In addition, this order specified that Idaho Power provide educational information for households that heat their homes with electricity provided by Idaho Power.

Three main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes to use energy wisely, to allow hands-on experience while installing a low-cost measure, and to reduce the energy burden for energy assistance/LIHEAP applicants.

In past years, the primary target for the program was households applying for energy assistance that did not qualify for weatherization prioritization. Households that were targeted through the Easy Savings Program generally did not include elderly or disabled individuals or families with children that are already prioritized for other Idaho Power weatherization services. For the 2011 to 2012 program, the priority status for weatherization assistance exclusion was removed. Customers with priority status for weatherization are now eligible to receive Easy $avings® program kits.

Each provided kit contained the following low-cost/no-cost energy saving items:

- CFLs (13 W and 18 W)
- Hot-water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers
- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets for the laundry
- *Quick Start Guide* to installation
- Survey inquiring about the installation experience and actions taken to reduce energy use

All educational materials are printed in English and Spanish. Returned surveys are used to track the effectiveness of the program. Tracking is done via a kit/survey unique numbering system.

In August 2012, Idaho Power placed an order with the Easy Savings Program vendor, Resource Action Programs (RAP), for a two-year supply of kits. This allowed time for the regional CAP agencies to receive kits and ready them for distribution by the beginning of the LIHEAP season, which begins on November 1 each year and ends the following March, depending on funding availability.

Fulfilling the payment requirements for program years 2011 to 2012, $250,000 were sent by Idaho Power to CAP agency executive directors in each region. Each agency used 30 percent of the agency's allotment to cover expenses for administering the program at their agency. An order for 4,255 kits was placed in August 2012. Kits were shipped from the vendor and received at agencies in October 2012 for distribution to customers. The goal is to have all kits distributed prior to November 2013.

Between October 2012 and December 31, 2012, 850 kits were distributed to Idaho Power customers approved to receive energy assistance benefits on their Idaho Power bills. A participant survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits. Tracking was done via a kit/survey numbering system. Returned surveys were used to track the educational impact of the program.

Of the 850 surveys distributed, 126 completed surveys were received back from customers describing their experience in installing kit items in their homes. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit, as well as questions confirming the installation of kit items.

Ninety-one percent of household respondents reported they have, or will, lower their heat during the day, and 82 percent reported they will lower their heat at night. Eighty-two percent of the households reported installing both CFLs provided, and another 12 percent said they installed one of the CFLs provided. Seventy-nine percent of the households reported installing the high-efficiency showerhead.

Overall, survey results show that over 58 percent of the households that received the kits and returned a survey installed five or more kit items. Seventy-four percent of the respondent households reported learning a lot about saving energy and money in their home after completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

Gift certificates valued at $100 each will be provided by CAPAI to encourage survey completion on the remaining 3,405 kits. A drawing from all returned surveys will be held in 2013. Five households will win a $100 gift certificate. Upon anticipated completion of kit distribution in October 2013, Idaho Power and CAPAI will consider changes for the program in 2014.

## Commercial Education Initiative

Since 2008, the Commercial Education Initiative has informed and educated commercial customers regarding energy efficiency, increased awareness of and participation in existing commercial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives. A major strength of the initiative is the emphasis on building strategic relationships. The program specialist works closely with Idaho Power CRs assigned to commercial market segments to capitalize on their established relationships with customers.

The initiative oversees the distribution of informational materials and works directly with trade allies and other market players who, in turn, support and promote Idaho Power's energy efficiency programs. Routinely, individual site visits are conducted to educate customers on energy-savings opportunities at their business. Additionally, these site visits serve as training opportunities for field staff, raising their knowledge for future site visits.

In 2012, Idaho Power carried out its plan to capitalize on effective customer projects by posting on Idaho Power's website six *Success Stories* highlighting customers' 2012 energy efficiency projects. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency programs. The Commercial Education Initiative works with and supports multiple stakeholders and organizations to increase customers' energy efficiency knowledge. Examples of key stakeholders include the IDL; BOMA; US Green Building Council; and American Society of Heating, Refrigeration,

and Air-Conditioning Engineers. Through funding provided by Idaho Power, the IDL performs several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities include sponsoring a building-simulation users group, conducting lunch-and-learn sessions held at various design and engineering firms, and offering a tool loan library. Customers also have access to equipment that enables them to measure and monitor energy consumption on various systems within their operation.

In 2012, the Commercial Education Initiative sought further opportunities to assist small communities interested in learning more about energy efficiency. The initiative continued to conduct site visits, used the Equipment Efficiency Specification Sheets, and distributed target market information tip sheets. Additionally, Idaho Power offered assistance to colleges providing energy-related technical education.

Plans for 2013 include 1) working with Idaho Power marketing specialists to increase customer awareness of the company's energy efficiency programs and their specific offerings, 2) coordinating training opportunities for CRs to increase their energy expertise, and 3) refining tools that allow customers to perform a cursory evaluation of their own facilities to identify energy efficiency opportunities and determine if a more in-depth evaluation or audit is needed. Customer support via facility walk-throughs and site-specific efficiency guidance will continue. Idaho Power will continue working with key stakeholders to provide outreach and training opportunities. In a partnership with NEEA and BOMA, Idaho Power is piloting an energy-savings competition for commercial office buildings. Similar competitions have successfully been held in Seattle, Washington, and Portland, Oregon. Branded as the Kilowatt Crackdown™, the goal of the competition is to help participants raise their energy awareness and increase building performance community wide. The Kilowatt Crackdown will be a beneficial educational opportunity for participants.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs but that still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

Idaho Power received four applications for LEEF in 2012. Projects included 1) the installation of computerized controllers on existing engine-block heaters in a bus yard, 2) the use of a solar thermal system to heat a residence in Idaho City, 3) the installation of a programmable logic controller on manufacturing ovens to reduce peak demand, and 4) the construction of an energy-efficient micro-home for demonstration purposes.

For each of these projects, Idaho Power convened a working group of engineers and cost-effectiveness analysts to review the application, request additional information, and perform a cost-effectiveness analysis. None of the projects were funded for the reasons stated below.

Three of the projects did not meet cost-effectiveness tests for various reasons. The committee found that less expensive timers would achieve the same savings as the proposed controllers for the block heaters. The residence in Idaho City planned to have a pellet stove for backup heat, so the primary heat source was not going to be electric. The manufacturing ovens proposal shifted use, but the existing peak period was not during Idaho Power's peak demand period, and there were no proposed energy savings associated with the proposal. The micro-home project was specific to the 2012 Green Expo trade show, and the application was received too late for the completion of funding and construction prior to the show. However, funding was put into the Residential Energy Efficiency Education Initiative budget in 2013 to complete a similar project that could be used for demonstration purposes.

## Residential Economizer Project Study

In 2011, a Residential Economizer Project Study was initiated involving the installation of 19 economizers into residential houses. An economizer draws cool, outside evening air into the A/C system of a house. Its purpose is to reduce the summer cooling energy required to cool the house. The reduction of cooling energy is derived from the reduced run time of the A/C mechanical system. Data collection devices were used to capture energy and temperature values in the houses fitted with these systems. The data was collected during summer 2011. It was analyzed by Idaho Power and third parties to determine potential energy savings. The installation of data-logging equipment, field monitoring, and the energy analysis report was performed by the IDL.

In early 2012, with the advice of EEAG, it was determined that securing additional data during summer 2012 would be beneficial when combined with data collected the prior year. Twenty-two additional houses were fitted with economizers and data-logging equipment. Twelve of the houses data logged in 2011 were also data logged in 2012. Ongoing progress was reported in February and July 2012 EEAG meetings. All 34 houses were analyzed at the end of 2012. The final report from the IDL is due after December 2012.

NEEA has been involved with the study since its beginning in 2011. The 2012 results will be shared with them. In 2011, NEEA planned to contribute to four study reports. Three of the studies were completed in 2011. These three include the baseline energy study, the contractor survey, and the customer survey. NEEA will review the 2012 results to determine if the fourth report, the market-transformation report, will be necessary based on factors including reported energy savings.

## Regional Technical Forum

The BPA and the Northwest Power and Conservation Council (NPCC) established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating on various sub-committees.

The forum's purpose is to advise the BPA, the NPCC, the region's utilities, and organizations, including NEEA and the Energy Trust of Oregon (ETO), on technical matters related to energy efficiency and renewable-resources development. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and renewable resource goals. Providing feedback and suggestions for improving the effectiveness of regional energy efficiency and renewable-resource development programs are additional activities of the RTF. The RTF also recommends a list of eligible conservation measures and the estimated savings associated with those measures. Idaho Power uses the information provided by the RTF when conducting research and analysis on new and current measures. The RTF meets monthly to review and provide comments on analyses and other materials prepared by the NPCC, BPA staff, and RTF contractors. Idaho Power uses the savings estimates and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics. In 2012, Idaho Power staff participated in all of the RTF's meetings and was involved in various sub-committees, such as the RTF Policy Advisory Committee. Idaho Power is also working with the RTF to bring the "out-of-compliance" irrigation hardware measures into compliance. The company partnered with the University of Idaho to conduct field testing of various irrigation components during the 2012 growing season. The research will be presented to the RTF in early 2013.

Since 2010, the RTF has been working toward developing a set of operative guidelines to describe the RTF's methods to select, develop, and maintain measure savings, costs, and other benefits. The guidelines were completed and adopted in 2012. In the meantime, the RTF has spent the past two

years reviewing previously deemed measures and determining its compliance to the new guidelines. A measure may fall under one of the four measure categories and one of the four measure statuses.

Measure categories include proven, provisional, planning, and small-saver savings. Proven savings meet the highest quality and reliability standards. Provisional savings estimates are those the RTF conditionally approves and requires additional data collection. It must be possible to obtain the data necessary to meet the proven quality of standards. Planning savings do not meet the quality of standards of the provisional or proven categories; however, these measures may be needed for the regional program operators. A data-collection plan must be developed that can bring the measure to the provisional or proven category. Small savers are measures that have savings too small to necessitate the resources needed to bring the measure to proven or provisional quality of standards.

Measure statuses include active, under review, de-activated, and out-of-compliance. The active measure status is when the measure's source data is current and contains reliable savings.

Prior to a measure's sunset date, a measure may change its status to under review if new sources of data become available. The measure's savings will be reviewed and may be re-estimated. A de-activated measure status refers to when the sunset date for a measure has passed and new savings estimates have not been approved. A measure may be de-activated if new findings invalidate the measure savings. Out-of-compliance measures are those measures that do not comply with one or more of the requirements from the guidelines. Once the RTF determines a measure is out of compliance, a plan to bring the measure into compliance must be approved within a year. This status is applicable to measures approved prior to June 1, 2011.

## Boise City Home Audit Project

In 2011, Idaho Power and the City of Boise partnered to create a limited-term, residential energy audit project that installed low-cost energy-saving measures and identified additional efficiency improvements. The City of Boise received ARRA funding from the DOE Energy Efficiency Conservation Block Grant (EECBG). At the end of 2011, a portion of the funds remained, and the project was extended to provide for an additional 226 home audits.

The home audit extension in 2012 resembled the original project. Idaho Power contracted with HPSs to perform the energy audits and installation of measures. The energy audit included a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Potential low-cost energy-saving measures that could be installed in each home included limited sealing of air leaks, such as mastic around the furnace unit; installing CFLs; insulating water pipes that are three feet or less between the water heater and the structure; and installing water heater blankets. The audit included instructing customers on a variety of items, including the replacement of their furnace filter and how to lower the temperature on their water heater.

Participating customers paid $49 for the audit and installation of measures, with the remaining cost covered by the EECBG funds. Energy audits of this type normally cost $300 or more, not including the measures, materials, and labor. The cost of the materials potentially installed at each home was approximately $100.

After the audit was complete, homeowners received a report and were provided information on programs that could assist them with the costs of implementing additional measures, including information on the City of Boise's Home Improvement Loan Program.

The target audience for this project was Boise residential customers living in single-family, site-built homes under 3,000 $ft^2$. The homes had to be owner-occupied year-round. The target was for 25 percent of participating homes to be all-electric.

Participants were recruited through direct-mail. In 2012, six small batches of recruitment letters were mailed for a total of 12,342 letters, with a response rate of 2.3 percent. Customers who were interested in participating in the project were directed to a website to complete an application. Those who either did not have internet access or were uncomfortable with filling out the application online were able to call and have their application taken over the phone. Participants were selected on a first-come, first-served basis.

The three energy auditors from the original project were selected to continue with the extension. Audits were randomly and evenly distributed between the three auditors.

Of the 225 audited homes, 182 homes (81%) were heated by gas, two homes (1%) were heated by oil, and 41 (18%) were heated by electricity. The average age of the homes in the 2012 project extension was 37.6 years old.

Home sizes ranged from 913 $ft^2$ to 3,176 $ft^2$. The average home size was 1,933 $ft^2$. Although the recommended maximum home size was 3,000 $ft^2$, a few homes over this size were completed. Table 13 shows the 2012 number of participating homes by ranges of square-foot increments.

Table 13. Number of participating homes by size

| Home Size | Count |
|---|---|
| 700–1000 $ft^2$ | 4 |
| 1001–1500 $ft^2$ | 63 |
| 1501–2000 $ft^2$ | 53 |
| 2001–2500 $ft^2$ | 66 |
| 2501–3000 $ft^2$ | 31 |
| 3001–3328 $ft^2$ | 9 |

Homes were located throughout the Boise city limits, with larger amounts of recruitment letters mailed in those zip codes reported to have a higher percentage of electrically heated homes. Table 14 compares the 2012 number of participating homes per zip code that heat by using electricity, gas, or oil.[2]

Table 14. Number of participating homes by zip code and heating source

| Zip Code | Electric | Gas | Oil | Total |
|---|---|---|---|---|
| 83702 | 7 | 19 | 1 | 27 |
| 83703 | 7 | 6 | 0 | 13 |
| 83704 | 8 | 52 | 0 | 60 |
| 83705 | 5 | 9 | 0 | 14 |
| 83706 | 8 | 29 | 0 | 37 |
| 83709 | 3 | 25 | 0 | 28 |
| 83712 | 1 | 10 | 1 | 12 |
| 83713 | 3 | 23 | 0 | 26 |
| 83714 | 0 | 1 | 0 | 1 |
| 83716 | 0 | 8 | 0 | 8 |

When performing an audit, the HPS determined which available measures were appropriate for the home, and, if the homeowner approved, those measures were installed. Table 15 lists by heating source and quantity of items installed in participating homes in 2012.

Table 15. Measures installed in participating homes by heat source

| | Quantity | Gas Home | Electric Home | Other |
|---|---|---|---|---|
| CFLs | 776 | | | |
| Water heater blankets | | 4 | 1 | |
| Pipe insulation | | 79 | 13 | 1 |
| Mastic | | 55 | 11 | 1 |

Once an audit was complete, the information obtained by the auditor was entered into a database. A personalized report was created and mailed to each participant detailing what was found at the home, what measures were installed, and further energy efficiency recommendations.

A survey was sent after the participant received their personalized report and allowed time for participant action regarding suggested energy efficiency actions. The survey gathered data on immediate actions the participant initiated following the audit and short-term actions they planned to take at a future date. It also inquired about reasons for inaction, such as expenses or difficulty finding a contractor. A copy of the survey is included in *Supplement 2: Evaluation*.

Idaho Power contracted the IDL and the City of Boise to provide an impact evaluation of the Boise City Home Audit Pilot. Using ARRA funds, energy audits were conducted and low-cost energy efficiency measures were installed at 650 homes located in Boise. The audits took place from late 2010 through summer 2011 and identified additional energy efficiency measures for future consideration by the customer.

The final report indicated that the average savings per home from direct install measures was 308 kWh in electricity and 3 therms in natural gas per year. Based on the average residential consumption in Idaho Power's service area, this represents a 2.4-percent reduction in annual electricity consumption. Although these savings estimates were to be originally calibrated using utility billing data, according to the International Performance Measurement and Verification Protocol (IPMVP), savings were not large enough to accurately differentiate from historical billing data.

The cost-effectiveness analysis conducted under IDLs assumptions indicates that this program, with installed measures for dual-fuel homes, would only be cost-effective under the PCT. The analysis shows that this program with the same installed measures for electrically heated homes would be cost effective under the UCT and TRC. A copy of the complete report is included in *Supplement 2: Evaluation*.

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# REGULATORY INITIATIVES

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27 filed with the IPUC on October 22, 2010, and is described in more detail below.

Since 2002, Idaho Power has recovered most its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM costs. In addition, since January 1, 2012, funding of Idaho customer incentives of demand response programs is now included in base rates and tracked in the annual PCA mechanism. On December 30, 2011, the IPUC issued Order No. 32426 in General Rate Case No. IPC-E-11-08 that approved including $11.3 million of demand response incentive payments as part of base rates. As of June 1, 2012, Idaho Power is including in the PCA an amount to true-up actual demand response incentive expenses for the previous year if the amount is different than the $11.3 million in base rates.

To address the removal of financial disincentives, Idaho Power tested the effects of an FCA mechanism in a five-year pilot initiative. In 2011, the FCA completed its fifth year in pilot status. As part of the 2011 General Rate Case No. IPC-E-11-08, Idaho Power requested the FCA become permanent. The IPUC decided the FCA should be addressed in a separate case. On October 19, 2011, the company filed Case No. IPC-E-11-19 with the IPUC. The case requested to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company submitted its Compliance Filing, requesting the IPUC issue an order authorizing either the continued use of the existing FCA methodology, without change, or in the alternative, a modified methodology that introduces a symmetrical cap on the calculated FCA balance based on the change in the annual energy consumption per customer of plus or minus 2 percent from the historical average. On January 31, 2013, the IPUC issued Final Order No. 32731, directing the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for Idaho customer incentives paid through the Custom Efficiency program as a regulatory asset beginning January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in DSRs. As of December 31, 2012, proceedings relating to this case are ongoing.

## Fixed-Cost Adjustment

Under the FCA, rates are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in energy efficiency and demand response resources designed to reduce customer usage. The FCA is limited to the residential and small general-service customer classes in recognition of the

fact that, for these customers, a high percentage of fixed costs are recovered through their volumetric energy charges.

During the five-year period in which the FCA Schedule 54 was in a pilot status, Idaho Power made strong progress toward improving and enhancing its efforts to promote energy efficiency and DSM activities. The company increased the number of energy efficiency and demand response programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained through these activities. Results from the first five years of the pilot indicated the true-up mechanism was working as intended.

As stated previously, on March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers.

On May 8, 2012, the IPUC issued Order No. 32544, approving the company's request to implement FCA rates for fixed-cost deferrals in 2011. Beginning June 1, 2012, the company implemented an overall rate adjustment of 0.28 percent to residential and small general-service customers to collect a combined $10.3 million in under-collected fixed costs. Residential customers experienced a rate increase of 0.0227 cents/kWh, while small general-service customers experienced an increase of 0.0324 cents/kWh. The rate adjustments will result in a collection of an additional $1 million over the then-current billed amounts and will be in place until May 31, 2013.

## Custom Efficiency Incentive Recovery

On October 31, 2012, the company filed Case No. IPC-E-12-24 requesting authority to include Custom Efficiency program Idaho incentive payments in rates. Previously, on May 17, 2011, the IPUC in Order No. 32245 had authorized Idaho Power to account for Custom Efficiency program incentive payments as a regulatory asset.

In the October 31, 2012, filing, Idaho Power requested the following of the IPUC: Recognize the 2011 Custom Efficiency incentive amounts as "used and useful"; begin recovery of these amounts in rates on June 1, 2013; specify the company's rate of return as the carrying charge for the regulatory asset account prior to amortization; specify a four-year amortization period for the regulatory asset; acknowledge that the unamortized portion of the regulatory asset will earn the company's rate of return, allow the company to institute annual spring filings for this process; and authorize the implementation of Schedule 56. The incremental annual revenue requested in the filing is $2,949,340, with a requested rate change effective date of June, 1, 2013, to coincide with other anticipated rate changes associated with the annual PCA and the annual FCA.

## Energy Efficiency Rider—Prudence Determination of Expenditures

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15 with the IPUC requesting an order finding that the company had prudently incurred $42,641,706 (later adjusted to $42,641,361) in DSM expenses in 2011. This adjusted number included $35,622,976 in Idaho Rider expenses and $7,018,385 in Custom Efficiency program incentive expenses. The filing included three reports: *Demand-Side Management 2011 Annual Report*, *Supplement 1: Cost Effectiveness*, and *Supplement 2: Evaluation*. Supplement 2 included *NEEA Market Effects Evaluations*. In Final Order No. 32667, dated October 22, 2012, and Reconsideration Order No. 32690, dated December 11, 2012, the IPUC approved in part and denied in part Idaho Power's request. In these orders, the IPUC approved $42,468,904.50 in 2011 DSM expenditures, including $35,450,519.50 in Idaho Rider expenses and $7,018,385 in Custom Efficiency

program incentives, as prudently incurred expenses. The IPUC disallowed the recovery of $82,855.50 for incentives paid to participants of the A/C Cool Credit program who did not receive a signal to cycle even though Idaho Power thought they were being cycled. In addition, the IPUC declined to decide the reasonableness of Idaho Power's 2011 Rider-funded, labor-related expense increase until the company provides further information.

## Cost-Effectiveness and Funding of Low-Income Weatherization

On February 15, 2012, the IPUC issued a notice that opened Case No. GNR-E-12-01 and scheduled a public workshop from March 19 to 20, 2012. This case was initiated in part because both Rocky Mountain Power and Avista Utilities had recently conducted evaluations of their low-income programs and found them not to be cost effective. In 2012, Idaho Power began an evaluation of their low-income program. In addition, CAPAI asked the IPUC to increase funding for low-income programs in both Idaho Power's and Rocky Mountain Power's service areas. In this case, utilities, interested persons, and IPUC staff were to explore in greater detail issues related to the funding, implementation, and evaluation of utility low-income weatherization and energy conservation education programs. IPUC staff, utilities, CAPAI, and CAP agencies participated in the March workshop.

On October 23, 2012, IPUC staff issued their draft *Report on Low Income Weatherization and Energy Conservation Education Programs*. In this draft report, IPUC staff set out their suggested criteria for consideration when increased funding is being deliberated. IPUC staff also provided recommendations and comments on cost-effective calculations and procedures, as well as utility funding level considerations. Parties to the case, including the three Idaho investor-owned electric utilities, provided reply comments in November 2012. Idaho Power, in its comments, emphasized that low-income program funding should be based on the need exhibited by qualified weatherization customers. A proposed methodology was provided in Idaho Power's comments. On December 7, 2012, IPUC staff filed reply comments. An IPUC order is still anticipated in this case.

## Demand Response Programs Suspension

On December 21, 2012, Idaho Power filed Case No. IPC-E-12-29, requesting a temporary suspension of two of its three demand response programs, A/C Cool Credit and Irrigation Peak Rewards. The temporary suspension was requested because the current load and resource balance being used to develop the 2013 IRP does not show a peak-hour deficit in the near term, making these programs unnecessary in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for these programs. The temporary suspension of the two demand response programs and their associated incentive payments would result in reduced costs for all Idaho Power customers in the form of a reduction in the 2013 to 2014 PCA that will be updated June 1, 2013. Before making this filing, Idaho Power convened a special meeting of EEAG on December 14, 2012, to review the issues and solicit member input. The group understood the rational for the filing; however, concerns were expressed about the impact on program participants and about how these program changes integrate in the IRP planning process. The temporary suspension of the programs requested in the filing will provide time to work with stakeholders on the redesign of the programs. The company requested the IPUC issue an order by March 1, 2013.

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# CONTINUED COMMITMENT

Every year, Idaho Power enhances its commitment to provide DSM programs that offer broader opportunities for Idaho Power's customers to manage their energy and demand use. Idaho Power also continues its effort to make its own facilities more energy efficient and to find ways to promote energy efficiency in its communities and with its employees. A review of specific efforts is listed in the following sections.

## Continued Expansion and Broad Availability of Energy Efficiency and Demand Response Programs

In 2012, Idaho Power broadened the marketing efforts and portfolio of programs offered to customers. Programs continue to add service areas where they are available to customers and continue to add new measures for customer participation. This expansion of programs and offerings helps ensure more customers each year have the opportunity to participate in programs. Some highlights for 2012 are as follows:

- Custom Efficiency awarded the single largest incentive in the program's history, on a chilled water economizer project designed to save approximately 10 million kWh annually.
- The See ya later, refrigerator® program reached a milestone when it picked up its 10,000th unit.
- In the education arena, the first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313.
- The network of participating contractors for the DHP Pilot expanded in 2012. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation trainings to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22-percent increase over 2011.
- The first biannual *Energy at Work* commercial newsletter was launched by the company. The goal of the newsletter is to provide pertinent and useful information to a customer segment with limited time.
- Idaho Power increased its use of online and social marketing, including an Easy Upgrades online advertising campaign and targeted behavioral advertisements on Facebook and Yahoo!.
- The Weatherization Solutions for Eligible Customers program expanded its service area into the Boise area through a new trade ally called Power Savers.
- In May 2012, Idaho Power issued its inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship.
- In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*.

## Building-Code Improvement Activity

Since 2005, the State of Idaho has been on a cycle of adopting a state-specific version of the IECC. The most recent example of this was the adoption of the 2009 IECC that became effective in Idaho on January 1, 2011. The 2012 IECC was published in 2012, and the Idaho Building Code Board took public comments on whether or not to pursue a similar code update for Idaho based on the latest IECC. Idaho Power is participating in these ongoing meetings and monitoring the situation to assess where support may be offered. The Idaho Building Code Board has convened another Energy Codes Collaborative in 2013 to revise the current energy code in Idaho.

Idaho Power also contributed to the *Idaho Residential Energy Code Compliance* study commissioned by NEEA in 2012. This report is measuring Idaho's level of compliance with energy codes as required by the 2009 ARRA, which mandates that states receiving these funds achieve 90-percent compliance with target codes by 2017. The report describes the study of Idaho residential compliance with the amended version of the 2009 IECC. The report, included in *Supplement 2: Evaluation*, indicates a relatively high compliance by builders with the residential energy code in Idaho and suggests the overall 90-percent compliance rate has already been achieved, although some measures, such as wall insulation and lighting, are below that rate.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power continues to support a policy of gradually moving all customers into rates designed to reflect their cost of service, provide cost-based price signals, and encourage the wise and efficient use of energy.

On January 19, 2012, Idaho Power filed Tariff Advice No. 12-02 to expand Schedule 05, Time-of-Day Pilot Plan, to Idaho customers while at the same time suspend Schedule 04, Energy Watch plan. Idaho Power proposed to expand Energy Watch plan at a later time. Included in the Advice filing, which later became Case No. IPC-E-12-05, was a report titled *2012 Time-Variant Pricing (TVP) Implementation Plan*. The overall goal of this implementation plan was to "utilize the new AMI system to offer customers a choice of pricing plans while providing them with better tools to manage their energy usage, to provide the company with the opportunity to further study the effects of a time-variant rate on customers' usage, and to help shape the company's future communication efforts." The company also planned to evaluate the impact of this new rate plan on its revenues and costs. The Time-of-Day pricing structure was designed to send price signals to customers that more closely reflect the costs of serving those customers. The plan provides participants the opportunity to move their usage from higher-priced time periods to lower-priced time periods and possibly lower their bills. On March 27, 2012, the IPUC issued Order No. 32499 and approved the proposed changes to the tariffs and directed Idaho Power to file a report analyzing the *2012 TVP Implementation Plan* results to IPUC staff prior to further revising its TVP tariffs.

Idaho Power set up a study to determine changes in energy usage caused by changes in participants' behavior in response to the new rate structure. A target market was determined and, throughout spring and summer 2012, participants were solicited by a weekly direct-mail effort. Potential participants were encouraged to visit Idaho Power's website (http://www.idahopower.com/TOD) to evaluate their usage under the different plan options and to make an educated decision regarding which plan was best for them. Over 126,000 customers were solicited. The direct-mail solicitation process ended in September. As of the end of 2012, over 1,500 customers signed up to become Time-of-Day plan participants. Through late 2012 and early 2013, Idaho Power will evaluate initial study findings and will file its report with the IPUC in spring 2013.

## Third-Party, Independent Verification

Idaho Power recognizes that the timely, credible, and transparent evaluation of all its DSM programs is critical in ensuring maximum program performance and the accurate reporting of program energy savings. Third-party contractors are used to provide primary research and impact, process, and market evaluations. These evaluations and research help ensure programs are being administered effectively and best-practice specifications are met. Reports from these evaluations provide valuable recommendations for program improvement and validate energy savings achieved through the company's DSM programs.

In 2012, impact evaluations were completed by third-party contractors on the following six DSM programs: Building Efficiency; Easy Upgrades; H&CE Program; See ya later, refrigerator®; Weatherization Solutions for Eligible Customers; and WAQC. A process evaluation was completed for the A/C Cool Credit program. Primary research was conducted on the Irrigation Efficiency Rewards and A/C Cool Credit programs. Copies of the reports can be found in *Supplement 2: Evaluation*.

In addition, Idaho Power uses third-party contractors to perform QA and OSVs for most programs. The H&CE Program, Home Improvement Program, ENERGY STAR® Homes Northwest, Easy Upgrades, and Building Efficiency programs use third-party contractors to perform QA or OSVs on approximately 10 percent of completed customer projects. The Energy House Calls and WAQC programs contract with third-party experts to perform QA analyses on approximately 5 percent of customer completed projects.

Throughout 2012, Idaho Power participated with NEEA to conduct several third-party assessments. These studies included the Residential Building Stock Assessment, an evaluation of the Northwest DHP Initiative, assessment of four Residential Consumer Electronics products, and several market effects evaluations in the residential, commercial, and industrial sectors. Copies of these reports can be found in *Supplement 2: Evaluation*.

The company also funds and participates in the RTF. The RTF is an advisory committee that was created in 1999 to develop regional standards and for the establishment of deemed savings derived from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information regarding energy efficiency programs and measures and uses the RTF databases to provide deemed-savings estimates for many of the energy efficiency measures implemented as part of the company's DSM programs.

It is anticipated that in 2013, Idaho Power will contract with third-party evaluators to complete process evaluations for the Energy Efficient Lighting, ENERGY STAR Homes Northwest, H&CE Program, Weatherization Solutions for Eligible Customers, WAQC, Easy Upgrades, and FlexPeak Management programs. The *2010–2013 Evaluation Plan* can be found in *Supplement 2: Evaluation*.

### *Energy Efficiency Potential Study*

Idaho Power contracted with EnerNOC Utility Solutions Consulting (EnerNOC Solutions) to provide an analysis of the technical, economic, and achievable energy efficiency over the next 20 years in the company's service area. In addition, EnerNOC Solutions provided an executable dynamic model that supports the potential study and allows for the testing of sensitivity. EnerNOC Solutions also updated load profiles by sector, program, and end use. Because of their disproportionate energy use, special-contract customer potential was analyzed separately. The achievable energy efficiency potential by sector is shown as follows:

- Residential achievable potential projects: 189,469 MWh in 2017, or approximately 21.6 aMW. This level of potential is equivalent to 3.5 percent of the residential baseline projection for that year. By 2032, the cumulative achievable projection savings are 701,104 MWh, 10.8 percent of the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Commercial achievable potential projects: 194,418 MWh, or approximately 22.2 aMW, of energy savings in 2017, which corresponds to 5.2 percent of the commercial baseline projection for that year. By 2032, the cumulative achievable projection savings are 633,771 MWh, 13.9 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Industrial achievable potential projects: 174,526 MWh, or approximately 19.9 aMW, of energy savings in 2017, which corresponds to 18 percent of the industrial baseline projection for that year. By 2032, the cumulative achievable projection savings are 488,465 MWH, 12.8 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Irrigation achievable potential projects: 36,360 MWh, or approximately 4.2 aMW, of energy savings in 2017, which corresponds to 6.8 percent of the irrigation baseline projection for that year. By 2032, the cumulative achievable projection savings are 229,821 MWh, 11.3 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

Achievable potential across the residential, commercial, industrial, and irrigation sectors is projected to be 594,772 MWh, or 67.9 aMW, in 2017 and increases to 234.4 aMW by 2032. This represents 4.3 percent of the baseline projection in 2017 and 12.2 percent in 2032. By 2032, achievable potential offsets 12.2 percent of the growth in the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

## Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, providing incentives, and educating its customers.

At the annual shareholders meeting held in May 2012, IDACORP, Inc., and Idaho Power issued the inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship. The sustainability report featured articles highlighting the company's long-standing commitment to operating in a sustainable manner, including groundbreaking raptor protection programs and innovative methods to gather and analyze data in waterways supporting company operations. IDACORP plans to issue its second sustainability report in May 2013.

The Idaho Power Green Team championed sustainable activities conducted by Idaho Power and its employees. In 2012, projects included coordinating monthly Green Bag educational seminars, supporting company-wide alternative transportation efforts, and implementing a project at the company café to compost the organic portion of its wastes.

Idaho Power's corporate headquarters (CHQ) continued to participate in the strategic elimination of power loads during peak use through the FlexPeak Management program. In August 2010, Idaho Power entered into an agreement with EnerNOC, Inc., to enroll the CHQ in FlexPeak Management—Idaho Power's commercial/industrial demand response program. EnerNOC enlists and contracts with Idaho Power's commercial and industrial customers to voluntarily reduce their electricity use primarily

during times of Idaho Power system peaks. EnerNOC provides participants with auditing assistance, energy-monitoring software, demand-reduction performance monitoring, coaching, and other related services. EnerNOC works closely with its program participants to estimate their reduction potential accurately. Unlike other program participants, Idaho Power does not receive any financial incentives to participate.

In 2012, Idaho Power committed to reduce its electrical consumption by 100 kW during demand-reduction events. The CHQ participated in all four of the FlexPeak events, which were initiated in June, July, and August. The average reduction achieved by the facility across the four events was 425 kW. The CHQ exceeded the committed reduction in all events. The maximum hourly reduction was 775 kW, achieved in July. Reductions were mostly obtained by turning off lights, adjusting A/C set-points, decreasing fan speeds, and curtailing elevator use. The facility reduction plan in place could be executed at any time to reduce electricity use if necessary.

In 2012, Idaho Power began an aggressive lighting retrofit in several of its facilities. This included upgraded lighting at eight of its hydroelectric power plants, the CHQ building, and two operations centers. Total projected first-year electrical savings were approximately 562,100 kWh. These savings should continue for 10 to 12 years.

Changes at the power plants included replacing magnetic ballasts and T-12 lamps with more efficient electronic ballasts and T-8 lamps. At the Hells Canyon Dam, external mercury vapor fixtures were replaced with LED fixtures.

Energy-efficient T-8 lighting was installed in all of the CHQ's hallways, basement, loading dock, stairwells, restrooms, coffee rooms, copy rooms, first/second floor light wall, electrical rooms, data rooms, and penthouse. Efficient electronic ballasts and lamps replaced the inefficient magnetic ballasts and lamps. Wall-, ceiling-, or fixture-mounted occupancy sensors were installed as appropriate. Halogen art display fixtures were retrofitted with LED lamps. In elevator shafts and pump rooms, CFLs replaced incandescent lamps.

The lighting retrofit and space remodel at the Payette Operations Center continued during 2012 with the removal of T-12 lighting, installation of T-8 lighting retrofit packages, and a decrease in cubicle heights to 53 inches for improved natural lighting. In addition, the Boise Center West (BCW) project installed dimmable LED lighting fixtures throughout the new data center.

In 2013, the BCW project will incorporate several energy-efficient attributes. Plans include using indirect clerestory windows, placing Dyson hand-insertion electric air dryers and water-saving features within the restrooms.

During 2012, planning continued for the 2013 installation of a new energy-efficient chilled water system for the CHQ. Although remodeling of the CHQ (carpets, blinds, lighting upgrade, paint, and new lowered cube height) was postponed for one year, the company anticipates continuing this project through 2016. Sub-station lighting retrofits were initiated in 2012 and will continue to be a focal point through at least 2020.

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# APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2012, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders, Idaho Custom Efficiency incentive payments, and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency and demand response programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2012. Appendix 4 shows similar data as Appendix 3 but also includes data for past years' program performance and B/C ratios from the utility and TRC perspectives for active programs. Appendix 5 contains program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. In these appendices, the data has been rounded to the nearest whole unit, which may result in minor rounding differences.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost-effectiveness information by program and energy-savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The *2012 DSM Detailed Expenses by Program* table reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of Idaho Power's third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information are included with each supplement.

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## **Appendix 1.** Idaho Rider, Oregon Rider, Idaho Custom Efficiency, and NEEA funding balances

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2012 Beginning Balance | $ | (5,321,997) |
| 2012 Funding plus Accrued Interest | | 35,101,807 |
| **Total 2012 Funds** | | **29,779,810** |
| 2012 Expenses | | (25,822,044) |
| 2011 AC Cool Credit Disallowance | | 82,856 |
| **2012 Year-End Balance** | **$** | **4,040,622** |
| **Oregon Energy Efficiency Rider** | | |
| 2012 Beginning Balance | $ | (3,537,441) |
| 2012 Funding plus Accrued Interest | | 1,004,836 |
| **Total 2012 Funds** | | **(2,532,605)** |
| 2012 Expenses | | (1,382,330) |
| **2012 Year-End Balance** | **$** | **(3,914,935)** |
| **Idaho Custom Efficiency Incentives** | | |
| 2012 Beginning Balance Accrued Incentives | $ | (7,018,385) |
| 2012 Beginning Balance Accrued Interest | | (212,339) |
| **2012 Total Beginning Balance** | **$** | **(7,230,724)** |
| 2012 Incentives Accrued | | (6,019,222) |
| 2012 Interest Accrued | | (836,255) |
| **2012 Year-End Balance** | **$** | **(14,086,201)** |
| **NEEA Payments and Escrow Credit Funds Balance** | | |
| 2012 Idaho Power Contractual Obligation[a] | $ | 3,379,756 |
| **2012 Year-End Balance** | **$** | **3,379,756** |

[a] Idaho Power shall prepay estimated expenses quarterly, where the amount shall be amortized over the respective quarter. Funding of NEEA, approved by IPUC Order 31080 dated 5/12/10. Reconciliation between the estimated expenditures and the actual expenditures for the quarter will be completed 30 days after the quarter end or by March 1 for year-end. A true-up of the variance will be included in the next quarter's invoice, not to exceed 125 percent of its five-year total direct-funding contribution.

## **Appendix 2.** 2012 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Idaho Power | Total Program |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit[a] | $ 4,804,566 | $ 92,810 | $ 830,618 | **$ 5,727,994** |
| Ductless Heat Pump Pilot | 153,017 | 6,850 | 0 | **159,867** |
| Energy Efficient Lighting | 1,110,329 | 16,507 | 0 | **1,126,836** |
| Energy House Calls | 272,666 | 3,217 | 0 | **275,884** |
| ENERGY STAR® Homes | 450,727 | 2,458 | 0 | **453,186** |
| Heating & Cooling Efficiency Program | 175,483 | 6,798 | 0 | **182,281** |
| Home Improvement Program | 385,091 | 0 | 0 | **385,091** |
| Home Products Program | 640,098 | 18,829 | 105 | **659,032** |
| Oregon Residential Weatherization | 0 | 4,051 | 465 | **4,516** |
| Rebate Advantage | 34,926 | 2,316 | 0 | **37,241** |
| See Ya Later Refrigerator | 596,167 | 16,979 | 0 | **613,146** |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 1,370,141 | **1,370,141** |
| Weatherization Solutions for Eligible Customers | 1,048,461 | 0 | 22,094 | **1,070,556** |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,579,121 | 13,451 | 0 | **1,592,572** |
| Comprehensive Lighting | 64,094 | 0 | 0 | **64,094** |
| Easy Upgrades | 5,150,422 | 199,331 | 0 | **5,349,753** |
| FlexPeak Management[a] | 98,973 | 150,489 | 2,760,360 | **3,009,822** |
| Oregon Commercial Audit | 0 | 12,470 | 0 | **12,470** |
| Custom Efficiency[b] | 923,050 | 115,866 | 6,053,665 | **7,092,581** |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 1,978,729 | 360,689 | 33,782 | **2,373,201** |
| Irrigation Peak Rewards[a] | 1,309,107 | 95,863 | 11,018,394 | **12,423,364** |
| **Energy Efficiency/Demand Response Total** | **$ 20,775,027** | **$ 1,118,975** | **$ 22,089,624** | **$ 43,983,625** |
| **Market Transformation** | | | | |
| NEEA[c] | 3,210,768 | 168,988 | 0 | **3,379,756** |
| **Market Transformation Total** | **$ 3,210,768** | **$ 168,988** | **$ 0** | **$ 3,379,756** |
| **Other Programs and Activities** | | | | |
| **Residential** | | | | |
| Residential Economizer Pilot[d] | 93,593 | (101) | 0 | **93,491** |
| Residential Energy Efficiency Education Initiative | 165,919 | 8,819 | 0 | **174,738** |
| **Commercial** | | | | |
| Commercial Energy Efficiency Education Initiative | 70,099 | 3,689 | 0 | **73,788** |
| **Other** | | | | |
| Energy Efficiency Direct Program Overhead | 271,622 | 14,329 | 0 | **285,951** |
| **Other Programs and Activities Total** | **$ 601,233** | **$ 26,736** | **$ 0** | **$ 627,968** |
| **Indirect Program Expenses** | | | | |
| Residential Overhead | 172,819 | 9,051 | 0 | **181,869** |
| Commercial/Industrial/Irrigation Overhead | 171,673 | 9,096 | 7,784 | **188,554** |
| Energy Efficiency Accounting and Analysis | 898,944 | 47,050 | 142,241 | **1,088,236** |
| Energy Efficiency Advisory Group | 2,710 | 142 | 0 | **2,853** |
| Special Accounting Entries[e] | (93,985) | 2,291 | (34,308) | **(126,002)** |
| **Indirect Program Expenses Total** | **$ 1,152,161** | **$ 67,631** | **$ 115,718** | **$ 1,335,509** |
| **Totals** | **$ 25,739,188** | **$ 1,382,330** | **$ 22,205,341** | **$ 49,326,859** |

[a] Per order 32426 the IPUC determined that IPC may recover 100 percent of its Idaho demand response incentives through the PCA mechanism.
[b] Idaho Custom Efficiency incentives, Idaho Power balance of $6,053,665, not included in base rates for 2012.
[C] NEEA Funding addressed in IPUC per Order No. 31080, dated May 12, 2010. 2013 annual expense expected at $3.8 million (see footnote, Appendix 1 for additional information).
[d] Residential Economizer 2011 Oregon Rider balance of $101 was reclassified to Idaho Rider in 2012.
[e] Special Accounting Entries, Idaho Power accrual amount of ($34,146), not included in base rates for 2012.

## **Appendix 3.** 2012 DSM program activity

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Demand Response** | | | | | | | | |
| A/C Cool Credit | 36,454 homes | $ 5,727,994 | $ 5,727,994 | n/a | 44.9 | n/a | n/a | n/a |
| Irrigation Peak Rewards[1] | 2,177 service points | 12,423,364 | 12,423,364 | n/a | 339.9 | n/a | n/a | n/a |
| FlexPeak Management | 102 sites | 3,009,822 | 3,009,822 | n/a | 52.8 | n/a | n/a | n/a |
| **Total** | | **$ 21,161,180** | **$ 21,161,180** | **n/a** | **437.6** | | | |
| **Energy Efficiency** | | | | | | | | |
| **Residential** | | | | | | | | |
| Ductless Heat Pump Pilot | 127 homes | 159,867 | 617,833 | 444,500 | | 20 | $ 0.024 | $ 0.094 |
| Energy Efficient Lighting | 925,460 bulbs | 1,126,836 | 2,407,355 | 16,708,659 | | 5 | 0.012 | 0.025 |
| Energy House Calls | 668 homes | 275,884 | 275,884 | 1,192,039 | | 18 | 0.016 | 0.016 |
| ENERGY STAR® Homes Northwest | 410 homes | 453,186 | 871,310 | 537,447 | | 35 | 0.046 | 0.089 |
| Heating & Cooling Efficiency Program | 141 projects | 182,281 | 676,530 | 688,855 | | 20 | 0.018 | 0.066 |
| Home Improvement Program | 840 insulation projects | 385,091 | 812,827 | 457,353 | | 45 | 0.044 | 0.093 |
| Home Products Program | 16,675 appliances/fixtures | 659,032 | 817,924 | 887,222 | | 14 | 0.061 | 0.075 |
| Oregon Residential Weatherization | 5 home | 4,516 | 11,657 | 11,985 | | 30 | 0.022 | 0.022 |
| Rebate Advantage | 35 homes | 37,241 | 71,911 | 187,108 | | 25 | 0.012 | 0.024 |
| See ya later, refrigerator® | 3,176 refrigerators/freezers | 613,146 | 613,146 | 1,576,426 | | 8 | 0.046 | 0.046 |
| Weatherization Assistance for Qualified Customers | 238 homes/non-profits | 1,370,141 | 1,819,945 | 648,304 | | 25 | 0.129 | 0.172 |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 1,070,556 | 257,466 | | 25 | 0.254 | 0.254 |
| **Sector Total** | | **$ 6,337,777** | **$ 10,066,879** | **23,597,363** | | **9** | **$ 0.029** | **$ 0.046** |
| **Commercial** | | | | | | | | |
| Building Efficiency | 84 projects | 1,592,572 | 8,204,883 | 20,450,037 | 2.3 | 12 | 0.007 | 0.036 |
| Easy Upgrades | 1,838 projects | 5,349,753 | 9,245,297 | 41,568,672 | 4.7 | 12 | 0.012 | 0.020 |
| Oregon Commercial Audits | 14 audits | 12,470 | 12,470 | | | | | |
| **Sector Total** | | **$ 6,954,795** | **$ 17,462,650** | **62,018,709** | **7.1** | **12** | **$ 0.010** | **$ 0.025** |
| **Industrial** | | | | | | | | |
| Custom Efficiency[2] | 126 projects | 7,092,581 | 12,975,629 | 54,253,106 | 7.6 | 12 | 0.012 | 0.021 |
| **Sector Total** | | **$ 7,092,581** | **$ 12,975,629** | **54,253,106** | **7.6** | **12** | **$ 0.012** | **$ 0.021** |
| **Irrigation** | | | | | | | | |
| Irrigation Efficiency Rewards[3] | 908 projects | 2,373,201 | 11,598,185 | 12,617,164 | 3.1 | 8 | 0.022 | 0.110 |
| **Sector Total** | | **$ 2,373,201** | **$ 11,598,185** | **12,617,164** | **3.1** | **8** | **$ 0.022** | **$ 0.110** |

## **Appendix 3.** 2012 DSM program activity (continued)

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance[4] | | $ 3,379,756 | $ 3,379,756 | 17,741,430 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Residential Economizer | | 93,491 | 93,491 | | | | | |
| Residential Energy Efficiency Education Initiative | | 174,738 | 174,738 | | | | | |
| **Commercial** | | | | | | | | |
| Commercial Education Initiative | | 73,788 | 73,788 | | | | | |
| Comprehensive Lighting[5] | | 64,094 | 64,094 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 285,951 | 285,951 | | | | | |
| Local Energy Efficiency Funds | | | | | | | | |
| **Total Program Direct Expense** | | **$ 47,991,350** | **$ 77,336,341** | **170,227,773** | **455.3** | | | |
| Indirect Program Expenses | | 1,335,509 | | | | | | |
| **Total DSM Expense** | | **$ 49,326,859** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2011 IRP and calculations include line-loss adjusted energy savings.

[b] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[c] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[d] Summer Peak Demand is reported where program MW reduction is documented. Demand response program reductions are reported with 13-percent peak loss assumptions.

[1] Peak demand represents enrolled capacity of the program during summer 2012.

[2] Custom Efficiency savings includes 19 Green Motors participants totaling 54,154 kWh of annual savings, but not in project totals.

[3] Irrigation Efficiency includes 23 Green Motors participants totaling 36,039 kWh of annual savings, not counted in project totals.

[4] Savings are preliminary estimates provided by NEEA.

[5] Comprehensive Lighting annual savings of 447,620 kWh from 6 projects are included in Easy Upgrades savings totals. For the combined cost-effectiveness analysis, see Easy Upgrades in Supplement 1.

## **Appendix 4.** Historical DSM expense and performance 2002–2012

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3.1 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6.3 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12.2 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 25.5 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 38.5 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39.0 | | | | | |
| 2011 | 37,728 | 2,896,542 | 2,896,542 | | | 24.0 | | | | | |
| 2012 | 36,454 | 5,727,994 | 5,727,994 | | | 44.9 | | | | | |
| **Total** | | **$ 22,027,036** | **$ 22,027,036** | | | | | | | **1.33** | **1.33** |
| FlexPeak Management | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19.3 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 47.5 | | | | | |
| 2011 | 111 | 2,057,730 | 2,057,730 | | | 58.8 | | | | | |
| 2012 | 102 | 3,009,822 | 3,009,822 | | | 52.8 | | | | | |
| **Total** | | **$ 7,498,913** | **$ 7,498,913** | | | | | | | **1.22** | **1.22** |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 5.6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40.3 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 31.8 | | | | | |
| 2007 | 947 | 1,615,881 | 1,615,881 | | | 37.4 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35.1 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160.2 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,514,246 | | | 249.7 | | | | | |
| 2011 | 2,342 | 12,086,222 | 12,086,222 | | | 320.0 | | | | | |
| 2012 | 2,433 | 12,423,364 | 12,423,364 | | | 339.9 | | | | | |
| **Total** | | **$ 53,680,830** | **$ 53,864,250** | | | | | | | **1.79** | **1.72** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | $ 202,005 | $ 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| 2011 | 131 | 191,183 | 550,033 | 458,500 | 0.05 | | 20 | 0.028 | 0.081 | | |
| 2012 | 127 | 159,867 | 617,833 | 444,500 | 0.05 | | 20 | 0.024 | 0.094 | | |
| **Total** | **458** | **$ 742,286** | **$ 2,059,030** | **1,676,180** | | | **20** | **$ 0.036** | **$ 0.105** | **4.22** | **1.44** |
| Energy Efficiency Packets | | | | | | | | | | | |
| 2002 | 2,925 | 755 | 755 | 155,757 | 0.02 | | 7 | 0.001 | 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | | |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,618 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,662 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2004 | | | | | | | | | | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| 2011 | 1,039,755 | 1,719,133 | 2,764,623 | 19,694,381 | 2.25 | | 5 | 0.015 | 0.024 | | |
| 2012 | 925,460 | 1,126,836 | 2,407,355 | 16,708,659 | 1.91 | | 5 | 0.012 | 0.025 | | |
| **Total** | **4,607,727** | **$ 9,060,131** | **$ 13,254,530** | **114,346,653** | | **0.0** | **5** | **$ 0.017** | **$ 0.025** | **4.47** | **3.05** |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | 26,053 | 26,053 | 25,989 | 0.00 | | 20 | 0.082 | 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 336,372 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy House Calls | | | | | | | | | | | |
| 2010 | 1,602 | $ 762,330 | $ 762,330 | 1,198,655 | 0.14 | | 20 | $ 0.054 | $ 0.054 | | |
| 2011 | 881 | 483,375 | 483,375 | 1,214,004 | 0.14 | | 20 | 0.027 | 0.027 | | |
| 2012 | 668 | 275,884 | 275,884 | 1,192,039 | 0.14 | | 18 | 0.016 | 0.016 | | |
| **Total** | **10,071** | **$ 4,543,355** | **$ 4,543,355** | **11,648,019** | | | **18** | **$ 0.034** | **$ 0.034** | **3.05** | **3.05** |
| ENERGY STAR® Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | 0 | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | 0.1 | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | 0.4 | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | 0.9 | 25 | 0.038 | 0.049 | | |
| 2007 | 303 | 475,044 | 400,637 | 629,634 | 0.07 | 0.6 | 25 | 0.056 | 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | 0.6 | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | 1.1 | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| 2011 | 308 | 259,762 | 651,249 | 728,030 | 0.08 | | 32 | 0.020 | 0.051 | | |
| 2012 | 410 | 453,186 | 871,310 | 537,447 | 0.06 | | 35 | 0.046 | 0.089 | | |
| **Total** | **3,062** | **$ 3,097,757** | **$ 4,643,317** | **5,382,155** | | | **35** | **$ 0.039** | **$ 0.058** | **3.77** | **2.51** |
| Heating & Cooling Efficiency Program | | | | | | | | | | | |
| 2006 | | 17,444 | 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | 27.344 | 27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,440 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.13 | | 20 | 0.025 | 0.083 | | |
| 2011 | 130 | 195,770 | 614,523 | 733,405 | 0.08 | | 20 | 0.018 | 0.056 | | |
| 2012 | 141 | 182,281 | 676,530 | 688,855 | 0.08 | | 20 | 0.018 | 0.066 | | |
| **Total** | **1,200** | **$ 2,163,300** | **$ 4,241,532** | **4,364,621** | | | **20** | **$ 0.041** | **$ 0.080** | **3.49** | **1.78** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | | |
| Home Improvement Program | | | | | | | | | | | | |
| 2008 | 282 | $ 123,454 | $ 157,866 | 317,814 | 0.04 | | 25 | $ 0.029 | $ 0.037 | | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | | |
| 2011 | 2,275 | 666,041 | 2,704,816 | 917,519 | 0.10 | | 45 | 0.038 | 0.155 | | | |
| 2012 | 840 | 385,091 | 812,827 | 457,353 | 0.05 | | 45 | 0.044 | 0.093 | | | |
| **Total** | **8,122** | **$ 2,440,442** | **$ 6,338,394** | **7,017,761** | | | **45** | **$ 0.022** | **$ 0.058** | **3.15** | **1.21** | 2 |
| Home Products Program | | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | 0 | | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | 0.06 | | 15 | 0.044 | 0.082 | | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | 0.19 | | 15 | 0.031 | 0.051 | | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | 0.16 | | 15 | 0.057 | 0.070 | | | |
| 2011 | 15,896 | 638,323 | 1,520,977 | 1,485,326 | 0.17 | | 15 | 0.034 | 0.080 | | | |
| 2012 | 16,675 | 659,032 | 817,924 | 887,222 | 0.10 | | 14 | 0.061 | 0.075 | | | |
| **Total** | **61,426** | **$ 2,900,964** | **$ $4,686,194** | **5,995,781** | | | **14** | **$ 0.048** | **$ 0.078** | **2.26** | **1.40** | |
| Oregon Residential Weatherization | | | | | | | | | | | | |
| 2002 | 24 | (662) | 23,971 | 4,580 | | | 25 | 0.010 | 0.389 | | | |
| 2003 | | (943) | | | | | | | | | | 3 |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | | |
| 2005 | 4 | 612 | 3,608 | 7,927 | 0.00 | | 25 | 0.006 | 0.034 | | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | | 4 |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | | |
| 2009 | 1 | 7,645 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | | |
| 2011 | 8 | 7,926 | 10,208 | 21,908 | 0.00 | | 30 | 0.021 | 0.027 | | | |
| 2012 | 5 | 4,516 | 11,657 | 11,985 | 0.00 | | 30 | 0.022 | 0.056 | | | |
| **Total** | **51** | **$ 41,525** | **$ 103,653** | **81,794** | | | **30** | **$ 0.036** | **$ 0.089** | **3.88** | **1.55** | 5 |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | $ 27,372 | $ 79,399 | 227,434 | 0.03 | | 45 | $ 0.008 | $ 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| 2011 | 25 | 63,469 | 85,044 | 159,325 | 0.02 | | 25 | 0.024 | 0.033 | | |
| 2012 | 35 | 37,241 | 71,911 | 187,108 | 0.02 | | 25 | 0.012 | 0.024 | | |
| **Total** | **760** | **$ 548,199** | **$ 1,235,052** | **2,981,920** | | | **25** | **$ 0.014** | **$ 0.031** | **8.71** | **3.87** |
| See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | 305,401 | 305,401 | 1,132,802 | 0.13 | | 8 | 0.041 | 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| 2011 | 3,449 | 654,393 | 654,393 | 1,712,423 | 0.20 | | 8 | 0.046 | 0.046 | | |
| 2012 | 3,176 | 613,146 | 613,146 | 1,576,426 | 0.18 | | 8 | 0.046 | 0.046 | | |
| **Total** | **11,438** | **$ 2,138,019** | **$ 2,138,019** | **5,989,387** | | | **8** | **$ 0.052** | **$ 0.052** | **1.70** | **1.70** |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 52,807 | 71,680 | 0.01 | | 25 | 0.057 | 0.057 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,719 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 228,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| 2011 | 117 | 788,148 | 788,148 | 1,141,194 | 0.13 | | 25 | 0.042 | 0.042 | | |
| 2012 | 141 | 1,070,556 | 1,070,556 | 257,466 | 0.03 | | 25 | 0.254 | 0.254 | | |
| **Total** | **362** | **$ 2,302,931** | **$ 2,302,931** | **1,995,368** | | | **25** | **$ 0.086** | **$ 0.086** | **1.47** | **1.47** |
| Window AC Trade-Up Pilot | | | | | | | | | | | |
| 2003 | 99 | 6,687 | 10,492 | 14,454 | | | 12 | 0.051 | 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.051** | **$ 0.079** | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | $ 235,048 | $ 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | $ 0.0290 | $ 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.0330 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.0370 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.0290 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.0250 | 0.032 | | |
| 2009 | 427 | 1,260,922 | 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.0210 | 0.033 | | |
| 2010 | 373 | 1,205,446 | 2,782,597 | 3,452,025 | 0.39 | | 25 | 0.0260 | 0.060 | | |
| 2011 | 273 | 1,278,112 | 1,861,836 | 2,648,676 | 0.30 | | 25 | 0.0360 | 0.053 | | |
| 2012 | 228 | 1,321,927 | 1,743,863 | 621,464 | 0.02 | | 25 | 0.1590 | 0.210 | | |
| **Total** | **3,921** | **$ 11,554,485** | **$ 17,832,228** | **26,055,329** | | | **25** | **$ 0.0330** | **$ 0.051** | **4.36** | **2.83** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.0270 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.0160 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.0350 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.0350 | 0.047 | | |
| 2006 | | | | | | | 25 | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.0540 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.0400 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.0230 | 0.031 | | |
| 2010 | 27 | 115,686 | 147,712 | 289,627 | 0.03 | | 25 | 0.0300 | 0.038 | | |
| 2011 | 14 | 46,303 | 63,981 | 134,972 | 0.02 | | 25 | 0.0260 | 0.035 | | |
| 2012 | 10 | 48,214 | 76,083 | 26,840 | 0.00 | | 25 | 0.1340 | 0.212 | | |
| **Total** | **191** | **$ 423,525** | **$ 624,488** | **976,051** | | | **25** | **$ 0.0323** | **$ 0.048** | **4.26** | **2.89** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.0130 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.0170 | 0.036 | | |
| 2004 | 40 | 69,409 | 105,021 | 125,919 | 0.01 | | 25 | 0.0410 | 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.0200** | **$ 0.037** | **6.73** | **3.57** |
| **WAQC—All Total** | | **$ 12,153,280** | **$ 18,786,907** | **27,692,237** | | | **25** | **0.0330** | **0.051** | **4.39** | **2.84** |

**Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | $ 5,764 | $ 9,061 | 33,976 | | | 10 | $ 0.021 | $ 0.033 | | |
| 2004 | | 344 | 344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.022** | **$ 0.034** | | |
| Building Efficiency Program | | | | | | | | | | | |
| 2004 | | 28,821 | 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | 0.043 | 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 802,839 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,127 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| 2011 | 63 | 1,291,425 | 3,320,015 | 11,514,641 | 1.31 | 0.9 | 12 | 0.010 | 0.026 | | |
| 2012 | 84 | 1,592,572 | 8,204,883 | 20,450,037 | 2.33 | 0.6 | 12 | 0.007 | 0.036 | | |
| **Total** | **423** | **$ 8,041,743** | **$ 20,394,250** | **59,544,566** | | | **12** | **$ 0.015** | **$ 0.038** | **6.50** | **2.56** |
| Easy Upgrades | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| 2011 | 1,732 | 4,719,466 | 9,519,364 | 38,723,073 | 4.42 | 4.4 | 12 | 0.011 | 0.022 | | |
| 2012 | 1,838 | 5,349,753 | 9,245,297 | 41,568,672 | 4.75 | 4.8 | 12 | 0.012 | 0.020 | | |
| **Total** | **7,099** | **$ 21,104,708** | **$ 48,506,776** | **182,399,866** | | | **12** | **$ 0.013** | **$ 0.029** | **7.57** | **3.29** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| 2011 | 6 | 2,568 | 2,990 | 66,189 | 0.01 | | 10 | 0.004 | 0.005 | | |
| **Total** | **77** | **$ 111,412** | **$ 214,280** | **716,255** | | | **10** | **$ 0.019** | **$ 0.037** | **3.70** | **1.92** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | | | |
| Oregon Commercial Audit | | | | | | | | | | | |
| 2002 | 24 | $ 5,200 | $ 5,200 | | | | | | | | |
| 2003 | 21 | 0 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| 2011 | 12 | 13,597 | 13,597 | | | | | | | | |
| 2012 | 14 | 12,470 | 12,470 | | | | | | | | |
| **Total** | **154** | **$ 64,537** | **$ 68,537** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,857** | **223,368** | | | **12** | **$ 0.012** | **$ 0.044** | | |
| **Industrial** | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | |
| 2003 | | 1,303 | 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | 0.058 | 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| 2011 | 166 | 8,783,811 | 19,830,834 | 67,979,157 | 7.76 | 7.8 | 12 | 0.012 | 0.026 | | |
| 2012 | 126 | 7,092,581 | 12,975,629 | 54,253,106 | 6.19 | 7.6 | 12 | 0.012 | 0.021 | | |
| **Total** | **862** | **$ 40,790,426** | **$ 92,213,608** | **347,935,471** | | | **12** | **$ 0.013** | **$ 0.029** | **7.48** | **3.31** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Program | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |
| 2005 | 38 | 150,577 | 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | 0.014 | 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| 2011 | 880 | 2,360,304 | 13,281,492 | 13,979,833 | 1.60 | 3.8 | 8 | 0.020 | 0.113 | | |
| 2012 | 908 | 2,373,201 | 11,598,185 | 12,617,164 | 1.44 | 3.1 | 8 | 0.022 | 0.110 | | |
| **Total** | **5,837** | **$ 16,425,973** | **$ 62,755,370** | **93,612,009** | | | **8** | **$ 0.026** | **$ 0.098** | **4.66** | **1.76** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | 48,853 | 48,853 | 1,825,000 | 0.21 | | 5 | 0.006 | 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| 2011 | | 89,856 | 89,856 | | | | | | | | |
| 2012 | | 73,788 | 73,788 | | | | | | | | |
| **Total** | | **$ 460,714** | **$ 460,714** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levelized Costs[a] | | Program Life Benefit/ Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Other Programs** | | | | | | | | | | | |
| Comprehensive Lighting | | | | | | | | | | | |
| 2011 | | $ 2,404 | $ 2,404 | | | | | | | | |
| 2012 | | 64,094 | 64,094 | | | | | | | | |
| **Total** | | **$ 66,498** | **$ 66,498** | | | | | | | | |
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |
| 2008 | | (1,913) | (1,913) | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | 56,909 | 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| 2011 | | 210,477 | 210,477 | | | | | | | | |
| 2012 | | 285,951 | 285,951 | | | | | | | | |
| **Total** | | **$ 1,006,079** | **$ 1,006,079** | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | 55,722 | 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |

**Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Residential Economizer Pilot | | | | | | | | | | | |
| 2011 | | $ 101,713 | $ 101,713 | | | | | | | | |
| 2012 | | 93,491 | 93,491 | | | | | | | | |
| **Total** | | **$ 195,204** | **$ 195,204** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |
| 2010 | | 222,092 | 222,092 | | | | | | | | |
| 2011 | | 159,645 | 159,645 | | | | | | | | |
| 2012 | | 174,738 | 174,738 | | | | | | | | |
| **Total** | | **$ 965,270** | **$ 965,270** | | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 45,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 45,522** | | | | | | | | |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2003 | 56 | 5,100 | 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $ 0.024 | $ 0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | 0.009 | 0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | 0.135 | 0.135 | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | 0.0 | 15 | 0.019 | 0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | 0.0 | 12 | 0.064 | 0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | 0.0 | | | | | |
| 2011 | 1 | 1,026 | 2,052 | 2,028 | | | 30 | 0.036 | 0.071 | | |
| **Total** | **544** | **$ 84,285** | **$ 132,961** | **234,326** | | | **14** | **$ 0.037** | **$ 0.058** | **2.95** | **1.87** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | $ 1,286,632 | $ 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,279 | 2.40 | | | | | | |
| 2009 | | 968,263 | 968,263 | 10,702,998 | 1.22 | | | | | | |
| 2010 | | 2,391,217 | 2,391,217 | 21,300,366 | 2.43 | | | | | | |
| 2011 | | 3,108,393 | 3,108,393 | 20,547,192 | 2.35 | | | | | | |
| 2012 | | 3,379,756 | 3,379,756 | 17,741,430 | 2.03 | | | | | | |
| **Total** | | **$ 16,926,319** | **$ 16,926,319** | **193,183,955** | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2009 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | 1,932,520 | 2,366,591 | 16,791,100 | 1.92 | 0.0 | | | | | |
| 2003 | | 2,566,228 | 3,125,572 | 18,654,343 | 2.12 | 0.0 | | | | | |
| 2004 | | 3,827,213 | 4,860,912 | 19,202,780 | 2.19 | 6.6 | | | | | |
| 2005 | | 6,523,348 | 10,383,577 | 37,978,035 | 4.34 | 44.3 | | | | | |
| 2006 | | 11,174,181 | 20,950,110 | 67,026,303 | 7.65 | 44.4 | | | | | |
| 2007 | | 14,896,816 | 27,123,018 | 91,145,357 | 10.40 | 58.5 | | | | | |
| 2008 | | 20,213,216 | 44,775,829 | 128,508,579 | 14.67 | 74.9 | | | | | |
| 2009 | | 33,821,062 | 53,090,852 | 143,146,365 | 16.34 | 236.6 | | | | | |
| 2010 | | 44,643,541 | 69,164,744 | 193,592,637 | 22.10 | 357.7 | | | | | |
| 2011 | | 44,877,117 | 79,436,532 | 183,861,776 | 20.99 | 419.6 | | | | | |
| 2012 | | 47,991,352 | 77,411,652 | 170,227,773 | 19.43 | 453.6 | | | | | |
| **Total Direct Program** | | **$ 232,466,593** | **$ 392,689,390** | **1,070,135,047** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Indirect Program Expenses** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | $ 128,855 | | | | | | | | | |
| 2003 | | (41,543) | | | | | | | | | |
| 2004 | | 142,337 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,310 | | | | | | | | | |
| 2011 | | 1,389,135 | | | | | | | | | |
| 2012 | | 1,335,509 | | | | | | | | | |
| **Total** | | **$ 7,402,629** | | | | | | | | | |
| **Total Expenses** | | | | | | | | | | | |
| 2002 | | 2,061,375 | | | | | | | | | |
| 2003 | | 2,524,685 | | | | | | | | | |
| 2004 | | 3,969,550 | | | | | | | | | |
| 2005 | | 6,700,972 | | | | | | | | | |
| 2006 | | 11,484,013 | | | | | | | | | |
| 2007 | | 15,662,377 | | | | | | | | | |
| 2008 | | 21,193,521 | | | | | | | | | |
| 2009 | | 34,846,766 | | | | | | | | | |
| 2010 | | 45,832,851 | | | | | | | | | |
| 2011 | | 46,266,252 | | | | | | | | | |
| 2012 | | 49,326,859 | | | | | | | | | |
| **Total 2002–2012** | | **$ 239,869,220** | | | | | | | | | |

[a] Levelized Costs are based on financial inputs from IPC's 2009 IRP and calculations include line-loss adjusted energy savings.

[b] Program life B/C ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by IPC to implement and manage a DSM program.

[d] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of IPC and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13-percent peak line losses.

[1] Peak MW achieved based on mid-week load reduction schedule.

[2] B/C ratios reflect impacts of the 28-percent realization rate for years 2008–2010 from the ADM 2011 impact evaluation.

[3] Utility cost reflects collected funds on previous bad loan write-offs.

[4] Utility cost reflects only audit and administration costs, there was no further activity in 2006.

[5] Levelized cost calculation includes bad loan write-off expense and funds collected from previously written off loans.

[6] Beginning in 2005, BPA funds were no longer applied to CAP agency payments.

[7] Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

[8] Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

[9] Savings are preliminary estimates provided by NEEA.

## **Appendix 5.** 2012 DSM program activity by state jurisdiction

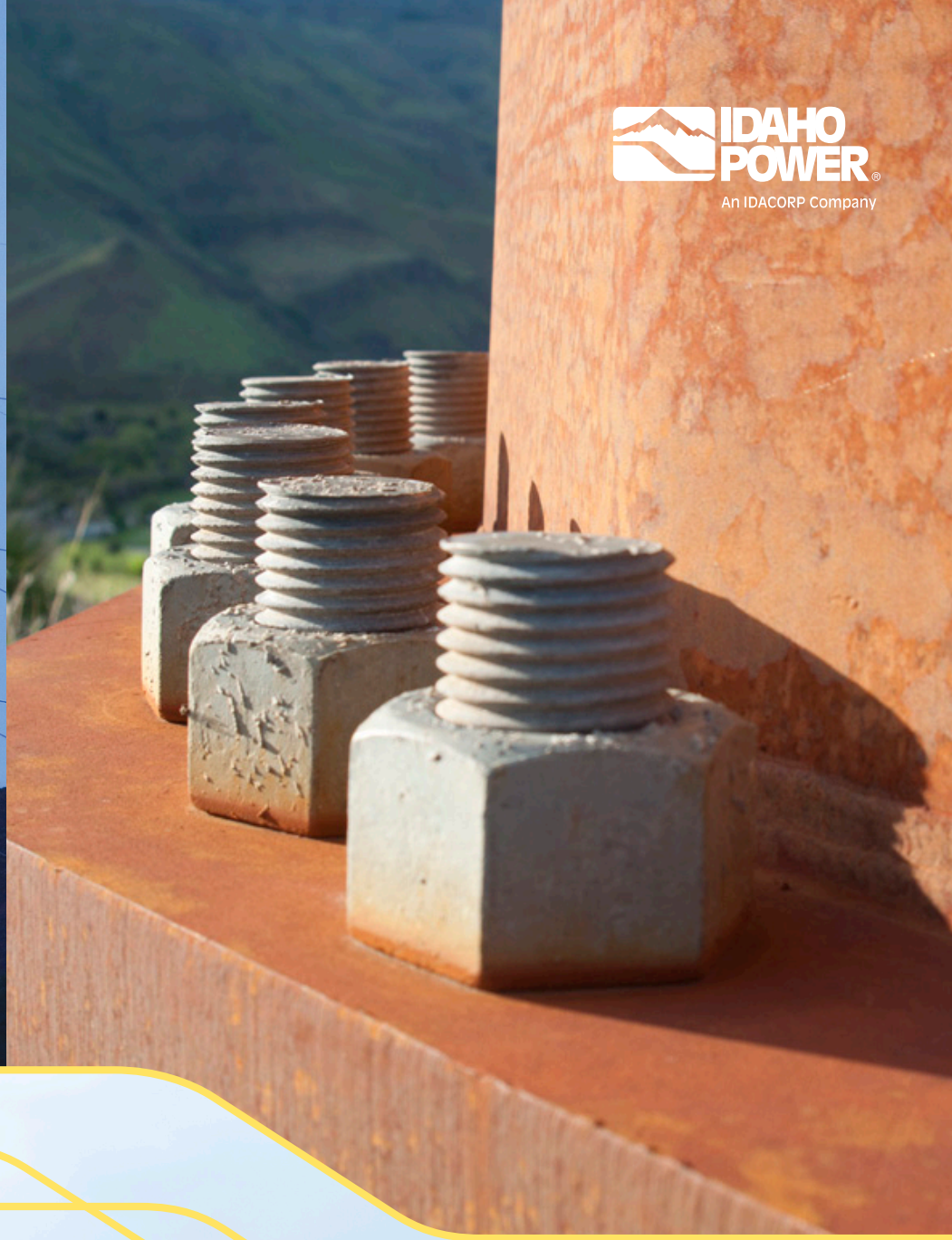
| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Demand Response** | | | **(MW)** | | | **(MW)** |
| A/C Cool Credit | 35,969 homes | $ 5,635,184 | 44.3 | 482 homes | $ 92,810 | 0.6 |
| Irrigation Peak Rewards | 2,396 service points | 12,325,148 | 338.0 | 37 service points | 98,216 | 1.6 |
| FlexPeak Management | 97 sites | 2,859,333 | 41.2 | 5 sites | 150,489 | 11.6 |
| **Total** | | **$ 20,819,664** | **423.5** | | **$ 341,515** | **13.9** |
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Residential** | | | | | | |
| Ductless Heat Pump Pilot | 122 homes | 153,017 | 427,000 | 5 homes | 6,850 | 17,500 |
| Energy Efficient Lighting | 913,397 bulbs | 1,110,329 | 16,496,129 | 12,063 bulbs | 16,507 | 212,530 |
| Energy House Calls | 620 homes | 272,666 | 1,122,497 | 48 homes | 3,217 | 69,542 |
| ENERGY STAR® Homes Northwest | 410 homes | 450,727 | 537,447 | 0 homes | 2,458 | 0 |
| Heating & Cooling Efficiency Program | 136 projects | 175,483 | 669,607 | 5 projects | 6,798 | 19,248 |
| Home Improvement Program | 840 insulation projects | 385,091 | 457,353 | 0 insulation projects | 0 | 0 |
| Home Products Program | 16,194 appliances/fixtures | 640,203 | 858,202 | 481 appliances/fixtures | 18,829 | 29,019 |
| Oregon Residential Weatherization | 0 home | 0 | 0 | 5 home | 4,516 | 11,985 |
| Rebate Advantage | 33 homes | 34,926 | 173,414 | 2 homes | 2,316 | 13,694 |
| See ya later, refrigerator® | 3,106 refrigerators/freezers | 596,167 | 1,546,075 | 61 refrigerators/freezers | 16,979 | 30,351 |
| Weatherization Assistance for Qualified Customers | 228 homes/non-profits | 1,321,927 | 621,464 | 10 homes/non-profits | 48,214 | 26,840 |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 257,466 | 0 homes | 0 | 0 |
| **Sector Total** | | **$ 6,211,092** | **23,166,654** | | **$ 126,684** | **430,709** |
| **Commercial** | | | | | | |
| Building Efficiency | 84 projects | 1,579,121 | 20,450,037 | 0 projects | 13,451 | 0 |
| Easy Upgrades | 1,787 projects | 5,150,422 | 40,656,743 | 51 projects | 199,331 | 911,929 |
| Oregon Commercial Audits | 0 audits | 0 | 0 | 14 audits | 12,470 | 0 |
| **Sector Total** | | **$ 6,729,543** | **61,106,780** | | **$ 225,252** | **911,929** |
| **Industrial** | | | | | | |
| Custom Efficiency | 122 projects | 6,976,700 | 53,137,995 | 4 projects | 115,881 | 1,115,111 |
| **Sector Total** | | **$ 6,976,700** | **53,137,995** | | **$ 115,881** | **1,115,111** |
| **Irrigation** | | | | | | |
| Irrigation Efficiency Rewards | 869 projects | 2,010,822 | 11,163,948 | 39 projects | 362,378 | 1,453,216 |
| **Sector Total** | | **$ 2,010,822** | **11,163,948** | | **$ 362,378** | **1,453,216** |

## **Appendix 5.** 2012 DSM program activity by state jurisdiction (continued)

| Program | Idaho | | | Oregon | | |
|---|---|---|---|---|---|---|
| | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings |
| **Market Transformation** | | | **(kWh)** | | | **(kWh)** |
| Northwest Energy Efficiency Alliance[1] | | $ 3,210,768 | 16,854,359 | | $ 168,988 | 887,072 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Residential Economizer Project | | 93,593 | | | (101) | |
| Residential Energy Efficiency Education Initiative | | 165,919 | | | 8,819 | |
| **Commercial** | | | | | | |
| Commercial Education Initiative | | 70,099 | | | 3,689 | |
| Comprehensive Lighting | | 64,094 | | | | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 271,622 | | | 14,329 | |
| **Total Program Direct Expense** | | **$ 46,623,916** | | | **$ 1,367,435** | |
| Indirect Program Expense | | 1,260,377 | | | 75,132 | |
| **Total Annual Savings** | | | **165,429,736** | | | **4,798,037** |
| **Total DSM Expense** | | **$ 47,884,293** | | | **$ 1,442,567** | |

[1] Savings are preliminary estimates provided by NEEA. Oregon is credited with 5 percent of annual NEEA savings.





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# 2013 Integrated Resource Plan

## APPENDIX C

## Technical Report

June 2013

# 2013

# Integrated Resource Plan

## APPENDIX C

# Technical Report

June 2013


## ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the Advisory Council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.


## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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# TABLE OF CONTENTS

Table of Contents ..... i
Introduction ..... 1
IRP Advisory Council ..... 2
List of Advisory Council Members ..... 2
IRP Advisory Council Meeting Schedule and Agenda ..... 3
Public Policy Issues ..... 5
Greenhouse Gas Emissions ..... 5
Flow Modeling ..... 8
Sales and Load Forecast Data ..... 11
Average Annual Forecast Growth Rates ..... 11
Expected-Case Load Forecast ..... 12
70th Percentile Load Forecast ..... 22
Load and Resource Balance Data ..... 31
Monthly Average Energy Load and Resource Balance ..... 31
Monthly Average Energy Surplus/Deficit Charts ..... 52
Peak-Hour Load and Resource Balance ..... 53
Peak-Hour Surplus/Deficit Charts ..... 73
Demand-Side Resource Data ..... 74
Cost Effectiveness ..... 74
Alternate Costs ..... 75
Supply-Side Resource Data ..... 83
Key Financial and Forecast Assumptions ..... 83
Cost Inputs and Operating Assumptions ..... 85
Transmission Cost Assumptions ..... 86
Levelized Cost of Production ..... 89
Resource Advantages and Disadvantages ..... 91
Resource Peak Hour Shape ..... 93
Capacity Factors for Solar PV ..... 93
Fuel Data ..... 96
Natural Gas and Coal Price Forecast ..... 96

Existing Resource Data....98
Hydroelectric and Thermal Plant Data....98
Qualifying Facility Data (PURPA)....99
Power Purchase Agreement Data....100
Hydro Modeling Results (PDR580)....101
Portfolio Analysis, Results, and Supporting Documentation....131
Stochastic Dispersion Plot....131
Regulatory Environmental Compliance Costs....131
Loss of Load Expectation Analysis....132
State of Oregon IRP Guidelines....137
Compliance with State of Oregon IRP Guidelines....145
State of Oregon IRP Electric Vehicles (EV) Guidelines....151
Compliance with EV Guidelines....155
State of Oregon Action Items Regarding Idaho Power's 2011 IRP....156
Compliance with State of Oregon Action Items Regarding Idaho Power's 2011 IRP....165

# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2013 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2013 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2012 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2013.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2623

irp@idahopower.com

# IRP ADVISORY COUNCIL

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council. The IRP Advisory Council generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and the natural gas power generation. Idaho Power also hosted 11 IRP Advisory Council meetings, including a resource portfolio design workshop. Idaho Power and members from the IRP Advisory Council also met in several small break-out sessions to discuss certain topics in greater detail. Idaho Power values these opportunities to convene, and the IRP Advisory Council members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRP Advisory Council and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRP Advisory Council recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

## List of Advisory Council Members

### Customer Representatives

Agricultural Representative.....Sid Erwin
Boise State University.....John Gardner
Idaho National Laboratory.....Kurt Myers
Micron.....John Velikoff
Simplot.....Don Sturtevant

### Public Interest Representatives

Boise Metro Chamber of Commerce.....Ray Stark
Idaho Conservation League.....Ben Otto
Idaho Department of Commerce.....Gynii Gilliam
Idaho Office of Energy Resources.....John Chatburn
Idaho State House of Representatives.....Representative Brent Crane
Idaho State Senate.....Senator Russ Fulcher
Idaho Technology Council.....Jay Larsen
Northwest Power and Conservation Council.....Shirley Lindstrom
Northwest Power and Conservation Council.....Jim Yost
Oil and Gas Industry Advisor.....David Hawk
University of Idaho Integrated Design Lab.....Kevin Van Den Wymelenberg
Water Issues Advisor.....Vince Alberdi

### Regulatory Commission Representatives

Idaho Public Utilities Commission.....Bryan Lanspery
Public Utility Commission of Oregon.....Brittany Andrus

# IRP Advisory Council Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2012 | Thursday, August 16 | Background and Process<br>Explanation of the IRP Process<br>Summary of 2012 Summer Peak Load Season<br>Preliminary Resources to Include in the Resource Stack<br>DSM Potential Study<br>Recent Transmission Issues<br>Boardman to Hemingway Update |
| 2012 | Thursday, September 6 | Thermal Fuels and Associated Issues<br>Natural Gas Price Forecast and Transportation<br>Coat and Gas Unit Forecast<br>Renewable Energy Credit<br>Carbon Adder and Proposed Federal Legislation<br>CSPP Forecast |
| 2012 | Wednesday, October 10 | Field Trip to Langly Gulch and Hemingway Substation |
| 2012 | Thursday, October 11 | Hydro Resources and Issues, Customer Load<br>Water Issues<br>Hydro Forecast<br>Load Forecast<br>DSM Program Forecast |
| 2012 | Thursday, November 15 | 2011 IRP Update<br>Environmental Compliance Cost Study<br>Boardman to Hemingway Update<br>Load Forecast<br>Natural Gas Price Forecast<br>DSM Update |
| 2012 | Friday, November 30 | Portfolio Design Workshop |
| 2012 | Thursday, December 13 | Portfolio Modeling Review<br>Portfolio Workshop Review<br>Load and Resource Balance<br>Resource Cost Summary<br>Portfolio Modeling Plan<br>Aurora Model Overview<br>Conservation Voltage Reduction |
| 2013 | Thursday, January 17 | Meeting Canceled |
| 2013 | Thursday, February 21 | 2011 IRP Update Filing and Resource Analysis<br>Coal Study Results<br>Boardman to Hemingway Update<br>Preliminary Resource Analysis<br>Idaho Power Response to Hurricane Sandy |
| 2013 | Thursday, March 14 | Risk Analysis Methods<br>Resource Alternatives Risk Analysis<br>Preliminary Resource Portfolio Analysis<br>Hells Canyon Relicensing |

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2013 | Thursday, April 11 | Risk Analysis Results<br>Resource Portfolio Risk Analysis<br>2013 Water Year Projections<br>DSM Annual Report |
| 2013 | Thursday, May 9 | Risk Analysis Results (continued)<br>Questions from the April Meeting Concerning the Resource Portfolio Risk Analysis<br>Results from the Two Resource Portfolios that Retire the North Valmy Coal Plant |
| 2013 | Thursday, June 6 | Conclusion<br>Draft IRP Document<br>IRP Public Presentation Review<br>Energy Imbalance Market<br>Summer 2013 Preparedness |

# PUBLIC POLICY ISSUES

## Greenhouse Gas Emissions

### *Climate Change and the Regulation of Greenhouse Gas Emissions*

#### Overview

Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- Changes in temperature and precipitation could affect customer demand and energy loads
- Extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities
- Changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation
- Legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general
- Consumer preference for, and resource planning decisions requiring, renewable or low greenhouse gas (GHG)-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure

Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. However, the regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units. Due in part to the uncertainty of future GHG regulations, in its 2011 IRP Idaho Power did not include any new conventional coal resources in its resource portfolios.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other global climate change requirements that may be

adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

### National and International GHG Initiatives

There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. In support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. Other communications from the Obama Administration have proposed the adoption of a clean energy standard in the U.S., calling for 80 percent of American energy to come from clean sources by 2035. Further, climate change regulation has been a recent priority of the U.S. Congress. In prior legislative sessions, legislation in both the U.S. House and Senate was introduced to enact a comprehensive climate change program, but these attempts were unsuccessful. At the same time, legislation has also been introduced seeking to amend the CAA to prohibit the EPA from promulgating regulations on the emissions of GHGs to address climate change and excluding GHGs from the definition of an "air pollutant" for purposes of addressing climate change. Neither areas of focus have culminated in legislation and have led to greater uncertainty as to the direction of GHG regulation.

At the same time, the EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year ($CO_2$ equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. Lawsuits opposing EPA's endangerment finding and Tailoring Rule were unsuccessful. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the new GHG Tailoring Rules.

In addition, in April 2012, the EPA proposed New Source Performance Standards (NSPS) limiting $CO_2$ emissions from new electric utility generating units (EGUs) fired by fossil fuels. The proposed requirements, which are limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of $CO_2$ per MWh. The EPA did not propose standards of performance for existing EGUs whose $CO_2$ emissions increase as a result of installation of pollution controls for conventional pollutants. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, if promulgated the new rule would impact the cost effectiveness of developing new generation units.

## State and Regional GHG Initiatives

On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of $CO_2$ equivalent annually. The mechanism was implemented in two phases, with Title V sources and entities with an air discharge permit required to start reporting 2009 emissions in 2010 and all other sources required to start reporting 2010 emissions in 2011. The Boardman coal-fired power plant, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel plants operating (i.e., Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

## Idaho Power's Voluntary GHG Reduction Initiatives

Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated $CO_2$ emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 672, 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2011, 2010, 2009, 2008, and 2007, respectively.

In 2010, Idaho Power and Ida-West together ranked as the 37th lowest emitter of $CO_2$ per MWh produced and the $35^{th}$ lowest emitter of $CO_2$ by tons of emissions among the nation’s 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, and other entities using publicly reported 2010 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the $58^{th}$ largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

## Public Nuisance-Related Suits for GHGs

In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court’s decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

# Flow Modeling

## Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was recently updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also recently updated with the release of ESPAM 2.0 in July 2012. Subsequent to the completion of the modeling for the 2013 IRP, a corrected version ESPAM 2.1 was released in late 2012. The ESPAM 2.1 update corrected issues discovered within the model in locations in the Snake River basin above Idaho Falls, Idaho. After reviewing output from the updated version of ESPAM, it was determined that the corrections would have no significant impact on the modeling that had been performed for the 2013 IRP.

Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition. Idaho Power completed an update to the combined model for the 2013 IRP.

## Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2009 and 2011 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dan demonstrated a statistically significant decline for the period of 1981 to 2011. Both reaches declined on average 29 cubic feet per second per month (cfs/month) with declines ranging from 25 to 35 cfs/month for American Falls and 18 to 39 cfs/month for Milner to Lower Salmon Falls. Declines in these two reaches met strict predefined criteria, and were therefore included as inputs into the model.

Weather modification was added to the model at two different levels of development. The existing level of development was added to the model for IRP years 2013 and 2014. For IRP years 2015 and beyond, weather modification was increased to reflect a projected level of a fully built-out program in Eastern Idaho. The amount of weather modification added to each year is based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 224,000 acre feet per year (acft/year) and the Upper Snake Basin adds an average of 410,000 acft/year.

Aquifer recharge was added to the model at levels reflected in the 2009 Comprehensive Aquifer Management Plan (CAMP) and the recharge limits included in the Swan Falls Reaffirmation agreement. Nine recharge diversions were modeled across the ESPA with a total maximum diversion of 1,315 cfs. Recharge peaks in IRP year 2019 at approximately 200,000 acft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

CAMP targeted a level of system conversion where ground water supplied irrigated land is converted to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources. The current model assumes a total of 13,683 acres of converted land on the ESPA with a total water savings of 1.4 acft or water per acre of irrigated land (acft/ac), and a maximum of 19,156 acft/year. This number is not solely based on the number of acres idled but also on available water to meet irrigation requirements. The modeled data show conversions reach a peak water savings of 17,600 acft in IRP year 2015. Subsequent reach declines reduce water available for system conversions. In IRP year 2027, water savings declined to 17,100 acft.

The model accounts for approximately 15,410 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions.

## Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2013 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2013 through 2015 in response to increased weather modification in the Upper Snake River Basin. Flows peak in 2015 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.5 Million acft/year. In 2027, those flows have declined to approximately 11.25 Million acft/year, with most of the declines attributable to spring discharge in the Milner to Lower Salmon Falls reach.

## 2013 Model Parameters

| IRP Year | Managed Recharge (acft/yr) | | Weather Modification (acft/yr) | | System Conversions (Ac) | CREP (Ac) | Lease Water | Reach Declines (acft/yr) | |
|---|---|---|---|---|---|---|---|---|---|
| | Above American Falls | Below American Falls | Snake River Basin | Payette Basin | | | 740 cfs in August | American Falls Inflows | Below Milner |
| 2013 | 54,500 | 48,400 | 124,000 | 224,000 | 13,683 | 16,684 | Yes | 82,671 | 84,535 |
| 2014 | 66,600 | 48,400 | 124,000 | 224,000 | 13,683 | 16,684 | Yes | 103,338 | 105,669 |
| 2015 | 66,600 | 90,800 | 410,000 | 224,000 | 13,683 | 16,684 | Yes | 124,006 | 126,803 |
| 2016 | 66,600 | 90,800 | 410,000 | 224,000 | 13,683 | 16,684 | No | 144,673 | 147,937 |
| 2017 | 66,600 | 108,900 | 410,000 | 224,000 | 13,683 | 16,684 | No | 165,340 | 169,071 |
| 2018 | 88,200 | 115,000 | 410,000 | 224,000 | 13,683 | 16,684 | No | 186,007 | 190,205 |
| 2019 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 206,674 | 211,339 |
| 2020 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 227,341 | 232,473 |
| 2021 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 248,008 | 253,607 |
| 2022 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 12,513 | No | 268,675 | 274,741 |
| 2023 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 8,342 | No | 289,342 | 295,875 |
| 2024 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 4,171 | No | 310,009 | 317,009 |
| 2025 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 330,676 | 338,143 |
| 2026 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 351,343 | 359,277 |
| 2027 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2028 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2029 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2030 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2031 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2032 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2013–2018 | 2013–2023 | 2013–2032 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.07% | 1.09% | 1.08% |
| Commercial Sales | 1.09% | 1.07% | 1.10% |
| Irrigation Sales | 0.05% | 0.07% | 0.01% |
| Industrial Sales | 2.25% | 1.95% | 1.71% |
| Additional Firm Sales | 0.97% | 2.03% | 1.16% |
| System Sales | 1.15% | 1.18% | 1.08% |
| Total Sales | 1.15% | 1.18% | 1.08% |
| **Loads** | | | |
| Residential Load | 1.08% | 1.09% | 1.08% |
| Commercial Load | 1.08% | 1.07% | 1.10% |
| Irrigation Load | 0.05% | 0.07% | 0.00% |
| Industrial Load | 2.23% | 1.94% | 1.69% |
| Additional Firm Sales | 0.97% | 2.03% | 1.16% |
| System Load Losses | 1.08% | 1.08% | 1.03% |
| System Load | 1.14% | 1.17% | 1.07% |
| Total Load | 1.14% | 1.17% | 1.07% |
| **Peaks** | | | |
| System Peak | 1.54% | 1.52% | 1.41% |
| Total Peak | 1.54% | 1.52% | 1.41% |
| Winter Peak | 0.81% | 0.90% | 0.82% |
| Summer Peak | 1.54% | 1.52% | 1.41% |
| **Customers** | | | |
| Residential Customers | 1.82% | 1.68% | 1.47% |
| Commercial Customers | 1.94% | 1.81% | 1.59% |
| Irrigation Customers | 1.30% | 1.26% | 1.20% |
| Industrial Customers | 1.18% | 1.15% | 0.99% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 792 | 670 | 567 | 487 | 442 | 467 | 589 | 566 | 461 | 457 | 580 | 806 |
| Commercial | 487 | 444 | 415 | 397 | 403 | 429 | 504 | 491 | 435 | 406 | 428 | 505 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 264 | 266 | 262 | 251 | 254 | 270 | 269 | 273 | 270 | 274 | 273 | 278 |
| Additional Firm | 118 | 116 | 113 | 115 | 110 | 112 | 116 | 116 | 112 | 112 | 120 | 122 |
| Loss | 164 | 146 | 131 | 128 | 148 | 180 | 214 | 195 | 155 | 124 | 135 | 169 |
| **System Load** | 1,828 | 1,644 | 1,491 | 1,451 | 1,655 | 1,982 | 2,336 | 2,143 | 1,728 | 1,416 | 1,537 | 1,882 |
| Light Load | 1,688 | 1,517 | 1,370 | 1,314 | 1,505 | 1,774 | 2,119 | 1,901 | 1,553 | 1,277 | 1,418 | 1,738 |
| Heavy Load | 1,938 | 1,739 | 1,586 | 1,550 | 1,774 | 2,149 | 2,506 | 2,317 | 1,882 | 1,516 | 1,632 | 2,005 |
| **Total Load** | 1,828 | 1,644 | 1,491 | 1,451 | 1,655 | 1,982 | 2,336 | 2,143 | 1,728 | 1,416 | 1,537 | 1,882 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,445 | 2,328 | 2,024 | 1,956 | 2,775 | 3,215 | 3,344 | 3,015 | 2,756 | 2,013 | 2,199 | 2,585 |
| **Total Peak Load** | 2,445 | 2,328 | 2,024 | 1,956 | 2,775 | 3,215 | 3,344 | 3,015 | 2,756 | 2,013 | 2,199 | 2,585 |

| Monthly Summary[1] | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 796 | 671 | 569 | 489 | 445 | 472 | 595 | 571 | 465 | 459 | 582 | 810 |
| Commercial | 494 | 449 | 421 | 403 | 409 | 436 | 512 | 499 | 443 | 412 | 435 | 512 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 647 | 505 | 296 | 43 | 0 | 1 |
| Industrial | 272 | 274 | 269 | 259 | 261 | 277 | 277 | 281 | 278 | 282 | 281 | 286 |
| Additional Firm | 121 | 117 | 115 | 117 | 113 | 110 | 118 | 118 | 114 | 114 | 122 | 124 |
| Loss | 166 | 148 | 133 | 129 | 150 | 182 | 217 | 198 | 157 | 125 | 137 | 170 |
| **System Load** | 1,850 | 1,661 | 1,510 | 1,470 | 1,678 | 2,004 | 2,366 | 2,172 | 1,754 | 1,436 | 1,558 | 1,903 |
| Light Load | 1,709 | 1,533 | 1,387 | 1,331 | 1,525 | 1,794 | 2,147 | 1,927 | 1,575 | 1,295 | 1,437 | 1,758 |
| Heavy Load | 1,962 | 1,757 | 1,606 | 1,571 | 1,798 | 2,173 | 2,539 | 2,365 | 1,896 | 1,538 | 1,664 | 2,017 |
| **Total Load** | 1,850 | 1,661 | 1,510 | 1,470 | 1,678 | 2,004 | 2,366 | 2,172 | 1,754 | 1,436 | 1,558 | 1,903 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,474 | 2,346 | 2,047 | 1,981 | 2,822 | 3,261 | 3,403 | 3,059 | 2,800 | 2,034 | 2,222 | 2,606 |
| **Total Peak Load** | 2,474 | 2,346 | 2,047 | 1,981 | 2,822 | 3,261 | 3,403 | 3,059 | 2,800 | 2,034 | 2,222 | 2,606 |

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 796 | 669 | 568 | 490 | 446 | 474 | 599 | 575 | 466 | 460 | 583 | 817 |
| Commercial | 498 | 452 | 424 | 407 | 413 | 441 | 517 | 504 | 448 | 416 | 438 | 517 |
| Irrigation | 2 | 2 | 2 | 73 | 301 | 530 | 649 | 507 | 298 | 43 | 0 | 1 |
| Industrial | 279 | 281 | 277 | 265 | 268 | 285 | 285 | 288 | 286 | 290 | 289 | 293 |
| Additional Firm | 124 | 121 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 167 | 148 | 134 | 130 | 151 | 183 | 219 | 199 | 158 | 127 | 138 | 172 |
| **System Load** | 1,866 | 1,673 | 1,524 | 1,485 | 1,695 | 2,025 | 2,390 | 2,194 | 1,773 | 1,452 | 1,574 | 1,928 |
| Light Load | 1,723 | 1,544 | 1,400 | 1,345 | 1,541 | 1,812 | 2,168 | 1,947 | 1,593 | 1,310 | 1,453 | 1,781 |
| Heavy Load | 1,979 | 1,770 | 1,621 | 1,587 | 1,827 | 2,180 | 2,564 | 2,389 | 1,917 | 1,555 | 1,681 | 2,044 |
| **Total Load** | 1,866 | 1,673 | 1,524 | 1,485 | 1,695 | 2,025 | 2,390 | 2,194 | 1,773 | 1,452 | 1,574 | 1,928 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,471 | 2,357 | 2,040 | 1,965 | 2,867 | 3,296 | 3,456 | 3,093 | 2,835 | 2,053 | 2,222 | 2,620 |
| **Total Peak Load** | 2,471 | 2,357 | 2,040 | 1,965 | 2,867 | 3,296 | 3,456 | 3,093 | 2,835 | 2,053 | 2,222 | 2,620 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 805 | 675 | 574 | 495 | 452 | 481 | 610 | 585 | 474 | 465 | 590 | 831 |
| Commercial | 503 | 457 | 429 | 411 | 417 | 446 | 523 | 510 | 454 | 421 | 443 | 523 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 643 | 502 | 294 | 43 | 0 | 1 |
| Industrial | 286 | 278 | 283 | 272 | 274 | 291 | 291 | 295 | 292 | 296 | 296 | 298 |
| Additional Firm | 124 | 117 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 169 | 149 | 135 | 132 | 152 | 185 | 220 | 201 | 160 | 128 | 140 | 175 |
| **System Load** | 1,889 | 1,676 | 1,542 | 1,502 | 1,710 | 2,041 | 2,408 | 2,214 | 1,791 | 1,471 | 1,595 | 1,955 |
| Light Load | 1,745 | 1,547 | 1,417 | 1,361 | 1,554 | 1,826 | 2,185 | 1,964 | 1,609 | 1,327 | 1,472 | 1,806 |
| Heavy Load | 2,014 | 1,772 | 1,632 | 1,606 | 1,844 | 2,197 | 2,600 | 2,394 | 1,937 | 1,585 | 1,694 | 2,073 |
| **Total Load** | 1,889 | 1,676 | 1,542 | 1,502 | 1,710 | 2,041 | 2,408 | 2,214 | 1,791 | 1,471 | 1,595 | 1,955 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,486 | 2,370 | 2,050 | 1,971 | 2,906 | 3,323 | 3,500 | 3,121 | 2,867 | 2,070 | 2,235 | 2,640 |
| **Total Peak Load** | 2,486 | 2,370 | 2,050 | 1,971 | 2,906 | 3,323 | 3,500 | 3,121 | 2,867 | 2,070 | 2,235 | 2,640 |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 818 | 683 | 582 | 503 | 460 | 491 | 623 | 597 | 483 | 473 | 600 | 845 |
| Commercial | 507 | 460 | 433 | 415 | 421 | 451 | 529 | 516 | 459 | 426 | 447 | 528 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 642 | 501 | 294 | 42 | 0 | 1 |
| Industrial | 291 | 293 | 288 | 276 | 279 | 297 | 296 | 300 | 298 | 302 | 301 | 303 |
| Additional Firm | 125 | 122 | 120 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 129 |
| Loss | 171 | 152 | 137 | 134 | 154 | 187 | 223 | 203 | 162 | 130 | 142 | 177 |
| **System Load** | 1,915 | 1,711 | 1,562 | 1,522 | 1,729 | 2,063 | 2,435 | 2,240 | 1,814 | 1,491 | 1,617 | 1,982 |
| Light Load | 1,768 | 1,579 | 1,435 | 1,378 | 1,572 | 1,847 | 2,209 | 1,987 | 1,629 | 1,345 | 1,492 | 1,831 |
| Heavy Load | 2,041 | 1,810 | 1,653 | 1,636 | 1,853 | 2,222 | 2,629 | 2,422 | 1,961 | 1,606 | 1,718 | 2,112 |
| **Total Load** | 1,915 | 1,711 | 1,562 | 1,522 | 1,729 | 2,063 | 2,435 | 2,240 | 1,814 | 1,491 | 1,617 | 1,982 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |
| **Total Peak Load** | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 690 | 589 | 510 | 467 | 500 | 635 | 609 | 491 | 479 | 608 | 858 |
| Commercial | 511 | 463 | 436 | 418 | 425 | 456 | 534 | 520 | 464 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 173 | 153 | 139 | 135 | 156 | 189 | 225 | 206 | 164 | 131 | 143 | 180 |
| **System Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| Light Load | 1,788 | 1,593 | 1,450 | 1,393 | 1,588 | 1,866 | 2,233 | 2,009 | 1,648 | 1,360 | 1,509 | 1,854 |
| Heavy Load | 2,052 | 1,826 | 1,670 | 1,654 | 1,872 | 2,245 | 2,657 | 2,449 | 1,997 | 1,615 | 1,737 | 2,139 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |
| **Total Peak Load** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 696 | 595 | 517 | 474 | 508 | 646 | 619 | 498 | 485 | 616 | 868 |
| Commercial | 516 | 466 | 440 | 422 | 429 | 461 | 539 | 526 | 470 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 527 | 646 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 175 | 154 | 140 | 136 | 157 | 191 | 228 | 208 | 166 | 133 | 145 | 182 |
| **System Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| Light Load | 1,808 | 1,608 | 1,466 | 1,409 | 1,605 | 1,886 | 2,258 | 2,032 | 1,667 | 1,376 | 1,527 | 1,877 |
| Heavy Load | 2,076 | 1,843 | 1,697 | 1,662 | 1,892 | 2,284 | 2,670 | 2,477 | 2,021 | 1,634 | 1,758 | 2,165 |
| **Total Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |
| **Total Peak Load** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 846 | 699 | 600 | 521 | 478 | 515 | 656 | 628 | 504 | 490 | 622 | 878 |
| Commercial | 521 | 470 | 444 | 427 | 434 | 466 | 545 | 532 | 476 | 439 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 177 | 155 | 142 | 138 | 159 | 193 | 230 | 210 | 167 | 135 | 147 | 184 |
| **System Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| Light Load | 1,832 | 1,612 | 1,485 | 1,428 | 1,625 | 1,909 | 2,284 | 2,058 | 1,689 | 1,395 | 1,548 | 1,904 |
| Heavy Load | 2,103 | 1,846 | 1,719 | 1,685 | 1,927 | 2,297 | 2,701 | 2,525 | 2,033 | 1,657 | 1,792 | 2,185 |
| **Total Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |
| **Total Peak Load** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 690 | 589 | 510 | 467 | 500 | 635 | 609 | 491 | 479 | 608 | 858 |
| Commercial | 511 | 463 | 436 | 418 | 425 | 456 | 534 | 520 | 464 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 173 | 153 | 139 | 135 | 156 | 189 | 225 | 206 | 164 | 131 | 143 | 180 |
| **System Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| Light Load | 1,788 | 1,593 | 1,450 | 1,393 | 1,588 | 1,866 | 2,233 | 2,009 | 1,648 | 1,360 | 1,509 | 1,854 |
| Heavy Load | 2,052 | 1,826 | 1,670 | 1,654 | 1,872 | 2,245 | 2,657 | 2,449 | 1,997 | 1,615 | 1,737 | 2,139 |
| **Total Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |
| **Total Peak Load** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 696 | 595 | 517 | 474 | 508 | 646 | 619 | 498 | 485 | 616 | 868 |
| Commercial | 516 | 466 | 440 | 422 | 429 | 461 | 539 | 526 | 470 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 527 | 646 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 175 | 154 | 140 | 136 | 157 | 191 | 228 | 208 | 166 | 133 | 145 | 182 |
| **System Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| Light Load | 1,808 | 1,608 | 1,466 | 1,409 | 1,605 | 1,886 | 2,258 | 2,032 | 1,667 | 1,376 | 1,527 | 1,877 |
| Heavy Load | 2,076 | 1,843 | 1,697 | 1,662 | 1,892 | 2,284 | 2,670 | 2,477 | 2,021 | 1,634 | 1,758 | 2,165 |
| **Total Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |
| **Total Peak Load** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 846 | 699 | 600 | 521 | 478 | 515 | 656 | 628 | 504 | 490 | 622 | 878 |
| Commercial | 521 | 470 | 444 | 427 | 434 | 466 | 545 | 532 | 476 | 439 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 177 | 155 | 142 | 138 | 159 | 193 | 230 | 210 | 167 | 135 | 147 | 184 |
| **System Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| Light Load | 1,832 | 1,612 | 1,485 | 1,428 | 1,625 | 1,909 | 2,284 | 2,058 | 1,689 | 1,395 | 1,548 | 1,904 |
| Heavy Load | 2,103 | 1,846 | 1,719 | 1,685 | 1,927 | 2,297 | 2,701 | 2,525 | 2,033 | 1,657 | 1,792 | 2,185 |
| **Total Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |
| **Total Peak Load** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 852 | 702 | 603 | 525 | 483 | 521 | 664 | 637 | 510 | 494 | 627 | 887 |
| Commercial | 525 | 473 | 448 | 431 | 438 | 471 | 551 | 538 | 481 | 444 | 464 | 550 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 529 | 649 | 507 | 297 | 43 | 0 | 1 |
| Industrial | 311 | 313 | 308 | 295 | 298 | 317 | 317 | 320 | 318 | 322 | 321 | 323 |
| Additional Firm | 143 | 138 | 135 | 136 | 130 | 127 | 135 | 135 | 130 | 131 | 144 | 148 |
| Loss | 179 | 157 | 143 | 140 | 161 | 195 | 232 | 213 | 169 | 136 | 149 | 187 |
| **System Load** | 2,012 | 1,785 | 1,639 | 1,600 | 1,811 | 2,160 | 2,548 | 2,349 | 1,906 | 1,570 | 1,705 | 2,095 |
| Light Load | 1,858 | 1,647 | 1,506 | 1,449 | 1,647 | 1,934 | 2,312 | 2,084 | 1,712 | 1,416 | 1,573 | 1,936 |
| Heavy Load | 2,145 | 1,888 | 1,735 | 1,710 | 1,953 | 2,326 | 2,734 | 2,558 | 2,061 | 1,692 | 1,811 | 2,221 |
| **Total Load** | 2,012 | 1,785 | 1,639 | 1,600 | 1,811 | 2,160 | 2,548 | 2,349 | 1,906 | 1,570 | 1,705 | 2,095 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,614 | 2,462 | 2,148 | 2,064 | 3,135 | 3,523 | 3,782 | 3,324 | 3,067 | 2,173 | 2,350 | 2,776 |
| **Total Peak Load** | 2,614 | 2,462 | 2,148 | 2,064 | 3,135 | 3,523 | 3,782 | 3,324 | 3,067 | 2,173 | 2,350 | 2,776 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 859 | 706 | 607 | 530 | 488 | 528 | 674 | 646 | 516 | 498 | 633 | 898 |
| Commercial | 530 | 477 | 452 | 435 | 443 | 477 | 557 | 544 | 487 | 449 | 468 | 556 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 316 | 318 | 313 | 300 | 303 | 322 | 322 | 326 | 323 | 328 | 327 | 328 |
| Additional Firm | 148 | 142 | 139 | 141 | 134 | 131 | 138 | 139 | 134 | 135 | 149 | 153 |
| Loss | 181 | 158 | 145 | 141 | 162 | 196 | 234 | 215 | 171 | 138 | 150 | 189 |
| **System Load** | 2,036 | 1,803 | 1,659 | 1,619 | 1,830 | 2,182 | 2,573 | 2,374 | 1,928 | 1,590 | 1,727 | 2,125 |
| Light Load | 1,881 | 1,664 | 1,524 | 1,466 | 1,664 | 1,953 | 2,335 | 2,106 | 1,732 | 1,434 | 1,594 | 1,963 |
| Heavy Load | 2,170 | 1,907 | 1,755 | 1,731 | 1,973 | 2,350 | 2,778 | 2,567 | 2,085 | 1,713 | 1,835 | 2,253 |
| **Total Load** | 2,036 | 1,803 | 1,659 | 1,619 | 1,830 | 2,182 | 2,573 | 2,374 | 1,928 | 1,590 | 1,727 | 2,125 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,636 | 2,480 | 2,164 | 2,077 | 3,180 | 3,559 | 3,835 | 3,361 | 3,104 | 2,194 | 2,370 | 2,803 |
| **Total Peak Load** | 2,636 | 2,480 | 2,164 | 2,077 | 3,180 | 3,559 | 3,835 | 3,361 | 3,104 | 2,194 | 2,370 | 2,803 |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 868 | 711 | 613 | 536 | 494 | 536 | 685 | 656 | 523 | 504 | 640 | 908 |
| Commercial | 536 | 481 | 457 | 440 | 448 | 483 | 564 | 550 | 494 | 454 | 473 | 562 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 321 | 323 | 318 | 305 | 308 | 327 | 327 | 331 | 328 | 333 | 332 | 333 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 139 | 134 | 136 | 150 | 153 |
| Loss | 183 | 160 | 146 | 143 | 164 | 198 | 237 | 217 | 173 | 139 | 152 | 191 |
| **System Load** | 2,058 | 1,819 | 1,676 | 1,636 | 1,848 | 2,204 | 2,599 | 2,399 | 1,949 | 1,608 | 1,747 | 2,149 |
| Light Load | 1,901 | 1,679 | 1,540 | 1,482 | 1,680 | 1,972 | 2,358 | 2,128 | 1,751 | 1,450 | 1,612 | 1,985 |
| Heavy Load | 2,194 | 1,924 | 1,774 | 1,760 | 1,981 | 2,373 | 2,806 | 2,594 | 2,108 | 1,733 | 1,855 | 2,290 |
| **Total Load** | 2,058 | 1,819 | 1,676 | 1,636 | 1,848 | 2,204 | 2,599 | 2,399 | 1,949 | 1,608 | 1,747 | 2,149 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,659 | 2,495 | 2,182 | 2,094 | 3,223 | 3,596 | 3,889 | 3,399 | 3,142 | 2,213 | 2,391 | 2,826 |
| **Total Peak Load** | 2,659 | 2,495 | 2,182 | 2,094 | 3,223 | 3,596 | 3,889 | 3,399 | 3,142 | 2,213 | 2,391 | 2,826 |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 875 | 714 | 617 | 540 | 499 | 542 | 694 | 665 | 529 | 508 | 645 | 917 |
| Commercial | 540 | 485 | 461 | 444 | 452 | 487 | 569 | 556 | 499 | 459 | 477 | 567 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 529 | 649 | 507 | 297 | 43 | 0 | 1 |
| Industrial | 326 | 317 | 323 | 310 | 312 | 332 | 332 | 336 | 333 | 338 | 337 | 338 |
| Additional Firm | 148 | 138 | 140 | 141 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 153 |
| Loss | 185 | 160 | 147 | 144 | 165 | 200 | 239 | 219 | 175 | 141 | 153 | 193 |
| **System Load** | 2,075 | 1,814 | 1,689 | 1,650 | 1,863 | 2,223 | 2,622 | 2,421 | 1,968 | 1,623 | 1,762 | 2,169 |
| Light Load | 1,917 | 1,674 | 1,552 | 1,495 | 1,694 | 1,989 | 2,379 | 2,148 | 1,768 | 1,464 | 1,626 | 2,004 |
| Heavy Load | 2,201 | 1,917 | 1,797 | 1,764 | 1,997 | 2,409 | 2,813 | 2,618 | 2,143 | 1,738 | 1,872 | 2,311 |
| **Total Load** | 2,075 | 1,814 | 1,689 | 1,650 | 1,863 | 2,223 | 2,622 | 2,421 | 1,968 | 1,623 | 1,762 | 2,169 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,668 | 2,502 | 2,186 | 2,096 | 3,263 | 3,630 | 3,939 | 3,433 | 3,176 | 2,228 | 2,399 | 2,840 |
| **Total Peak Load** | 2,668 | 2,502 | 2,186 | 2,096 | 3,263 | 3,630 | 3,939 | 3,433 | 3,176 | 2,228 | 2,399 | 2,840 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 881 | 716 | 620 | 544 | 503 | 548 | 703 | 673 | 534 | 511 | 650 | 927 |
| Commercial | 544 | 487 | 464 | 447 | 455 | 492 | 574 | 561 | 504 | 463 | 481 | 573 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 647 | 505 | 297 | 43 | 0 | 1 |
| Industrial | 330 | 333 | 327 | 314 | 317 | 337 | 337 | 341 | 338 | 343 | 342 | 343 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 140 | 135 | 136 | 150 | 153 |
| Loss | 186 | 162 | 148 | 145 | 166 | 201 | 240 | 221 | 176 | 142 | 155 | 195 |
| **System Load** | 2,091 | 1,841 | 1,701 | 1,663 | 1,876 | 2,238 | 2,640 | 2,439 | 1,984 | 1,637 | 1,777 | 2,193 |
| Light Load | 1,931 | 1,699 | 1,563 | 1,506 | 1,706 | 2,003 | 2,396 | 2,164 | 1,782 | 1,476 | 1,639 | 2,026 |
| Heavy Load | 2,217 | 1,948 | 1,810 | 1,777 | 2,011 | 2,426 | 2,833 | 2,656 | 2,145 | 1,753 | 1,898 | 2,324 |
| **Total Load** | 2,091 | 1,841 | 1,701 | 1,663 | 1,876 | 2,238 | 2,640 | 2,439 | 1,984 | 1,637 | 1,777 | 2,193 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,670 | 2,511 | 2,184 | 2,088 | 3,302 | 3,657 | 3,985 | 3,461 | 3,205 | 2,242 | 2,402 | 2,855 |
| **Total Peak Load** | 2,670 | 2,511 | 2,184 | 2,088 | 3,302 | 3,657 | 3,985 | 3,461 | 3,205 | 2,242 | 2,402 | 2,855 |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 890 | 721 | 625 | 550 | 509 | 557 | 715 | 684 | 542 | 517 | 657 | 940 |
| Commercial | 549 | 492 | 469 | 452 | 461 | 498 | 581 | 568 | 511 | 468 | 486 | 579 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 525 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 335 | 338 | 332 | 319 | 322 | 342 | 342 | 346 | 343 | 348 | 347 | 348 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 188 | 163 | 150 | 146 | 168 | 203 | 242 | 222 | 178 | 143 | 156 | 198 |
| **System Load** | 2,112 | 1,857 | 1,718 | 1,679 | 1,892 | 2,256 | 2,662 | 2,461 | 2,003 | 1,654 | 1,796 | 2,219 |
| Light Load | 1,951 | 1,714 | 1,578 | 1,521 | 1,720 | 2,019 | 2,415 | 2,183 | 1,799 | 1,492 | 1,657 | 2,050 |
| Heavy Load | 2,240 | 1,964 | 1,827 | 1,795 | 2,040 | 2,429 | 2,856 | 2,680 | 2,166 | 1,772 | 1,918 | 2,352 |
| **Total Load** | 2,112 | 1,857 | 1,718 | 1,679 | 1,892 | 2,256 | 2,662 | 2,461 | 2,003 | 1,654 | 1,796 | 2,219 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,691 | 2,525 | 2,199 | 2,102 | 3,343 | 3,688 | 4,034 | 3,494 | 3,240 | 2,259 | 2,421 | 2,879 |
| **Total Peak Load** | 2,691 | 2,525 | 2,199 | 2,102 | 3,343 | 3,688 | 4,034 | 3,494 | 3,240 | 2,259 | 2,421 | 2,879 |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 900 | 726 | 631 | 556 | 516 | 565 | 727 | 695 | 549 | 523 | 665 | 951 |
| Commercial | 555 | 496 | 475 | 457 | 466 | 505 | 588 | 575 | 518 | 474 | 492 | 586 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 525 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 340 | 343 | 337 | 323 | 327 | 347 | 347 | 351 | 348 | 353 | 352 | 353 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 190 | 165 | 151 | 148 | 169 | 205 | 245 | 225 | 180 | 145 | 158 | 200 |
| **System Load** | 2,135 | 1,873 | 1,735 | 1,697 | 1,911 | 2,279 | 2,690 | 2,488 | 2,025 | 1,673 | 1,816 | 2,243 |
| Light Load | 1,972 | 1,728 | 1,594 | 1,537 | 1,737 | 2,039 | 2,440 | 2,207 | 1,819 | 1,509 | 1,675 | 2,072 |
| Heavy Load | 2,275 | 1,981 | 1,837 | 1,814 | 2,060 | 2,454 | 2,886 | 2,709 | 2,190 | 1,803 | 1,928 | 2,378 |
| **Total Load** | 2,135 | 1,873 | 1,735 | 1,697 | 1,911 | 2,279 | 2,690 | 2,488 | 2,025 | 1,673 | 1,816 | 2,243 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,714 | 2,539 | 2,217 | 2,120 | 3,386 | 3,729 | 4,090 | 3,535 | 3,281 | 2,278 | 2,442 | 2,902 |
| **Total Peak Load** | 2,714 | 2,539 | 2,217 | 2,120 | 3,386 | 3,729 | 4,090 | 3,535 | 3,281 | 2,278 | 2,442 | 2,902 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 907 | 729 | 635 | 560 | 521 | 572 | 736 | 704 | 556 | 527 | 670 | 962 |
| Commercial | 560 | 500 | 479 | 462 | 471 | 510 | 594 | 581 | 525 | 479 | 496 | 593 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 527 | 645 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 345 | 335 | 342 | 328 | 331 | 352 | 352 | 356 | 353 | 358 | 357 | 358 |
| Additional Firm | 146 | 136 | 138 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 147 | 150 |
| Loss | 192 | 164 | 153 | 149 | 171 | 207 | 247 | 227 | 182 | 146 | 160 | 202 |
| **System Load** | 2,152 | 1,866 | 1,748 | 1,710 | 1,926 | 2,298 | 2,713 | 2,510 | 2,044 | 1,688 | 1,831 | 2,266 |
| Light Load | 1,987 | 1,722 | 1,606 | 1,549 | 1,751 | 2,057 | 2,462 | 2,227 | 1,836 | 1,522 | 1,689 | 2,094 |
| Heavy Load | 2,293 | 1,973 | 1,850 | 1,839 | 2,064 | 2,474 | 2,929 | 2,715 | 2,210 | 1,819 | 1,945 | 2,415 |
| **Total Load** | 2,152 | 1,866 | 1,748 | 1,710 | 1,926 | 2,298 | 2,713 | 2,510 | 2,044 | 1,688 | 1,831 | 2,266 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,721 | 2,548 | 2,220 | 2,120 | 3,427 | 3,763 | 4,141 | 3,570 | 3,316 | 2,293 | 2,449 | 2,918 |
| **Total Peak Load** | 2,721 | 2,548 | 2,220 | 2,120 | 3,427 | 3,763 | 4,141 | 3,570 | 3,316 | 2,293 | 2,449 | 2,918 |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 916 | 734 | 640 | 566 | 527 | 580 | 748 | 715 | 563 | 533 | 678 | 974 |
| Commercial | 567 | 505 | 484 | 467 | 476 | 517 | 602 | 589 | 532 | 486 | 502 | 600 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 525 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 350 | 352 | 347 | 333 | 336 | 357 | 357 | 361 | 358 | 363 | 362 | 363 |
| Additional Firm | 145 | 140 | 137 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 146 | 149 |
| Loss | 194 | 167 | 154 | 151 | 172 | 209 | 249 | 229 | 184 | 148 | 161 | 205 |
| **System Load** | 2,173 | 1,899 | 1,764 | 1,727 | 1,942 | 2,318 | 2,737 | 2,534 | 2,065 | 1,706 | 1,850 | 2,293 |
| Light Load | 2,007 | 1,753 | 1,621 | 1,564 | 1,766 | 2,074 | 2,483 | 2,248 | 1,855 | 1,538 | 1,706 | 2,119 |
| Heavy Load | 2,304 | 2,009 | 1,868 | 1,857 | 2,082 | 2,496 | 2,955 | 2,741 | 2,248 | 1,827 | 1,965 | 2,443 |
| **Total Load** | 2,173 | 1,899 | 1,764 | 1,727 | 1,942 | 2,318 | 2,737 | 2,534 | 2,065 | 1,706 | 1,850 | 2,293 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,740 | 2,560 | 2,234 | 2,132 | 3,468 | 3,798 | 4,192 | 3,606 | 3,353 | 2,311 | 2,466 | 2,942 |
| **Total Peak Load** | 2,740 | 2,560 | 2,234 | 2,132 | 3,468 | 3,798 | 4,192 | 3,606 | 3,353 | 2,311 | 2,466 | 2,942 |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 926 | 739 | 646 | 572 | 534 | 589 | 761 | 727 | 571 | 539 | 686 | 986 |
| Commercial | 573 | 510 | 490 | 473 | 483 | 525 | 610 | 597 | 540 | 492 | 508 | 608 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 525 | 644 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 355 | 357 | 352 | 337 | 341 | 362 | 362 | 366 | 363 | 368 | 367 | 368 |
| Additional Firm | 152 | 147 | 144 | 145 | 138 | 136 | 143 | 143 | 138 | 139 | 154 | 158 |
| Loss | 196 | 169 | 156 | 153 | 174 | 211 | 252 | 232 | 186 | 150 | 164 | 207 |
| **System Load** | 2,205 | 1,924 | 1,790 | 1,752 | 1,968 | 2,347 | 2,771 | 2,568 | 2,093 | 1,731 | 1,879 | 2,329 |
| Light Load | 2,036 | 1,775 | 1,645 | 1,587 | 1,789 | 2,101 | 2,515 | 2,278 | 1,881 | 1,562 | 1,733 | 2,152 |
| Heavy Load | 2,338 | 2,035 | 1,904 | 1,873 | 2,109 | 2,545 | 2,974 | 2,777 | 2,280 | 1,854 | 1,996 | 2,482 |
| **Total Load** | 2,205 | 1,924 | 1,790 | 1,752 | 1,968 | 2,347 | 2,771 | 2,568 | 2,093 | 1,731 | 1,879 | 2,329 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,776 | 2,586 | 2,262 | 2,159 | 3,519 | 3,847 | 4,256 | 3,656 | 3,402 | 2,338 | 2,498 | 2,979 |
| **Total Peak Load** | 2,776 | 2,586 | 2,262 | 2,159 | 3,519 | 3,847 | 4,256 | 3,656 | 3,402 | 2,338 | 2,498 | 2,979 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 934 | 743 | 651 | 578 | 539 | 597 | 772 | 737 | 578 | 544 | 692 | 997 |
| Commercial | 580 | 516 | 496 | 479 | 489 | 532 | 618 | 605 | 548 | 499 | 514 | 616 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 645 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 360 | 362 | 356 | 342 | 345 | 367 | 367 | 371 | 368 | 373 | 372 | 374 |
| Additional Firm | 151 | 146 | 143 | 144 | 138 | 135 | 143 | 143 | 138 | 139 | 153 | 156 |
| Loss | 198 | 170 | 157 | 154 | 176 | 213 | 255 | 235 | 188 | 152 | 165 | 210 |
| **System Load** | 2,226 | 1,938 | 1,806 | 1,769 | 1,987 | 2,370 | 2,799 | 2,595 | 2,116 | 1,749 | 1,897 | 2,355 |
| Light Load | 2,055 | 1,789 | 1,659 | 1,602 | 1,806 | 2,121 | 2,540 | 2,302 | 1,901 | 1,578 | 1,750 | 2,175 |
| Heavy Load | 2,349 | 2,050 | 1,921 | 1,891 | 2,117 | 2,570 | 2,987 | 2,825 | 2,273 | 1,873 | 2,015 | 2,484 |
| **Total Load** | 2,226 | 1,938 | 1,806 | 1,769 | 1,987 | 2,370 | 2,799 | 2,595 | 2,116 | 1,749 | 1,897 | 2,355 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,791 | 2,597 | 2,272 | 2,167 | 3,562 | 3,888 | 4,312 | 3,697 | 3,443 | 2,356 | 2,513 | 2,999 |
| **Total Peak Load** | 2,791 | 2,597 | 2,272 | 2,167 | 3,562 | 3,888 | 4,312 | 3,697 | 3,443 | 2,356 | 2,513 | 2,999 |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 942 | 746 | 655 | 583 | 545 | 605 | 782 | 747 | 585 | 549 | 698 | 1,008 |
| Commercial | 587 | 521 | 502 | 485 | 495 | 539 | 627 | 613 | 557 | 506 | 521 | 625 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 365 | 355 | 361 | 347 | 350 | 372 | 372 | 376 | 373 | 379 | 377 | 379 |
| Additional Firm | 151 | 140 | 142 | 144 | 137 | 135 | 142 | 142 | 137 | 138 | 152 | 156 |
| Loss | 200 | 170 | 159 | 156 | 177 | 215 | 257 | 237 | 190 | 153 | 167 | 212 |
| **System Load** | 2,246 | 1,933 | 1,822 | 1,786 | 2,004 | 2,391 | 2,825 | 2,619 | 2,137 | 1,767 | 1,916 | 2,380 |
| Light Load | 2,074 | 1,784 | 1,674 | 1,617 | 1,822 | 2,140 | 2,563 | 2,324 | 1,920 | 1,594 | 1,768 | 2,199 |
| Heavy Load | 2,370 | 2,055 | 1,928 | 1,909 | 2,147 | 2,575 | 3,014 | 2,852 | 2,296 | 1,904 | 2,025 | 2,511 |
| **Total Load** | 2,246 | 1,933 | 1,822 | 1,786 | 2,004 | 2,391 | 2,825 | 2,619 | 2,137 | 1,767 | 1,916 | 2,380 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,807 | 2,596 | 2,282 | 2,174 | 3,603 | 3,925 | 4,365 | 3,735 | 3,482 | 2,374 | 2,527 | 3,020 |
| **Total Peak Load** | 2,807 | 2,596 | 2,282 | 2,174 | 3,603 | 3,925 | 4,365 | 3,735 | 3,482 | 2,374 | 2,527 | 3,020 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,024,661 | 5,054,545 | 5,063,083 | 5,130,952 | 5,221,061 | 5,299,496 | 5,371,170 | 5,426,100 | 5,476,110 | 5,532,311 |
| Commercial | 3,900,064 | 3,960,646 | 3,996,617 | 4,043,282 | 4,082,719 | 4,117,425 | 4,158,116 | 4,202,778 | 4,244,120 | 4,288,491 |
| Irrigation | 1,751,463 | 1,762,474 | 1,768,998 | 1,750,913 | 1,749,671 | 1,756,095 | 1,760,483 | 1,765,522 | 1,768,531 | 1,765,357 |
| Industrial | 2,334,380 | 2,402,175 | 2,466,748 | 2,523,489 | 2,568,734 | 2,609,536 | 2,653,663 | 2,698,998 | 2,743,911 | 2,788,219 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,020,339 | 14,205,040 | 14,348,247 | 14,502,137 | 14,684,485 | 14,842,152 | 15,011,132 | 15,208,498 | 15,425,772 | 15,603,078 |
| **Total Sales** | 14,020,339 | 14,205,040 | 14,348,247 | 14,502,137 | 14,684,485 | 14,842,152 | 15,011,132 | 15,208,498 | 15,425,772 | 15,603,078 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,027,296 | 5,055,690 | 5,068,397 | 5,154,035 | 5,227,150 | 5,305,125 | 5,375,632 | 5,447,007 | 5,480,685 | 5,537,710 |
| Commercial | 3,903,440 | 3,962,715 | 3,999,260 | 4,056,500 | 4,084,729 | 4,119,758 | 4,160,664 | 4,216,430 | 4,246,659 | 4,291,303 |
| Irrigation | 1,751,467 | 1,762,477 | 1,768,991 | 1,750,951 | 1,749,674 | 1,756,097 | 1,760,485 | 1,765,562 | 1,768,530 | 1,765,357 |
| Industrial | 2,340,228 | 2,407,744 | 2,471,642 | 2,527,392 | 2,572,253 | 2,613,342 | 2,657,573 | 2,702,871 | 2,747,733 | 2,792,033 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,032,203 | 14,213,826 | 14,361,089 | 14,542,378 | 14,696,106 | 14,853,922 | 15,022,054 | 15,246,971 | 15,436,707 | 15,615,103 |
| **Total Sales** | 14,032,203 | 14,213,826 | 14,361,089 | 14,542,378 | 14,696,106 | 14,853,922 | 15,022,054 | 15,246,971 | 15,436,707 | 15,615,103 |
| Loss | 1,380,235 | 1,396,630 | 1,408,407 | 1,426,063 | 1,440,637 | 1,456,526 | 1,472,745 | 1,492,086 | 1,505,449 | 1,520,629 |
| **Required Generation** | 15,412,437 | 15,610,455 | 15,769,496 | 15,968,441 | 16,136,743 | 16,310,448 | 16,494,799 | 16,739,057 | 16,942,156 | 17,135,732 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 574 | 577 | 579 | 587 | 597 | 606 | 614 | 620 | 626 | 632 |
| Commercial | 446 | 452 | 457 | 462 | 466 | 470 | 475 | 480 | 485 | 490 |
| Irrigation | 200 | 201 | 202 | 199 | 200 | 200 | 201 | 201 | 202 | 202 |
| Industrial | 267 | 275 | 282 | 288 | 294 | 298 | 303 | 308 | 314 | 319 |
| Additional Firm | 115 | 117 | 120 | 120 | 121 | 121 | 122 | 127 | 136 | 140 |
| Loss | 158 | 159 | 161 | 162 | 164 | 166 | 168 | 170 | 172 | 174 |
| **System Load** | 1,759 | 1,782 | 1,800 | 1,818 | 1,842 | 1,862 | 1,883 | 1,906 | 1,934 | 1,956 |
| Light Load | 1,599 | 1,620 | 1,636 | 1,653 | 1,674 | 1,693 | 1,712 | 1,732 | 1,758 | 1,778 |
| Heavy Load | 1,885 | 1,909 | 1,928 | 1,947 | 1,974 | 1,995 | 2,017 | 2,041 | 2,072 | 2,096 |
| **Total Load** | 1,759 | 1,782 | 1,800 | 1,818 | 1,842 | 1,862 | 1,883 | 1,906 | 1,934 | 1,956 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,344 | 3,403 | 3,456 | 3,500 | 3,555 | 3,609 | 3,664 | 3,722 | 3,782 | 3,835 |
| **Total Peak Load** | 3,344 | 3,403 | 3,456 | 3,500 | 3,555 | 3,609 | 3,664 | 3,722 | 3,782 | 3,835 |

| | 2023 | 2024 | 2024 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,599,951 | 5,652,900 | 5,698,298 | 5,769,278 | 5,841,976 | 5,896,722 | 5,965,645 | 6,041,626 | 6,104,767 | 6,163,934 |
| Commercial | 4,337,889 | 4,377,042 | 4,412,765 | 4,464,888 | 4,517,788 | 4,562,924 | 4,618,921 | 4,680,777 | 4,740,317 | 4,802,348 |
| Irrigation | 1,764,576 | 1,768,216 | 1,763,156 | 1,752,206 | 1,754,887 | 1,758,862 | 1,752,877 | 1,753,702 | 1,757,850 | 1,755,683 |
| Industrial | 2,832,435 | 2,875,947 | 2,917,139 | 2,961,183 | 3,005,317 | 3,047,482 | 3,090,882 | 3,134,512 | 3,177,840 | 3,222,016 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 15,768,851 | 15,905,405 | 16,025,359 | 16,175,955 | 16,348,269 | 16,483,491 | 16,640,325 | 16,878,617 | 17,042,974 | 17,200,980 |
| **Total Sales** | 15,768,851 | 15,905,405 | 16,025,359 | 16,175,955 | 16,348,269 | 16,483,491 | 16,640,325 | 16,878,617 | 17,042,974 | 17,200,980 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,604,321 | 5,673,871 | 5,703,975 | 5,775,094 | 5,846,523 | 5,919,794 | 5,971,741 | 6,046,816 | 6,109,685 | 6,186,758 |
| Commercial | 4,340,155 | 4,390,757 | 4,415,734 | 4,467,902 | 4,520,389 | 4,578,115 | 4,622,430 | 4,684,166 | 4,743,845 | 4,818,548 |
| Irrigation | 1,764,577 | 1,768,253 | 1,763,152 | 1,752,207 | 1,754,889 | 1,758,898 | 1,752,877 | 1,753,704 | 1,757,849 | 1,755,721 |
| Industrial | 2,836,188 | 2,879,500 | 2,920,938 | 2,964,990 | 3,008,954 | 3,051,226 | 3,094,645 | 3,138,249 | 3,181,650 | 3,225,818 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 15,779,241 | 15,943,680 | 16,037,799 | 16,188,593 | 16,359,055 | 16,525,533 | 16,653,693 | 16,890,934 | 17,055,229 | 17,243,844 |
| **Total Sales** | 15,779,241 | 15,943,680 | 16,037,799 | 16,188,593 | 16,359,055 | 16,525,533 | 16,653,693 | 16,890,934 | 17,055,229 | 17,243,844 |
| Loss | 1,536,622 | 1,553,151 | 1,561,805 | 1,577,035 | 1,594,124 | 1,611,513 | 1,624,411 | 1,644,521 | 1,661,381 | 1,680,699 |
| **Required Generation** | 17,315,863 | 17,496,832 | 17,599,604 | 17,765,627 | 17,953,179 | 18,137,046 | 18,278,105 | 18,535,456 | 18,716,610 | 18,924,543 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 640 | 646 | 651 | 659 | 667 | 674 | 682 | 690 | 697 | 704 |
| Commercial | 495 | 500 | 504 | 510 | 516 | 521 | 528 | 535 | 542 | 549 |
| Irrigation | 201 | 201 | 201 | 200 | 200 | 200 | 200 | 200 | 201 | 200 |
| Industrial | 324 | 328 | 333 | 338 | 343 | 347 | 353 | 358 | 363 | 367 |
| Additional Firm | 141 | 140 | 141 | 140 | 140 | 139 | 138 | 145 | 144 | 143 |
| Loss | 175 | 177 | 178 | 180 | 182 | 183 | 185 | 188 | 190 | 191 |
| **System Load** | 1,977 | 1,992 | 2,009 | 2,028 | 2,049 | 2,065 | 2,087 | 2,116 | 2,137 | 2,154 |
| Light Load | 1,797 | 1,811 | 1,826 | 1,844 | 1,863 | 1,877 | 1,897 | 1,923 | 1,942 | 1,959 |
| Heavy Load | 2,119 | 2,134 | 2,153 | 2,172 | 2,196 | 2,213 | 2,236 | 2,267 | 2,283 | 2,301 |
| **Total Load** | 1,977 | 1,992 | 2,009 | 2,028 | 2,049 | 2,065 | 2,087 | 2,116 | 2,137 | 2,154 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,889 | 3,939 | 3,985 | 4,034 | 4,090 | 4,141 | 4,192 | 4,256 | 4,312 | 4,365 |
| **Total Peak Load** | 3,889 | 3,939 | 3,985 | 4,034 | 4,090 | 4,141 | 4,192 | 4,256 | 4,312 | 4,365 |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 816 | 698 | 581 | 494 | 457 | 491 | 612 | 579 | 471 | 468 | 592 | 820 |
| Commercial | 496 | 453 | 419 | 402 | 410 | 436 | 510 | 495 | 439 | 409 | 432 | 510 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 264 | 266 | 262 | 251 | 254 | 270 | 269 | 273 | 270 | 274 | 273 | 278 |
| Additional Firm | 118 | 116 | 113 | 115 | 110 | 112 | 116 | 116 | 112 | 112 | 120 | 122 |
| Loss | 168 | 150 | 133 | 131 | 156 | 188 | 219 | 199 | 158 | 126 | 137 | 171 |
| **System Load** | 1,864 | 1,684 | 1,511 | 1,484 | 1,740 | 2,067 | 2,390 | 2,178 | 1,762 | 1,437 | 1,555 | 1,902 |
| Light Load | 1,722 | 1,554 | 1,388 | 1,344 | 1,582 | 1,850 | 2,168 | 1,933 | 1,583 | 1,296 | 1,435 | 1,757 |
| Heavy Load | 1,977 | 1,782 | 1,607 | 1,586 | 1,865 | 2,241 | 2,564 | 2,356 | 1,919 | 1,539 | 1,652 | 2,027 |
| **Total Load** | 1,864 | 1,684 | 1,511 | 1,484 | 1,740 | 2,067 | 2,390 | 2,178 | 1,762 | 1,437 | 1,555 | 1,902 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,505 | 2,384 | 2,092 | 1,971 | 2,805 | 3,264 | 3,382 | 3,027 | 2,778 | 2,026 | 2,267 | 2,683 |
| **Total Peak Load** | 2,505 | 2,384 | 2,092 | 1,971 | 2,805 | 3,264 | 3,382 | 3,027 | 2,778 | 2,026 | 2,267 | 2,683 |

| Monthly Summary[1] | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 820 | 699 | 583 | 496 | 460 | 496 | 618 | 585 | 474 | 470 | 595 | 823 |
| Commercial | 503 | 459 | 425 | 408 | 416 | 444 | 518 | 503 | 447 | 416 | 438 | 517 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 574 | 667 | 520 | 314 | 48 | 0 | 1 |
| Industrial | 272 | 274 | 269 | 259 | 261 | 277 | 277 | 281 | 278 | 282 | 281 | 286 |
| Additional Firm | 121 | 117 | 115 | 117 | 113 | 110 | 118 | 118 | 114 | 114 | 122 | 124 |
| Loss | 170 | 152 | 135 | 133 | 158 | 190 | 222 | 201 | 160 | 127 | 139 | 172 |
| **System Load** | 1,887 | 1,702 | 1,530 | 1,503 | 1,763 | 2,090 | 2,421 | 2,208 | 1,788 | 1,457 | 1,576 | 1,923 |
| Light Load | 1,743 | 1,570 | 1,406 | 1,362 | 1,603 | 1,871 | 2,197 | 1,959 | 1,606 | 1,314 | 1,454 | 1,777 |
| Heavy Load | 2,001 | 1,800 | 1,627 | 1,607 | 1,889 | 2,266 | 2,598 | 2,404 | 1,933 | 1,561 | 1,683 | 2,039 |
| **Total Load** | 1,887 | 1,702 | 1,530 | 1,503 | 1,763 | 2,090 | 2,421 | 2,208 | 1,788 | 1,457 | 1,576 | 1,923 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,534 | 2,403 | 2,115 | 1,996 | 2,852 | 3,310 | 3,442 | 3,071 | 2,822 | 2,047 | 2,289 | 2,704 |
| **Total Peak Load** | 2,534 | 2,403 | 2,115 | 1,996 | 2,852 | 3,310 | 3,442 | 3,071 | 2,822 | 2,047 | 2,289 | 2,704 |

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 820 | 696 | 582 | 496 | 462 | 499 | 622 | 588 | 476 | 470 | 596 | 831 |
| Commercial | 507 | 462 | 428 | 412 | 420 | 448 | 524 | 508 | 452 | 420 | 442 | 522 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 576 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 279 | 281 | 277 | 265 | 268 | 285 | 285 | 288 | 286 | 290 | 289 | 293 |
| Additional Firm | 124 | 121 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 171 | 152 | 136 | 134 | 160 | 192 | 224 | 203 | 162 | 129 | 140 | 175 |
| **System Load** | 1,903 | 1,714 | 1,544 | 1,519 | 1,780 | 2,112 | 2,445 | 2,231 | 1,807 | 1,473 | 1,593 | 1,949 |
| Light Load | 1,758 | 1,582 | 1,418 | 1,376 | 1,619 | 1,890 | 2,219 | 1,979 | 1,624 | 1,329 | 1,470 | 1,800 |
| Heavy Load | 2,018 | 1,813 | 1,642 | 1,623 | 1,920 | 2,274 | 2,624 | 2,429 | 1,954 | 1,578 | 1,701 | 2,066 |
| **Total Load** | 1,903 | 1,714 | 1,544 | 1,519 | 1,780 | 2,112 | 2,445 | 2,231 | 1,807 | 1,473 | 1,593 | 1,949 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,530 | 2,413 | 2,108 | 1,980 | 2,898 | 3,345 | 3,495 | 3,106 | 2,856 | 2,065 | 2,289 | 2,718 |
| **Total Peak Load** | 2,530 | 2,413 | 2,108 | 1,980 | 2,898 | 3,345 | 3,495 | 3,106 | 2,856 | 2,065 | 2,289 | 2,718 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 702 | 588 | 502 | 468 | 507 | 634 | 599 | 483 | 476 | 603 | 845 |
| Commercial | 512 | 466 | 433 | 416 | 425 | 454 | 530 | 514 | 458 | 425 | 447 | 528 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 286 | 278 | 283 | 272 | 274 | 291 | 291 | 295 | 292 | 296 | 296 | 298 |
| Additional Firm | 124 | 117 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 173 | 153 | 137 | 135 | 161 | 193 | 226 | 205 | 163 | 130 | 142 | 177 |
| **System Load** | 1,927 | 1,717 | 1,562 | 1,536 | 1,797 | 2,129 | 2,465 | 2,251 | 1,826 | 1,492 | 1,614 | 1,976 |
| Light Load | 1,779 | 1,585 | 1,436 | 1,391 | 1,633 | 1,905 | 2,236 | 1,997 | 1,640 | 1,346 | 1,489 | 1,826 |
| Heavy Load | 2,053 | 1,815 | 1,654 | 1,642 | 1,937 | 2,292 | 2,661 | 2,434 | 1,974 | 1,608 | 1,714 | 2,095 |
| **Total Load** | 1,927 | 1,717 | 1,562 | 1,536 | 1,797 | 2,129 | 2,465 | 2,251 | 1,826 | 1,492 | 1,614 | 1,976 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,546 | 2,426 | 2,118 | 1,986 | 2,937 | 3,371 | 3,541 | 3,134 | 2,888 | 2,083 | 2,303 | 2,738 |
| **Total Peak Load** | 2,546 | 2,426 | 2,118 | 1,986 | 2,937 | 3,371 | 3,541 | 3,134 | 2,888 | 2,083 | 2,303 | 2,738 |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 842 | 711 | 597 | 511 | 477 | 518 | 648 | 612 | 492 | 484 | 613 | 859 |
| Commercial | 517 | 470 | 437 | 420 | 429 | 459 | 535 | 520 | 463 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 662 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 291 | 293 | 288 | 276 | 279 | 297 | 296 | 300 | 298 | 302 | 301 | 303 |
| Additional Firm | 125 | 122 | 120 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 129 |
| Loss | 175 | 156 | 139 | 137 | 163 | 195 | 228 | 207 | 165 | 132 | 144 | 180 |
| **System Load** | 1,952 | 1,752 | 1,582 | 1,556 | 1,817 | 2,152 | 2,493 | 2,278 | 1,849 | 1,513 | 1,636 | 2,004 |
| Light Load | 1,803 | 1,617 | 1,454 | 1,409 | 1,652 | 1,926 | 2,262 | 2,021 | 1,661 | 1,364 | 1,509 | 1,851 |
| Heavy Load | 2,081 | 1,854 | 1,675 | 1,673 | 1,947 | 2,318 | 2,691 | 2,463 | 1,999 | 1,630 | 1,738 | 2,135 |
| **Total Load** | 1,952 | 1,752 | 1,582 | 1,556 | 1,817 | 2,152 | 2,493 | 2,278 | 1,849 | 1,513 | 1,636 | 2,004 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,574 | 2,445 | 2,139 | 2,007 | 2,982 | 3,410 | 3,596 | 3,174 | 2,929 | 2,103 | 2,328 | 2,765 |
| **Total Peak Load** | 2,574 | 2,445 | 2,139 | 2,007 | 2,982 | 3,410 | 3,596 | 3,174 | 2,929 | 2,103 | 2,328 | 2,765 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 853 | 718 | 604 | 518 | 484 | 527 | 661 | 624 | 501 | 490 | 621 | 872 |
| Commercial | 521 | 472 | 440 | 424 | 433 | 463 | 540 | 525 | 468 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 572 | 665 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 177 | 157 | 141 | 138 | 164 | 197 | 231 | 209 | 167 | 134 | 145 | 182 |
| **System Load** | 1,974 | 1,768 | 1,599 | 1,572 | 1,835 | 2,175 | 2,520 | 2,303 | 1,869 | 1,529 | 1,654 | 2,029 |
| Light Load | 1,823 | 1,631 | 1,469 | 1,424 | 1,668 | 1,946 | 2,286 | 2,043 | 1,679 | 1,379 | 1,526 | 1,874 |
| Heavy Load | 2,093 | 1,870 | 1,692 | 1,691 | 1,966 | 2,342 | 2,720 | 2,491 | 2,036 | 1,638 | 1,757 | 2,162 |
| **Total Load** | 1,974 | 1,768 | 1,599 | 1,572 | 1,835 | 2,175 | 2,520 | 2,303 | 1,869 | 1,529 | 1,654 | 2,029 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,595 | 2,459 | 2,156 | 2,023 | 3,025 | 3,448 | 3,651 | 3,212 | 2,966 | 2,120 | 2,347 | 2,789 |
| **Total Peak Load** | 2,595 | 2,459 | 2,156 | 2,023 | 3,025 | 3,448 | 3,651 | 3,212 | 2,966 | 2,120 | 2,347 | 2,789 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 863 | 724 | 610 | 524 | 491 | 536 | 673 | 635 | 508 | 496 | 629 | 882 |
| Commercial | 525 | 476 | 444 | 428 | 437 | 469 | 546 | 530 | 474 | 438 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 573 | 666 | 520 | 314 | 47 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 179 | 158 | 142 | 140 | 166 | 199 | 233 | 212 | 169 | 135 | 147 | 184 |
| **System Load** | 1,996 | 1,785 | 1,616 | 1,590 | 1,854 | 2,198 | 2,547 | 2,330 | 1,891 | 1,548 | 1,674 | 2,054 |
| Light Load | 1,844 | 1,647 | 1,485 | 1,440 | 1,686 | 1,967 | 2,311 | 2,067 | 1,699 | 1,396 | 1,544 | 1,897 |
| Heavy Load | 2,117 | 1,888 | 1,719 | 1,699 | 1,987 | 2,383 | 2,734 | 2,519 | 2,060 | 1,657 | 1,778 | 2,188 |
| **Total Load** | 1,996 | 1,785 | 1,616 | 1,590 | 1,854 | 2,198 | 2,547 | 2,330 | 1,891 | 1,548 | 1,674 | 2,054 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,620 | 2,474 | 2,175 | 2,042 | 3,068 | 3,487 | 3,707 | 3,251 | 3,005 | 2,139 | 2,368 | 2,814 |
| **Total Peak Load** | 2,620 | 2,474 | 2,175 | 2,042 | 3,068 | 3,487 | 3,707 | 3,251 | 3,005 | 2,139 | 2,368 | 2,814 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 870 | 727 | 614 | 529 | 496 | 544 | 683 | 644 | 514 | 501 | 635 | 891 |
| Commercial | 531 | 480 | 449 | 432 | 442 | 474 | 552 | 537 | 480 | 443 | 464 | 550 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 181 | 159 | 144 | 141 | 168 | 202 | 236 | 214 | 171 | 137 | 149 | 186 |
| **System Load** | 2,022 | 1,789 | 1,637 | 1,611 | 1,877 | 2,225 | 2,578 | 2,359 | 1,916 | 1,569 | 1,698 | 2,083 |
| Light Load | 1,868 | 1,651 | 1,504 | 1,459 | 1,706 | 1,991 | 2,339 | 2,093 | 1,721 | 1,415 | 1,566 | 1,924 |
| Heavy Load | 2,144 | 1,891 | 1,741 | 1,722 | 2,023 | 2,396 | 2,766 | 2,568 | 2,072 | 1,680 | 1,813 | 2,208 |
| **Total Load** | 2,022 | 1,789 | 1,637 | 1,611 | 1,877 | 2,225 | 2,578 | 2,359 | 1,916 | 1,569 | 1,698 | 2,083 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,648 | 2,493 | 2,197 | 2,063 | 3,117 | 3,529 | 3,766 | 3,293 | 3,046 | 2,161 | 2,394 | 2,843 |
| **Total Peak Load** | 2,648 | 2,493 | 2,197 | 2,063 | 3,117 | 3,529 | 3,766 | 3,293 | 3,046 | 2,161 | 2,394 | 2,843 |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 877 | 730 | 617 | 533 | 501 | 550 | 692 | 653 | 520 | 505 | 640 | 901 |
| Commercial | 535 | 484 | 453 | 436 | 446 | 479 | 558 | 542 | 485 | 448 | 468 | 555 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 311 | 313 | 308 | 295 | 298 | 317 | 317 | 320 | 318 | 322 | 321 | 323 |
| Additional Firm | 143 | 138 | 135 | 136 | 130 | 127 | 135 | 135 | 130 | 131 | 144 | 148 |
| Loss | 183 | 161 | 145 | 143 | 170 | 204 | 238 | 216 | 173 | 138 | 150 | 189 |
| **System Load** | 2,051 | 1,828 | 1,660 | 1,635 | 1,901 | 2,253 | 2,609 | 2,389 | 1,942 | 1,592 | 1,725 | 2,117 |
| Light Load | 1,894 | 1,687 | 1,526 | 1,481 | 1,728 | 2,017 | 2,368 | 2,120 | 1,744 | 1,436 | 1,591 | 1,956 |
| Heavy Load | 2,186 | 1,933 | 1,758 | 1,748 | 2,050 | 2,426 | 2,800 | 2,601 | 2,100 | 1,716 | 1,832 | 2,244 |
| **Total Load** | 2,051 | 1,828 | 1,660 | 1,635 | 1,901 | 2,253 | 2,609 | 2,389 | 1,942 | 1,592 | 1,725 | 2,117 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,674 | 2,519 | 2,216 | 2,079 | 3,168 | 3,572 | 3,827 | 3,337 | 3,088 | 2,186 | 2,418 | 2,874 |
| **Total Peak Load** | 2,674 | 2,519 | 2,216 | 2,079 | 3,168 | 3,572 | 3,827 | 3,337 | 3,088 | 2,186 | 2,418 | 2,874 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 884 | 734 | 622 | 537 | 507 | 558 | 702 | 662 | 526 | 509 | 646 | 912 |
| Commercial | 540 | 488 | 457 | 440 | 451 | 485 | 564 | 548 | 492 | 453 | 473 | 562 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 316 | 318 | 313 | 300 | 303 | 322 | 322 | 326 | 323 | 328 | 327 | 328 |
| Additional Firm | 148 | 142 | 139 | 141 | 134 | 131 | 138 | 139 | 134 | 135 | 149 | 153 |
| Loss | 185 | 163 | 147 | 145 | 171 | 205 | 240 | 219 | 175 | 140 | 152 | 191 |
| **System Load** | 2,075 | 1,846 | 1,680 | 1,654 | 1,921 | 2,276 | 2,635 | 2,414 | 1,964 | 1,612 | 1,747 | 2,147 |
| Light Load | 1,917 | 1,703 | 1,543 | 1,498 | 1,746 | 2,037 | 2,391 | 2,142 | 1,764 | 1,454 | 1,611 | 1,984 |
| Heavy Load | 2,212 | 1,953 | 1,778 | 1,768 | 2,071 | 2,451 | 2,845 | 2,611 | 2,123 | 1,737 | 1,855 | 2,276 |
| **Total Load** | 2,075 | 1,846 | 1,680 | 1,654 | 1,921 | 2,276 | 2,635 | 2,414 | 1,964 | 1,612 | 1,747 | 2,147 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,696 | 2,537 | 2,232 | 2,092 | 3,213 | 3,608 | 3,881 | 3,374 | 3,126 | 2,207 | 2,438 | 2,901 |
| **Total Peak Load** | 2,696 | 2,537 | 2,232 | 2,092 | 3,213 | 3,608 | 3,881 | 3,374 | 3,126 | 2,207 | 2,438 | 2,901 |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 893 | 739 | 627 | 543 | 513 | 566 | 714 | 673 | 533 | 515 | 653 | 922 |
| Commercial | 546 | 492 | 462 | 445 | 456 | 491 | 571 | 555 | 498 | 458 | 478 | 568 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 574 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 321 | 323 | 318 | 305 | 308 | 327 | 327 | 331 | 328 | 333 | 332 | 333 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 139 | 134 | 136 | 150 | 153 |
| Loss | 187 | 164 | 148 | 146 | 173 | 207 | 243 | 221 | 177 | 141 | 154 | 193 |
| **System Load** | 2,097 | 1,862 | 1,697 | 1,672 | 1,940 | 2,298 | 2,662 | 2,440 | 1,985 | 1,630 | 1,766 | 2,171 |
| Light Load | 1,937 | 1,719 | 1,559 | 1,514 | 1,763 | 2,057 | 2,415 | 2,165 | 1,783 | 1,470 | 1,630 | 2,006 |
| Heavy Load | 2,235 | 1,970 | 1,796 | 1,798 | 2,078 | 2,475 | 2,874 | 2,638 | 2,147 | 1,757 | 1,876 | 2,313 |
| **Total Load** | 2,097 | 1,862 | 1,697 | 1,672 | 1,940 | 2,298 | 2,662 | 2,440 | 1,985 | 1,630 | 1,766 | 2,171 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,719 | 2,551 | 2,249 | 2,109 | 3,257 | 3,645 | 3,935 | 3,412 | 3,164 | 2,225 | 2,458 | 2,924 |
| **Total Peak Load** | 2,719 | 2,551 | 2,249 | 2,109 | 3,257 | 3,645 | 3,935 | 3,412 | 3,164 | 2,225 | 2,458 | 2,924 |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 900 | 742 | 631 | 548 | 519 | 574 | 724 | 682 | 539 | 519 | 658 | 931 |
| Commercial | 551 | 495 | 466 | 449 | 460 | 496 | 576 | 561 | 504 | 463 | 482 | 573 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 326 | 317 | 323 | 310 | 312 | 332 | 332 | 336 | 333 | 338 | 337 | 338 |
| Additional Firm | 148 | 138 | 140 | 141 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 153 |
| Loss | 188 | 164 | 149 | 147 | 174 | 209 | 245 | 223 | 178 | 143 | 155 | 195 |
| **System Load** | 2,115 | 1,857 | 1,710 | 1,686 | 1,955 | 2,318 | 2,685 | 2,462 | 2,004 | 1,645 | 1,782 | 2,191 |
| Light Load | 1,953 | 1,714 | 1,572 | 1,527 | 1,778 | 2,075 | 2,437 | 2,185 | 1,800 | 1,484 | 1,644 | 2,024 |
| Heavy Load | 2,242 | 1,963 | 1,820 | 1,802 | 2,095 | 2,513 | 2,882 | 2,663 | 2,182 | 1,762 | 1,893 | 2,334 |
| **Total Load** | 2,115 | 1,857 | 1,710 | 1,686 | 1,955 | 2,318 | 2,685 | 2,462 | 2,004 | 1,645 | 1,782 | 2,191 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,728 | 2,558 | 2,254 | 2,111 | 3,298 | 3,679 | 3,987 | 3,445 | 3,198 | 2,240 | 2,467 | 2,938 |
| **Total Peak Load** | 2,728 | 2,558 | 2,254 | 2,111 | 3,298 | 3,679 | 3,987 | 3,445 | 3,198 | 2,240 | 2,467 | 2,938 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 905 | 744 | 634 | 551 | 523 | 580 | 733 | 690 | 545 | 522 | 663 | 941 |
| Commercial | 554 | 498 | 469 | 453 | 464 | 501 | 581 | 566 | 509 | 467 | 485 | 579 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 574 | 667 | 520 | 314 | 48 | 0 | 1 |
| Industrial | 330 | 333 | 327 | 314 | 317 | 337 | 337 | 341 | 338 | 343 | 342 | 343 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 140 | 135 | 136 | 150 | 153 |
| Loss | 190 | 166 | 150 | 148 | 175 | 211 | 247 | 225 | 180 | 144 | 157 | 197 |
| **System Load** | 2,130 | 1,885 | 1,723 | 1,699 | 1,969 | 2,334 | 2,705 | 2,481 | 2,020 | 1,659 | 1,796 | 2,215 |
| Light Load | 1,967 | 1,739 | 1,583 | 1,538 | 1,790 | 2,089 | 2,454 | 2,201 | 1,815 | 1,496 | 1,657 | 2,046 |
| Heavy Load | 2,259 | 1,994 | 1,833 | 1,816 | 2,110 | 2,530 | 2,902 | 2,702 | 2,184 | 1,777 | 1,918 | 2,348 |
| **Total Load** | 2,130 | 1,885 | 1,723 | 1,699 | 1,969 | 2,334 | 2,705 | 2,481 | 2,020 | 1,659 | 1,796 | 2,215 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,730 | 2,568 | 2,252 | 2,103 | 3,337 | 3,705 | 4,033 | 3,473 | 3,226 | 2,254 | 2,470 | 2,952 |
| **Total Peak Load** | 2,730 | 2,568 | 2,252 | 2,103 | 3,337 | 3,705 | 4,033 | 3,473 | 3,226 | 2,254 | 2,470 | 2,952 |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 915 | 749 | 640 | 557 | 530 | 589 | 745 | 702 | 552 | 528 | 670 | 954 |
| Commercial | 560 | 503 | 474 | 458 | 470 | 507 | 589 | 573 | 516 | 473 | 491 | 586 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 335 | 338 | 332 | 319 | 322 | 342 | 342 | 346 | 343 | 348 | 347 | 348 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 192 | 167 | 152 | 150 | 177 | 212 | 249 | 227 | 181 | 146 | 158 | 200 |
| **System Load** | 2,152 | 1,900 | 1,739 | 1,715 | 1,985 | 2,353 | 2,727 | 2,503 | 2,039 | 1,677 | 1,815 | 2,241 |
| Light Load | 1,987 | 1,754 | 1,598 | 1,553 | 1,804 | 2,105 | 2,474 | 2,221 | 1,832 | 1,512 | 1,675 | 2,070 |
| Heavy Load | 2,282 | 2,010 | 1,850 | 1,833 | 2,140 | 2,533 | 2,926 | 2,726 | 2,205 | 1,795 | 1,939 | 2,375 |
| **Total Load** | 2,152 | 1,900 | 1,739 | 1,715 | 1,985 | 2,353 | 2,727 | 2,503 | 2,039 | 1,677 | 1,815 | 2,241 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,751 | 2,581 | 2,267 | 2,117 | 3,379 | 3,737 | 4,083 | 3,506 | 3,262 | 2,272 | 2,489 | 2,977 |
| **Total Peak Load** | 2,751 | 2,581 | 2,267 | 2,117 | 3,379 | 3,737 | 4,083 | 3,506 | 3,262 | 2,272 | 2,489 | 2,977 |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 924 | 754 | 645 | 564 | 537 | 598 | 758 | 713 | 560 | 534 | 678 | 964 |
| Commercial | 567 | 508 | 480 | 463 | 475 | 514 | 596 | 580 | 523 | 479 | 496 | 592 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 340 | 343 | 337 | 323 | 327 | 347 | 347 | 351 | 348 | 353 | 352 | 353 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 194 | 169 | 153 | 152 | 178 | 215 | 251 | 229 | 183 | 147 | 160 | 202 |
| **System Load** | 2,174 | 1,916 | 1,757 | 1,733 | 2,004 | 2,377 | 2,755 | 2,530 | 2,062 | 1,695 | 1,835 | 2,265 |
| Light Load | 2,008 | 1,768 | 1,614 | 1,570 | 1,822 | 2,127 | 2,500 | 2,245 | 1,852 | 1,529 | 1,693 | 2,092 |
| Heavy Load | 2,317 | 2,027 | 1,859 | 1,852 | 2,161 | 2,559 | 2,957 | 2,755 | 2,230 | 1,827 | 1,949 | 2,401 |
| **Total Load** | 2,174 | 1,916 | 1,757 | 1,733 | 2,004 | 2,377 | 2,755 | 2,530 | 2,062 | 1,695 | 1,835 | 2,265 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,774 | 2,596 | 2,285 | 2,135 | 3,422 | 3,777 | 4,139 | 3,547 | 3,303 | 2,291 | 2,509 | 3,000 |
| **Total Peak Load** | 2,774 | 2,596 | 2,285 | 2,135 | 3,422 | 3,777 | 4,139 | 3,547 | 3,303 | 2,291 | 2,509 | 3,000 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 931 | 757 | 649 | 568 | 542 | 606 | 768 | 723 | 566 | 538 | 683 | 975 |
| Commercial | 572 | 512 | 484 | 467 | 480 | 519 | 602 | 586 | 529 | 484 | 501 | 599 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 573 | 666 | 519 | 314 | 47 | 0 | 1 |
| Industrial | 345 | 335 | 342 | 328 | 331 | 352 | 352 | 356 | 353 | 358 | 357 | 358 |
| Additional Firm | 146 | 136 | 138 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 147 | 150 |
| Loss | 195 | 169 | 155 | 153 | 180 | 216 | 254 | 231 | 185 | 149 | 161 | 204 |
| **System Load** | 2,191 | 1,910 | 1,769 | 1,747 | 2,020 | 2,397 | 2,780 | 2,553 | 2,081 | 1,710 | 1,850 | 2,288 |
| Light Load | 2,024 | 1,762 | 1,626 | 1,582 | 1,837 | 2,145 | 2,522 | 2,265 | 1,869 | 1,542 | 1,707 | 2,114 |
| Heavy Load | 2,335 | 2,019 | 1,873 | 1,878 | 2,165 | 2,581 | 3,001 | 2,761 | 2,250 | 1,842 | 1,965 | 2,438 |
| **Total Load** | 2,191 | 1,910 | 1,769 | 1,747 | 2,020 | 2,397 | 2,780 | 2,553 | 2,081 | 1,710 | 1,850 | 2,288 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,781 | 2,605 | 2,288 | 2,135 | 3,463 | 3,812 | 4,191 | 3,582 | 3,337 | 2,306 | 2,517 | 3,016 |
| **Total Peak Load** | 2,781 | 2,605 | 2,288 | 2,135 | 3,463 | 3,812 | 4,191 | 3,582 | 3,337 | 2,306 | 2,517 | 3,016 |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 940 | 761 | 654 | 574 | 549 | 615 | 781 | 734 | 574 | 543 | 690 | 988 |
| Commercial | 578 | 517 | 489 | 473 | 486 | 526 | 610 | 594 | 537 | 490 | 507 | 607 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 517 | 313 | 47 | 0 | 1 |
| Industrial | 350 | 352 | 347 | 333 | 336 | 357 | 357 | 361 | 358 | 363 | 362 | 363 |
| Additional Firm | 145 | 140 | 137 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 146 | 149 |
| Loss | 197 | 171 | 156 | 154 | 182 | 218 | 256 | 234 | 187 | 150 | 163 | 207 |
| **System Load** | 2,212 | 1,943 | 1,786 | 1,763 | 2,037 | 2,417 | 2,804 | 2,578 | 2,101 | 1,728 | 1,869 | 2,315 |
| Light Load | 2,043 | 1,793 | 1,641 | 1,597 | 1,852 | 2,163 | 2,545 | 2,287 | 1,888 | 1,558 | 1,724 | 2,139 |
| Heavy Load | 2,346 | 2,055 | 1,890 | 1,896 | 2,183 | 2,603 | 3,028 | 2,788 | 2,288 | 1,850 | 1,985 | 2,467 |
| **Total Load** | 2,212 | 1,943 | 1,786 | 1,763 | 2,037 | 2,417 | 2,804 | 2,578 | 2,101 | 1,728 | 1,869 | 2,315 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,800 | 2,616 | 2,301 | 2,147 | 3,505 | 3,847 | 4,244 | 3,619 | 3,375 | 2,324 | 2,534 | 3,040 |
| **Total Peak Load** | 2,800 | 2,616 | 2,301 | 2,147 | 3,505 | 3,847 | 4,244 | 3,619 | 3,375 | 2,324 | 2,534 | 3,040 |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 950 | 766 | 660 | 581 | 556 | 625 | 794 | 746 | 582 | 550 | 698 | 1,000 |
| Commercial | 585 | 522 | 496 | 479 | 492 | 534 | 618 | 602 | 545 | 497 | 513 | 615 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 355 | 357 | 352 | 337 | 341 | 362 | 362 | 366 | 363 | 368 | 367 | 368 |
| Additional Firm | 152 | 147 | 144 | 145 | 138 | 136 | 143 | 143 | 138 | 139 | 154 | 158 |
| Loss | 200 | 173 | 158 | 156 | 184 | 221 | 259 | 236 | 189 | 152 | 165 | 210 |
| **System Load** | 2,245 | 1,967 | 1,811 | 1,789 | 2,064 | 2,448 | 2,840 | 2,612 | 2,130 | 1,754 | 1,898 | 2,352 |
| Light Load | 2,073 | 1,815 | 1,664 | 1,620 | 1,876 | 2,191 | 2,577 | 2,317 | 1,914 | 1,581 | 1,751 | 2,172 |
| Heavy Load | 2,380 | 2,081 | 1,927 | 1,912 | 2,212 | 2,654 | 3,047 | 2,824 | 2,320 | 1,878 | 2,016 | 2,506 |
| **Total Load** | 2,245 | 1,967 | 1,811 | 1,789 | 2,064 | 2,448 | 2,840 | 2,612 | 2,130 | 1,754 | 1,898 | 2,352 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,836 | 2,642 | 2,329 | 2,174 | 3,556 | 3,895 | 4,308 | 3,668 | 3,424 | 2,351 | 2,566 | 3,077 |
| **Total Peak Load** | 2,836 | 2,642 | 2,329 | 2,174 | 3,556 | 3,895 | 4,308 | 3,668 | 3,424 | 2,351 | 2,566 | 3,077 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 958 | 770 | 665 | 586 | 562 | 633 | 805 | 757 | 589 | 554 | 705 | 1,011 |
| Commercial | 592 | 527 | 501 | 485 | 499 | 541 | 627 | 610 | 553 | 504 | 519 | 623 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 572 | 665 | 519 | 313 | 47 | 0 | 1 |
| Industrial | 360 | 362 | 356 | 342 | 345 | 367 | 367 | 371 | 368 | 373 | 372 | 374 |
| Additional Firm | 151 | 146 | 143 | 144 | 138 | 135 | 143 | 143 | 138 | 139 | 153 | 156 |
| Loss | 202 | 174 | 160 | 158 | 185 | 223 | 262 | 239 | 192 | 154 | 167 | 212 |
| **System Load** | 2,265 | 1,981 | 1,827 | 1,806 | 2,083 | 2,472 | 2,868 | 2,639 | 2,153 | 1,771 | 1,917 | 2,377 |
| Light Load | 2,092 | 1,828 | 1,679 | 1,636 | 1,893 | 2,212 | 2,603 | 2,341 | 1,934 | 1,598 | 1,768 | 2,196 |
| Heavy Load | 2,390 | 2,096 | 1,944 | 1,930 | 2,219 | 2,679 | 3,060 | 2,874 | 2,313 | 1,897 | 2,036 | 2,507 |
| **Total Load** | 2,265 | 1,981 | 1,827 | 1,806 | 2,083 | 2,472 | 2,868 | 2,639 | 2,153 | 1,771 | 1,917 | 2,377 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,851 | 2,654 | 2,339 | 2,181 | 3,599 | 3,936 | 4,365 | 3,710 | 3,465 | 2,369 | 2,580 | 3,097 |
| **Total Peak Load** | 2,851 | 2,654 | 2,339 | 2,181 | 3,599 | 3,936 | 4,365 | 3,710 | 3,465 | 2,369 | 2,580 | 3,097 |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 965 | 773 | 669 | 591 | 568 | 641 | 817 | 767 | 596 | 559 | 710 | 1,021 |
| Commercial | 599 | 533 | 508 | 491 | 505 | 549 | 635 | 619 | 561 | 510 | 526 | 632 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 572 | 665 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 365 | 355 | 361 | 347 | 350 | 372 | 372 | 376 | 373 | 379 | 377 | 379 |
| Additional Firm | 151 | 140 | 142 | 144 | 137 | 135 | 142 | 142 | 137 | 138 | 152 | 156 |
| Loss | 204 | 174 | 161 | 159 | 187 | 225 | 264 | 241 | 194 | 155 | 169 | 214 |
| **System Load** | 2,286 | 1,977 | 1,843 | 1,822 | 2,100 | 2,493 | 2,894 | 2,664 | 2,174 | 1,789 | 1,935 | 2,402 |
| Light Load | 2,111 | 1,824 | 1,694 | 1,650 | 1,910 | 2,231 | 2,626 | 2,364 | 1,953 | 1,614 | 1,785 | 2,219 |
| Heavy Load | 2,412 | 2,101 | 1,951 | 1,948 | 2,251 | 2,685 | 3,088 | 2,901 | 2,336 | 1,928 | 2,045 | 2,534 |
| **Total Load** | 2,286 | 1,977 | 1,843 | 1,822 | 2,100 | 2,493 | 2,894 | 2,664 | 2,174 | 1,789 | 1,935 | 2,402 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,867 | 2,652 | 2,349 | 2,189 | 3,642 | 3,973 | 4,418 | 3,748 | 3,504 | 2,387 | 2,594 | 3,118 |
| **Total Peak Load** | 2,867 | 2,652 | 2,349 | 2,189 | 3,642 | 3,973 | 4,418 | 3,748 | 3,504 | 2,387 | 2,594 | 3,118 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,164,791 | 5,195,891 | 5,206,261 | 5,276,623 | 5,369,337 | 5,450,107 | 5,523,750 | 5,580,441 | 5,632,102 | 5,689,844 |
| Commercial | 3,948,571 | 4,009,836 | 4,046,655 | 4,094,416 | 4,134,995 | 4,170,810 | 4,212,514 | 4,258,123 | 4,300,385 | 4,345,653 |
| Irrigation | 1,881,550 | 1,892,561 | 1,899,085 | 1,881,000 | 1,879,758 | 1,886,182 | 1,890,570 | 1,895,609 | 1,898,618 | 1,895,444 |
| Industrial | 2,334,380 | 2,402,175 | 2,466,748 | 2,523,489 | 2,568,734 | 2,609,536 | 2,653,663 | 2,698,998 | 2,743,911 | 2,788,219 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,339,064 | 14,525,663 | 14,671,549 | 14,829,029 | 15,015,124 | 15,176,235 | 15,348,197 | 15,548,270 | 15,768,116 | 15,947,860 |
| **Total Sales** | 14,339,064 | 14,525,663 | 14,671,549 | 14,829,029 | 15,015,124 | 15,176,235 | 15,348,197 | 15,548,270 | 15,768,116 | 15,947,860 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,167,413 | 5,197,036 | 5,211,598 | 5,300,406 | 5,375,457 | 5,455,753 | 5,528,219 | 5,602,024 | 5,636,673 | 5,695,236 |
| Commercial | 3,951,973 | 4,011,934 | 4,049,337 | 4,107,904 | 4,137,048 | 4,173,184 | 4,215,100 | 4,272,056 | 4,302,959 | 4,348,499 |
| Irrigation | 1,881,554 | 1,892,564 | 1,899,078 | 1,881,038 | 1,879,761 | 1,886,184 | 1,890,572 | 1,895,649 | 1,898,617 | 1,895,444 |
| Industrial | 2,340,228 | 2,407,744 | 2,471,642 | 2,527,392 | 2,572,253 | 2,613,342 | 2,657,573 | 2,702,871 | 2,747,733 | 2,792,033 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,350,940 | 14,534,478 | 14,684,455 | 14,870,240 | 15,026,819 | 15,188,062 | 15,359,163 | 15,587,701 | 15,779,082 | 15,959,913 |
| **Total Sales** | 14,350,940 | 14,534,478 | 14,684,455 | 14,870,240 | 15,026,819 | 15,188,062 | 15,359,163 | 15,587,701 | 15,779,082 | 15,959,913 |
| Loss | 1,414,977 | 1,431,581 | 1,443,654 | 1,461,800 | 1,476,685 | 1,492,948 | 1,509,490 | 1,529,225 | 1,542,768 | 1,558,213 |
| **Required Generation** | 15,765,916 | 15,966,059 | 16,128,108 | 16,332,040 | 16,503,504 | 16,681,010 | 16,868,653 | 17,116,926 | 17,321,850 | 17,518,125 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 590 | 593 | 595 | 603 | 614 | 623 | 631 | 638 | 643 | 650 |
| Commercial | 451 | 458 | 462 | 468 | 472 | 476 | 481 | 486 | 491 | 496 |
| Irrigation | 215 | 216 | 217 | 214 | 215 | 215 | 216 | 216 | 217 | 216 |
| Industrial | 267 | 275 | 282 | 288 | 294 | 298 | 303 | 308 | 314 | 319 |
| Additional Firm | 115 | 117 | 120 | 120 | 121 | 121 | 122 | 127 | 136 | 140 |
| Loss | 162 | 163 | 165 | 166 | 169 | 170 | 172 | 174 | 176 | 178 |
| **System Load** | 1,800 | 1,823 | 1,841 | 1,859 | 1,884 | 1,904 | 1,926 | 1,949 | 1,977 | 2,000 |
| Light Load | 1,636 | 1,657 | 1,673 | 1,690 | 1,712 | 1,731 | 1,750 | 1,771 | 1,797 | 1,818 |
| Heavy Load | 1,928 | 1,953 | 1,972 | 1,992 | 2,019 | 2,040 | 2,063 | 2,087 | 2,119 | 2,143 |
| **Total Load** | 1,800 | 1,823 | 1,841 | 1,859 | 1,884 | 1,904 | 1,926 | 1,949 | 1,977 | 2,000 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,382 | 3,442 | 3,495 | 3,541 | 3,596 | 3,651 | 3,707 | 3,766 | 3,827 | 3,881 |
| **Total Peak Load** | 3,382 | 3,442 | 3,495 | 3,541 | 3,596 | 3,651 | 3,707 | 3,766 | 3,827 | 3,881 |

| | 2023 | 2024 | 2024 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,758,958 | 5,813,316 | 5,860,061 | 5,932,333 | 6,006,257 | 6,062,171 | 6,132,197 | 6,209,218 | 6,273,351 | 6,333,447 |
| Commercial | 4,395,933 | 4,435,955 | 4,472,534 | 4,525,502 | 4,579,235 | 4,625,191 | 4,681,997 | 4,744,649 | 4,804,978 | 4,867,787 |
| Irrigation | 1,894,663 | 1,898,303 | 1,893,243 | 1,882,293 | 1,884,974 | 1,888,949 | 1,882,964 | 1,883,789 | 1,887,937 | 1,885,770 |
| Industrial | 2,832,435 | 2,875,947 | 2,917,139 | 2,961,183 | 3,005,317 | 3,047,482 | 3,090,882 | 3,134,512 | 3,177,840 | 3,222,016 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 16,115,989 | 16,254,821 | 16,376,977 | 16,529,711 | 16,704,083 | 16,841,293 | 17,000,039 | 17,240,168 | 17,406,305 | 17,566,020 |
| **Total Sales** | 16,115,989 | 16,254,821 | 16,376,977 | 16,529,711 | 16,704,083 | 16,841,293 | 17,000,039 | 17,240,168 | 17,406,305 | 17,566,020 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,763,317 | 5,834,947 | 5,865,721 | 5,938,129 | 6,010,781 | 6,085,880 | 6,138,263 | 6,214,376 | 6,278,234 | 6,356,880 |
| Commercial | 4,398,233 | 4,449,963 | 4,475,535 | 4,528,549 | 4,581,867 | 4,640,688 | 4,685,537 | 4,748,069 | 4,808,536 | 4,884,307 |
| Irrigation | 1,894,665 | 1,898,340 | 1,893,239 | 1,882,294 | 1,884,976 | 1,888,985 | 1,882,964 | 1,883,791 | 1,887,936 | 1,885,808 |
| Industrial | 2,836,188 | 2,879,500 | 2,920,938 | 2,964,990 | 3,008,954 | 3,051,226 | 3,094,645 | 3,138,249 | 3,181,650 | 3,225,818 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 16,126,403 | 16,294,050 | 16,389,434 | 16,542,362 | 16,714,878 | 16,884,279 | 17,013,410 | 17,252,484 | 17,418,556 | 17,609,813 |
| **Total Sales** | 16,126,403 | 16,294,050 | 16,389,434 | 16,542,362 | 16,714,878 | 16,884,279 | 17,013,410 | 17,252,484 | 17,418,556 | 17,609,813 |
| Loss | 1,574,463 | 1,591,342 | 1,600,133 | 1,615,595 | 1,632,909 | 1,650,617 | 1,663,620 | 1,683,930 | 1,700,984 | 1,720,590 |
| **Required Generation** | 17,700,866 | 17,885,392 | 17,989,567 | 18,157,957 | 18,347,787 | 18,534,896 | 18,677,030 | 18,936,415 | 19,119,540 | 19,330,402 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 658 | 664 | 670 | 678 | 686 | 693 | 701 | 709 | 717 | 724 |
| Commercial | 502 | 507 | 511 | 517 | 523 | 528 | 535 | 542 | 549 | 556 |
| Irrigation | 216 | 216 | 216 | 215 | 215 | 215 | 215 | 215 | 216 | 215 |
| Industrial | 324 | 328 | 333 | 338 | 343 | 347 | 353 | 358 | 363 | 367 |
| Additional Firm | 141 | 140 | 141 | 140 | 140 | 139 | 138 | 145 | 144 | 143 |
| Loss | 180 | 181 | 183 | 184 | 186 | 188 | 190 | 192 | 194 | 196 |
| **System Load** | 2,021 | 2,036 | 2,054 | 2,073 | 2,094 | 2,110 | 2,132 | 2,162 | 2,183 | 2,201 |
| Light Load | 1,837 | 1,851 | 1,867 | 1,884 | 1,904 | 1,918 | 1,938 | 1,965 | 1,984 | 2,000 |
| Heavy Load | 2,166 | 2,181 | 2,200 | 2,221 | 2,244 | 2,261 | 2,284 | 2,316 | 2,332 | 2,351 |
| **Total Load** | 2,021 | 2,036 | 2,054 | 2,073 | 2,094 | 2,110 | 2,132 | 2,162 | 2,183 | 2,201 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,935 | 3,987 | 4,033 | 4,083 | 4,139 | 4,191 | 4,244 | 4,308 | 4,365 | 4,418 |
| **Total Peak Load** | 3,935 | 3,987 | 4,033 | 4,083 | 4,139 | 4,191 | 4,244 | 4,308 | 4,365 | 4,418 |

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 |
| Load Forecast (70th% w/DSM) | (1,864) | (1,684) | (1,511) | (1,484) | (1,740) | (2,067) | (2,390) | (2,178) | (1,762) | (1,437) | (1,555) | (1,902) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 933 | 933 | 806 | 699 | 841 | 915 | 933 | 933 | 933 | 933 | 932 | 933 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 579 | 603 | 595 | 676 | 868 | 703 | 517 | 383 | 436 | 413 | 364 | 469 |
| Hydro (70th%)—Other | 216 | 234 | 215 | 236 | 328 | 337 | 278 | 251 | 224 | 219 | 202 | 208 |
| Shoshone Falls Upgrade (70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 837 | 811 | 912 | 1,195 | 1,040 | 867 | 634 | 660 | 632 | 566 | 677 |
| **CSPP (PURPA)** | 201 | 207 | 212 | 262 | 306 | 297 | 263 | 241 | 247 | 235 | 242 | 199 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 205 | 292 | 194 | 264 | 68 | 0 | 0 | 0 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,539 | 2,342 | 1,882 | 1,926 | 2,620 | 3,126 | 2,837 | 2,662 | 2,249 | 2,127 | 2,084 | 2,431 |
| **Monthly Surplus/Deficit** | 675 | 657 | 371 | 442 | 880 | 1,059 | 447 | 483 | 487 | 690 | 529 | 529 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 2 | 3 | 3 | 3 | 1 | 0 | 0 | 0 |
| Commercial/Industrial | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM (aMW)** | 6 | 6 | 6 | 7 | 9 | 10 | 10 | 9 | 8 | 7 | 6 | 7 |
| **Monthly Surplus/Deficit** | 682 | 664 | 378 | 449 | 889 | 1,068 | 457 | 493 | 495 | 697 | 535 | 535 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 682 | 664 | 378 | 449 | 889 | 1,068 | 457 | 493 | 495 | 697 | 535 | 535 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 14 | 14 | 14 | 15 | 16 | 16 | 16 | 16 | 15 | 14 | 14 | 14 |
| Load Forecast (70th% w/DSM) | (1,887) | (1,702) | (1,530) | (1,503) | (1,763) | (2,090) | (2,421) | (2,208) | (1,788) | (1,457) | (1,576) | (1,923) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 933 | 933 | 779 | 668 | 853 | 915 | 932 | 932 | 932 | 932 | 931 | 932 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 575 | 602 | 594 | 673 | 867 | 701 | 516 | 381 | 435 | 410 | 364 | 466 |
| Hydro (70th%)—Other | 215 | 221 | 213 | 228 | 327 | 336 | 278 | 250 | 223 | 219 | 201 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 790 | 823 | 806 | 901 | 1,194 | 1,037 | 865 | 632 | 658 | 629 | 565 | 673 |
| **CSPP (PURPA)** | 203 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 230 | 352 | 237 | 277 | 113 | 0 | 0 | 1 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,536 | 2,341 | 1,863 | 1,896 | 2,667 | 3,195 | 2,889 | 2,683 | 2,302 | 2,134 | 2,094 | 2,438 |
| **Monthly Surplus/Deficit** | 650 | 639 | 333 | 392 | 904 | 1,104 | 468 | 475 | 515 | 677 | 518 | 515 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 4 | 6 | 6 | 5 | 3 | 0 | 0 | 0 |
| Commercial/Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM (aMW)** | 13 | 13 | 13 | 14 | 17 | 19 | 20 | 19 | 16 | 14 | 13 | 13 |
| **Monthly Surplus/Deficit** | 663 | 653 | 347 | 407 | 921 | 1,124 | 487 | 494 | 530 | 691 | 531 | 528 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 663 | 653 | 347 | 407 | 921 | 1,124 | 487 | 494 | 530 | 691 | 531 | 528 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 21 | 21 | 21 | 22 | 24 | 24 | 24 | 23 | 23 | 22 | 21 | 21 |
| Load Forecast (70th% w/DSM) | (1,903) | (1,714) | (1,544) | (1,519) | (1,780) | (2,112) | (2,445) | (2,231) | (1,807) | (1,473) | (1,593) | (1,949) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 932 | 932 | 832 | 648 | 687 | 812 | 932 | 932 | 932 | 932 | 931 | 932 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 582 | 619 | 598 | 715 | 869 | 705 | 516 | 381 | 434 | 418 | 363 | 479 |
| Hydro (70th%)—Other | 218 | 258 | 214 | 259 | 331 | 340 | 278 | 251 | 224 | 221 | 202 | 209 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 799 | 877 | 813 | 974 | 1,199 | 1,045 | 865 | 632 | 658 | 639 | 566 | 688 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 276 | 342 | 237 | 274 | 147 | 0 | 0 | 15 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,557 | 2,395 | 1,922 | 1,949 | 2,552 | 3,089 | 2,889 | 2,681 | 2,336 | 2,145 | 2,095 | 2,467 |
| **Monthly Surplus/Deficit** | 654 | 681 | 378 | 430 | 771 | 978 | 444 | 450 | 529 | 671 | 502 | 518 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 6 | 8 | 8 | 7 | 4 | 1 | 0 | 0 |
| Commercial/Industrial | 19 | 19 | 19 | 19 | 19 | 20 | 20 | 20 | 19 | 19 | 19 | 19 |
| Residential | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total New DSM (aMW)** | 20 | 20 | 20 | 21 | 26 | 28 | 29 | 27 | 23 | 20 | 20 | 20 |
| **Monthly Surplus/Deficit** | 673 | 700 | 398 | 451 | 797 | 1,006 | 473 | 478 | 552 | 691 | 521 | 538 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 673 | 700 | 398 | 451 | 797 | 1,006 | 473 | 478 | 552 | 691 | 521 | 538 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 26 | 26 | 26 | 27 | 29 | 30 | 30 | 29 | 28 | 26 | 26 | 26 |
| Load Forecast (70th% w/DSM) | (1,927) | (1,717) | (1,562) | (1,536) | (1,797) | (2,129) | (2,465) | (2,251) | (1,826) | (1,492) | (1,614) | (1,976) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 932 | 932 | 703 | 686 | 716 | 839 | 938 | 938 | 938 | 938 | 937 | 938 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 581 | 617 | 599 | 712 | 872 | 704 | 515 | 351 | 432 | 416 | 364 | 488 |
| Hydro (70th%)—Other | 218 | 283 | 214 | 261 | 330 | 340 | 277 | 206 | 224 | 221 | 202 | 208 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 798 | 900 | 813 | 973 | 1,202 | 1,043 | 791 | 556 | 656 | 637 | 566 | 696 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 314 | 342 | 237 | 272 | 178 | 0 | 0 | 34 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,551 | 2,412 | 1,807 | 1,997 | 2,611 | 3,104 | 2,811 | 2,602 | 2,368 | 2,168 | 2,117 | 2,497 |
| **Monthly Surplus/Deficit** | 624 | 694 | 244 | 461 | 815 | 975 | 347 | 351 | 542 | 675 | 504 | 520 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 7 | 9 | 10 | 8 | 4 | 1 | 0 | 0 |
| Commercial/Industrial | 25 | 24 | 24 | 24 | 25 | 25 | 25 | 25 | 24 | 24 | 24 | 24 |
| Residential | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total New DSM (aMW)** | 27 | 26 | 26 | 28 | 33 | 36 | 37 | 35 | 31 | 27 | 26 | 26 |
| **Monthly Surplus/Deficit** | 651 | 721 | 270 | 489 | 848 | 1,012 | 383 | 386 | 572 | 703 | 530 | 547 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 651 | 721 | 270 | 489 | 848 | 1,012 | 383 | 386 | 572 | 703 | 530 | 547 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 30 | 30 | 30 | 31 | 34 | 35 | 35 | 34 | 33 | 30 | 30 | 30 |
| Load Forecast (70th% w/DSM) | (1,952) | (1,752) | (1,582) | (1,556) | (1,817) | (2,152) | (2,493) | (2,278) | (1,849) | (1,513) | (1,636) | (2,004) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 938 | 938 | 940 | 781 | 709 | 835 | 944 | 944 | 944 | 944 | 943 | 944 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 580 | 616 | 596 | 700 | 867 | 702 | 513 | 349 | 431 | 414 | 364 | 487 |
| Hydro (70th%)—Other | 217 | 275 | 206 | 251 | 330 | 338 | 276 | 205 | 223 | 220 | 201 | 208 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 797 | 891 | 802 | 951 | 1,197 | 1,041 | 789 | 554 | 654 | 634 | 565 | 694 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 359 | 347 | 237 | 269 | 219 | 0 | 0 | 61 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,555 | 2,409 | 2,032 | 2,070 | 2,644 | 3,102 | 2,816 | 2,603 | 2,412 | 2,171 | 2,123 | 2,528 |
| **Monthly Surplus/Deficit** | 603 | 656 | 449 | 514 | 828 | 950 | 323 | 325 | 564 | 658 | 487 | 524 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 8 | 11 | 11 | 9 | 5 | 1 | 0 | 0 |
| Commercial/Industrial | 29 | 29 | 29 | 29 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 30 |
| Residential | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 | 4 | 4 |
| **Total New DSM (aMW)** | 33 | 33 | 33 | 35 | 41 | 44 | 45 | 43 | 38 | 34 | 33 | 33 |
| **Monthly Surplus/Deficit** | 636 | 689 | 482 | 550 | 868 | 994 | 368 | 368 | 602 | 692 | 520 | 558 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 636 | 689 | 482 | 550 | 868 | 994 | 368 | 368 | 602 | 692 | 520 | 558 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 34 | 34 | 34 | 35 | 39 | 40 | 40 | 39 | 37 | 34 | 34 | 34 |
| Load Forecast (70th% w/DSM) | (1,974) | (1,768) | (1,599) | (1,572) | (1,835) | (2,175) | (2,520) | (2,303) | (1,869) | (1,529) | (1,654) | (2,029) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 944 | 944 | 881 | 731 | 743 | 922 | 948 | 948 | 948 | 948 | 947 | 948 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 579 | 606 | 588 | 699 | 866 | 694 | 512 | 348 | 430 | 410 | 364 | 480 |
| Hydro (70th%)—Other | 215 | 233 | 206 | 250 | 330 | 337 | 276 | 204 | 222 | 219 | 201 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 839 | 794 | 949 | 1,196 | 1,032 | 788 | 552 | 652 | 630 | 564 | 687 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 385 | 342 | 237 | 267 | 257 | 0 | 0 | 86 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,559 | 2,363 | 1,965 | 2,017 | 2,704 | 3,175 | 2,818 | 2,603 | 2,452 | 2,170 | 2,126 | 2,550 |
| **Monthly Surplus/Deficit** | 585 | 595 | 367 | 445 | 869 | 1,000 | 298 | 299 | 583 | 641 | 472 | 521 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 9 | 12 | 13 | 11 | 6 | 1 | 0 | 0 |
| Commercial/Industrial | 35 | 35 | 35 | 35 | 35 | 36 | 36 | 36 | 35 | 35 | 35 | 35 |
| Residential | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| **Total New DSM (aMW)** | 42 | 42 | 41 | 44 | 51 | 55 | 55 | 53 | 48 | 42 | 42 | 42 |
| **Monthly Surplus/Deficit** | 627 | 636 | 408 | 489 | 920 | 1,055 | 353 | 352 | 630 | 683 | 513 | 563 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 827 | 836 | 608 | 989 | 1,420 | 1,555 | 853 | 852 | 1,130 | 883 | 713 | 763 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 37 | 37 | 37 | 39 | 44 | 45 | 45 | 44 | 41 | 38 | 37 | 37 |
| Load Forecast (70th% w/DSM) | (1,996) | (1,785) | (1,616) | (1,590) | (1,854) | (2,198) | (2,547) | (2,330) | (1,891) | (1,548) | (1,674) | (2,054) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 948 | 948 | 901 | 833 | 731 | 865 | 954 | 954 | 954 | 954 | 953 | 954 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 578 | 602 | 588 | 695 | 865 | 690 | 511 | 347 | 428 | 399 | 363 | 474 |
| Hydro (70th%)—Other | 215 | 223 | 200 | 243 | 329 | 337 | 275 | 203 | 221 | 219 | 199 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 793 | 825 | 788 | 937 | 1,195 | 1,027 | 788 | 549 | 649 | 618 | 564 | 684 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 384 | 342 | 237 | 265 | 270 | 0 | 0 | 111 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,561 | 2,353 | 1,979 | 2,109 | 2,690 | 3,113 | 2,825 | 2,604 | 2,468 | 2,164 | 2,131 | 2,577 |
| **Monthly Surplus/Deficit** | 565 | 568 | 363 | 519 | 836 | 915 | 277 | 274 | 576 | 617 | 457 | 524 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 10 | 14 | 15 | 12 | 7 | 1 | 0 | 0 |
| Commercial/Industrial | 40 | 39 | 40 | 39 | 40 | 41 | 41 | 41 | 40 | 39 | 40 | 40 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM (aMW)** | 49 | 49 | 49 | 52 | 60 | 64 | 65 | 62 | 56 | 50 | 49 | 50 |
| **Monthly Surplus/Deficit** | 614 | 617 | 412 | 571 | 895 | 979 | 342 | 337 | 633 | 667 | 507 | 573 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 814 | 817 | 612 | 1,071 | 1,395 | 1,479 | 842 | 837 | 1,133 | 867 | 707 | 773 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 42 | 42 | 42 | 44 | 49 | 50 | 51 | 49 | 46 | 43 | 42 | 42 |
| Load Forecast (70th% w/DSM) | (2,022) | (1,789) | (1,637) | (1,611) | (1,877) | (2,225) | (2,578) | (2,359) | (1,916) | (1,569) | (1,698) | (2,083) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 948 | 948 | 949 | 762 | 686 | 910 | 954 | 954 | 954 | 954 | 954 | 954 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 577 | 599 | 588 | 691 | 865 | 687 | 510 | 345 | 427 | 395 | 364 | 469 |
| Hydro (70th%)—Other | 214 | 220 | 198 | 236 | 329 | 336 | 274 | 202 | 220 | 218 | 198 | 206 |
| Shoshone Falls Upgrade(70th%) | 6 | 15 | 0 | 1 | 15 | 17 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 798 | 834 | 786 | 929 | 1,208 | 1,039 | 786 | 547 | 647 | 613 | 563 | 677 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 383 | 342 | 237 | 262 | 269 | 0 | 4 | 139 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,566 | 2,361 | 2,025 | 2,029 | 2,657 | 3,170 | 2,822 | 2,599 | 2,464 | 2,160 | 2,136 | 2,598 |
| **Monthly Surplus/Deficit** | 543 | 572 | 388 | 418 | 781 | 945 | 245 | 240 | 549 | 591 | 439 | 515 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 12 | 16 | 17 | 14 | 8 | 1 | 0 | 0 |
| Commercial/Industrial | 45 | 45 | 45 | 45 | 46 | 47 | 47 | 47 | 45 | 45 | 46 | 45 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 54 | 54 | 54 | 57 | 66 | 71 | 72 | 69 | 62 | 55 | 55 | 54 |
| **Monthly Surplus/Deficit** | 598 | 626 | 443 | 475 | 847 | 1,017 | 317 | 309 | 610 | 647 | 493 | 570 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 798 | 826 | 643 | 975 | 1,347 | 1,517 | 817 | 809 | 1,110 | 847 | 693 | 770 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| Load Forecast (70th% w/DSM) | (2,051) | (1,828) | (1,660) | (1,635) | (1,901) | (2,253) | (2,609) | (2,389) | (1,942) | (1,592) | (1,725) | (2,117) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 811 | 624 | 658 | 791 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 576 | 593 | 588 | 687 | 864 | 684 | 508 | 344 | 425 | 395 | 364 | 479 |
| Hydro (70th%)—Other | 213 | 219 | 196 | 238 | 327 | 333 | 273 | 201 | 219 | 217 | 197 | 205 |
| Shoshone Falls Upgrade(70th%) | 6 | 12 | 0 | 1 | 15 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 824 | 784 | 926 | 1,206 | 1,033 | 784 | 544 | 643 | 612 | 562 | 686 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,596 | 2,267 | 1,884 | 1,888 | 2,678 | 3,099 | 2,819 | 2,593 | 2,458 | 2,104 | 2,159 | 2,639 |
| **Monthly Surplus/Deficit** | 545 | 439 | 224 | 253 | 776 | 845 | 209 | 204 | 516 | 512 | 435 | 522 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial/Industrial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Monthly Surplus/Deficit** | 605 | 499 | 284 | 317 | 851 | 925 | 290 | 281 | 585 | 574 | 495 | 582 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 805 | 699 | 484 | 817 | 1,351 | 1,425 | 790 | 781 | 1,085 | 774 | 695 | 782 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| Load Forecast (70th% w/DSM) | (2,051) | (1,828) | (1,660) | (1,635) | (1,901) | (2,253) | (2,609) | (2,389) | (1,942) | (1,592) | (1,725) | (2,117) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 811 | 624 | 658 | 791 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 576 | 593 | 588 | 687 | 864 | 684 | 508 | 344 | 425 | 395 | 364 | 479 |
| Hydro (70th%)—Other | 213 | 219 | 196 | 238 | 327 | 333 | 273 | 201 | 219 | 217 | 197 | 205 |
| Shoshone Falls Upgrade(70th%) | 6 | 12 | 0 | 1 | 15 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 824 | 784 | 926 | 1,206 | 1,033 | 784 | 544 | 643 | 612 | 562 | 686 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,596 | 2,267 | 1,884 | 1,888 | 2,678 | 3,099 | 2,819 | 2,593 | 2,458 | 2,104 | 2,159 | 2,639 |
| **Monthly Surplus/Deficit** | 545 | 439 | 224 | 253 | 776 | 845 | 209 | 204 | 516 | 512 | 435 | 522 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial/Industrial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Monthly Surplus/Deficit** | 605 | 499 | 284 | 317 | 851 | 925 | 290 | 281 | 585 | 574 | 495 | 582 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 805 | 699 | 484 | 817 | 1,351 | 1,425 | 790 | 781 | 1,085 | 774 | 695 | 782 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 49 | 49 | 49 | 51 | 58 | 60 | 60 | 58 | 55 | 50 | 49 | 49 |
| Load Forecast (70th% w/DSM) | (2,075) | (1,846) | (1,680) | (1,654) | (1,921) | (2,276) | (2,635) | (2,414) | (1,964) | (1,612) | (1,747) | (2,147) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 784 | 702 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 575 | 592 | 588 | 685 | 863 | 682 | 507 | 342 | 423 | 391 | 364 | 471 |
| Hydro (70th%)—Other | 212 | 218 | 194 | 233 | 326 | 332 | 273 | 200 | 218 | 216 | 196 | 204 |
| Shoshone Falls Upgrade(70th%) | 6 | 9 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 793 | 819 | 782 | 919 | 1,204 | 1,031 | 782 | 542 | 641 | 607 | 561 | 677 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 113 | 0 | 0 | 0 | 433 | 349 | 237 | 308 | 318 | 0 | 103 | 254 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,620 | 2,262 | 1,856 | 1,959 | 2,747 | 3,060 | 2,763 | 2,585 | 2,453 | 2,099 | 2,178 | 2,659 |
| **Monthly Surplus/Deficit** | 544 | 416 | 177 | 305 | 826 | 784 | 128 | 171 | 490 | 488 | 431 | 512 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 15 | 22 | 22 | 19 | 10 | 2 | 0 | 0 |
| Commercial/Industrial | 59 | 58 | 58 | 58 | 59 | 60 | 60 | 60 | 58 | 58 | 58 | 58 |
| Residential | 9 | 9 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 10 |
| **Total New DSM (aMW)** | 68 | 67 | 67 | 72 | 84 | 90 | 91 | 88 | 78 | 70 | 68 | 67 |
| **Monthly Surplus/Deficit** | 613 | 483 | 244 | 376 | 910 | 875 | 219 | 258 | 567 | 557 | 499 | 580 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 813 | 683 | 444 | 876 | 1,410 | 1,375 | 719 | 758 | 1,067 | 757 | 699 | 780 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 52 | 52 | 52 | 55 | 62 | 64 | 65 | 62 | 58 | 53 | 52 | 52 |
| Load Forecast (70th% w/DSM) | (2,097) | (1,862) | (1,697) | (1,672) | (1,940) | (2,298) | (2,662) | (2,440) | (1,985) | (1,630) | (1,766) | (2,171) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 574 | 591 | 587 | 682 | 862 | 681 | 505 | 341 | 422 | 387 | 364 | 463 |
| Hydro (70th%)—Other | 211 | 214 | 193 | 223 | 326 | 332 | 272 | 199 | 217 | 216 | 195 | 202 |
| Shoshone Falls Upgrade(70th%) | 6 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 791 | 812 | 780 | 905 | 1,202 | 1,029 | 779 | 539 | 638 | 602 | 560 | 668 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 136 | 0 | 0 | 0 | 431 | 346 | 237 | 306 | 316 | 0 | 123 | 291 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,641 | 2,254 | 1,848 | 1,905 | 2,743 | 3,055 | 2,761 | 2,581 | 2,449 | 2,094 | 2,198 | 2,687 |
| **Monthly Surplus/Deficit** | 543 | 392 | 151 | 234 | 804 | 757 | 99 | 141 | 464 | 464 | 431 | 516 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 5 | 18 | 25 | 26 | 22 | 11 | 2 | 0 | 0 |
| Commercial/Industrial | 64 | 64 | 64 | 64 | 65 | 67 | 67 | 67 | 64 | 64 | 64 | 65 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM (aMW)** | 74 | 74 | 73 | 79 | 92 | 100 | 101 | 97 | 85 | 76 | 74 | 74 |
| **Monthly Surplus/Deficit** | 617 | 466 | 224 | 313 | 896 | 857 | 200 | 237 | 549 | 540 | 505 | 590 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 817 | 666 | 424 | 813 | 1,396 | 1,357 | 700 | 737 | 1,049 | 740 | 705 | 790 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 55 | 54 | 55 | 57 | 65 | 68 | 68 | 66 | 62 | 56 | 55 | 55 |
| Load Forecast (70th% w/DSM) | (2,115) | (1,857) | (1,710) | (1,686) | (1,955) | (2,318) | (2,685) | (2,462) | (2,004) | (1,645) | (1,782) | (2,191) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 573 | 590 | 587 | 677 | 861 | 680 | 504 | 339 | 421 | 383 | 364 | 458 |
| Hydro (70th%)—Other | 209 | 212 | 191 | 211 | 325 | 331 | 271 | 198 | 216 | 215 | 194 | 201 |
| Shoshone Falls Upgrade(70th%) | 5 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 809 | 778 | 889 | 1,201 | 1,027 | 777 | 537 | 637 | 598 | 559 | 662 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 143 | 0 | 0 | 0 | 430 | 342 | 237 | 303 | 315 | 0 | 132 | 312 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,643 | 2,251 | 1,846 | 1,889 | 2,741 | 3,049 | 2,759 | 2,575 | 2,446 | 2,090 | 2,206 | 2,702 |
| **Monthly Surplus/Deficit** | 529 | 394 | 135 | 203 | 785 | 731 | 74 | 113 | 442 | 445 | 424 | 511 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 20 | 28 | 29 | 25 | 13 | 2 | 0 | 0 |
| Commercial/Industrial | 71 | 71 | 71 | 71 | 71 | 74 | 74 | 74 | 72 | 71 | 71 | 72 |
| Residential | 12 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 12 | 12 |
| **Total New DSM (aMW)** | 84 | 83 | 84 | 89 | 104 | 113 | 114 | 109 | 97 | 86 | 84 | 84 |
| **Monthly Surplus/Deficit** | 612 | 478 | 219 | 292 | 889 | 844 | 188 | 222 | 540 | 531 | 508 | 595 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 812 | 678 | 419 | 792 | 1,389 | 1,344 | 688 | 722 | 1,040 | 731 | 708 | 795 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 57 | 57 | 57 | 60 | 68 | 71 | 72 | 69 | 64 | 58 | 57 | 57 |
| Load Forecast (70th% w/DSM) | (2,130) | (1,885) | (1,723) | (1,699) | (1,969) | (2,334) | (2,705) | (2,481) | (2,020) | (1,659) | (1,796) | (2,215) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 572 | 589 | 587 | 667 | 861 | 678 | 502 | 338 | 420 | 379 | 365 | 457 |
| Hydro (70th%)—Other | 208 | 212 | 190 | 210 | 325 | 330 | 270 | 197 | 215 | 214 | 193 | 200 |
| Shoshone Falls Upgrade(70th%) | 5 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 784 | 807 | 777 | 877 | 1,200 | 1,025 | 775 | 535 | 635 | 593 | 559 | 660 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 160 | 0 | 0 | 0 | 428 | 342 | 237 | 300 | 313 | 0 | 135 | 321 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,658 | 2,249 | 1,845 | 1,877 | 2,737 | 3,047 | 2,757 | 2,570 | 2,442 | 2,085 | 2,208 | 2,709 |
| **Monthly Surplus/Deficit** | 528 | 365 | 122 | 178 | 769 | 713 | 52 | 89 | 422 | 426 | 412 | 494 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 23 | 32 | 33 | 28 | 15 | 3 | 0 | 0 |
| Commercial/Industrial | 77 | 77 | 77 | 77 | 77 | 80 | 80 | 80 | 77 | 77 | 78 | 77 |
| Residential | 16 | 16 | 16 | 16 | 16 | 14 | 14 | 14 | 16 | 16 | 16 | 16 |
| **Total New DSM (aMW)** | 93 | 93 | 93 | 99 | 116 | 126 | 127 | 122 | 108 | 96 | 94 | 93 |
| **Monthly Surplus/Deficit** | 621 | 458 | 216 | 278 | 885 | 839 | 179 | 211 | 530 | 522 | 506 | 587 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 821 | 658 | 416 | 778 | 1,385 | 1,339 | 679 | 711 | 1,030 | 722 | 706 | 787 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 59 | 59 | 59 | 62 | 71 | 74 | 75 | 72 | 67 | 60 | 59 | 59 |
| Load Forecast (70th% w/DSM) | (2,152) | (1,900) | (1,739) | (1,715) | (1,985) | (2,353) | (2,727) | (2,503) | (2,039) | (1,677) | (1,815) | (2,241) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 570 | 588 | 587 | 666 | 860 | 677 | 501 | 336 | 419 | 375 | 365 | 456 |
| Hydro (70th%)—Other | 205 | 211 | 189 | 209 | 325 | 329 | 269 | 196 | 214 | 213 | 192 | 200 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 779 | 805 | 775 | 875 | 1,199 | 1,022 | 773 | 532 | 632 | 588 | 558 | 659 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 183 | 0 | 0 | 0 | 427 | 342 | 237 | 298 | 311 | 0 | 154 | 319 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,676 | 2,247 | 1,843 | 1,876 | 2,735 | 3,045 | 2,754 | 2,565 | 2,438 | 2,081 | 2,226 | 2,706 |
| **Monthly Surplus/Deficit** | 524 | 347 | 104 | 161 | 750 | 692 | 28 | 62 | 399 | 404 | 411 | 465 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 7 | 26 | 36 | 38 | 32 | 17 | 3 | 0 | 0 |
| Commercial/Industrial | 83 | 83 | 83 | 83 | 84 | 86 | 86 | 86 | 83 | 83 | 84 | 83 |
| Residential | 21 | 21 | 21 | 21 | 21 | 18 | 18 | 18 | 21 | 21 | 21 | 21 |
| **Total New DSM (aMW)** | 104 | 104 | 104 | 111 | 131 | 141 | 142 | 136 | 120 | 107 | 105 | 104 |
| **Monthly Surplus/Deficit** | 628 | 451 | 208 | 271 | 881 | 833 | 170 | 198 | 519 | 511 | 516 | 569 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 828 | 651 | 408 | 771 | 1,381 | 1,333 | 670 | 698 | 1,019 | 711 | 716 | 769 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 61 | 61 | 61 | 64 | 74 | 77 | 77 | 74 | 69 | 63 | 61 | 61 |
| Load Forecast (70th% w/DSM) | (2,174) | (1,916) | (1,757) | (1,733) | (2,004) | (2,377) | (2,755) | (2,530) | (2,062) | (1,695) | (1,835) | (2,265) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 218 | 0 | 0 | 0 | 425 | 342 | 237 | 295 | 308 | 0 | 174 | 317 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,700 | 2,245 | 1,841 | 1,874 | 2,731 | 3,042 | 2,752 | 2,560 | 2,433 | 2,077 | 2,246 | 2,702 |
| **Monthly Surplus/Deficit** | 526 | 329 | 84 | 141 | 727 | 666 | (3) | 29 | 371 | 382 | 411 | 437 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 8 | 29 | 41 | 43 | 36 | 19 | 4 | 0 | 0 |
| Commercial/Industrial | 89 | 88 | 88 | 88 | 90 | 92 | 92 | 92 | 89 | 89 | 89 | 89 |
| Residential | 27 | 27 | 27 | 27 | 26 | 23 | 23 | 23 | 27 | 27 | 27 | 27 |
| **Total New DSM (aMW)** | 116 | 115 | 115 | 123 | 146 | 156 | 158 | 151 | 134 | 119 | 115 | 115 |
| **Monthly Surplus/Deficit** | 642 | 444 | 199 | 264 | 873 | 822 | 155 | 181 | 505 | 501 | 526 | 552 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 842 | 644 | 399 | 764 | 1,373 | 1,322 | 655 | 681 | 1,005 | 701 | 726 | 752 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 63 | 62 | 62 | 66 | 75 | 79 | 79 | 76 | 71 | 64 | 63 | 63 |
| Load Forecast (70th% w/DSM) | (2,191) | (1,910) | (1,769) | (1,747) | (2,020) | (2,397) | (2,780) | (2,553) | (2,081) | (1,710) | (1,850) | (2,288) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 236 | 0 | 7 | 0 | 423 | 342 | 237 | 293 | 306 | 0 | 182 | 314 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,718 | 2,245 | 1,848 | 1,874 | 2,729 | 3,042 | 2,752 | 2,558 | 2,431 | 2,077 | 2,254 | 2,699 |
| **Monthly Surplus/Deficit** | 527 | 336 | 78 | 127 | 709 | 646 | (27) | 4 | 350 | 367 | 403 | 410 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 9 | 33 | 46 | 48 | 40 | 21 | 4 | 0 | 0 |
| Commercial/Industrial | 96 | 94 | 94 | 95 | 96 | 98 | 98 | 98 | 95 | 95 | 95 | 96 |
| Residential | 33 | 33 | 33 | 33 | 33 | 29 | 29 | 29 | 33 | 33 | 33 | 33 |
| **Total New DSM (aMW)** | 128 | 127 | 127 | 137 | 161 | 174 | 175 | 168 | 149 | 132 | 128 | 128 |
| **Monthly Surplus/Deficit** | 655 | 463 | 206 | 264 | 871 | 819 | 148 | 172 | 499 | 499 | 531 | 538 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 855 | 663 | 406 | 764 | 1,371 | 1,319 | 648 | 672 | 999 | 699 | 731 | 738 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 64 | 64 | 64 | 68 | 77 | 80 | 81 | 78 | 73 | 65 | 64 | 64 |
| Load Forecast (70th% w/DSM) | (2,212) | (1,943) | (1,786) | (1,763) | (2,037) | (2,417) | (2,804) | (2,578) | (2,101) | (1,728) | (1,869) | (2,315) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 247 | 0 | 24 | 0 | 421 | 342 | 237 | 290 | 304 | 0 | 199 | 312 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,729 | 2,245 | 1,865 | 1,874 | 2,727 | 3,042 | 2,752 | 2,555 | 2,429 | 2,077 | 2,271 | 2,697 |
| **Monthly Surplus/Deficit** | 517 | 303 | 79 | 111 | 690 | 625 | (52) | (23) | 327 | 349 | 402 | 381 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 10 | 37 | 52 | 54 | 45 | 24 | 5 | 0 | 0 |
| Commercial/Industrial | 100 | 100 | 100 | 100 | 101 | 104 | 104 | 104 | 101 | 100 | 100 | 101 |
| Residential | 38 | 38 | 38 | 38 | 37 | 33 | 33 | 33 | 37 | 38 | 38 | 37 |
| **Total New DSM (aMW)** | 138 | 138 | 137 | 148 | 175 | 189 | 191 | 182 | 163 | 142 | 138 | 139 |
| **Monthly Surplus/Deficit** | 655 | 440 | 217 | 259 | 866 | 814 | 138 | 160 | 490 | 491 | 540 | 520 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 855 | 640 | 417 | 759 | 1,366 | 1,314 | 638 | 660 | 990 | 691 | 740 | 720 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 65 | 65 | 65 | 69 | 79 | 82 | 83 | 80 | 74 | 67 | 65 | 66 |
| Load Forecast (70th% w/DSM) | (2,245) | (1,967) | (1,811) | (1,789) | (2,064) | (2,448) | (2,840) | (2,612) | (2,130) | (1,754) | (1,898) | (2,352) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 281 | 0 | 61 | 0 | 419 | 342 | 237 | 287 | 302 | 0 | 231 | 310 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,763 | 2,245 | 1,902 | 1,874 | 2,725 | 3,042 | 2,752 | 2,552 | 2,427 | 2,077 | 2,303 | 2,695 |
| **Monthly Surplus/Deficit** | 519 | 278 | 90 | 85 | 662 | 594 | (87) | (60) | 296 | 323 | 404 | 343 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 38 | 54 | 56 | 47 | 25 | 5 | 0 | 0 |
| Commercial/Industrial | 105 | 105 | 105 | 105 | 105 | 109 | 109 | 109 | 106 | 105 | 105 | 106 |
| Residential | 43 | 43 | 43 | 43 | 43 | 38 | 38 | 38 | 43 | 43 | 43 | 43 |
| **Total New DSM (aMW)** | 148 | 148 | 148 | 158 | 186 | 200 | 202 | 194 | 174 | 152 | 148 | 149 |
| **Monthly Surplus/Deficit** | 667 | 426 | 239 | 243 | 848 | 795 | 115 | 134 | 470 | 476 | 553 | 492 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 867 | 626 | 439 | 743 | 1,348 | 1,295 | 615 | 634 | 970 | 676 | 753 | 692 |

# Monthly Average Energy Load and Resource Balance (continued)

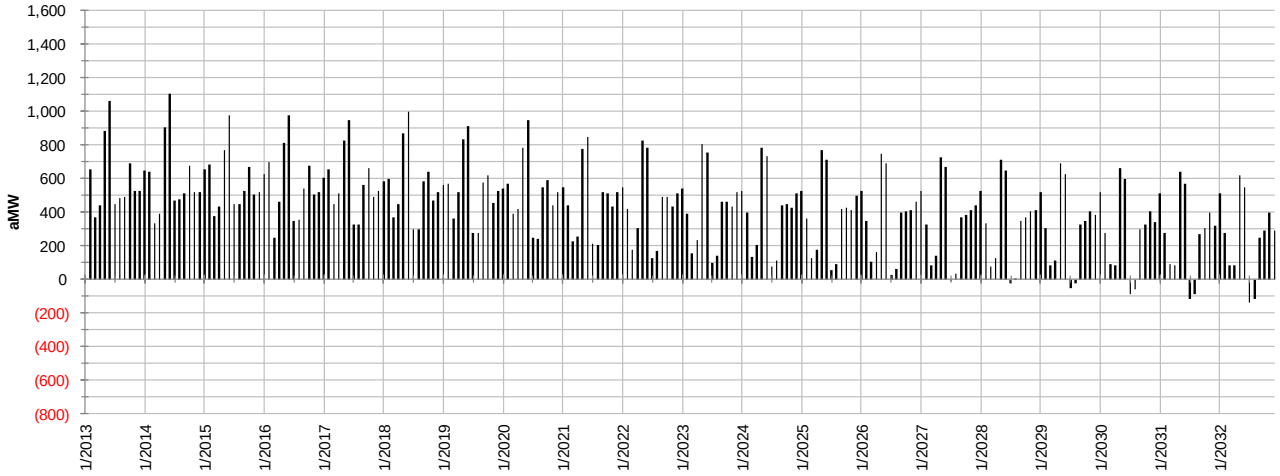
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 66 | 66 | 66 | 70 | 80 | 83 | 84 | 81 | 75 | 68 | 66 | 66 |
| Load Forecast (70th% w/DSM) | (2,265) | (1,981) | (1,827) | (1,806) | (2,083) | (2,472) | (2,868) | (2,639) | (2,153) | (1,771) | (1,917) | (2,377) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 291 | 12 | 78 | 15 | 418 | 342 | 237 | 285 | 300 | 0 | 245 | 308 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,773 | 2,257 | 1,919 | 1,889 | 2,724 | 3,042 | 2,752 | 2,550 | 2,425 | 2,077 | 2,317 | 2,693 |
| **Monthly Surplus/Deficit** | 508 | 276 | 92 | 83 | 642 | 571 | (116) | (89) | 272 | 306 | 400 | 316 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 40 | 56 | 58 | 49 | 26 | 5 | 0 | 0 |
| Commercial/Industrial | 110 | 110 | 110 | 109 | 110 | 114 | 114 | 114 | 110 | 109 | 111 | 110 |
| Residential | 48 | 48 | 48 | 48 | 48 | 42 | 42 | 42 | 48 | 48 | 47 | 48 |
| **Total New DSM (aMW)** | 158 | 157 | 158 | 168 | 198 | 212 | 214 | 205 | 184 | 162 | 159 | 158 |
| **Monthly Surplus/Deficit** | 666 | 433 | 249 | 252 | 840 | 783 | 98 | 116 | 455 | 468 | 559 | 474 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 866 | 633 | 449 | 752 | 1,340 | 1,283 | 598 | 616 | 955 | 668 | 759 | 674 |

# Monthly Average Energy Load and Resource Balance (continued)

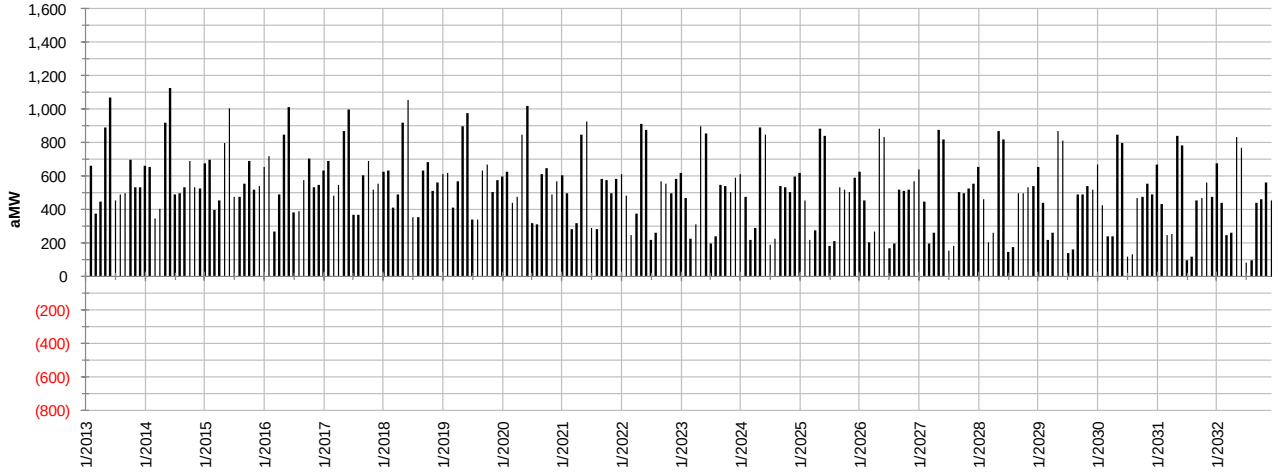
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 67 | 67 | 67 | 70 | 81 | 84 | 84 | 81 | 75 | 68 | 67 | 67 |
| Load Forecast (70th% w/DSM) | (2,286) | (1,977) | (1,843) | (1,822) | (2,100) | (2,493) | (2,894) | (2,664) | (2,174) | (1,789) | (1,935) | (2,402) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 34 | 36 | 33 | 31 | 30 | 35 | 37 | 25 | 31 | 40 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 65 | 67 | 64 | 62 | 61 | 65 | 68 | 56 | 62 | 71 | 78 |
| **Firm Pacific NW Import Capability** | 313 | 10 | 85 | 33 | 416 | 342 | 237 | 281 | 299 | 0 | 259 | 306 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,795 | 2,252 | 1,926 | 1,906 | 2,722 | 3,041 | 2,752 | 2,546 | 2,423 | 2,077 | 2,329 | 2,691 |
| **Monthly Surplus/Deficit** | 510 | 275 | 83 | 84 | 622 | 548 | (142) | (118) | 249 | 288 | 394 | 288 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 12 | 42 | 59 | 61 | 51 | 27 | 5 | 0 | 0 |
| Commercial/Industrial | 115 | 115 | 114 | 114 | 117 | 119 | 119 | 119 | 115 | 115 | 115 | 115 |
| Residential | 52 | 52 | 52 | 52 | 52 | 46 | 46 | 46 | 52 | 52 | 52 | 52 |
| **Total New DSM (aMW)** | 167 | 167 | 167 | 178 | 210 | 224 | 226 | 216 | 194 | 172 | 167 | 167 |
| **Monthly Surplus/Deficit** | 677 | 442 | 249 | 262 | 832 | 772 | 84 | 98 | 443 | 460 | 561 | 456 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 877 | 642 | 449 | 762 | 1,332 | 1,272 | 584 | 598 | 943 | 660 | 761 | 656 |

# Monthly Average Energy Surplus/Deficit Charts

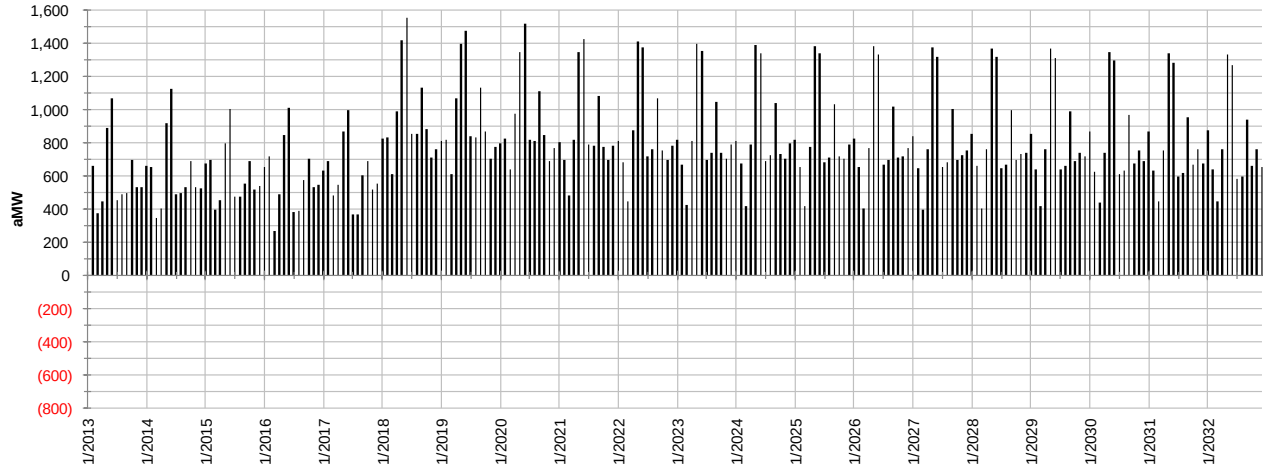
**Average energy monthly surpluses and deficits with existing DSM and existing resources**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, and IRP DSM**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources**



# Peak-Hour Load and Resource Balance

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,513) | (2,392) | (2,099) | (1,978) | (2,813) | (3,272) | (3,390) | (3,035) | (2,785) | (2,033) | (2,274) | (2,690) |
| Existing DSM (EE) | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,505) | (2,384) | (2,092) | (1,971) | (2,805) | (3,264) | (3,382) | (3,027) | (2,778) | (2,026) | (2,267) | (2,683) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,505) | (2,384) | (2,092) | (1,971) | (2,805) | (3,264) | (3,382) | (3,027) | (2,778) | (2,026) | (2,267) | (2,683) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 854 | 1,085 | 1,023 | 1,062 | 1,133 | 1,027 | 916 | 878 | 761 | 887 | 673 | 938 |
| Hydro (90th%)—Other | 245 | 246 | 224 | 244 | 347 | 360 | 304 | 270 | 255 | 249 | 240 | 245 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,099 | 1,331 | 1,247 | 1,306 | 1,480 | 1,387 | 1,268 | 1,148 | 1,016 | 1,136 | 912 | 1,183 |
| **CSPP (PURPA)** | 73 | 76 | 82 | 117 | 163 | 171 | 177 | 168 | 155 | 117 | 84 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 205 | 292 | 194 | 264 | 68 | 0 | 0 | 0 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,940 | 3,186 | 3,099 | 3,189 | 3,572 | 3,632 | 3,420 | 3,359 | 3,018 | 3,020 | 2,759 | 3,038 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 2 | 3 | 3 | 3 | 1 | 0 | 0 | 0 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM Peak Reduction** | 6 | 6 | 6 | 7 | 9 | 10 | 10 | 9 | 8 | 7 | 6 | 7 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 441 | 809 | 1,013 | 1,225 | 776 | 378 | 48 | 342 | 248 | 1,001 | 499 | 362 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,548) | (2,417) | (2,129) | (2,010) | (2,868) | (3,325) | (3,458) | (3,087) | (2,837) | (2,061) | (2,303) | (2,718) |
| Existing DSM (EE) | 14 | 14 | 14 | 15 | 16 | 16 | 16 | 16 | 15 | 14 | 14 | 14 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,534) | (2,403) | (2,115) | (1,996) | (2,852) | (3,310) | (3,442) | (3,071) | (2,822) | (2,047) | (2,289) | (2,704) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,534) | (2,403) | (2,115) | (1,996) | (2,852) | (3,310) | (3,442) | (3,071) | (2,822) | (2,047) | (2,289) | (2,704) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 852 | 1,078 | 1,017 | 1,061 | 1,132 | 1,024 | 914 | 874 | 758 | 880 | 673 | 935 |
| Hydro (90th%)—Other | 244 | 245 | 224 | 243 | 343 | 356 | 303 | 269 | 255 | 248 | 238 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,097 | 1,323 | 1,241 | 1,304 | 1,475 | 1,380 | 1,265 | 1,143 | 1,012 | 1,129 | 911 | 1,179 |
| **CSPP (PURPA)** | 75 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 230 | 352 | 237 | 277 | 113 | 0 | 0 | 1 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,940 | 3,192 | 3,103 | 3,141 | 3,661 | 3,697 | 3,471 | 3,379 | 3,070 | 3,024 | 2,769 | 3,047 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 4 | 6 | 6 | 5 | 3 | 0 | 0 | 0 |
| Commercial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM Peak Reduction** | 13 | 13 | 13 | 14 | 17 | 19 | 20 | 19 | 16 | 14 | 13 | 13 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 419 | 803 | 1,001 | 1,159 | 825 | 406 | 49 | 326 | 265 | 991 | 493 | 356 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,552) | (2,435) | (2,129) | (2,002) | (2,922) | (3,369) | (3,520) | (3,129) | (2,879) | (2,087) | (2,310) | (2,739) |
| Existing DSM (EE) | 21 | 21 | 21 | 22 | 24 | 24 | 24 | 23 | 23 | 22 | 21 | 21 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,530) | (2,413) | (2,108) | (1,980) | (2,898) | (3,345) | (3,495) | (3,106) | (2,856) | (2,065) | (2,289) | (2,718) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,530) | (2,413) | (2,108) | (1,980) | (2,898) | (3,345) | (3,495) | (3,106) | (2,856) | (2,065) | (2,289) | (2,718) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 855 | 1,080 | 1,029 | 1,062 | 1,134 | 1,025 | 914 | 873 | 756 | 886 | 672 | 937 |
| Hydro (90th%)—Other | 244 | 246 | 231 | 245 | 352 | 365 | 304 | 272 | 255 | 252 | 241 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,100 | 1,326 | 1,260 | 1,307 | 1,487 | 1,390 | 1,266 | 1,145 | 1,011 | 1,138 | 913 | 1,181 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 276 | 342 | 237 | 274 | 147 | 0 | 0 | 15 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,954 | 3,195 | 3,122 | 3,202 | 3,718 | 3,697 | 3,472 | 3,377 | 3,103 | 3,033 | 2,771 | 3,063 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (24) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 6 | 8 | 8 | 7 | 4 | 1 | 0 | 0 |
| Commercial | 19 | 19 | 19 | 19 | 19 | 20 | 20 | 20 | 19 | 19 | 19 | 19 |
| Residential | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total New DSM Peak Reduction** | 20 | 20 | 20 | 21 | 26 | 28 | 29 | 27 | 23 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 443 | 801 | 1,034 | 1,243 | 846 | 381 | 5 | 299 | 270 | 988 | 501 | 364 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,572) | (2,452) | (2,144) | (2,013) | (2,967) | (3,401) | (3,571) | (3,163) | (2,916) | (2,109) | (2,329) | (2,764) |
| Existing DSM (EE) | 26 | 26 | 26 | 27 | 29 | 30 | 30 | 29 | 28 | 26 | 26 | 26 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,546) | (2,426) | (2,118) | (1,986) | (2,937) | (3,371) | (3,541) | (3,134) | (2,888) | (2,083) | (2,303) | (2,738) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,546) | (2,426) | (2,118) | (1,986) | (2,937) | (3,371) | (3,541) | (3,134) | (2,888) | (2,083) | (2,303) | (2,738) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 854 | 1,082 | 1,026 | 1,061 | 1,133 | 1,022 | 911 | 797 | 753 | 881 | 672 | 934 |
| Hydro (90th%)—Other | 244 | 248 | 231 | 244 | 353 | 365 | 303 | 233 | 256 | 252 | 241 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,098 | 1,329 | 1,257 | 1,305 | 1,485 | 1,388 | 1,215 | 1,030 | 1,009 | 1,133 | 913 | 1,178 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 314 | 342 | 237 | 272 | 178 | 0 | 0 | 34 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,948 | 3,194 | 3,125 | 3,209 | 3,692 | 3,688 | 3,415 | 3,256 | 3,129 | 3,037 | 2,784 | 3,076 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (126) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 7 | 9 | 10 | 8 | 4 | 1 | 0 | 0 |
| Commercial | 25 | 24 | 24 | 24 | 25 | 25 | 25 | 25 | 24 | 24 | 24 | 24 |
| Residential | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total New DSM Peak Reduction** | 27 | 26 | 26 | 28 | 33 | 36 | 37 | 35 | 31 | 27 | 26 | 26 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (89) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 429 | 794 | 1,034 | 1,251 | 788 | 452 | 11 | 258 | 272 | 981 | 508 | 364 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,603) | (2,475) | (2,169) | (2,038) | (3,016) | (3,445) | (3,632) | (3,208) | (2,961) | (2,134) | (2,358) | (2,795) |
| Existing DSM (EE) | 30 | 30 | 30 | 31 | 34 | 35 | 35 | 34 | 33 | 30 | 30 | 30 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,574) | (2,445) | (2,139) | (2,007) | (2,982) | (3,410) | (3,596) | (3,174) | (2,929) | (2,103) | (2,328) | (2,765) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,574) | (2,445) | (2,139) | (2,007) | (2,982) | (3,410) | (3,596) | (3,174) | (2,929) | (2,103) | (2,328) | (2,765) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 852 | 1,080 | 1,023 | 1,060 | 1,132 | 1,020 | 909 | 794 | 750 | 875 | 673 | 932 |
| Hydro (90th%)—Other | 244 | 246 | 231 | 244 | 350 | 363 | 303 | 232 | 256 | 252 | 240 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,096 | 1,326 | 1,254 | 1,304 | 1,482 | 1,383 | 1,212 | 1,026 | 1,006 | 1,126 | 914 | 1,176 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 359 | 347 | 237 | 269 | 219 | 0 | 0 | 61 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,946 | 3,191 | 3,123 | 3,208 | 3,791 | 3,688 | 3,413 | 3,250 | 3,167 | 3,030 | 2,785 | 3,101 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (184) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 8 | 11 | 11 | 9 | 5 | 1 | 0 | 0 |
| Commercial | 29 | 29 | 29 | 29 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 30 |
| Residential | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 | 4 | 4 |
| **Total New DSM Peak Reduction** | 33 | 33 | 33 | 35 | 41 | 44 | 45 | 43 | 38 | 34 | 33 | 33 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (139) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 405 | 779 | 1,016 | 1,236 | 850 | 471 | 11 | 269 | 276 | 961 | 490 | 368 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,629) | (2,492) | (2,190) | (2,059) | (3,064) | (3,488) | (3,691) | (3,251) | (3,003) | (2,154) | (2,381) | (2,823) |
| Existing DSM (EE) | 34 | 34 | 34 | 35 | 39 | 40 | 40 | 39 | 37 | 34 | 34 | 34 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,595) | (2,459) | (2,156) | (2,023) | (3,025) | (3,448) | (3,651) | (3,212) | (2,966) | (2,120) | (2,347) | (2,789) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,595) | (2,459) | (2,156) | (2,023) | (3,025) | (3,448) | (3,651) | (3,212) | (2,966) | (2,120) | (2,347) | (2,789) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 850 | 1,073 | 1,013 | 1,058 | 1,131 | 1,017 | 907 | 790 | 747 | 870 | 673 | 930 |
| Hydro (90th%)—Other | 243 | 245 | 230 | 244 | 347 | 358 | 302 | 231 | 255 | 250 | 240 | 243 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,093 | 1,318 | 1,243 | 1,303 | 1,478 | 1,376 | 1,209 | 1,021 | 1,002 | 1,121 | 912 | 1,173 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 385 | 342 | 237 | 267 | 257 | 0 | 0 | 86 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,943 | 3,183 | 3,111 | 3,206 | 3,812 | 3,676 | 3,409 | 3,243 | 3,201 | 3,025 | 2,784 | 3,123 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (242) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 9 | 12 | 13 | 11 | 6 | 1 | 0 | 0 |
| Commercial | 35 | 35 | 35 | 35 | 35 | 36 | 36 | 36 | 35 | 35 | 35 | 35 |
| Residential | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| **Total New DSM Peak Reduction** | 42 | 42 | 41 | 44 | 51 | 55 | 55 | 53 | 48 | 42 | 42 | 42 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (187) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 589 | 966 | 1,197 | 1,727 | 1,338 | 782 | 313 | 584 | 782 | 1,147 | 678 | 575 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,657) | (2,511) | (2,212) | (2,081) | (3,112) | (3,532) | (3,752) | (3,295) | (3,046) | (2,176) | (2,406) | (2,851) |
| Existing DSM (EE) | 37 | 37 | 37 | 39 | 44 | 45 | 45 | 44 | 41 | 38 | 37 | 37 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,620) | (2,474) | (2,175) | (2,042) | (3,068) | (3,487) | (3,707) | (3,251) | (3,005) | (2,139) | (2,368) | (2,814) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,620) | (2,474) | (2,175) | (2,042) | (3,068) | (3,487) | (3,707) | (3,251) | (3,005) | (2,139) | (2,368) | (2,814) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 848 | 1,071 | 1,007 | 1,057 | 1,130 | 1,015 | 905 | 787 | 744 | 862 | 674 | 927 |
| Hydro (90th%)—Other | 243 | 245 | 230 | 243 | 344 | 355 | 302 | 231 | 229 | 250 | 238 | 242 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,091 | 1,316 | 1,237 | 1,300 | 1,473 | 1,371 | 1,208 | 1,018 | 973 | 1,112 | 912 | 1,171 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 384 | 342 | 237 | 265 | 270 | 0 | 0 | 111 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,941 | 3,180 | 3,106 | 3,204 | 3,749 | 3,670 | 3,409 | 3,237 | 3,184 | 3,016 | 2,783 | 3,146 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (298) | (14) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 10 | 14 | 15 | 12 | 7 | 1 | 0 | 0 |
| Commercial | 40 | 39 | 40 | 39 | 40 | 41 | 41 | 41 | 40 | 39 | 40 | 40 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM Peak Reduction** | 49 | 49 | 49 | 52 | 60 | 64 | 65 | 62 | 56 | 50 | 49 | 50 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (233) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 570 | 956 | 1,180 | 1,713 | 1,241 | 747 | 267 | 548 | 736 | 1,128 | 664 | 582 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,690) | (2,535) | (2,239) | (2,107) | (3,166) | (3,580) | (3,817) | (3,342) | (3,092) | (2,204) | (2,436) | (2,885) |
| Existing DSM (EE) | 42 | 42 | 42 | 44 | 49 | 50 | 51 | 49 | 46 | 43 | 42 | 42 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,648) | (2,493) | (2,197) | (2,063) | (3,117) | (3,529) | (3,766) | (3,293) | (3,046) | (2,161) | (2,394) | (2,843) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,648) | (2,493) | (2,197) | (2,063) | (3,117) | (3,529) | (3,766) | (3,293) | (3,046) | (2,161) | (2,394) | (2,843) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 843 | 1,068 | 1,005 | 1,056 | 1,128 | 1,013 | 902 | 783 | 741 | 853 | 673 | 927 |
| Hydro (90th%)—Other | 243 | 243 | 230 | 243 | 341 | 353 | 301 | 230 | 228 | 250 | 237 | 241 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 9 | 11 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,088 | 1,313 | 1,235 | 1,298 | 1,479 | 1,377 | 1,205 | 1,013 | 968 | 1,103 | 910 | 1,170 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 383 | 342 | 237 | 262 | 269 | 0 | 4 | 139 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,938 | 3,178 | 3,104 | 3,202 | 3,811 | 3,676 | 3,406 | 3,230 | 3,179 | 3,007 | 2,785 | 3,173 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (360) | (64) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 12 | 16 | 17 | 14 | 8 | 1 | 0 | 0 |
| Commercial | 45 | 45 | 45 | 45 | 46 | 47 | 47 | 47 | 45 | 45 | 46 | 45 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM Peak Reduction** | 54 | 54 | 54 | 57 | 66 | 71 | 72 | 69 | 62 | 55 | 55 | 54 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (288) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 545 | 939 | 1,161 | 1,696 | 1,261 | 719 | 212 | 506 | 695 | 1,101 | 646 | 584 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,720) | (2,564) | (2,261) | (2,126) | (3,222) | (3,627) | (3,882) | (3,391) | (3,139) | (2,232) | (2,463) | (2,919) |
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,674) | (2,519) | (2,216) | (2,079) | (3,168) | (3,572) | (3,827) | (3,337) | (3,088) | (2,186) | (2,418) | (2,874) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,674) | (2,519) | (2,216) | (2,079) | (3,168) | (3,572) | (3,827) | (3,337) | (3,088) | (2,186) | (2,418) | (2,874) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 841 | 1,066 | 1,004 | 1,054 | 1,127 | 1,009 | 899 | 779 | 737 | 840 | 674 | 923 |
| Hydro (90th%)—Other | 242 | 243 | 229 | 243 | 341 | 328 | 300 | 229 | 227 | 248 | 235 | 241 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 8 | 10 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,086 | 1,311 | 1,233 | 1,297 | 1,476 | 1,347 | 1,202 | 1,008 | 964 | 1,089 | 909 | 1,166 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,965 | 3,118 | 3,044 | 3,143 | 3,802 | 3,643 | 3,398 | 3,218 | 3,168 | 2,935 | 2,806 | 3,197 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (429) | (119) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM Peak Reduction** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (349) | (41) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 552 | 860 | 1,088 | 1,628 | 1,208 | 650 | 151 | 459 | 648 | 1,011 | 649 | 583 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,745) | (2,585) | (2,281) | (2,144) | (3,272) | (3,668) | (3,941) | (3,432) | (3,180) | (2,257) | (2,487) | (2,950) |
| Existing DSM (EE) | 49 | 49 | 49 | 51 | 58 | 60 | 60 | 58 | 55 | 50 | 49 | 49 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,696) | (2,537) | (2,232) | (2,092) | (3,213) | (3,608) | (3,881) | (3,374) | (3,126) | (2,207) | (2,438) | (2,901) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,696) | (2,537) | (2,232) | (2,092) | (3,213) | (3,608) | (3,881) | (3,374) | (3,126) | (2,207) | (2,438) | (2,901) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 839 | 1,063 | 1,000 | 1,052 | 1,126 | 1,006 | 896 | 775 | 733 | 831 | 674 | 920 |
| Hydro (90th%)—Other | 242 | 242 | 229 | 242 | 339 | 326 | 300 | 228 | 226 | 247 | 234 | 240 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 8 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,083 | 1,307 | 1,229 | 1,294 | 1,473 | 1,342 | 1,198 | 1,003 | 960 | 1,078 | 909 | 1,162 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 113 | 0 | 0 | 0 | 433 | 349 | 237 | 308 | 318 | 0 | 103 | 254 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,988 | 3,115 | 3,040 | 3,140 | 3,798 | 3,591 | 3,341 | 3,208 | 3,162 | 2,924 | 2,826 | 3,222 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (17) | (540) | (166) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 15 | 22 | 22 | 19 | 10 | 2 | 0 | 0 |
| Commercial | 59 | 58 | 58 | 58 | 59 | 60 | 60 | 60 | 58 | 58 | 58 | 58 |
| Residential | 9 | 9 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 10 |
| **Total New DSM Peak Reduction** | 68 | 67 | 67 | 72 | 84 | 90 | 91 | 88 | 78 | 70 | 68 | 67 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (449) | (78) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 560 | 845 | 1,075 | 1,619 | 1,168 | 574 | 51 | 422 | 614 | 987 | 656 | 588 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,771) | (2,603) | (2,301) | (2,164) | (3,319) | (3,709) | (4,000) | (3,474) | (3,222) | (2,278) | (2,510) | (2,976) |
| Existing DSM (EE) | 52 | 52 | 52 | 55 | 62 | 64 | 65 | 62 | 58 | 53 | 52 | 52 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,719) | (2,551) | (2,249) | (2,109) | (3,257) | (3,645) | (3,935) | (3,412) | (3,164) | (2,225) | (2,458) | (2,924) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,719) | (2,551) | (2,249) | (2,109) | (3,257) | (3,645) | (3,935) | (3,412) | (3,164) | (2,225) | (2,458) | (2,924) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 835 | 1,061 | 1,001 | 1,051 | 1,124 | 1,003 | 893 | 770 | 730 | 828 | 674 | 918 |
| Hydro (90th%)—Other | 241 | 242 | 228 | 241 | 336 | 323 | 299 | 227 | 225 | 246 | 234 | 240 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 7 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,078 | 1,305 | 1,229 | 1,292 | 1,467 | 1,335 | 1,195 | 997 | 955 | 1,074 | 908 | 1,159 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 181 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 136 | 0 | 0 | 0 | 431 | 346 | 237 | 306 | 316 | 0 | 123 | 291 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,007 | 3,112 | 3,040 | 3,138 | 3,790 | 3,580 | 3,337 | 3,201 | 3,156 | 2,921 | 2,845 | 3,257 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (65) | (598) | (211) | (9) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 5 | 18 | 25 | 26 | 22 | 11 | 2 | 0 | 0 |
| Commercial | 64 | 64 | 64 | 64 | 65 | 67 | 67 | 67 | 64 | 64 | 64 | 65 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM Peak Reduction** | 74 | 74 | 73 | 79 | 92 | 100 | 101 | 97 | 85 | 76 | 74 | 74 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (497) | (114) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 562 | 834 | 1,064 | 1,608 | 1,125 | 535 | 3 | 386 | 577 | 971 | 661 | 607 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,783) | (2,613) | (2,308) | (2,168) | (3,363) | (3,746) | (4,055) | (3,511) | (3,259) | (2,296) | (2,522) | (2,993) |
| Existing DSM (EE) | 55 | 54 | 55 | 57 | 65 | 68 | 68 | 66 | 62 | 56 | 55 | 55 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,728) | (2,558) | (2,254) | (2,111) | (3,298) | (3,679) | (3,987) | (3,445) | (3,198) | (2,240) | (2,467) | (2,938) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,728) | (2,558) | (2,254) | (2,111) | (3,298) | (3,679) | (3,987) | (3,445) | (3,198) | (2,240) | (2,467) | (2,938) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 832 | 1,058 | 999 | 1,049 | 1,112 | 1,000 | 891 | 766 | 727 | 819 | 673 | 917 |
| Hydro (90th%)—Other | 240 | 242 | 228 | 240 | 335 | 321 | 298 | 226 | 225 | 245 | 233 | 239 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 7 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,075 | 1,301 | 1,228 | 1,289 | 1,453 | 1,330 | 1,191 | 992 | 951 | 1,064 | 906 | 1,158 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 143 | 0 | 0 | 0 | 430 | 342 | 237 | 303 | 315 | 0 | 132 | 312 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,011 | 3,109 | 3,039 | 3,135 | 3,775 | 3,572 | 3,334 | 3,192 | 3,150 | 2,911 | 2,852 | 3,276 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (106) | (653) | (254) | (47) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 20 | 28 | 29 | 25 | 13 | 2 | 0 | 0 |
| Commercial | 71 | 71 | 71 | 71 | 71 | 74 | 74 | 74 | 72 | 71 | 71 | 72 |
| Residential | 12 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 12 | 12 |
| **Total New DSM Peak Reduction** | 84 | 83 | 84 | 89 | 104 | 113 | 114 | 109 | 97 | 86 | 84 | 84 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (539) | (144) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 550 | 550 | 550 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 567 | 834 | 1,068 | 1,614 | 1,081 | 557 | 11 | 406 | 550 | 956 | 669 | 623 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,786) | (2,624) | (2,308) | (2,163) | (3,406) | (3,776) | (4,105) | (3,542) | (3,291) | (2,312) | (2,527) | (3,009) |
| Existing DSM (EE) | 57 | 57 | 57 | 60 | 68 | 71 | 72 | 69 | 64 | 58 | 57 | 57 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,730) | (2,568) | (2,252) | (2,103) | (3,337) | (3,705) | (4,033) | (3,473) | (3,226) | (2,254) | (2,470) | (2,952) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,730) | (2,568) | (2,252) | (2,103) | (3,337) | (3,705) | (4,033) | (3,473) | (3,226) | (2,254) | (2,470) | (2,952) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 830 | 1,055 | 998 | 1,047 | 1,111 | 998 | 888 | 761 | 723 | 812 | 674 | 914 |
| Hydro (90th%)—Other | 240 | 241 | 228 | 240 | 334 | 320 | 298 | 225 | 224 | 245 | 232 | 239 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,073 | 1,298 | 1,225 | 1,287 | 1,451 | 1,326 | 1,188 | 987 | 947 | 1,057 | 906 | 1,155 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 160 | 0 | 0 | 0 | 428 | 342 | 237 | 300 | 313 | 0 | 135 | 321 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,025 | 3,105 | 3,036 | 3,133 | 3,771 | 3,569 | 3,331 | 3,184 | 3,144 | 2,903 | 2,854 | 3,282 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (137) | (703) | (289) | (82) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 23 | 32 | 33 | 28 | 15 | 3 | 0 | 0 |
| Commercial | 77 | 77 | 77 | 77 | 77 | 80 | 80 | 80 | 77 | 77 | 78 | 77 |
| Residential | 16 | 16 | 16 | 16 | 16 | 14 | 14 | 14 | 16 | 16 | 16 | 16 |
| **Total New DSM Peak Reduction** | 93 | 93 | 93 | 99 | 116 | 126 | 127 | 122 | 108 | 96 | 94 | 93 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (10) | (575) | (167) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 600 | 600 | 600 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 589 | 830 | 1,078 | 1,629 | 1,050 | 590 | 25 | 433 | 526 | 944 | 678 | 623 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,810) | (2,640) | (2,326) | (2,180) | (3,450) | (3,811) | (4,157) | (3,578) | (3,328) | (2,332) | (2,548) | (3,036) |
| Existing DSM (EE) | 59 | 59 | 59 | 62 | 71 | 74 | 75 | 72 | 67 | 60 | 59 | 59 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,751) | (2,581) | (2,267) | (2,117) | (3,379) | (3,737) | (4,083) | (3,506) | (3,262) | (2,272) | (2,489) | (2,977) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,751) | (2,581) | (2,267) | (2,117) | (3,379) | (3,737) | (4,083) | (3,506) | (3,262) | (2,272) | (2,489) | (2,977) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 827 | 1,050 | 994 | 1,046 | 1,109 | 995 | 885 | 758 | 720 | 803 | 675 | 910 |
| Hydro (90th%)—Other | 239 | 241 | 227 | 239 | 331 | 318 | 297 | 225 | 223 | 244 | 231 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,068 | 1,292 | 1,222 | 1,285 | 1,447 | 1,322 | 1,184 | 982 | 943 | 1,047 | 906 | 1,150 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 183 | 0 | 0 | 0 | 427 | 342 | 237 | 298 | 311 | 0 | 154 | 319 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,044 | 3,099 | 3,032 | 3,131 | 3,766 | 3,564 | 3,327 | 3,177 | 3,138 | 2,893 | 2,874 | 3,275 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (173) | (756) | (329) | (124) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 7 | 26 | 36 | 38 | 32 | 17 | 3 | 0 | 0 |
| Commercial | 83 | 83 | 83 | 83 | 84 | 86 | 86 | 86 | 83 | 83 | 84 | 83 |
| Residential | 21 | 21 | 21 | 21 | 21 | 18 | 18 | 18 | 21 | 21 | 21 | 21 |
| **Total New DSM Peak Reduction** | 104 | 104 | 104 | 111 | 131 | 141 | 142 | 136 | 120 | 107 | 105 | 104 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (32) | (613) | (193) | (3) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 650 | 650 | 650 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 597 | 822 | 1,069 | 1,625 | 1,018 | 618 | 37 | 457 | 497 | 928 | 690 | 603 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,835) | (2,657) | (2,346) | (2,199) | (3,496) | (3,854) | (4,217) | (3,622) | (3,372) | (2,354) | (2,570) | (3,061) |
| Existing DSM (EE) | 61 | 61 | 61 | 64 | 74 | 77 | 77 | 74 | 69 | 63 | 61 | 61 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,774) | (2,596) | (2,285) | (2,135) | (3,422) | (3,777) | (4,139) | (3,547) | (3,303) | (2,291) | (2,509) | (3,000) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,774) | (2,596) | (2,285) | (2,135) | (3,422) | (3,777) | (4,139) | (3,547) | (3,303) | (2,291) | (2,509) | (3,000) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825.0 | 1,047.9 | 990.6 | 1,044.4 | 1,107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 218 | 0 | 0 | 0 | 425 | 342 | 237 | 295 | 308 | 0 | 174 | 317 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,077 | 3,097 | 3,028 | 3,104 | 3,761 | 3,560 | 3,324 | 3,170 | 3,131 | 2,886 | 2,894 | 3,254 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (217) | (816) | (378) | (172) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 8 | 29 | 41 | 43 | 36 | 19 | 4 | 0 | 0 |
| Commercial | 89 | 88 | 88 | 88 | 90 | 92 | 92 | 92 | 89 | 89 | 89 | 89 |
| Residential | 27 | 27 | 27 | 27 | 26 | 23 | 23 | 23 | 27 | 27 | 27 | 27 |
| **Total New DSM Peak Reduction** | 116 | 115 | 115 | 123 | 146 | 156 | 158 | 151 | 134 | 119 | 115 | 115 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (61) | (658) | (226) | (37) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 700 | 700 | 700 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 619 | 816 | 1,059 | 1,593 | 985 | 639 | 42 | 474 | 463 | 914 | 700 | 570 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,844) | (2,667) | (2,350) | (2,201) | (3,538) | (3,891) | (4,270) | (3,659) | (3,408) | (2,370) | (2,579) | (3,079) |
| Existing DSM (EE) | 63 | 62 | 62 | 66 | 75 | 79 | 79 | 76 | 71 | 64 | 63 | 63 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,781) | (2,605) | (2,288) | (2,135) | (3,463) | (3,812) | (4,191) | (3,582) | (3,337) | (2,306) | (2,517) | (3,016) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,781) | (2,605) | (2,288) | (2,135) | (3,463) | (3,812) | (4,191) | (3,582) | (3,337) | (2,306) | (2,517) | (3,016) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825.0 | 1047.9 | 990.6 | 1044.4 | 1107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 236 | 0 | 7 | 0 | 423 | 342 | 237 | 293 | 306 | 0 | 182 | 314 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,095 | 3,097 | 3,035 | 3,104 | 3,759 | 3,560 | 3,324 | 3,168 | 3,129 | 2,886 | 2,902 | 3,251 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (252) | (868) | (414) | (208) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 9 | 33 | 46 | 48 | 40 | 21 | 4 | 0 | 0 |
| Commercial | 96 | 94 | 94 | 95 | 96 | 98 | 98 | 98 | 95 | 95 | 95 | 96 |
| Residential | 33 | 33 | 33 | 33 | 33 | 29 | 29 | 29 | 33 | 33 | 33 | 33 |
| **Total New DSM Peak Reduction** | 128 | 127 | 127 | 137 | 161 | 174 | 175 | 168 | 149 | 132 | 128 | 128 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (78) | (693) | (247) | (59) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 700 | 700 | 700 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 642 | 819 | 1,075 | 1,607 | 958 | 622 | 7 | 453 | 441 | 912 | 713 | 563 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,864) | (2,680) | (2,365) | (2,214) | (3,582) | (3,927) | (4,325) | (3,697) | (3,447) | (2,389) | (2,598) | (3,104) |
| Existing DSM (EE) | 64 | 64 | 64 | 68 | 77 | 80 | 81 | 78 | 73 | 65 | 64 | 64 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,800) | (2,616) | (2,301) | (2,147) | (3,505) | (3,847) | (4,244) | (3,619) | (3,375) | (2,324) | (2,534) | (3,040) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,800) | (2,616) | (2,301) | (2,147) | (3,505) | (3,847) | (4,244) | (3,619) | (3,375) | (2,324) | (2,534) | (3,040) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825.0 | 1,047.9 | 990.6 | 1,044.4 | 1,107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 247 | 0 | 24 | 0 | 421 | 342 | 237 | 290 | 304 | 0 | 199 | 312 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,106 | 3,097 | 3,052 | 3,104 | 3,757 | 3,560 | 3,324 | 3,165 | 3,127 | 2,886 | 2,919 | 3,249 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (287) | (920) | (454) | (248) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 10 | 37 | 52 | 54 | 45 | 24 | 5 | 0 | 0 |
| Commercial | 100 | 100 | 100 | 100 | 101 | 104 | 104 | 104 | 101 | 100 | 100 | 101 |
| Residential | 38 | 38 | 38 | 38 | 37 | 33 | 33 | 33 | 37 | 38 | 38 | 37 |
| **Total New DSM Peak Reduction** | 138 | 138 | 137 | 148 | 175 | 189 | 191 | 182 | 163 | 142 | 138 | 139 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (98) | (729) | (271) | (85) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 250 | 250 | 250 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 750 | 750 | 750 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 644 | 818 | 1,089 | 1,606 | 928 | 652 | 21 | 479 | 415 | 904 | 723 | 547 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,902) | (2,708) | (2,395) | (2,242) | (3,635) | (3,978) | (4,391) | (3,748) | (3,498) | (2,418) | (2,631) | (3,142) |
| Existing DSM (EE) | 65 | 65 | 65 | 69 | 79 | 82 | 83 | 80 | 74 | 67 | 65 | 66 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,836) | (2,642) | (2,329) | (2,174) | (3,556) | (3,895) | (4,308) | (3,668) | (3,424) | (2,351) | (2,566) | (3,077) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,836) | (2,642) | (2,329) | (2,174) | (3,556) | (3,895) | (4,308) | (3,668) | (3,424) | (2,351) | (2,566) | (3,077) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 281 | 0 | 61 | 0 | 419 | 342 | 237 | 287 | 302 | 0 | 231 | 310 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,140 | 3,097 | 3,089 | 3,104 | 3,755 | 3,560 | 3,324 | 3,162 | 3,125 | 2,886 | 2,951 | 3,247 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (336) | (984) | (507) | (299) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 38 | 54 | 56 | 47 | 25 | 5 | 0 | 0 |
| Commercial | 105 | 105 | 105 | 105 | 105 | 109 | 109 | 109 | 106 | 105 | 105 | 106 |
| Residential | 43 | 43 | 43 | 43 | 43 | 38 | 38 | 38 | 43 | 43 | 43 | 43 |
| **Total New DSM Peak Reduction** | 148 | 148 | 148 | 158 | 186 | 200 | 202 | 194 | 174 | 152 | 148 | 149 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (135) | (782) | (313) | (125) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 800 | 800 | 800 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 652 | 802 | 1,108 | 1,589 | 886 | 665 | 18 | 487 | 375 | 887 | 733 | 519 |

# Peak-Hour Load and Resource Balance (continued)

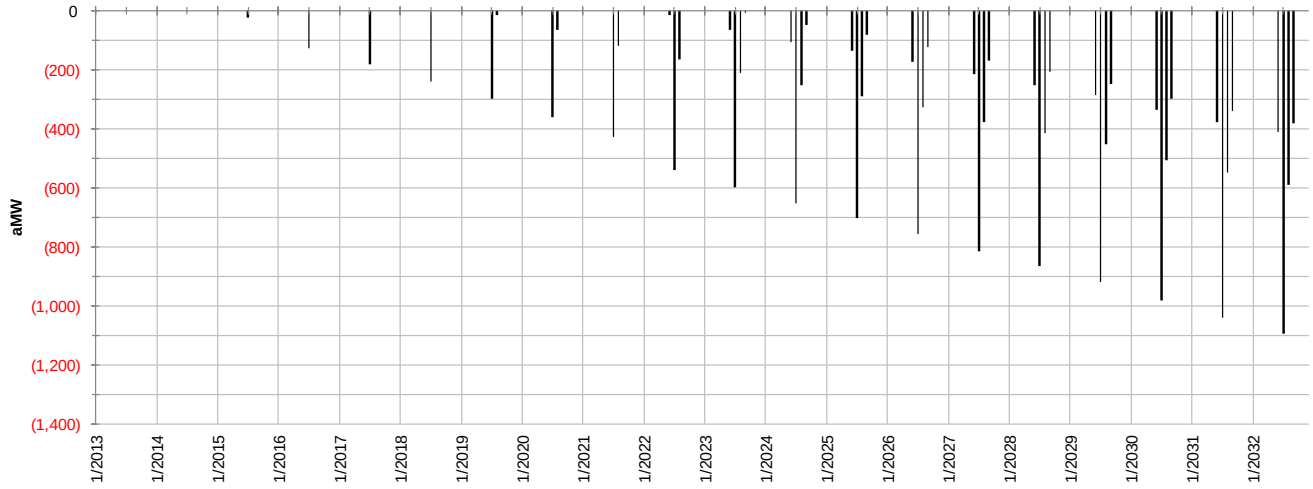
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,918) | (2,720) | (2,405) | (2,251) | (3,679) | (4,019) | (4,448) | (3,790) | (3,540) | (2,437) | (2,646) | (3,163) |
| Existing DSM (EE) | 66 | 66 | 66 | 70 | 80 | 83 | 84 | 81 | 75 | 68 | 66 | 66 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,851) | (2,654) | (2,339) | (2,181) | (3,599) | (3,936) | (4,365) | (3,710) | (3,465) | (2,369) | (2,580) | (3,097) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,851) | (2,654) | (2,339) | (2,181) | (3,599) | (3,936) | (4,365) | (3,710) | (3,465) | (2,369) | (2,580) | (3,097) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 291 | 12 | 78 | 15 | 418 | 342 | 237 | 285 | 300 | 0 | 245 | 308 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,150 | 3,109 | 3,106 | 3,119 | 3,754 | 3,560 | 3,324 | 3,160 | 3,123 | 2,886 | 2,965 | 3,245 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (376) | (1,041) | (550) | (342) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 40 | 56 | 58 | 49 | 26 | 5 | 0 | 0 |
| Commercial | 110 | 110 | 110 | 109 | 110 | 114 | 114 | 114 | 110 | 109 | 111 | 110 |
| Residential | 48 | 48 | 48 | 48 | 48 | 42 | 42 | 42 | 48 | 48 | 47 | 48 |
| **Total New DSM Peak Reduction** | 158 | 157 | 158 | 168 | 198 | 212 | 214 | 205 | 184 | 162 | 159 | 158 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (164) | (827) | (345) | (158) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 350 | 350 | 350 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 850 | 850 | 850 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 656 | 812 | 1,125 | 1,606 | 853 | 686 | 23 | 505 | 342 | 879 | 743 | 505 |

# Peak-Hour Load and Resource Balance (continued)

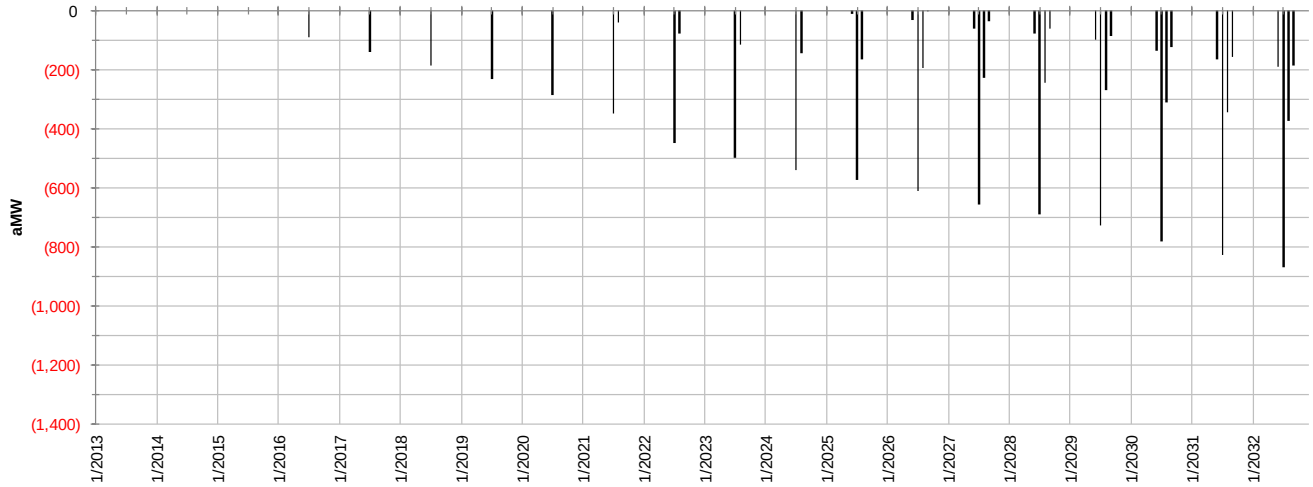
| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,933) | (2,719) | (2,416) | (2,260) | (3,722) | (4,057) | (4,503) | (3,829) | (3,579) | (2,455) | (2,661) | (3,185) |
| Existing DSM (EE) | 67 | 67 | 67 | 70 | 81 | 84 | 84 | 81 | 75 | 68 | 67 | 67 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,867) | (2,652) | (2,349) | (2,189) | (3,642) | (3,973) | (4,418) | (3,748) | (3,504) | (2,387) | (2,594) | (3,118) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,867) | (2,652) | (2,349) | (2,189) | (3,642) | (3,973) | (4,418) | (3,748) | (3,504) | (2,387) | (2,594) | (3,118) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 | 966 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 313 | 10 | 85 | 33 | 416 | 342 | 237 | 281 | 299 | 0 | 259 | 306 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,172 | 3,107 | 3,113 | 3,137 | 3,752 | 3,560 | 3,324 | 3,156 | 3,122 | 2,886 | 2,979 | 3,243 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (413) | (1,095) | (592) | (382) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 12 | 42 | 59 | 61 | 51 | 27 | 5 | 0 | 0 |
| Commercial | 115 | 115 | 114 | 114 | 117 | 119 | 119 | 119 | 115 | 115 | 115 | 115 |
| Residential | 52 | 52 | 52 | 52 | 52 | 46 | 46 | 46 | 52 | 52 | 52 | 52 |
| **Total New DSM Peak Reduction** | 167 | 167 | 167 | 178 | 210 | 224 | 226 | 216 | 194 | 172 | 167 | 167 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (190) | (869) | (375) | (187) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 370 | 370 | 370 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 870 | 870 | 870 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 672 | 821 | 1,131 | 1,627 | 821 | 680 | 1 | 495 | 313 | 871 | 752 | 492 |

# Peak-Hour Surplus/Deficit Charts

### Peak-hour monthly deficits with existing DSM and existing resources




### Peak-hour monthly deficits with existing DSM, existing resources, and IRP DSM




### Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness*, (http://www.idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program,

the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant will verify the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations.

The financial assumptions used in the analysis for the 2013 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

## Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AURORA model. The preferred portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward marginal electricity prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing throughout each year of the planning period. The resulting categories are:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods. The estimated levelized capacity cost of a new SCCT is approximately $102 per kW over a 30-year period. When multiplied by the Effective Load Carry Capacity (ELCC) of 93 percent, the annual avoided capacity cost is $95/kW. For demand response or direct load control DSM programs $95 per kW becomes the cost threshold for program cost-effectiveness. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 depending on the calendar year.

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 3 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 show the 20-year cumulative forecasted impact of energy efficiency by customer class, and the associated annual TRC.

Table DSM-7 outlines the 20-year flow of avoided generation and the benefits attributed to energy efficiency programs.

Table DSM-8 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

Table DSM-9 summarizes the 20 year cumulative forecasted new potential for energy efficiency.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided 30-Year Levelized Capacity Costs** | |
| SCCT | $102/kW |
| **Financial Assumptions** | |
| Weighted average cost of capital (2008 year ending after tax) | 6.77% |
| Financial escalation factor | 3.00% |
| **Transmission Losses** | |
| Non-summer secondary losses | 10.90% |
| Summer peak loss | 13.00% |

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak* (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2013 | $76.49 | $34.48 | $25.31 | $34.93 | $30.02 |
| 2014 | $80.75 | $37.08 | $27.11 | $37.34 | $31.76 |
| 2015 | $84.72 | $39.35 | $29.10 | $40.13 | $33.67 |
| 2016 | $86.92 | $40.96 | $30.40 | $41.62 | $34.89 |
| 2017 | $89.91 | $43.92 | $31.84 | $43.66 | $36.65 |
| 2018 | $105.15 | $56.81 | $41.02 | $56.36 | $48.35 |
| 2019 | $110.73 | $59.75 | $43.63 | $58.59 | $50.43 |
| 2020 | $116.20 | $63.46 | $46.03 | $60.93 | $52.05 |
| 2021 | $123.89 | $68.11 | $49.29 | $65.65 | $55.83 |
| 2022 | $133.18 | $73.43 | $53.52 | $71.81 | $60.51 |
| 2023 | $141.12 | $76.86 | $57.74 | $76.07 | $64.49 |
| 2024 | $148.17 | $83.42 | $60.91 | $80.83 | $68.21 |
| 2025 | $156.30 | $87.00 | $65.11 | $86.57 | $72.62 |
| 2026 | $163.99 | $91.41 | $68.20 | $92.53 | $77.24 |
| 2027 | $172.62 | $96.14 | $72.06 | $97.31 | $80.92 |
| 2028 | $180.43 | $102.13 | $75.83 | $103.04 | $85.24 |
| 2029 | $188.75 | $107.61 | $78.85 | $106.65 | $89.01 |
| 2030 | $197.88 | $116.12 | $82.84 | $112.22 | $94.27 |
| 2031 | $207.57 | $121.61 | $86.58 | $118.59 | $98.88 |
| 2032 | $218.39 | $133.14 | $91.20 | $125.54 | $104.29 |

* Estimated variable operations and management costs of a 170 MW capacity SCCT.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. Cumulative existing energy efficiency portfolio forecast 2013–2032**
*(aMW w/transmission losses)*

| Year | Commercial/Industrial | Irrigation | Residential | Total |
|---|---|---|---|---|
| 2013 | 11 | 3 | 1 | 15 |
| 2014 | 20 | 7 | 3 | 30 |
| 2015 | 29 | 11 | 4 | 44 |
| 2016 | 37 | 14 | 5 | 56 |
| 2017 | 45 | 18 | 6 | 69 |
| 2018 | 53 | 22 | 7 | 82 |
| 2019 | 60 | 26 | 8 | 94 |
| 2020 | 68 | 27 | 10 | 105 |
| 2021 | 76 | 29 | 11 | 116 |
| 2022 | 86 | 30 | 13 | 129 |
| 2023 | 94 | 31 | 14 | 139 |
| 2024 | 103 | 35 | 16 | 154 |
| 2025 | 111 | 39 | 18 | 168 |
| 2026 | 118 | 44 | 19 | 181 |
| 2027 | 125 | 50 | 21 | 196 |
| 2028 | 133 | 57 | 23 | 213 |
| 2029 | 139 | 61 | 26 | 226 |
| 2030 | 145 | 67 | 27 | 239 |
| 2031 | 151 | 72 | 27 | 250 |
| 2032 | 157 | 76 | 28 | 261 |

**Table DSM-6. Existing energy efficiency portfolio TRC 2013–2032**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2013 | $17,684,888 | $4,444,305 | $5,086,693 | $18,384,322 |
| 2014 | $15,023,476 | $4,457,135 | $5,234,296 | $19,369,878 |
| 2015 | $14,489,836 | $5,436,652 | $4,658,449 | $21,075,362 |
| 2016 | $15,795,923 | $5,422,132 | $3,079,095 | $24,297,150 |
| 2017 | $12,804,433 | $6,222,769 | $3,485,460 | $22,512,662 |
| 2018 | $18,933,992 | $8,491,051 | $3,832,902 | $31,257,946 |
| 2019 | $14,504,997 | $8,473,738 | $4,116,430 | $27,095,166 |
| 2020 | $16,784,968 | $11,988,119 | $4,458,449 | $33,231,536 |
| 2021 | $16,569,043 | $15,941,955 | $4,777,871 | $37,288,869 |
| 2022 | $24,300,214 | $12,054,486 | $5,258,756 | $41,613,456 |
| 2023 | $21,616,897 | $11,248,712 | $5,519,440 | $38,385,049 |
| 2024 | $24,308,004 | $22,807,017 | $5,908,096 | $53,023,117 |
| 2025 | $19,146,569 | $27,109,620 | $6,319,791 | $52,575,980 |
| 2026 | $17,637,971 | $18,967,276 | $6,673,290 | $43,278,537 |
| 2027 | $16,436,862 | $18,996,353 | $7,018,133 | $42,451,348 |
| 2028 | $20,547,973 | $19,800,123 | $7,405,932 | $47,754,028 |
| 2029 | $18,360,242 | $17,039,341 | $7,748,039 | $43,147,622 |
| 2030 | $16,662,697 | $19,003,939 | $3,224,961 | $38,891,596 |
| 2031 | $15,856,083 | $17,560,593 | $3,375,416 | $36,792,091 |
| 2032 | $20,858,372 | $12,799,825 | $3,245,360 | $36,903,556 |
| **20-Year NPV** | **$188,245,928** | **$123,502,451** | **$52,623,496** | **$364,755,770** |

**Table DSM-7. Existing energy efficiency portfolio avoided energy costs 2013–2032**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2013 | $1,995,192 | $785,140 | $82,481 | $2,862,813 |
| 2014 | $4,447,169 | $1,877,276 | $306,505 | $6,630,950 |
| 2015 | $7,448,806 | $3,562,786 | $608,946 | $11,620,538 |
| 2016 | $10,536,474 | $4,823,818 | $936,699 | $16,296,990 |
| 2017 | $13,603,373 | $6,184,262 | $1,326,187 | $21,113,822 |
| 2018 | $21,636,893 | $10,091,290 | $2,252,452 | $33,980,635 |
| 2019 | $26,150,714 | $12,719,356 | $2,941,227 | $41,811,296 |
| 2020 | $31,747,645 | $13,994,828 | $3,744,939 | $49,487,412 |
| 2021 | $37,762,710 | $15,493,623 | $4,672,567 | $57,928,901 |
| 2022 | $45,798,427 | $17,142,980 | $5,825,460 | $68,766,868 |
| 2023 | $52,827,025 | $18,655,035 | $7,029,285 | $78,511,345 |
| 2024 | $60,135,516 | $21,307,128 | $8,281,800 | $89,724,444 |
| 2025 | $67,330,305 | $24,745,002 | $9,733,405 | $101,808,713 |
| 2026 | $75,445,701 | $29,484,780 | $11,436,383 | $116,366,864 |
| 2027 | $83,498,887 | $34,951,122 | $13,269,044 | $131,719,053 |
| 2028 | $93,058,554 | $41,361,986 | $15,432,666 | $149,853,206 |
| 2029 | $101,824,572 | $46,837,103 | $17,697,063 | $166,358,738 |
| 2030 | $112,112,296 | $53,607,202 | $19,343,108 | $185,062,606 |
| 2031 | $120,032,498 | $59,203,492 | $20,675,610 | $199,911,600 |
| 2032 | $128,401,187 | $64,820,001 | $22,038,852 | $215,260,039 |
| **20-Year NPV** | **$437,466,195** | **$189,233,708** | **$63,693,931** | **$690,393,833** |

**Table DSM-8. Existing energy efficiency portfolio cost-effectiveness summary**

| | Impact | 20-Year NPV | | TRC | |
|---|---|---|---|---|---|
| | 2032 Load (aMW) | Resource Costs | Alternate Energy Benefits | B/C Ratio | Levelized Costs ($/kWh) |
| Industrial/Commercial | 157 | $188,245,928 | $467,521,430 | 2.5 | 0.028 |
| Residential | 76 | $123,886,346 | $190,935,664 | 1.5 | 0.046 |
| Irrigation | 28 | $52,623,496 | $76,220,052 | 1.4 | 0.049 |
| **Total** | **261** | **$364,755,770** | **$734,677,146** | **2.0** | **0.035** |

**Table DSM-9. Cumulative new energy efficiency portfolio forecast 2013–2032**
*(aMW w/transmission losses)*

| Year | Commercial/ Industrial | Residential | Irrigation | Total |
|---|---|---|---|---|
| 2013 | 6 | 0 | 1 | 8 |
| 2014 | 13 | 0 | 2 | 15 |
| 2015 | 19 | 1 | 3 | 23 |
| 2016 | 25 | 2 | 3 | 30 |
| 2017 | 30 | 4 | 4 | 37 |
| 2018 | 35 | 6 | 5 | 46 |
| 2019 | 40 | 10 | 5 | 55 |
| 2020 | 46 | 9 | 6 | 60 |
| 2021 | 51 | 9 | 7 | 67 |
| 2022 | 59 | 9 | 8 | 76 |
| 2023 | 65 | 9 | 9 | 83 |
| 2024 | 72 | 12 | 10 | 94 |
| 2025 | 78 | 16 | 12 | 105 |
| 2026 | 84 | 20 | 13 | 117 |
| 2027 | 90 | 26 | 15 | 130 |
| 2028 | 96 | 32 | 17 | 145 |
| 2029 | 101 | 36 | 19 | 157 |
| 2030 | 106 | 41 | 20 | 167 |
| 2031 | 111 | 46 | 21 | 178 |
| 2032 | 116 | 51 | 21 | 188 |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.04% |
| Preferred | 0.00% |
| Common | 49.96% |
| **Total** | **100.00%** |
| **Cost** | |
| Debt | 5.73% |
| Preferred | 0.00% |
| Common | 10.00% |
| Average Weighted Cost | 7.86% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | 30 Years |
| Discount rate (weighted average cost of capital[1]) | 6.70% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 3.00% |
| Emissions adder escalation rate | 3.00% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.78% |

[1] Incorporates tax effects.

| Emission Intensity Rate (lbs per MWh by technology, adder brought into the analysis beginning in 2018) | |
|---|---|
| | **$CO_2$** |
| Small aeroderivative SCCT | 1,115 |
| Large aeroderivative SCCT | 1,047 |
| Large frame SCCT | 1,413 |
| CCCT 1x1 | 809 |
| CCCT 2x1 | 809 |
| Combined heat and power (CHP) | 1,115 |
| Distributed generation–gas fired | 1,115 |
| Pulverized coal | 1,901 |
| IGCC | 2,279 |
| IGCC w/carbon sequestration | 421 |

| Emissions Adder Rates | |
|---|---|
| $CO_2$ | $14.64 per ton (2018 $) |

**Fuel Forecast Base Case (Nominal, $ per MMBtu)**

| Year | Natural Gas[1] | Regional Coal | Uranium[2] |
|---|---|---|---|
| 2013 | $5.55 | $2.32 | $0.70 |
| 2014 | $5.88 | $2.44 | $0.70 |
| 2015 | $6.19 | $2.42 | $0.71 |
| 2016 | $6.35 | $2.45 | $0.71 |
| 2017 | $6.57 | $2.56 | $0.72 |
| 2018 | $6.83 | $2.68 | $0.72 |
| 2019 | $7.22 | $2.64 | $0.73 |
| 2020 | $7.59 | $2.70 | $0.73 |
| 2021 | $8.15 | $2.79 | $0.73 |
| 2022 | $8.84 | $2.89 | $0.74 |
| 2023 | $9.42 | $2.98 | $0.74 |
| 2024 | $9.91 | $3.07 | $0.75 |
| 2025 | $10.49 | $3.17 | $0.75 |
| 2026 | $11.03 | $3.27 | $0.76 |
| 2027 | $11.65 | $3.38 | $0.76 |
| 2028 | $12.19 | $3.48 | $0.77 |
| 2029 | $12.76 | $3.59 | $0.77 |
| 2030 | $13.40 | $3.71 | $0.77 |
| 2031 | $14.09 | $3.87 | $0.78 |
| 2032 | $14.86 | $4.00 | $0.78 |
| 2033 | $14.95 | $4.02 | $0.79 |
| 2034 | $15.04 | $4.04 | $0.79 |
| 2035 | $15.13 | $4.07 | $0.80 |
| 2036 | $15.22 | $4.09 | $0.80 |
| 2037 | $15.31 | $4.12 | $0.81 |
| 2038 | $15.40 | $4.14 | $0.81 |
| 2039 | $15.49 | $4.17 | $0.82 |
| 2040 | $15.59 | $4.19 | $0.82 |
| 2041 | $15.68 | $4.22 | $0.83 |
| 2042 | $15.78 | $4.24 | $0.83 |

[1] Henry Hub + Sumas basis + transportation cost = Idaho city gate price

[2] Nuclear fuel

# Cost Inputs and Operating Assumptions

(All costs in 2013 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Transmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Variable O&M $/kW | Emissions $/MWh | Heat Rate Btu/kWh |
|---|---|---|---|---|---|---|---|---|---|
| Advanced Nuclear | 250 | $6,866 | $625 | $7,491 | $11,381 | $143 | $1 | $0 | 10,488 |
| Biomass Digesters | 50 | $4,311 | $285 | $4,596 | $4,921 | $107 | $16 | $0 | NA |
| CCCT—(1x1) F Class | 270 | $1,120 | $140 | $1,260 | $1,477 | $8 | $2 | $7 | 6,800 |
| CCCT—(2x1) F Class | 580 | $1,039 | $109 | $1,148 | $1,346 | $6 | $2 | $7 | 6,738 |
| CHP/Co-Generation | 100 | $1,975 | $25 | $2,000 | $2,142 | $8 | $5 | $0 | 9,200 |
| Conventional Scrubbed Coal | 600 | $3,253 | $730 | $3,983 | $4,754 | $26 | $4 | $26 | 9,200 |
| Distributed Generation (Option # 1) Load shed | 10 | $0 | $0 | $0 | $0 | $63 | $0 | $0 | 9,050 |
| Distributed Generation (Option # 2) Grid synchronized | 15 | $0 | $160 | $160 | $166 | $63 | $0 | $0 | 9,050 |
| Geothermal—Idaho | 26 | $6,630 | $979 | $7,609 | $8,442 | $144 | $5 | $0 | NA |
| Geothermal—Nevada | 26 | $6,630 | $552 | $7,182 | $7,968 | $144 | $5 | $0 | NA |
| Geothermal—Oregon | 26 | $6,630 | $787 | $7,417 | $8,229 | $144 | $5 | $0 | NA |
| IGCC | 550 | $4,513 | $730 | $5,243 | $6,547 | $35 | $7 | $25 | 8,765 |
| Low Drop/Small Hydro New | 10 | $4,000 | $80 | $4,080 | $4,784 | $15 | $4 | $0 | NA |
| Pulverized Coal w/ carbon capture and sequestration | 455 | $7,755 | $730 | $8,485 | $10,595 | $143 | $7 | $5 | 12,600 |
| Pumped Storage Fueled by LL Wind | 500 | $2,510 | $646 | $3,156 | $3,700 | $5 | $0 | $0 | NA |
| SCCT—Industrial Frame | 170 | $733 | $88 | $821 | $875 | $4 | $3 | $13 | 11,870 |
| SCCT—Large Aeroderivative | 100 | $1,250 | $149 | $1,399 | $1,491 | $15 | $3 | $10 | 8,800 |
| SCCT—Small Aeroderivative | 47 | $1,113 | $31 | $1,144 | $1,219 | $14 | $5 | $8 | 9,370 |
| Solar—1-Axis Tracking Flat Plate PV (Utility) | 1 | $4,029 | $0 | $4,029 | $4,108 | $27 | $0 | $0 | NA |
| Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW) | 10 | $3,268 | $80 | $3,348 | $3,414 | $27 | $0 | $0 | NA |
| Solar—Concentrating Solar Power | 100 | $5,398 | $212 | $5,610 | $6,578 | $56 | $0 | $0 | NA |
| Solar—Concentrating Solar Power with Energy Storage | 100 | $7,771 | $212 | $7,983 | $9,360 | $56 | $0 | $0 | NA |
| Solar—Flat Plate PV (Distributed)[4] | 10 | $5,610 | $0 | $5,610 | $5,720 | $55 | $0 | $0 | NA |
| Solar—Flat Plate PV (Utility) | 1 | $3,714 | $0 | $3,714 | $3,787 | $27 | $0 | $0 | NA |
| Solar—Flat Plate PV (Utility 10MW) | 10 | $2,996 | $80 | $3,076 | $3,136 | $27 | $0 | $0 | NA |
| Transmission—Boardman to Hemingway[5] | 350 | $0 | $602 | $602 | $602 | $1 | $0 | $0 | NA |
| Wind—Eastern Oregon | 100 | $2,229 | $1,210 | $3,439 | $3,675 | $37 | $1 | $0 | NA |
| Wind—Magic Valley | 100 | $2,229 | $369 | $2,598 | $2,776 | $37 | $1 | $0 | NA |
| Wind—Southeast Idaho | 100 | $2,229 | $382 | $2,611 | $2,790 | $37 | $1 | $0 | NA |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

[4] Approximately 2,500 4-kW PV systems.

[5] 350-MW average, 500-MW summer, and 200-MW winter.

# Transmission Cost Assumptions

## *Cost Assumptions by Supply-Side Resource Type*

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Advanced Nuclear | | | | |
| 250 | $625 | Pro-rated the 250 MW based on Idaho Power's present 21.2% share of estimated $900 million Boardman to Hemingway project cost plus BPA wheeling rates to get to Boardman Station | 230 kV upgrades from Hemingway to Bowmont and Hubbard stations | Assume transmission in place by 2025 for access to Boardman area from Central Washington. Use BPA tariff rate to Boardman and pro-rata share of Boardman to Hemingway to Treasure Valley. |
| Biomass Digesters | | | | |
| 50 | $285 | Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker and miscellaneous line work and station reconfigurations. | Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker, and miscellaneous line work and station reconfigurations. | Assume pro-rata share of Midpoint West path upgrades. |
| CCCT—(1x1) F Class | | | | |
| 270 | $140 | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line. | New supporting transmission will be required. Entire project assumed as backbone upgrade. | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line. |
| CCCT—(2x1) F Class | | | | |
| 580 | $109 | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation. | New supporting transmission will be required. Entire project assumed as backbone upgrade. | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation. |
| CHP/Co-Generation | | | | |
| 100 | $25 | Assume Amalgamated Sugar location. Interconnection requires a tap of existing 138-kV line. Interconnection will require approximately 0.5 mile, 138-kV line and tap substation. | Approximately 0.5 mile, 138-kV line and 138-kV source substation with transformer. | Assume no additional transmission required. |
| Conventional Scrubbed Coal | | | | |
| 600 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| Distributed Generation—(Option # 1) Load Shed | | | | |
| 10 | $0 | No upgrades required for load shed. | No upgrades required for load shed. | No backbone upgrades required. |
| Distributed Generation—(Option # 2) Grid synchronized | | | | |
| 15 | $160 | Assume feeder interconnection with minor amount of distribution rebuild. | Assume a small amount of distribution rebuild. | No backbone upgrades required. |
| Geothermal—Idaho | | | | |
| 26 | $979 | Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay. Assume 26 MW fits on existing backbone. | Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Geothermal—Nevada | | | | |
| 26 | $552 | Assume a location 20 miles from existing 138-kV line. Assume 26 MW fits on existing 138-kV line. | Assume 20 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | No backbone upgrades required. |
| Geothermal—Oregon | | | | |
| 26 | $787 | Assume a project similar to Neal Hot Springs Interconnect (1 breaker station, line switches, 10-mile interconnect). Assume 26 MW fits on existing backbone. | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | No backbone upgrades required. |
| IGCC | | | | |
| 550 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| Low Drop/Small Hydro New | | | | |
| 10 | $80 | Assume 46-kV sub-transmission or local feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Pumped Storage Fueled by LL Wind | | | | |
| 500 | $646 | Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location. | Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location. | No backbone upgrades assumed in the upgrade costs; however, this assumption will vary drastically based on size of resource and number of locations |
| Pulverized Coal with Carbon Capture and Sequestration | | | | |
| 455 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| SCCT—Industrial Frame | | | | |
| 170 | $88 | See requirements in previous estimate and also rebuild 16 miles of existing 230-kV construction to bundled conductor. | Langley Substation expansion, new transformer terminal. | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation, 16 mile, 230-kV bundled conductor rebuild of Caldwell–Langley line. |
| SCCT—Large Aeroderivative | | | | |
| 100 | $149 | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation plus Langley site expansion for second generating unit (new transformer terminal in substation). | Langley substation expansion, new transformer terminal. | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation |
| SCCT—Small Aeroderivative | | | | |
| 47 | $31 | Assume an addition to existing generation site in Mountain Home area. New 230-kV terminal and associated station modifications. | New 230-kV terminal and associated station modifications. | No backbone upgrades required. |
| Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW) | | | | |
| 10 | $80 | Assume 34.5 kV feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Solar—1-Axis Tracking Flat Plate PV (Utility) | | | | |
| 1 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |
| Solar—Flat Plate PV (Distributed)[2] | | | | |
| 10 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Solar—Flat Plate PV (Utility 10 MW) | | | | |
| 10 | $80 | Assume 34.5-kV feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Solar—Flat Plate PV (Utility) | | | | |
| 1 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |
| Solar—Concentrating Solar Power | | | | |
| 100 | $212 | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station. | New three-terminal 230-kV switching station connecting existing 230-kV line. |
| Solar—Concentrating Solar Power with Energy Storage | | | | |
| 100 | $212 | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station. | New three-terminal 230-kV switching station connecting existing 230-kV line. |
| Transmission—Boardman to Hemingway | | | | |
| 350–Average<br>500–Summer<br>200–Winter | $602 | Per the Boardman to Hemingway Funding Agreement, Idaho Power's share of the project is 21.2% of an estimated $900 million project cost. Project also requires 230-kV local interconnection upgrades from Hemingway into the Treasure Valley. | 230-kV upgrades from Hemingway to Bowmont and Hubbard | Pro-rata share of Boardman to Hemingway. |
| Wind—Eastern Oregon | | | | |
| 100 | $1,210 | Assume location near Quartz Substation. A new 110 mile, 230-kV line will need to be constructed into Treasure Valley. | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | 110 mile, 230-kV line to Treasure Valley. |
| Wind—Magic Valley | | | | |
| 100 | $369 | Assume 10 mile interconnection to existing 230/138-kV substation plus 230-kV substation upgrades plus 1/16$^{th}$ share of Gateway West segment between Cedar Hill and Hemingway | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | Upgrades at 230/138 kV integration substation + 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line |
| Wind—Southeast Idaho | | | | |
| 100 | $382 | Assume 10 mile interconnection to local 138-kV substation plus Borah West path RAS upgrades plus 1/16$^{th}$ share of Gateway West segment between Cedar Hill and Hemingway | Assume 138-kV step-up station with transformer with 10 miles of 138-kV local transmission to 138-kV point of interconnection. | New terminal at 138-kV point of interconnection plus Borah West RAS upgrades plus 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line |

[1] 2013 dollars, no AFUDC

[2] Approximately 2,500 4-kW PV systems.

# Levelized Cost of Production

**30-Year Levelized Cost of Production (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Emission Adders | Total Cost per MWh[1] | Annual Capacity Factor |
|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | $156 | $41 | $8 | $0 | $0 | $205 | 85% |
| Biomass Digesters (50 MW) | $64 | $47 | $0 | $0 | $0 | $111 | 90% |
| CCCT—1x1 (270 MW) | $27 | $6 | $67 | $0 | $7 | $106 | 65% |
| CCCT—2x1 (580 MW) | $24 | $7 | $66 | $0 | $7 | $104 | 65% |
| Combined Heat and Power (100 MW) | $27 | $11 | $74 | $0 | $0 | $111 | 93% |
| Distributed Generation—Grid Sync (15 MW) | $1,941 | $10,305 | $0 | $0 | $0 | $12,246 | 0% |
| Distributed Generation—Load Shed (10 MW) | $0 | $10,305 | $0 | $0 | $0 | $10,305 | 0% |
| Geothermal—Idaho (26 MW) | $107 | $41 | $0 | $0 | $0 | $148 | 92% |
| Geothermal—Nevada (26 MW) | $101 | $41 | $0 | $0 | $0 | $142 | 92% |
| Geothermal—Oregon (26 MW) | $104 | $41 | $0 | $0 | $0 | $145 | 92% |
| IGCC (550 MW) | $90 | $24 | $27 | $0 | $25 | $166 | 85% |
| Low Drop/Small Hydro New (10 MW) | $124 | $20 | $0 | $0 | $0 | $144 | 45% |
| Pulverized Coal (600 MW) | $63 | $16 | $29 | $0 | $26 | $133 | 88% |
| Pulverized Coal w/Carbon Capture and Sequestration (455 MW) | $145 | $48 | $40 | $0 | $5 | $238 | 85% |
| Pumped Storage Fueled by LL Wind | $173 | $18 | $0 | $49 | $0 | $239 | 25% |
| SCCT—Industrial Frame (170 MW) | $170 | $29 | $116 | $0 | $13 | $328 | 6% |
| SCCT—Large Aero (100 MW) | $174 | $42 | $86 | $0 | $10 | $312 | 10% |
| SCCT—Small Aero (47 MW) | $178 | $50 | $92 | $0 | $8 | $327 | 8% |
| Solar—Concentrating Energy (100 MW) | $206 | $84 | $0 | $0 | $0 | $290 | 18% |
| Solar—Concentrating Energy Storage (100 MW) | $202 | $63 | $0 | $0 | $0 | $265 | 28% |
| Solar—Flat Plate PV Distributed (10 MW) [2] | $227 | $84 | $0 | $0 | $0 | $311 | 17% |
| Solar—Flat Plate PV Utility (10 MW) | $117 | $38 | $0 | $0 | $0 | $154 | 19% |
| Solar—Flat Plate PV Utility (1 MW) | $179 | $41 | $0 | $0 | $0 | $220 | 19% |
| Solar—Flat Plate Tracking PV Utility (1 MW) | $153 | $34 | $0 | $0 | $0 | $187 | 24% |
| Solar—Flat Plate Tracking PV Utility (10 MW) | $102 | $31 | $0 | $0 | $0 | $133 | 24% |
| Transmission—Boardman to Hemingway (350 MW)[3] | $20 | $2 | $0 | $68 | $0 | $89 | 34% |
| Wind—Eastern Oregon (100 MW) | $165 | $47 | $0 | $0 | $0 | $212 | 26% |
| Wind—Magic Valley (100 MW) | $125 | $44 | $0 | $0 | $0 | $169 | 26% |
| Wind—Southeast Idaho(100 MW) | $125 | $44 | $0 | $0 | $0 | $169 | 26% |

[1] Includes fixed and variable costs and property taxes.

[2] Approximately 2,500 4-kW PV systems.

[3] 350-MW average, 500-MW summer, and 200-MW winter.

| 30-Year Levelized Capacity (fixed) Cost per kW/Month | | | | | |
|---|---|---|---|---|---|
| **Supply-Side Resources** | **Cost of Capital** | **Non-Fuel O&M[1]** | **Fuel** | **Emission Adders** | **Total Cost per kW** |
| Advanced Nuclear (250 MW) | $97 | $25 | $0 | $0 | $122 |
| Biomass Digesters (50 MW) | $42 | $16 | $0 | $0 | $58 |
| CCCT—1x1 (270 MW) | $13 | $2 | $0 | $0 | $14 |
| CCCT—2x1 (580 MW) | $11 | $2 | $0 | $0 | $13 |
| Combined Heat and Power (100 MW) | $18 | $2 | $0 | $0 | $21 |
| Distributed Generation—Grid Sync (15 MW) | $1 | $8 | $0 | $0 | $9 |
| Distributed Generation—Load Shed (10 MW) | $0 | $8 | $0 | $0 | $8 |
| Geothermal—Idaho (26 MW) | $72 | $23 | $0 | $0 | $95 |
| Geothermal—Nevada (26 MW) | $68 | $22 | $0 | $0 | $90 |
| Geothermal—Oregon (26 MW) | $70 | $23 | $0 | $0 | $93 |
| IGCC (550 MW) | $56 | $9 | $0 | $0 | $64 |
| Low Drop/Small Hydro New (10 MW) | $41 | $5 | $0 | $0 | $46 |
| Pulverized Coal (600 MW) | $40 | $6 | $0 | $0 | $47 |
| Pulverized Coal w/Carbon Capture and Sequestration (455 MW) | $90 | $24 | $0 | $0 | $114 |
| Pumped Storage Fueled by LL Wind | $32 | $3 | $0 | $0 | $35 |
| SCCT—Industrial Frame (170 MW) | $7 | $1 | $0 | $0 | $9 |
| SCCT—Large Aero (100 MW) | $13 | $3 | $0 | $0 | $15 |
| SCCT—Small Aero (47 MW) | $10 | $2 | $0 | $0 | $13 |
| Solar—Concentrating Energy (100 MW) | $56 | $11 | $0 | $0 | $67 |
| Solar—Concentrating Energy Storage (100 MW) | $80 | $13 | $0 | $0 | $93 |
| Solar—Flat Plate PV Distributed (10 MW)[1] | $49 | $10 | $0 | $0 | $59 |
| Solar—Flat Plate PV Utility (1 MW) | $32 | $6 | $0 | $0 | $38 |
| Solar—Flat Plate PV Utility (10 MW) | $27 | $5 | $0 | $0 | $32 |
| Solar—Flat Plate Tracking PV Utility (1 MW) | $35 | $6 | $0 | $0 | $41 |
| Solar—Flat Plate Tracking PV Utility (10 MW) | $29 | $5 | $0 | $0 | $35 |
| Transmission—Boardman to Hemingway (350 MW)[2] | $5 | $0 | $0 | $0 | $5 |
| Wind—Eastern Oregon (100 MW) | $31 | $7 | $0 | $0 | $38 |
| Wind—Magic Valley (100 MW) | $24 | $6 | $0 | $0 | $30 |
| Wind—Southeast Idaho(100 MW) | $24 | $6 | $0 | $0 | $30 |

[1] Approximately 2,500 4-kW PV systems.

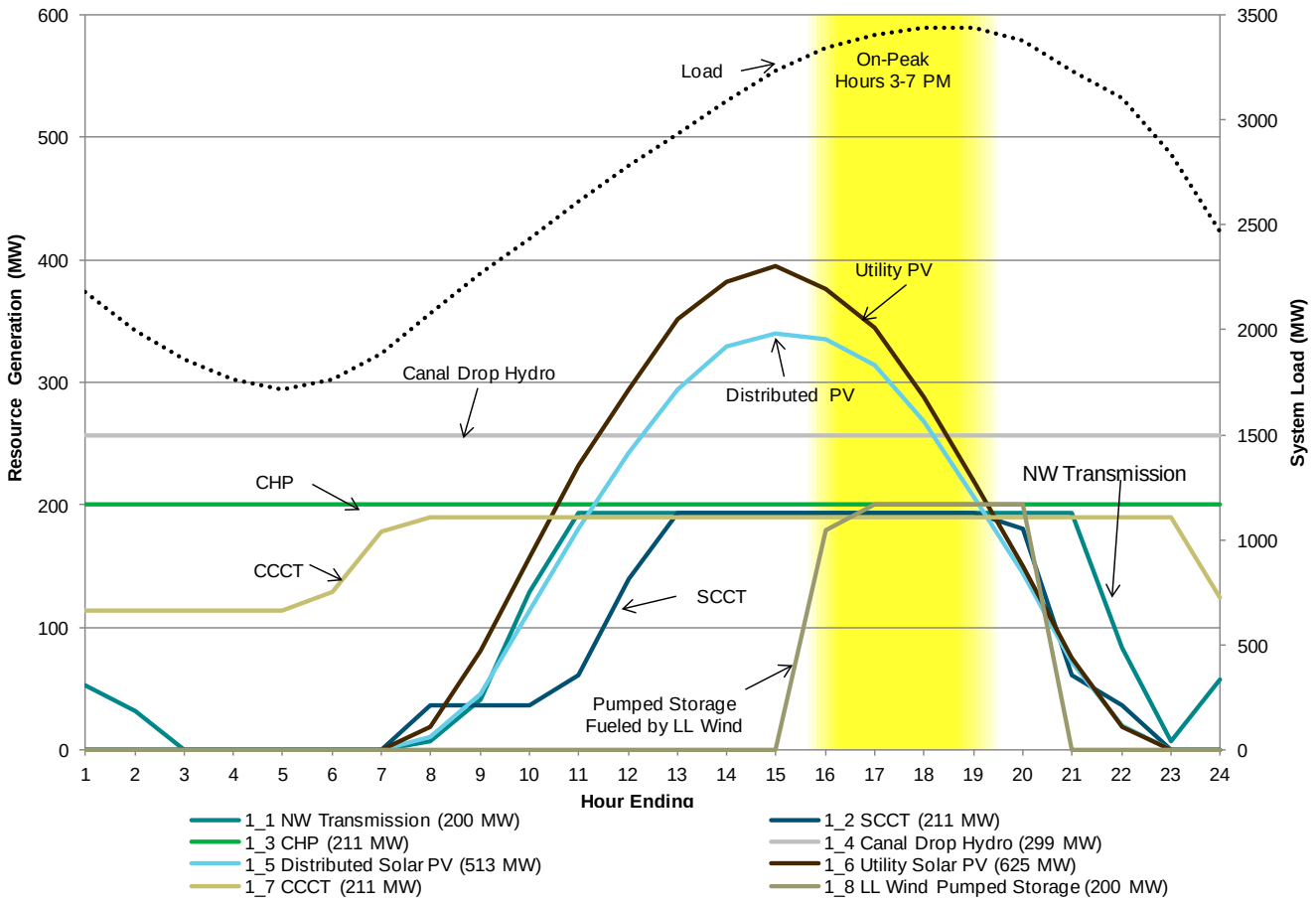
[2] 350-MW average, 500-MW summer, and 200-MW winter.

# Resource Advantages and Disadvantages

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Biomass** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• Uncertainty surrounding future tax incentives<br>• Fuel supply risk |
| **Coal** | | |
| Pulverized | • Abundant, low-cost fuel<br>• Less price volatility than natural gas<br>• Proven and reliable technology<br>• Dispatchable resource<br>• Well suited for baseload operations | • Potential lack of public acceptance<br>• Significant particulate and gas emissions, particularly $CO_2$<br>• Significant capital investment<br>• Long construction lead times<br>• Lengthy environmental permitting and siting processes |
| Advanced Technology | • Abundant, low cost fuel<br>• Potentially lower greenhouse gas emissions if $CO_2$ is sequestered<br>• Potential for financial incentives<br>• Dispatchable resource | • New, unproven technologies<br>• Higher capital costs than pulverized coal<br>• Long construction lead times |
| **Distributed Generation** | • Utilize existing backup generators at customer sites<br>• Dispatchable resource<br>• Provides operating reserves | • More expensive than other resource options<br>• Limited number of sites<br>• Fuel price risk and volatility<br>• Existing air quality permits may need to be modified<br>• Small size, many sites would be required |
| **Geothermal** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk (once developed)<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• High exploration costs due to drilling risks<br>• Uncertainty surrounding future tax incentives |
| **Hydro** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of sites<br>• Future development is limited to small sites or at existing dams without power generation<br>• Fish and other environmental issues |
| **In-stream Generation** | • Renewable resource<br>• No harmful emissions<br>• No fuel cost | • Small size, many sites would be required<br>• Environmental impact and permitting<br>• High maintenance cost |

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Natural Gas** | | |
| CCCT | • Proven and reliable technology<br>• Dispatchable resource<br>• Provides operating reserves necessary for integration of renewable generation<br>• More efficient than a SCCT<br>• Greater than 50% reduction in $CO_2$ emissions per MWh of output compared to conventional pulverized coal technology | • Fuel price risk and volatility<br>• Potential fuel supply and transportation issues |
| SCCT | • Dispatchable resource<br>• Proven, reliable resource<br>• Low capital cost<br>• Short construction lead times<br>• Ideal for peaking service | • High variable operating cost<br>• Fuel price risk and volatility<br>• Less efficient than a CCCT |
| **Nuclear** | • Forecasted low fuel costs<br>• Forecasted adequate fuel availability<br>• Lack of greenhouse gas emissions<br>• Potential low cost of production<br>• Proven technology (existing reactor types) | • Lack of public acceptance<br>• Safety concerns<br>• Waste disposal<br>• Construction cost uncertainties and the potential for construction cost overruns<br>• Security concerns |
| **Solar** (General) | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs<br>• Generation would match well with summer peak loads. | • More expensive than other resource options<br>• Poor generation during winter months<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Limited utility scale projects exist |
| Parabolic Trough | • Can be built with thermal storage | • Utility scale production is limited |
| Power Tower | • By using molten salt, thermal storage can be built integrally into the system | • Utility scale production is unproven<br>• Requires land slope of 1% or less |
| Parabolic Dish | • Off-grid electricity production in remote areas | • Not suitable for storage options<br>• Unproven technology |
| Photovoltaic | • Proven & reliable technology<br>• Suitable for distributed generation | • Cloud cover creates a rapid power drop-off<br>• Utility scale projects are only practical up to 10 MW |
| **Transmission** | • Provides peak-hour capacity<br>• Can help integrate renewable generation<br>• Lower capital cost compared to other resources<br>• Expanded capacity for off-system sales<br>• Stability associated with possible long-term firm contracts (sales and purchases) | • Siting is difficult with impact to many land owners<br>• Exposure to potential market volatility<br>• Considerable lead times required |
| **Wind** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of good sites in southern Idaho<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Avian and aesthetic impacts<br>• Uncertainty surrounding future tax incentives |

# Resource Peak Hour Shape




# Capacity Factors for Solar PV

The following tables show capacity factors for solar photovoltaic (PV) panels located in Boise, Idaho. The data is from a tool, PVWatts™, developed by the Nation Renewable Energy Laboratory (NREL). NREL describes PVWatts in the following manner:

> NREL's PVWatts™ calculator determines the energy production and cost savings of grid-connected photovoltaic (PV) energy systems throughout the world. It allows homeowners, installers, manufacturers, and researchers to easily develop estimates of the performance of hypothetical PV installations.
>
> The PVWatts calculator works by creating hour-by-hour performance simulations that provide estimated monthly and annual energy production in kilowatts and energy value. Users can select a location and choose to use default values or their own system parameters for size, electric cost, array type, tilt angle, and azimuth angle. In addition, the PVWatts calculator can provide hourly performance data for the selected location.

Using typical meteorological year weather data for the selected location, the PVWatts calculator determines the solar radiation incident of the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour is calculated from the PV system DC rating and the incident solar radiation and then corrected for the PV cell temperature. The AC energy for each hour is calculated by multiplying the DC energy by the overall DC-to-AC derate factor and adjusting for inverter efficiency as a function of load. Hourly values of AC energy are then summed to calculate monthly and annual AC energy production.

The following NREL PVWatts data are for a solar PV array in the Boise area. The PV oriented to the southwest is equivalent to a north-based azimuth of 225 degrees. The PV oriented to the south is equivalent to a north-based azimuth of 180 degrees. The following link displays the PVWatts data in Boise: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/US/Idaho/Boise.html.

## *Capacity Factors for Southerly Oriented PV in Boise*

| Time | Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 am–1 am | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 1 am–2 am | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 am–3 am | 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 am–4 am | 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 am–5 am | 5 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 am–6 am | 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 6 am–7 am | 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.3% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 am–8 am | 8 | 0.0% | 0.0% | 0.7% | 6.4% | 9.6% | 10.9% | 8.1% | 6.6% | 6.2% | 3.5% | 0.2% | 0.0% |
| 8 am–9 am | 9 | 1.3% | 7.4% | 15.9% | 23.1% | 25.7% | 26.4% | 24.2% | 24.8% | 24.3% | 20.6% | 9.8% | 1.9% |
| 9 am–10 am | 10 | 15.5% | 25.4% | 31.1% | 38.4% | 38.8% | 41.6% | 39.2% | 41.8% | 41.5% | 36.5% | 23.1% | 15.3% |
| 10 am–11 am | 11 | 26.1% | 39.5% | 41.8% | 48.0% | 49.3% | 49.8% | 52.6% | 51.7% | 50.1% | 48.0% | 36.2% | 28.0% |
| 11 am–12 pm | 12 | 33.4% | 47.6% | 51.3% | 55.2% | 54.5% | 56.2% | 59.1% | 61.0% | 56.2% | 54.5% | 41.0% | 35.9% |
| 12 pm–1 pm | 13 | 36.7% | 51.2% | 54.6% | 54.9% | 58.3% | 60.6% | 62.0% | 63.0% | 60.7% | 59.3% | 42.9% | 38.9% |
| 1 pm–2 pm | 14 | 39.7% | 47.7% | 50.9% | 56.2% | 58.8% | 57.9% | 62.6% | 62.6% | 61.8% | 52.7% | 43.1% | 37.6% |
| 2 pm–3 pm | 15 | 32.5% | 44.3% | 50.2% | 54.3% | 52.4% | 53.1% | 58.0% | 58.9% | 55.5% | 49.7% | 34.8% | 32.3% |
| 3 pm–4 pm | 16 | 25.3% | 32.3% | 39.8% | 42.3% | 41.3% | 43.9% | 49.0% | 49.8% | 47.1% | 38.0% | 21.8% | 22.1% |
| 4 pm–5 pm | 17 | 11.4% | 20.1% | 25.6% | 28.7% | 31.6% | 31.3% | 34.5% | 35.2% | 30.7% | 21.0% | 8.2% | 7.4% |
| 5 pm–6 pm | 18 | 0.6% | 5.3% | 11.4% | 14.6% | 15.5% | 17.0% | 18.5% | 17.5% | 12.6% | 4.0% | 0.1% | 0.0% |
| 6 pm–7 pm | 19 | 0.0% | 0.0% | 0.1% | 0.2% | 1.0% | 1.8% | 1.5% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 pm–8 pm | 20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 pm–9 pm | 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 pm–10 pm | 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 pm–11 pm | 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 pm–12 am | 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Average** | | **9.3%** | **13.4%** | **15.6%** | **17.6%** | **18.2%** | **18.8%** | **19.6%** | **19.7%** | **18.6%** | **16.2%** | **10.9%** | **9.1%** |
| **Annual Average** | | **15.6%** | | | | | | | | | | | |

All values are in Mountain Standard Time (MST) and have not been adjusted for Daylight Savings Time (DST). DST begins on the second Saturday in March and ends the first Sunday in November.

## Capacity Factors for Southwesterly Oriented PV in Boise

| Time | Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 am–1 am | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 1 am–2 am | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 am–3 am | 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 am–4 am | 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 am–5 am | 5 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 am–6 am | 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 6 am–7 am | 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.3% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 am–8 am | 8 | 0.0% | 0.0% | 0.0% | 1.1% | 2.2% | 2.8% | 1.8% | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% |
| 8 am–9 am | 9 | 0.0% | 0.1% | 1.1% | 4.4% | 5.2% | 6.1% | 2.8% | 1.9% | 1.3% | 0.4% | 0.1% | 0.0% |
| 9 am–10 am | 10 | 1.8% | 3.3% | 11.4% | 16.6% | 18.7% | 18.9% | 15.4% | 15.2% | 14.7% | 13.5% | 6.9% | 1.7% |
| 10 am–11 am | 11 | 14.3% | 19.7% | 25.2% | 31.6% | 33.6% | 33.5% | 33.0% | 32.0% | 31.1% | 29.6% | 21.6% | 14.9% |
| 11 am–12 pm | 12 | 24.2% | 33.2% | 38.9% | 43.9% | 44.7% | 45.9% | 46.8% | 47.7% | 43.9% | 42.1% | 30.8% | 25.8% |
| 12 pm–1 pm | 13 | 30.7% | 42.3% | 47.2% | 49.4% | 53.6% | 55.6% | 55.9% | 56.1% | 53.8% | 52.0% | 37.0% | 32.5% |
| 1 pm–2 pm | 14 | 36.6% | 44.0% | 48.9% | 55.6% | 59.6% | 58.8% | 62.8% | 62.0% | 60.8% | 51.4% | 41.3% | 35.0% |
| 2 pm–3 pm | 15 | 32.9% | 45.2% | 53.1% | 59.2% | 58.8% | 59.7% | 64.7% | 64.7% | 60.7% | 54.1% | 37.1% | 33.3% |
| 3 pm–4 pm | 16 | 28.7% | 36.8% | 46.9% | 51.5% | 51.8% | 55.4% | 61.8% | 62.0% | 58.6% | 47.4% | 26.6% | 26.3% |
| 4 pm–5 pm | 17 | 16.3% | 27.3% | 35.8% | 41.3% | 48.8% | 47.6% | 52.9% | 53.4% | 47.1% | 33.5% | 13.8% | 11.7% |
| 5 pm–6 pm | 18 | 1.8% | 12.2% | 24.6% | 30.1% | 34.1% | 38.5% | 41.4% | 40.3% | 32.1% | 15.1% | 1.0% | 0.0% |
| 6 pm–7 pm | 19 | 0.0% | 0.0% | 8.1% | 15.3% | 17.5% | 23.1% | 25.7% | 21.7% | 10.3% | 0.0% | 0.0% | 0.0% |
| 7 pm–8 pm | 20 | 0.0% | 0.0% | 0.0% | 0.1% | 2.9% | 6.6% | 8.5% | 2.7% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 pm–9 pm | 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 pm–10 pm | 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 pm–11 pm | 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 pm–12 am | 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Average** | | **9.3%** | **7.8%** | **11.0%** | **14.2%** | **16.7%** | **18.0%** | **18.9%** | **19.7%** | **19.2%** | **17.3%** | **14.1%** | **9.0%** |
| **Annual Average** | | **14.5%** | | | | | | | | | | | |

All values are in MST and have not been adjusted for DST. DST begins on the second Saturday in March and ends the first Sunday in November.

The tables show a PV oriented to the southwest produces more energy in the months of June and July. The PV oriented to the south generates more energy in all other months, and the south orientation generates more energy annually. Annual average capacity factors for a southern PV orientation in Boise is 15.6 percent, and for a southwestern orientation is 14.5 percent.

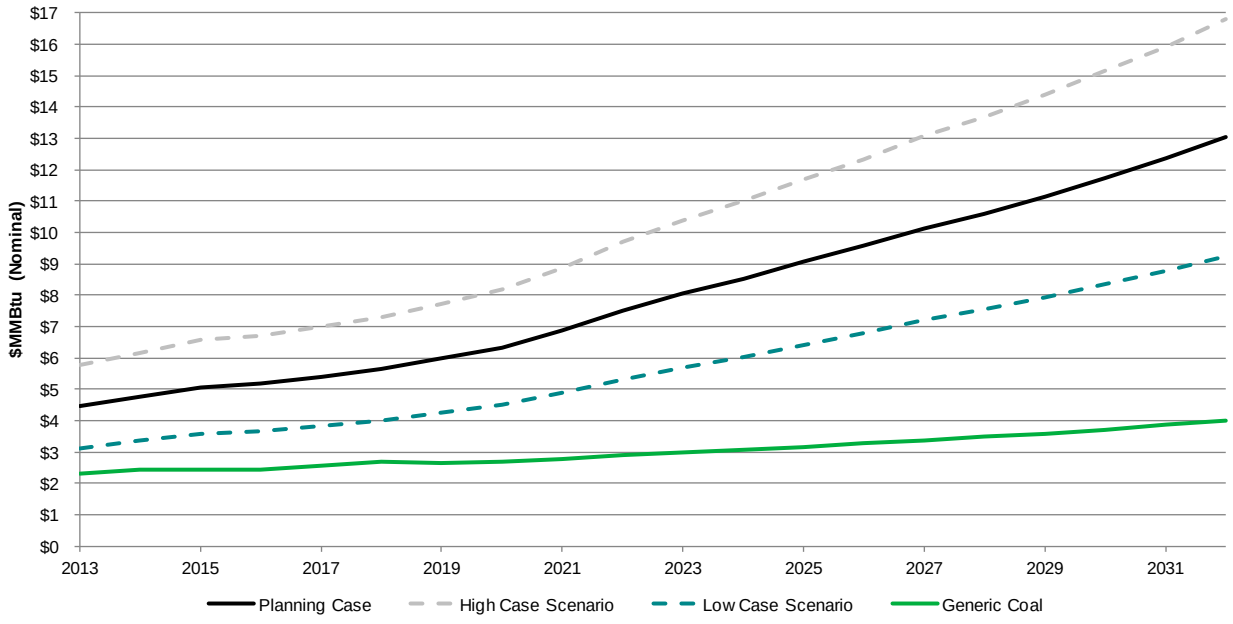
The tables indicate the southwest orientation in Boise has a 25.7 percent capacity factor from 6:00 to 7:00 pm in July and the south orientation has a 1.5 percent capacity factor during the same hour in July. Even though the southwestern exposure has a considerably greater capacity factor in late afternoon in July, the southwestern exposure capacity factor is still only 26 percent during the 6:00 to 7:00 pm hour in July. To meet a 100 MW capacity deficit during the 6:00 to 7:00 pm hour in July would require almost 400 MW of installed nameplate solar PV according to the NREL data. It is likely that the $90^{th}$ percentile exceedance criteria used by Idaho Power for capacity resource planning would further increase the quantity of solar generation needed to address a capacity deficit.

# FUEL DATA

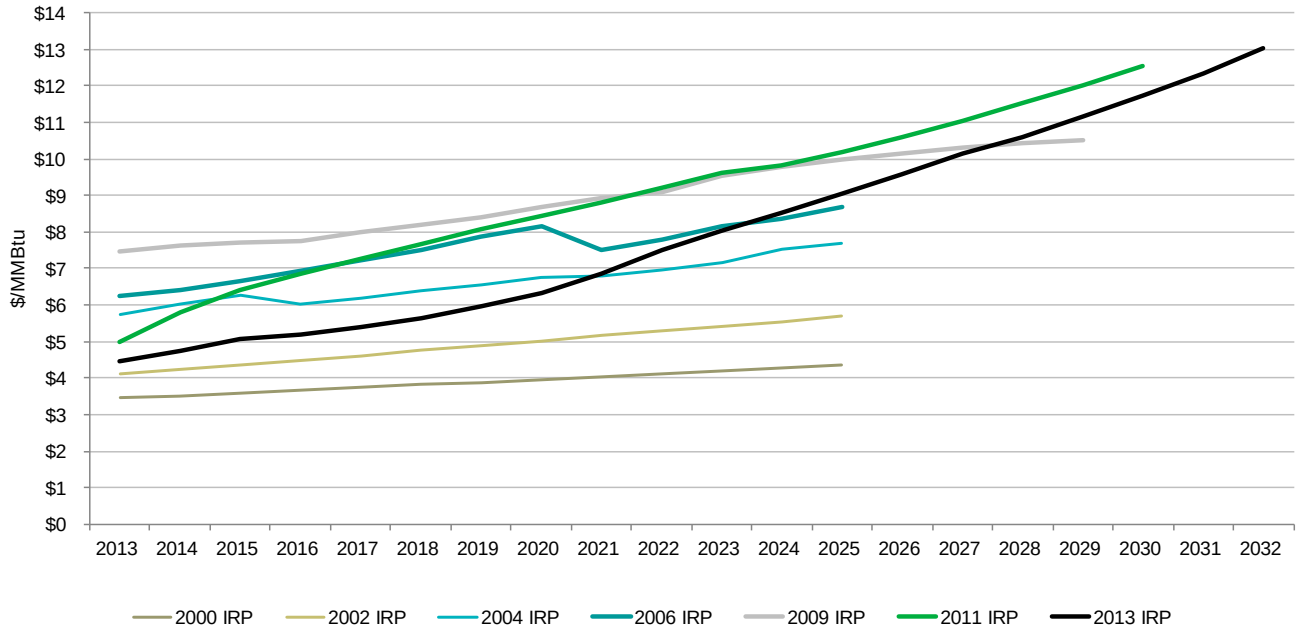
## Natural Gas and Coal Price Forecast

| Year | Sumas (Expected) | Sumas (High) | Sumas (Low) | Regional Coal |
|---|---|---|---|---|
| 2013 | $4.46 | $5.79 | $3.13 | $2.32 |
| 2014 | $4.76 | $6.17 | $3.36 | $2.44 |
| 2015 | $5.06 | $6.56 | $3.57 | $2.42 |
| 2016 | $5.19 | $6.71 | $3.66 | $2.45 |
| 2017 | $5.40 | $6.98 | $3.81 | $2.56 |
| 2018 | $5.64 | $7.29 | $3.99 | $2.68 |
| 2019 | $5.98 | $7.73 | $4.23 | $2.64 |
| 2020 | $6.34 | $8.18 | $4.49 | $2.70 |
| 2021 | $6.87 | $8.87 | $4.87 | $2.79 |
| 2022 | $7.51 | $9.69 | $5.32 | $2.89 |
| 2023 | $8.05 | $10.40 | $5.71 | $2.98 |
| 2024 | $8.52 | $11.00 | $6.04 | $3.07 |
| 2025 | $9.05 | $11.68 | $6.42 | $3.17 |
| 2026 | $9.56 | $12.34 | $6.78 | $3.27 |
| 2027 | $10.14 | $13.08 | $7.19 | $3.38 |
| 2028 | $10.61 | $13.69 | $7.53 | $3.48 |
| 2029 | $11.14 | $14.38 | $7.91 | $3.59 |
| 2030 | $11.74 | $15.15 | $8.33 | $3.71 |
| 2031 | $12.34 | $15.93 | $8.76 | $3.87 |
| 2032 | $13.03 | $16.81 | $9.25 | $4.00 |

**Sumas Natural Gas and Coal Price Forecast**



**Sumas Natural Gas Price Forecast Comparison (planning case)**



# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 106,190 |
| Bliss | 86,250 | 75,000 | 75,000 | 84,860 |
| Brownlee | 650,444 | 585,400 | 585,400 | 678,040 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,280 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 95,420 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,430 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 449,580 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 69,140 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 13,500 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,400 |
| Milner | 62,890 | 59,448 | 59,448 | 61,880 |
| Oxbow | 211,112 | 190,000 | 190,000 | 218,520 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 12,500 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800 | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 54,170 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,000 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 16,560 |
| **Total Hydro** | **1,897,046** | **1,709,045** | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC)[6,7] kW | Net Dependable Capability (NDC)[6,7] Summer kW | Net Dependable Capability (NDC)[6,7] Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,501 | | 703,667 | 703,667 |
| Boardman (Idaho Power share) | 67,600 | 64,200 | | 57,800 | 58,300 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 261,000 | 261,000 |
| **Total Thermal** | **1,193,653** | **1,118,201** | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit #1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,405 | | |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,066 | | |
| Langley Gulch CT | 220,000 | 187,000 | 176,880 | | |
| Langley Gulch ST | 154,650 | 131,452 | 122,765 | | |
| **Total Natural Gas** | **867,650** | **762,152** | | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,965,229** | **3,594,398** | | | |

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Status as of June 17, 2013.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Lowline Canal | 2.50 | May-1985 | Apr-2005 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Lowline Midway Hydro | 7.97 | Aug-2007 | Aug-2027 |
| Birch Creek | 0.05 | Nov-1984 | Oct-2019 | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Magic Reservoir | 9.07 | Jun-1989 | May-2024 |
| Blind Canyon | 1.50 | Dec-1994 | Dec-2014 | Malad River | 0.62 | May-1984 | Apr-2019 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Marco Ranches | 1.20 | Aug-1985 | Jul-2020 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Mile 28 | 1.50 | Jun-1994 | May-2029 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mill Creek | 0.80 | Nov-2011 | Jun-2017 |
| Canyon Springs | 0.13 | Oct-1984 | Non firm | Mitchell Butte | 2.09 | May-1989 | May-2024 |
| Cedar Draw | 1.55 | Jun-1984 | May-2019 | Mora Drop | 1.90 | Oct-2006 | Sep-2026 |
| Clark Canyon | 4.70 | Dec-2013 | Estimated | Mud Creek S&S | 0.52 | Feb-1982 | Feb-2017 |
| Clear Springs Trout | 0.52 | Nov-1983 | Oct-2018 | Mud Creek White | 0.21 | Jan-1986 | Jan-2021 |
| Crystal Springs | 2.44 | Apr-1986 | Mar-2021 | Owyhee Dam CSPP | 5.00 | Aug-1985 | Aug-2015 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pristine Springs | 0.13 | May-2005 | Apr-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Pristine Springs #3 | 0.20 | May-2005 | Apr-2015 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Fargo Drop | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #2 | 1.90 | Apr-1989 | Mar-2024 |
| Fisheries Development Co | 0.26 | Jul-1990 | Non firm | Sagebrush | 0.43 | Sep-1985 | Aug-2020 |
| Geo Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sahko Hydro | 0.50 | Jun-2006 | Feb-2021 |
| Hailey CSPP | 0.06 | Jun-1985 | Jun-2020 | Schaffner | 0.53 | Aug-1986 | Jul-2021 |
| Hazelton A | 8.10 | Jun-1990 | Mar-2026 | Shingle Creek | 0.22 | Aug-1983 | Jul-2018 |
| Hazelton B | 7.60 | May-1993 | Apr-2028 | Shoshone #2 | 0.58 | May-1996 | Apr-2031 |
| Horseshoe Bend Hydroelectric | 9.50 | Sep-1995 | Sep-2030 | Shoshone CSPP | 0.37 | Jun-1982 | Jun-2017 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Kasel and Witherspoon | 0.90 | Mar-1984 | Feb-2019 | Snedigar | 0.54 | Jan-1985 | Dec-2019 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Mar-2019 | Tiber Dam | 7.50 | Jun-2004 | May-2024 |
| Lateral # 10 | 2.06 | May-1985 | Apr-2020 | Trout—Co | 0.24 | Dec-1986 | Nov-2021 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | Tunnel #1 | 7.00 | Jun-1993 | May-2028 |
| Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 | White Water Ranch | 0.16 | Aug-1985 | Jul-2020 |
| Littlewood–Arkoosh | 0.87 | Aug-1986 | Jul-2021 | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 147.92 MW** | | | | | | | |
| **Thermal Projects** | | | | | | | |
| Magic Valley Natural Gas | 10.00 | Nov-1996 | Nov-2016 | TASCO—Nampa Natural Gas | 2.00 | Sep-2003 | Non firm |
| Magic West Natural Gas | 10.00 | Dec-1996 | Nov-2016 | TASCO—Twin Falls Natural Gas | 3.00 | Aug-2001 | Non firm |
| Simplot Pocatello Cogen | 15.90 | Mar-2013 | Feb-2016 | | | | |
| **Total Thermal Nameplate Rating 40.90 MW** | | | | | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2009 | Aug-2019 | Hidden Hollow Landfill Gas | 3.20 | Oct-2006 | Jan-2027 |
| Bettencourt Dry Creek | 2.25 | Aug-2008 | Aug-2018 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | Rock Creek Dairy | 4.00 | May-2012 | Aug-2027 |
| Double A Digester Project | 4.50 | Jan-2012 | Jan-2032 | Tamarack CSPP | 5.00 | Jun-1983 | May-2018 |
| **Total Biomass Nameplate Rating 23.19 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 |
| Burley Butte Wind | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind | 10.50 | Jan-2011 | Jan-2031 |
| Cold Springs Windfarm | 23.00 | Dec-2012 | Dec-2032 | Rockland Wind Project | 80.00 | Dec-2011 | Dec-2031 |
| Desert Meadow Windfarm | 23.00 | Dec-2012 | Dec-2032 | Ryegrass Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Salmon Falls Wind | 22.00 | Apr-2011 | Apr-2031 |
| Golden Valley Wind | 12.00 | Feb-2011 | Feb-2031 | Sawtooth Wind Project | 22.00 | Nov-2011 | Nov-2031 |
| Hammett Hill Windfarm | 23.00 | Dec-2012 | Dec-2032 | Thousand Springs Wind | 12.00 | Jan-2011 | Jan-2031 |
| High Mesa | 40.00 | Dec-2012 | Dec-2032 | Tuana Gulch Wind | 10.50 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind Park | 9.00 | Feb-2006 | Feb-2026 | Tuana Springs Expansion | 35.70 | May-2010 | Jun-2030 |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Two Ponds Windfarm | 23.00 | Dec-2012 | Dec-2012 |
| Lime Wind Energy | 3.00 | Dec-2011 | Dec-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Mainline Windfarm | 23.00 | Dec-2012 | Dec-2032 | | | | |
| **Total Wind Nameplate Rating 576.92 MW** | | | | | | | |
| **Total Nameplate Rating 788.93 MW** | | | | | | | |

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of June 17, 2013. In the case of CSPP projects, nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

# Power Purchase Agreement Data

**Idaho Power Company Power Purchase Agreements Status as of April 1, 2013**

| Project | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | September 2012 | September 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

# Hydro Modeling Results (PDR580)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 343.1 | 293.0 | 343.5 | 435.3 | 421.2 | 424.5 | 242.8 | 170.4 | 215.4 | 193.2 | 152.6 | 253.0 | 290.7 |
| Oxbow | HCC | 143.5 | 127.9 | 150.4 | 181.0 | 168.9 | 171.1 | 103.2 | 78.0 | 98.7 | 88.8 | 69.4 | 106.5 | 123.9 |
| Hells Canyon | HCC | 282.0 | 255.2 | 304.1 | 371.7 | 348.1 | 345.5 | 204.8 | 153.1 | 193.8 | 175.2 | 138.2 | 211.3 | 248.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.6 | 24.4 | 24.3 | 51.0 | 80.6 | 88.2 | 81.8 | 67.7 | 41.1 | 15.3 | 0.0 | 13.5 | 42.6 |
| Bliss | ROR | 49.5 | 49.5 | 42.8 | 49.8 | 46.8 | 42.9 | 35.5 | 32.1 | 37.8 | 40.4 | 38.3 | 42.6 | 42.3 |
| C .J. Strike | ROR | 64.4 | 64.9 | 57.1 | 64.4 | 62.0 | 53.6 | 38.3 | 34.8 | 45.3 | 51.5 | 50.5 | 55.4 | 53.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.9 | 35.0 | 28.5 | 34.6 | 33.1 | 29.2 | 23.1 | 19.4 | 24.2 | 26.3 | 24.7 | 29.5 | 28.5 |
| Milner | ROR | 40.1 | 40.2 | 20.7 | 36.3 | 31.4 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 4.6 | 24.3 | 19.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 20.8 | 21.1 | 18.6 | 20.9 | 20.0 | 17.5 | 13.3 | 12.1 | 15.2 | 17.0 | 16.7 | 18.1 | 17.6 |
| Twin Falls | ROR | 39.6 | 39.9 | 22.4 | 35.9 | 32.1 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 9.2 | 25.9 | 21.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.9 | 14.1 | 11.5 | 14.9 | 16.4 | 15.1 | 19.0 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.4 | 13.3 | 11.0 | 13.9 | 15.2 | 14.1 | 17.5 | 15.7 |
| **HCC Total** | | **768.6** | **676.1** | **798.0** | **988.0** | **938.1** | **941.1** | **550.8** | **401.5** | **507.9** | **457.2** | **360.2** | **570.8** | **663.2** |
| **ROR Total** | | **348.3** | **349.8** | **285.5** | **370.9** | **388.0** | **357.5** | **283.2** | **258.3** | **236.1** | **228.4** | **209.3** | **284.5** | **300.0** |
| **Total** | | **1116.9** | **1025.9** | **1083.5** | **1358.9** | **1326.0** | **1298.6** | **834.0** | **659.8** | **744.0** | **685.6** | **569.5** | **855.3** | **963.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 342.2 | 292.5 | 342.6 | 435.0 | 420.5 | 423.9 | 242.2 | 169.8 | 213.6 | 194.0 | 152.9 | 247.9 | 289.8 |
| Oxbow | HCC | 143.1 | 127.7 | 150.0 | 180.9 | 168.6 | 170.9 | 103.0 | 77.7 | 97.7 | 88.9 | 69.3 | 104.3 | 123.5 |
| Hells Canyon | HCC | 281.3 | 254.9 | 303.3 | 371.4 | 347.5 | 345.1 | 204.3 | 152.6 | 191.7 | 175.4 | 138.1 | 207.0 | 247.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.3 | 24.2 | 23.6 | 50.7 | 79.6 | 88.1 | 81.8 | 67.6 | 41.0 | 15.2 | 0.0 | 11.0 | 42.1 |
| Bliss | ROR | 49.0 | 49.3 | 42.3 | 49.6 | 46.8 | 42.8 | 35.3 | 31.9 | 37.6 | 40.2 | 38.1 | 42.4 | 42.1 |
| C .J. Strike | ROR | 64.1 | 64.6 | 56.8 | 64.1 | 61.8 | 53.3 | 38.1 | 34.6 | 45.0 | 51.3 | 50.3 | 53.2 | 53.1 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.5 | 34.9 | 27.8 | 34.4 | 32.5 | 29.1 | 23.0 | 19.3 | 24.0 | 26.2 | 24.5 | 28.9 | 28.3 |
| Milner | ROR | 38.2 | 39.9 | 18.7 | 36.0 | 30.5 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 4.6 | 20.1 | 18.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 20.5 | 21.0 | 18.5 | 20.8 | 19.9 | 17.4 | 13.3 | 12.1 | 15.1 | 16.9 | 16.5 | 17.5 | 17.5 |
| Twin Falls | ROR | 37.9 | 39.7 | 21.8 | 35.7 | 31.2 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 9.2 | 22.1 | 20.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.2 | 18.8 | 14.1 | 11.4 | 14.8 | 16.3 | 15.0 | 18.5 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 13.2 | 10.9 | 13.8 | 15.1 | 14.0 | 17.0 | 15.6 |
| **HCC Total** | | **766.6** | **675.1** | **795.9** | **987.3** | **936.5** | **939.9** | **549.5** | **400.1** | **502.9** | **458.3** | **360.3** | **559.2** | **661.0** |
| **ROR Total** | | **341.9** | **348.4** | **280.6** | **369.3** | **384.4** | **356.6** | **282.6** | **257.5** | **235.0** | **227.5** | **208.3** | **269.4** | **296.8** |
| **Total** | | **1108.5** | **1023.5** | **1076.5** | **1356.6** | **1320.8** | **1296.5** | **832.1** | **657.6** | **737.9** | **685.8** | **568.6** | **828.6** | **957.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 350.5 | 292.8 | 342.1 | 440.5 | 435.0 | 438.7 | 242.3 | 169.7 | 222.1 | 192.9 | 152.6 | 255.1 | 294.5 |
| Oxbow | HCC | 146.5 | 127.9 | 149.8 | 183.1 | 174.2 | 176.7 | 103.0 | 77.7 | 100.3 | 89.0 | 69.4 | 107.4 | 125.4 |
| Hells Canyon | HCC | 287.9 | 255.1 | 302.9 | 375.8 | 358.7 | 356.4 | 204.3 | 152.5 | 195.9 | 175.5 | 138.3 | 213.1 | 251.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.5 | 24.6 | 25.2 | 59.0 | 86.2 | 91.8 | 82.4 | 68.5 | 41.5 | 17.2 | 0.0 | 16.7 | 44.8 |
| Bliss | ROR | 49.8 | 49.4 | 42.2 | 53.0 | 51.0 | 44.8 | 35.3 | 31.9 | 37.6 | 40.4 | 38.7 | 46.2 | 43.4 |
| C .J. Strike | ROR | 65.3 | 65.1 | 56.9 | 68.0 | 66.4 | 55.2 | 38.0 | 34.5 | 44.9 | 51.6 | 50.8 | 58.6 | 54.6 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 35.2 | 34.9 | 27.8 | 37.4 | 36.7 | 30.2 | 23.0 | 19.2 | 23.9 | 26.4 | 24.7 | 32.1 | 29.3 |
| Milner | ROR | 41.5 | 40.4 | 20.5 | 44.3 | 40.9 | 22.9 | 5.9 | 6.7 | 0.0 | 0.0 | 5.5 | 29.7 | 21.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 21.0 | 21.2 | 18.6 | 21.9 | 21.4 | 18.0 | 13.3 | 12.1 | 15.1 | 17.0 | 16.8 | 19.0 | 18.0 |
| Twin Falls | ROR | 41.5 | 40.2 | 22.1 | 43.6 | 40.4 | 25.5 | 10.2 | 11.5 | 0.0 | 6.6 | 9.5 | 30.6 | 23.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 14.0 | 11.3 | 14.7 | 16.4 | 15.2 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.7 | 13.2 | 10.9 | 13.8 | 15.2 | 14.2 | 17.7 | 15.7 |
| **HCC Total** | | **784.9** | **675.8** | **794.8** | **999.4** | **967.9** | **971.8** | **549.6** | **399.9** | **518.2** | **457.4** | **360.3** | **575.6** | **671.3** |
| **ROR Total** | | **354.2** | **350.6** | **284.4** | **405.2** | **424.9** | **375.2** | **283.0** | **258.1** | **235.3** | **230.5** | **211.5** | **308.5** | **310.1** |
| **Total** | | **1139.1** | **1026.4** | **1079.2** | **1404.6** | **1392.8** | **1347.0** | **832.6** | **658.0** | **753.5** | **687.9** | **571.8** | **884.1** | **981.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 349.6 | 295.1 | 341.2 | 440.2 | 434.2 | 438.2 | 241.7 | 156.9 | 216.9 | 193.3 | 152.6 | 254.6 | 292.9 |
| Oxbow | HCC | 146.1 | 128.8 | 149.4 | 183.0 | 173.9 | 176.4 | 102.7 | 71.6 | 99.7 | 89.1 | 69.4 | 107.2 | 124.8 |
| Hells Canyon | HCC | 287.2 | 257.0 | 302.1 | 375.6 | 358.1 | 356.0 | 203.8 | 141.1 | 195.7 | 175.8 | 138.3 | 212.6 | 250.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.3 | 24.4 | 25.0 | 58.8 | 86.0 | 91.8 | 82.3 | 64.3 | 42.2 | 17.4 | 0.0 | 20.6 | 44.8 |
| Bliss | ROR | 49.5 | 49.2 | 42.0 | 52.9 | 50.8 | 44.7 | 35.2 | 28.1 | 37.4 | 40.4 | 38.7 | 48.5 | 43.1 |
| C .J. Strike | ROR | 65.0 | 64.9 | 57.2 | 67.7 | 66.1 | 55.0 | 37.8 | 29.7 | 44.7 | 51.6 | 51.1 | 61.8 | 54.4 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 35.0 | 34.7 | 27.6 | 37.6 | 36.5 | 30.1 | 22.9 | 16.0 | 23.8 | 26.3 | 24.7 | 34.1 | 29.1 |
| Milner | ROR | 41.2 | 40.2 | 20.1 | 43.9 | 40.6 | 22.5 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 36.0 | 21.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 21.0 | 21.1 | 18.6 | 21.8 | 21.3 | 17.9 | 13.2 | 10.4 | 15.0 | 17.0 | 16.9 | 19.9 | 17.8 |
| Twin Falls | ROR | 41.3 | 39.9 | 21.7 | 43.3 | 40.2 | 25.3 | 10.2 | 0.0 | 0.0 | 6.6 | 10.0 | 36.1 | 22.9 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.9 | 8.8 | 14.6 | 16.4 | 15.1 | 19.1 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.4 | 16.8 | 17.4 | 17.7 | 13.1 | 8.8 | 13.7 | 15.2 | 14.1 | 17.7 | 15.5 |
| **HCC Total** | | **782.9** | **680.9** | **792.7** | **998.8** | **966.2** | **970.6** | **548.2** | **369.6** | **512.2** | **458.2** | **360.3** | **574.4** | **667.9** |
| **ROR Total** | | **352.7** | **349.2** | **283.2** | **404.0** | **423.4** | **374.1** | **282.2** | **212.5** | **235.1** | **230.6** | **212.2** | **332.5** | **307.6** |
| **Total** | | **1135.6** | **1030.1** | **1075.9** | **1402.8** | **1389.6** | **1344.7** | **830.4** | **582.1** | **747.3** | **688.8** | **572.5** | **906.9** | **975.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 349.0 | 292.0 | 338.8 | 440.0 | 433.1 | 437.7 | 241.2 | 156.4 | 215.0 | 193.5 | 152.4 | 254.5 | 292.0 |
| Oxbow | HCC | 145.9 | 127.5 | 148.4 | 182.9 | 173.5 | 176.3 | 102.5 | 71.4 | 98.7 | 89.0 | 69.3 | 107.2 | 124.4 |
| Hells Canyon | HCC | 286.7 | 254.5 | 300.2 | 375.4 | 357.2 | 355.6 | 203.4 | 140.6 | 193.6 | 175.6 | 138.0 | 212.5 | 249.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.1 | 24.2 | 24.8 | 58.2 | 85.5 | 91.4 | 82.2 | 64.2 | 42.5 | 17.3 | 0.0 | 20.6 | 44.6 |
| Bliss | ROR | 49.4 | 49.1 | 41.8 | 51.6 | 50.4 | 44.6 | 35.0 | 28.0 | 37.3 | 40.2 | 38.7 | 48.2 | 42.9 |
| C .J. Strike | ROR | 64.8 | 64.7 | 56.5 | 66.6 | 65.6 | 54.8 | 37.7 | 29.5 | 44.5 | 51.4 | 50.9 | 61.5 | 54.0 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.8 | 34.5 | 27.0 | 36.7 | 36.1 | 30.1 | 22.8 | 15.8 | 23.6 | 26.2 | 24.5 | 33.9 | 28.8 |
| Milner | ROR | 41.0 | 40.0 | 18.2 | 42.1 | 40.0 | 22.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 36.0 | 20.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.1 | 18.4 | 21.5 | 21.2 | 17.9 | 13.1 | 10.4 | 15.0 | 16.9 | 16.8 | 19.8 | 17.8 |
| Twin Falls | ROR | 41.1 | 39.6 | 20.4 | 41.7 | 39.6 | 25.0 | 10.2 | 0.0 | 0.0 | 6.6 | 10.0 | 36.2 | 22.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.8 | 8.7 | 14.5 | 16.3 | 15.0 | 19.1 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.1 | 16.8 | 17.4 | 17.7 | 13.0 | 8.7 | 13.6 | 15.1 | 14.0 | 17.7 | 15.5 |
| **HCC Total** | | **781.6** | **674.0** | **787.4** | **998.3** | **963.8** | **969.6** | **547.1** | **368.4** | **507.2** | **458.1** | **359.7** | **574.2** | **665.8** |
| **ROR Total** | | **351.5** | **348.0** | **277.8** | **396.4** | **420.3** | **372.9** | **281.4** | **211.7** | **234.8** | **229.7** | **211.5** | **331.7** | **305.6** |
| **Total** | | **1133.1** | **1022.0** | **1065.2** | **1394.7** | **1384.1** | **1342.5** | **828.5** | **580.1** | **741.9** | **687.8** | **571.2** | **905.9** | **971.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 348.6 | 291.7 | 338.2 | 439.6 | 432.8 | 437.1 | 240.7 | 155.8 | 213.4 | 193.6 | 152.5 | 253.9 | 291.5 |
| Oxbow | HCC | 145.7 | 127.4 | 148.2 | 182.8 | 173.4 | 176.0 | 102.3 | 71.1 | 97.8 | 89.0 | 69.3 | 106.9 | 124.2 |
| Hells Canyon | HCC | 286.4 | 254.2 | 299.7 | 375.1 | 357.0 | 355.2 | 203.0 | 140.1 | 192.0 | 175.5 | 138.1 | 212.1 | 249.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.1 | 24.2 | 24.6 | 58.0 | 85.4 | 91.1 | 82.1 | 64.2 | 42.5 | 17.3 | 0.0 | 17.3 | 44.2 |
| Bliss | ROR | 49.3 | 49.0 | 41.2 | 51.4 | 49.9 | 44.5 | 34.9 | 27.8 | 37.2 | 40.0 | 38.4 | 45.7 | 42.4 |
| C .J. Strike | ROR | 64.7 | 64.5 | 56.3 | 66.4 | 64.8 | 54.4 | 37.5 | 29.3 | 44.2 | 51.0 | 50.5 | 58.5 | 53.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.8 | 34.4 | 26.6 | 35.4 | 35.7 | 30.0 | 22.6 | 15.7 | 23.5 | 26.0 | 24.4 | 31.8 | 28.4 |
| Milner | ROR | 41.0 | 40.0 | 15.5 | 40.1 | 38.8 | 22.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 30.6 | 20.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 20.9 | 18.4 | 21.4 | 21.0 | 17.7 | 13.1 | 10.3 | 14.9 | 16.9 | 16.7 | 19.0 | 17.6 |
| Twin Falls | ROR | 41.2 | 39.6 | 19.2 | 39.3 | 38.6 | 24.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.6 | 31.5 | 21.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.8 | 8.6 | 14.3 | 16.1 | 14.9 | 19.2 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.8 | 16.8 | 17.4 | 17.7 | 13.0 | 8.6 | 13.5 | 15.0 | 14.0 | 17.7 | 15.4 |
| **HCC Total** | | **780.7** | **673.3** | **786.1** | **997.5** | **963.1** | **968.3** | **546.0** | **367.0** | **503.2** | **458.1** | **359.9** | **572.9** | **664.7** |
| **ROR Total** | | **351.4** | **347.4** | **272.2** | **390.0** | **416.1** | **371.4** | **280.8** | **210.9** | **233.9** | **228.6** | **210.1** | **310.0** | **301.9** |
| **Total** | | **1132.1** | **1020.7** | **1058.3** | **1387.5** | **1379.2** | **1339.7** | **826.8** | **577.9** | **737.1** | **686.7** | **570.0** | **882.9** | **966.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 347.7 | 291.4 | 336.7 | 438.8 | 432.5 | 436.6 | 240.1 | 155.3 | 211.9 | 193.8 | 152.6 | 253.5 | 290.9 |
| Oxbow | HCC | 145.4 | 127.2 | 147.5 | 182.5 | 173.3 | 175.8 | 102.1 | 70.8 | 97.0 | 88.9 | 69.3 | 106.7 | 123.9 |
| Hells Canyon | HCC | 285.7 | 253.9 | 298.4 | 374.5 | 356.7 | 354.8 | 202.5 | 139.6 | 190.4 | 175.4 | 138.1 | 211.7 | 248.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.9 | 24.0 | 24.3 | 57.8 | 85.2 | 90.7 | 82.1 | 64.1 | 42.4 | 17.7 | 0.0 | 15.7 | 44.0 |
| Bliss | ROR | 49.1 | 48.8 | 40.8 | 51.0 | 49.7 | 44.4 | 34.7 | 27.7 | 37.0 | 39.9 | 38.2 | 44.6 | 42.2 |
| C .J. Strike | ROR | 64.4 | 64.3 | 55.7 | 66.1 | 64.5 | 54.1 | 37.2 | 29.1 | 44.0 | 50.9 | 49.9 | 57.0 | 53.1 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.6 | 34.2 | 26.2 | 34.5 | 35.5 | 29.8 | 22.5 | 15.5 | 23.3 | 25.9 | 24.1 | 30.7 | 28.1 |
| Milner | ROR | 40.7 | 39.6 | 14.7 | 36.2 | 38.6 | 21.7 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 28.0 | 19.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.8 | 20.8 | 18.2 | 21.4 | 20.9 | 17.7 | 13.0 | 10.2 | 14.8 | 16.8 | 16.4 | 18.6 | 17.5 |
| Twin Falls | ROR | 40.9 | 39.3 | 18.4 | 36.2 | 38.4 | 24.2 | 10.2 | 0.0 | 0.0 | 6.6 | 9.5 | 29.1 | 21.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.7 | 8.5 | 14.2 | 16.0 | 14.7 | 19.2 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.5 | 16.8 | 17.4 | 17.7 | 12.9 | 8.5 | 13.4 | 14.9 | 13.8 | 17.7 | 15.3 |
| **HCC Total** | | **778.8** | **672.5** | **782.6** | **995.8** | **962.5** | **967.2** | **544.7** | **365.7** | **499.2** | **458.1** | **360.0** | **571.9** | **663.2** |
| **ROR Total** | | **349.8** | **345.8** | **268.4** | **381.2** | **414.7** | **369.4** | **279.9** | **210.0** | **232.9** | **228.4** | **208.2** | **299.3** | **299.0** |
| **Total** | | **1128.6** | **1018.3** | **1051.0** | **1377.0** | **1377.2** | **1336.6** | **824.6** | **575.7** | **732.1** | **686.5** | **568.2** | **871.2** | **962.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 346.8 | 290.9 | 336.4 | 437.2 | 432.2 | 436.0 | 239.5 | 154.6 | 210.5 | 193.9 | 152.7 | 252.9 | 290.3 |
| Oxbow | HCC | 145.0 | 127.1 | 147.4 | 181.8 | 173.2 | 175.6 | 101.8 | 70.6 | 96.3 | 88.9 | 69.3 | 106.5 | 123.6 |
| Hells Canyon | HCC | 284.9 | 253.6 | 298.2 | 373.1 | 356.5 | 354.3 | 202.0 | 139.1 | 189.0 | 175.4 | 138.1 | 211.2 | 247.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.7 | 23.7 | 23.7 | 56.4 | 84.9 | 90.4 | 82.1 | 64.0 | 42.4 | 17.3 | 0.0 | 14.5 | 43.6 |
| Bliss | ROR | 48.8 | 48.6 | 40.8 | 50.6 | 49.5 | 44.2 | 34.6 | 27.5 | 36.8 | 39.8 | 38.1 | 43.7 | 41.9 |
| C .J. Strike | ROR | 64.0 | 64.0 | 55.6 | 65.6 | 64.3 | 53.8 | 37.0 | 28.9 | 43.7 | 50.6 | 49.7 | 55.7 | 52.7 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.4 | 34.0 | 26.2 | 34.2 | 35.3 | 29.6 | 22.4 | 15.4 | 23.1 | 25.7 | 24.0 | 29.9 | 27.9 |
| Milner | ROR | 40.4 | 39.3 | 14.8 | 35.4 | 38.3 | 21.1 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 26.0 | 18.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.4 | 20.5 | 18.2 | 21.2 | 20.9 | 17.6 | 12.9 | 10.2 | 14.8 | 16.8 | 16.3 | 18.2 | 17.3 |
| Twin Falls | ROR | 40.6 | 39.0 | 18.4 | 35.2 | 38.1 | 24.0 | 10.2 | 0.0 | 0.0 | 6.6 | 9.5 | 27.3 | 20.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.6 | 8.4 | 14.1 | 15.9 | 14.6 | 19.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.5 | 16.8 | 17.4 | 17.6 | 12.8 | 8.4 | 13.2 | 14.8 | 13.7 | 17.7 | 15.3 |
| **HCC Total** | | **776.7** | **671.6** | **782.0** | **992.1** | **961.8** | **965.9** | **543.3** | **364.3** | **495.7** | **458.2** | **360.1** | **570.6** | **661.9** |
| **ROR Total** | | **347.7** | **343.9** | **267.8** | **376.6** | **413.3** | **367.4** | **279.2** | **209.2** | **231.8** | **227.2** | **207.5** | **290.9** | **296.9** |
| **Total** | | **1124.4** | **1015.5** | **1049.8** | **1368.7** | **1375.0** | **1333.3** | **822.5** | **573.5** | **727.5** | **685.4** | **567.6** | **861.5** | **958.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 345.7 | 290.4 | 335.4 | 433.8 | 431.9 | 435.4 | 238.8 | 154.0 | 207.9 | 194.5 | 152.6 | 252.5 | 289.4 |
| Oxbow | HCC | 144.5 | 126.8 | 147.0 | 180.4 | 173.0 | 175.4 | 101.5 | 70.2 | 94.9 | 88.9 | 69.2 | 106.3 | 123.2 |
| Hells Canyon | HCC | 284.1 | 253.1 | 297.4 | 370.5 | 356.2 | 353.8 | 201.5 | 138.5 | 186.2 | 175.4 | 137.9 | 210.9 | 247.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.5 | 23.5 | 22.3 | 56.1 | 84.5 | 89.8 | 82.1 | 63.9 | 42.2 | 16.5 | 0.0 | 13.2 | 43.1 |
| Bliss | ROR | 48.6 | 48.3 | 40.4 | 50.4 | 49.3 | 44.1 | 34.4 | 27.3 | 36.6 | 39.6 | 37.7 | 43.2 | 41.7 |
| C .J. Strike | ROR | 63.7 | 63.6 | 55.3 | 64.4 | 63.9 | 53.4 | 36.8 | 28.6 | 43.5 | 50.4 | 49.5 | 54.3 | 52.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.1 | 33.8 | 25.9 | 33.8 | 35.1 | 29.5 | 22.2 | 15.2 | 23.0 | 25.6 | 23.7 | 29.4 | 27.6 |
| Milner | ROR | 40.2 | 38.9 | 14.1 | 35.0 | 37.9 | 20.8 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 23.8 | 18.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.3 | 20.4 | 18.1 | 20.9 | 20.8 | 17.5 | 12.9 | 10.1 | 14.7 | 16.7 | 16.2 | 17.8 | 17.2 |
| Twin Falls | ROR | 40.3 | 38.6 | 17.2 | 34.8 | 37.8 | 23.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 25.6 | 20.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.1 | 13.4 | 8.2 | 14.0 | 15.8 | 14.4 | 18.9 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.3 | 16.8 | 17.4 | 17.6 | 12.7 | 8.3 | 13.1 | 14.7 | 13.5 | 17.4 | 15.2 |
| **HCC Total** | | **774.3** | **670.3** | **779.8** | **984.7** | **961.1** | **964.6** | **541.8** | **362.7** | **489.0** | **458.8** | **359.7** | **569.7** | **659.7** |
| **ROR Total** | | **346.1** | **341.9** | **263.2** | **373.4** | **411.3** | **365.3** | **278.3** | **208.0** | **230.9** | **225.6** | **205.5** | **282.3** | **294.3** |
| **Total** | | **1120.4** | **1012.2** | **1043.0** | **1358.1** | **1372.3** | **1329.9** | **820.1** | **570.7** | **719.8** | **684.4** | **565.2** | **852.0** | **954.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 344.6 | 289.9 | 334.8 | 433.4 | 431.5 | 434.8 | 238.2 | 153.3 | 205.7 | 194.8 | 153.0 | 249.8 | 288.6 |
| Oxbow | HCC | 144.1 | 126.6 | 146.7 | 180.3 | 172.9 | 175.1 | 101.3 | 69.9 | 93.7 | 88.9 | 69.3 | 105.2 | 122.8 |
| Hells Canyon | HCC | 283.2 | 252.7 | 296.9 | 370.2 | 355.9 | 353.4 | 201.0 | 137.9 | 184.0 | 175.3 | 138.1 | 208.6 | 246.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.3 | 23.2 | 22.0 | 52.2 | 84.3 | 89.5 | 82.1 | 63.8 | 42.1 | 17.3 | 0.0 | 11.9 | 42.6 |
| Bliss | ROR | 48.3 | 48.0 | 40.1 | 50.1 | 49.1 | 43.9 | 34.3 | 27.1 | 36.4 | 39.4 | 37.6 | 42.2 | 41.4 |
| C .J. Strike | ROR | 63.3 | 63.3 | 54.9 | 64.1 | 63.6 | 53.2 | 36.6 | 28.4 | 43.2 | 50.2 | 49.2 | 52.8 | 51.9 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.9 | 33.6 | 25.7 | 33.4 | 34.9 | 29.4 | 22.1 | 15.1 | 22.8 | 25.5 | 23.6 | 28.4 | 27.4 |
| Milner | ROR | 39.9 | 38.5 | 13.5 | 34.1 | 37.6 | 20.4 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 21.5 | 18.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.2 | 20.3 | 18.0 | 20.8 | 20.8 | 17.4 | 12.8 | 10.0 | 14.6 | 16.5 | 16.2 | 17.4 | 17.1 |
| Twin Falls | ROR | 40.0 | 38.3 | 17.2 | 34.0 | 37.5 | 23.3 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 23.4 | 20.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.0 | 13.3 | 8.1 | 13.8 | 15.7 | 14.3 | 18.1 | 16.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.2 | 16.8 | 17.4 | 17.5 | 12.6 | 8.2 | 13.0 | 14.6 | 13.4 | 16.7 | 15.1 |
| **HCC Total** | | **771.9** | **669.2** | **778.4** | **983.9** | **960.2** | **963.3** | **540.5** | **361.1** | **483.3** | **459.0** | **360.4** | **563.6** | **657.9** |
| **ROR Total** | | **344.3** | **340.0** | **261.2** | **366.7** | **409.8** | **363.5** | **277.6** | **207.1** | **229.7** | **225.5** | **204.8** | **271.1** | **291.8** |
| **Total** | | **1116.2** | **1009.2** | **1039.6** | **1350.6** | **1370.0** | **1326.8** | **818.1** | **568.2** | **713.0** | **684.5** | **565.2** | **834.7** | **949.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 343.4 | 286.8 | 334.6 | 433.1 | 431.05 | 434.2 | 237.6 | 152.6 | 203.55 | 195.2 | 153 | 246.4 | 287.6 |
| Oxbow | HCC | 143.6 | 125.3 | 146.6 | 180.1 | 172.7 | 174.9 | 101 | 69.6 | 92.5 | 88.9 | 69.2 | 103.7 | 122.3 |
| Hells Canyon | HCC | 282.3 | 250.1 | 296.7 | 369.9 | 355.6 | 352.9 | 200.4 | 137.3 | 181.7 | 175.3 | 137.9 | 205.7 | 245.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.7 | 22.9 | 21.7 | 51.9 | 83.75 | 89.3 | 82.1 | 63.8 | 41.95 | 17.1 | 0 | 10.4 | 42.3 |
| Bliss | ROR | 48.1 | 47.8 | 39.8 | 49.7 | 48.8 | 43.6 | 34.1 | 26.9 | 36.2 | 39.3 | 37.3 | 41.1 | 41.1 |
| C .J. Strike | ROR | 62.9 | 62.9 | 54.5 | 63.7 | 63.3 | 53 | 36.4 | 28.1 | 43 | 50 | 48.9 | 52.8 | 51.6 |
| Cascade | ROR | 1.5 | 1.5 | 3 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.3 | 33.3 | 25.1 | 33.0 | 34.7 | 29.3 | 21.9 | 14.9 | 22.7 | 25.3 | 23.4 | 27.5 | 27.0 |
| Milner | ROR | 38.8 | 38.1 | 13.0 | 33.2 | 36.8 | 20.0 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 18.8 | 17.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.1 | 20.2 | 17.9 | 20.4 | 20.5 | 17.4 | 12.8 | 9.9 | 14.5 | 16.4 | 16.1 | 17.4 | 17.0 |
| Twin Falls | ROR | 38.5 | 37.9 | 16.9 | 33.2 | 36.8 | 23.0 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 21.3 | 19.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.9 | 13.2 | 8.0 | 13.7 | 15.6 | 14.1 | 17.4 | 15.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.8 | 16.8 | 17.4 | 17.4 | 12.5 | 8.1 | 12.9 | 14.5 | 13.3 | 16.1 | 14.9 |
| **HCC Total** | | **769.3** | **662.2** | **777.9** | **983.1** | **959.4** | **962.0** | **539.0** | **359.5** | **477.8** | **459.4** | **360.1** | **555.8** | **655.5** |
| **ROR Total** | | **339.8** | **337.9** | **258.3** | **363.1** | **406.6** | **361.8** | **276.8** | **206.1** | **228.7** | **224.5** | **203.6** | **261.5** | **289.1** |
| **Total** | | **1109.1** | **1000.1** | **1036.2** | **1346.2** | **1366.0** | **1323.8** | **815.8** | **565.6** | **706.5** | **683.9** | **563.7** | **817.3** | **944.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 342.4 | 286.4 | 336.0 | 432.6 | 430.7 | 433.6 | 237.0 | 152.0 | 200.9 | 195.6 | 153.6 | 242.5 | 286.9 |
| Oxbow | HCC | 143.2 | 125.1 | 147.2 | 180.0 | 172.6 | 174.7 | 100.7 | 69.3 | 91.1 | 88.8 | 69.4 | 102.0 | 122.0 |
| Hells Canyon | HCC | 281.4 | 249.8 | 297.9 | 369.5 | 355.3 | 352.5 | 199.9 | 136.7 | 178.9 | 175.2 | 138.3 | 202.5 | 244.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.5 | 22.6 | 21.3 | 51.7 | 83.5 | 89.1 | 82.0 | 63.6 | 41.9 | 16.4 | 0.0 | 8.9 | 42.0 |
| Bliss | ROR | 47.5 | 47.5 | 39.6 | 49.3 | 48.6 | 43.4 | 34.0 | 26.7 | 36.0 | 39.1 | 36.9 | 40.0 | 40.7 |
| C .J. Strike | ROR | 62.6 | 62.5 | 53.4 | 63.3 | 63.0 | 52.8 | 36.2 | 27.8 | 42.7 | 49.8 | 48.6 | 52.0 | 51.2 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.1 | 33.1 | 25.0 | 32.7 | 34.4 | 29.1 | 21.8 | 14.7 | 22.5 | 25.2 | 23.2 | 26.5 | 26.8 |
| Milner | ROR | 38.4 | 37.7 | 12.6 | 32.4 | 36.0 | 19.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.0 | 16.1 | 17.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.0 | 20.1 | 17.6 | 20.3 | 20.4 | 17.3 | 12.7 | 9.8 | 14.4 | 16.3 | 16.0 | 17.2 | 16.8 |
| Twin Falls | ROR | 38.2 | 37.6 | 16.5 | 32.5 | 36.1 | 22.7 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 19.0 | 19.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.2 | 19.1 | 18.8 | 13.1 | 7.9 | 13.6 | 15.5 | 14.0 | 16.6 | 15.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 16.8 | 17.4 | 17.3 | 12.4 | 8.0 | 12.8 | 14.5 | 13.2 | 15.4 | 14.8 |
| **HCC Total** | | **767.0** | **661.3** | **781.1** | **982.1** | **958.5** | **960.8** | **537.6** | **358.0** | **470.9** | **459.6** | **361.3** | **547.0** | **653.8** |
| **ROR Total** | | **337.7** | **335.9** | **255.3** | **360.3** | **403.9** | **359.7** | **276.0** | **204.9** | **227.6** | **223.1** | **202.3** | **250.4** | **286.4** |
| **Total** | | **1104.7** | **997.2** | **1036.4** | **1342.4** | **1362.4** | **1320.5** | **813.6** | **562.9** | **698.5** | **682.7** | **563.6** | **797.4** | **940.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 340.6 | 285.9 | 335.1 | 432.2 | 430.4 | 433.0 | 236.3 | 151.2 | 198.7 | 196.0 | 153.5 | 239.8 | 286.1 |
| Oxbow | HCC | 142.4 | 124.9 | 146.9 | 179.8 | 172.5 | 174.4 | 100.5 | 68.9 | 90.0 | 88.8 | 69.3 | 100.8 | 121.6 |
| Hells Canyon | HCC | 280.0 | 249.4 | 297.1 | 369.2 | 355.1 | 352.0 | 199.4 | 136.0 | 176.7 | 175.2 | 138.0 | 200.2 | 244.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.3 | 22.4 | 21.1 | 51.4 | 83.2 | 89.0 | 82.0 | 63.5 | 41.8 | 16.1 | 0.0 | 7.8 | 41.7 |
| Bliss | ROR | 47.3 | 47.3 | 39.3 | 48.9 | 48.4 | 43.1 | 33.8 | 26.5 | 35.8 | 38.9 | 37.0 | 39.1 | 40.5 |
| C .J. Strike | ROR | 62.1 | 62.2 | 53.1 | 63.0 | 62.8 | 52.6 | 36.0 | 27.6 | 42.4 | 49.6 | 48.4 | 50.8 | 50.9 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.9 | 32.9 | 25.0 | 32.5 | 34.2 | 29.0 | 21.7 | 14.6 | 22.3 | 25.0 | 23.0 | 25.7 | 26.6 |
| Milner | ROR | 38.1 | 37.4 | 12.2 | 32.1 | 35.7 | 18.9 | 5.9 | 0.0 | 0.0 | 0.0 | 5.0 | 14.1 | 16.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.9 | 20.0 | 17.5 | 20.3 | 20.3 | 17.3 | 12.7 | 9.8 | 14.4 | 16.3 | 16.0 | 16.8 | 16.8 |
| Twin Falls | ROR | 37.9 | 37.3 | 16.1 | 32.2 | 35.8 | 22.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 17.1 | 18.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 18.7 | 13.0 | 7.8 | 13.4 | 15.4 | 13.9 | 16.0 | 15.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 16.8 | 17.4 | 17.2 | 12.3 | 7.9 | 12.7 | 14.4 | 13.1 | 14.9 | 14.7 |
| **HCC Total** | | **763.0** | **660.2** | **779.1** | **981.2** | **957.9** | **959.4** | **536.2** | **356.1** | **465.3** | **460.0** | **360.8** | **540.8** | **651.7** |
| **ROR Total** | | **336.0** | **334.3** | **253.6** | **358.5** | **402.3** | **358.3** | **275.3** | **204.1** | **226.6** | **222.0** | **201.8** | **241.0** | **284.5** |
| **Total** | | **1099.0** | **994.5** | **1032.7** | **1339.7** | **1360.2** | **1317.7** | **811.5** | **560.2** | **691.8** | **682.0** | **562.6** | **781.8** | **936.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 338.7 | 285.6 | 334.1 | 431.3 | 430.1 | 428.0 | 235.7 | 150.4 | 196.5 | 196.5 | 153.9 | 236.7 | 284.8 |
| Oxbow | HCC | 141.7 | 124.8 | 146.4 | 179.4 | 172.3 | 172.5 | 100.2 | 68.6 | 88.8 | 88.8 | 69.4 | 99.5 | 121.0 |
| Hells Canyon | HCC | 278.5 | 249.1 | 296.3 | 368.5 | 354.8 | 348.2 | 198.9 | 135.3 | 174.4 | 175.2 | 138.2 | 197.6 | 242.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.1 | 22.2 | 20.8 | 51.1 | 82.8 | 88.8 | 82.0 | 63.4 | 41.7 | 17.0 | 0.0 | 6.8 | 41.6 |
| Bliss | ROR | 47.0 | 47.1 | 39.1 | 48.5 | 48.2 | 42.6 | 33.6 | 26.3 | 35.7 | 38.8 | 36.3 | 38.2 | 40.1 |
| C .J. Strike | ROR | 61.3 | 61.9 | 52.8 | 62.6 | 62.7 | 52.4 | 35.8 | 27.4 | 42.2 | 49.4 | 48.0 | 50.0 | 50.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.7 | 32.7 | 24.8 | 32.3 | 34.0 | 28.1 | 21.5 | 14.4 | 22.1 | 24.9 | 22.9 | 24.9 | 26.3 |
| Milner | ROR | 37.8 | 37.1 | 12.2 | 31.7 | 35.4 | 18.7 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 12.4 | 16.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.7 | 19.9 | 17.4 | 20.2 | 20.2 | 17.2 | 12.6 | 9.7 | 14.3 | 16.2 | 15.9 | 16.5 | 16.7 |
| Twin Falls | ROR | 37.7 | 37.0 | 15.7 | 31.9 | 35.6 | 22.5 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 15.5 | 18.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 18.0 | 12.9 | 7.6 | 13.3 | 15.3 | 13.7 | 15.4 | 15.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 16.8 | 17.4 | 16.6 | 12.2 | 7.8 | 12.6 | 14.3 | 12.9 | 14.4 | 14.6 |
| **HCC Total** | | **758.9** | **659.5** | **776.8** | **979.2** | **957.2** | **948.7** | **534.8** | **354.3** | **459.6** | **460.5** | **361.5** | **533.8** | **648.7** |
| **ROR Total** | | **333.8** | **332.7** | **252.0** | **356.4** | **400.9** | **354.8** | **274.4** | **203.0** | **225.7** | **222.2** | **199.6** | **232.8** | **282.4** |
| **Total** | | **1092.7** | **992.2** | **1028.8** | **1335.6** | **1358.0** | **1303.5** | **809.2** | **557.3** | **685.3** | **682.7** | **561.1** | **766.6** | **931.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.7 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.2** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.3** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 256.5 | 264.8 | 259.1 | 301.5 | 390.1 | 316.6 | 228.7 | 162.7 | 184.9 | 177.2 | 156.2 | 208.7 | 242.2 |
| Oxbow | HCC | 108.2 | 113.0 | 110.6 | 123.5 | 157.5 | 127.8 | 96.9 | 74.3 | 84.9 | 79.2 | 69.5 | 87.3 | 102.7 |
| Hells Canyon | HCC | 214.2 | 225.5 | 225.7 | 251.2 | 320.0 | 258.2 | 191.3 | 145.8 | 166.4 | 156.2 | 138.1 | 173.1 | 205.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.7 | 11.1 | 33.8 | 72.6 | 88.6 | 83.0 | 64.1 | 34.1 | 11.6 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 38.3 | 39.7 | 37.4 | 37.2 | 42.1 | 40.8 | 34.8 | 31.5 | 37.1 | 39.3 | 37.4 | 37.4 | 37.8 |
| C .J. Strike | ROR | 49.9 | 52.8 | 49.0 | 49.9 | 52.7 | 47.0 | 36.8 | 33.9 | 44.3 | 50.1 | 48.5 | 48.5 | 47.0 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.9 | 25.0 | 22.2 | 23.0 | 28.5 | 28.3 | 22.7 | 19.1 | 23.6 | 25.5 | 24.0 | 23.8 | 24.1 |
| Milner | ROR | 8.9 | 10.6 | 5.2 | 3.7 | 17.0 | 17.0 | 5.9 | 6.7 | 0.0 | 0.0 | 3.6 | 6.2 | 7.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 11.3 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 16.3 | 17.4 | 16.2 | 16.3 | 17.4 | 15.5 | 12.9 | 11.9 | 14.9 | 16.4 | 16.0 | 16.0 | 15.6 |
| Twin Falls | ROR | 11.5 | 13.7 | 8.6 | 7.3 | 19.9 | 20.6 | 10.2 | 11.5 | 0.0 | 6.6 | 8.3 | 9.5 | 10.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.7 | 15.7 | 13.6 | 14.2 | 18.5 | 18.2 | 13.8 | 11.2 | 14.4 | 15.8 | 14.6 | 14.5 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.6 | 12.8 | 13.4 | 17.1 | 16.8 | 13 | 10.8 | 13.5 | 14.7 | 13.7 | 13.6 | 14.0 |
| **HCC Total** | | **578.9** | **603.3** | **595.4** | **676.2** | **867.6** | **702.6** | **516.9** | **382.8** | **436.1** | **412.6** | **363.8** | **469.1** | **550.4** |
| **ROR Total** | | **215.8** | **233.5** | **215.2** | **235.6** | **327.8** | **336.9** | **278.2** | **251.1** | **224.1** | **219.3** | **202.1** | **208.2** | **245.7** |
| **Total** | | **794.7** | **836.8** | **810.6** | **911.8** | **1195.4** | **1039.5** | **795.1** | **633.9** | **660.2** | **631.9** | **565.9** | **677.3** | **796.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 254.6 | 264.1 | 258.4 | 300.2 | 389.8 | 315.8 | 228.2 | 162.1 | 184.3 | 176.1 | 156.3 | 207.3 | 241.4 |
| Oxbow | HCC | 107.4 | 112.7 | 110.2 | 123.0 | 157.3 | 127.5 | 96.7 | 74.0 | 84.6 | 78.6 | 69.6 | 86.7 | 102.4 |
| Hells Canyon | HCC | 212.7 | 224.9 | 225.1 | 250.2 | 319.7 | 257.5 | 190.8 | 145.3 | 165.8 | 155.2 | 138.1 | 171.9 | 204.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 10.4 | 32.8 | 72.6 | 88.5 | 83.1 | 64 | 34.05 | 11.6 | 0 | 0 | 33.1 |
| Bliss | ROR | 38.2 | 39.4 | 36.8 | 36.1 | 42 | 40.6 | 34.7 | 31.4 | 36.9 | 39.2 | 37.2 | 37.1 | 37.5 |
| C .J. Strike | ROR | 49.8 | 51.8 | 48.7 | 48.9 | 52.6 | 46.8 | 36.6 | 33.7 | 44.1 | 49.8 | 48.3 | 48 | 46.6 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.8 | 24.2 | 22.2 | 22.6 | 28.4 | 28.2 | 22.5 | 18.9 | 23.4 | 25.4 | 23.9 | 23.6 | 23.9 |
| Milner | ROR | 8.9 | 8.8 | 4.8 | 2.3 | 17 | 17 | 5.9 | 6.7 | 0 | 0 | 3.6 | 6.2 | 6.8 |
| Shoshone Falls | ROR | 12 | 12 | 12 | 10 | 12 | 12 | 12 | 12 | 6.7 | 10.5 | 12 | 12 | 11.3 |
| Swan Falls | ROR | 16.2 | 17.1 | 16.1 | 16.2 | 17.3 | 15.5 | 12.8 | 11.8 | 14.8 | 16.4 | 15.9 | 15.9 | 15.5 |
| Twin Falls | ROR | 11.5 | 12.1 | 8.3 | 6.2 | 19.9 | 20.6 | 10.2 | 11.5 | 0 | 6.6 | 8.3 | 9.5 | 10.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.6 | 15.0 | 13.6 | 14.0 | 18.5 | 18.1 | 13.7 | 11.1 | 14.3 | 15.7 | 14.5 | 14.4 | 14.8 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.1 | 12.8 | 13.1 | 17.0 | 16.7 | 12.9 | 10.7 | 13.4 | 14.6 | 13.6 | 13.5 | 13.8 |
| **HCC Total** | | **574.7** | **601.7** | **593.7** | **673.4** | **866.8** | **700.8** | **515.7** | **381.4** | **434.6** | **409.9** | **364.0** | **465.9** | **548.5** |
| **ROR Total** | | **215.3** | **220.8** | **212.8** | **227.7** | **327.3** | **336.1** | **277.5** | **250.2** | **223.2** | **218.6** | **201.3** | **206.9** | **243.1** |
| **Total** | | **790.0** | **822.5** | **806.5** | **901.1** | **1194.1** | **1036.9** | **793.2** | **631.6** | **657.8** | **628.5** | **565.3** | **672.8** | **791.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 257.8 | 271.6 | 260.5 | 319.5 | 390.6 | 317.6 | 228.2 | 162.0 | 184.0 | 179.2 | 155.8 | 213.0 | 245.0 |
| Oxbow | HCC | 108.8 | 115.9 | 111.1 | 130.7 | 157.6 | 128.2 | 96.7 | 74.0 | 84.4 | 80.2 | 69.5 | 89.1 | 103.9 |
| Hells Canyon | HCC | 215.3 | 231.1 | 226.8 | 265.1 | 320.3 | 259.0 | 190.9 | 145.2 | 165.6 | 158.1 | 137.9 | 176.7 | 207.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.9 | 13.5 | 37.1 | 72.7 | 89.4 | 83.2 | 65.2 | 34.9 | 13.4 | 0.0 | 0.0 | 34.9 |
| Bliss | ROR | 38.4 | 40.8 | 37.3 | 38.8 | 42.5 | 40.7 | 34.6 | 31.3 | 36.8 | 39.4 | 37.6 | 37.4 | 38.0 |
| C .J. Strike | ROR | 50.1 | 54.5 | 48.3 | 52.7 | 52.8 | 47.1 | 36.6 | 33.6 | 44.0 | 50.1 | 48.5 | 49.1 | 47.3 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.4 | 27.0 | 22.1 | 24.9 | 28.6 | 28.4 | 22.5 | 18.8 | 23.3 | 25.6 | 24.1 | 23.8 | 24.5 |
| Milner | ROR | 8.9 | 17.1 | 4.0 | 8.5 | 18.2 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 3.6 | 6.2 | 8.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 11.9 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 16.4 | 17.7 | 16.0 | 17.3 | 17.4 | 15.7 | 12.8 | 11.8 | 14.8 | 16.4 | 15.9 | 16.1 | 15.7 |
| Twin Falls | ROR | 11.7 | 19.5 | 7.8 | 11.3 | 20.6 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 8.3 | 9.5 | 11.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 15.0 | 17.2 | 13.5 | 15.8 | 18.6 | 18.2 | 13.7 | 11.0 | 14.2 | 15.8 | 14.7 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 14.0 | 16.0 | 12.8 | 14.7 | 17.1 | 16.8 | 12.9 | 10.6 | 13.4 | 14.7 | 13.8 | 13.6 | 14.2 |
| **HCC Total** | | **581.9** | **618.6** | **598.4** | **715.3** | **868.5** | **704.8** | **515.8** | **381.2** | **433.9** | **417.5** | **363.2** | **478.8** | **556.5** |
| **ROR Total** | | **217.5** | **258.0** | **214.3** | **258.6** | **330.5** | **340.3** | **277.5** | **250.9** | **223.7** | **221.3** | **202.5** | **208.9** | **250.3** |
| **Total** | | **799.4** | **876.6** | **812.7** | **973.9** | **1199.0** | **1045.1** | **793.3** | **632.1** | **657.6** | **638.8** | **565.7** | **687.7** | **806.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 257.4 | 270.8 | 260.8 | 318.1 | 392.0 | 317.1 | 227.6 | 149.1 | 183.3 | 178.6 | 155.9 | 216.8 | 244.0 |
| Oxbow | HCC | 108.6 | 115.6 | 111.3 | 130.1 | 158.2 | 128.0 | 96.5 | 67.9 | 84.1 | 79.9 | 69.6 | 90.8 | 103.4 |
| Hells Canyon | HCC | 214.9 | 230.5 | 227.1 | 264.0 | 321.5 | 258.5 | 190.4 | 133.7 | 164.9 | 157.6 | 138.1 | 179.9 | 206.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 14.0 | 13.3 | 38.8 | 72.7 | 89.4 | 83.1 | 61.2 | 36.0 | 13.6 | 0.0 | 0.0 | 35.2 |
| Bliss | ROR | 38.5 | 42.4 | 36.4 | 38.9 | 42.4 | 40.6 | 34.5 | 27.6 | 36.6 | 39.2 | 37.6 | 37.3 | 37.7 |
| C .J. Strike | ROR | 49.9 | 54.8 | 47.7 | 52.4 | 52.7 | 47.0 | 36.4 | 28.8 | 43.7 | 49.9 | 48.4 | 48.9 | 46.7 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.3 | 29.1 | 22.2 | 25.1 | 28.5 | 28.2 | 22.4 | 15.6 | 23.2 | 25.5 | 23.9 | 23.8 | 24.3 |
| Milner | ROR | 9.0 | 24.2 | 4.6 | 8.7 | 18.2 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 8.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.3 | 17.9 | 15.8 | 17.3 | 17.4 | 15.6 | 12.8 | 10.1 | 14.7 | 16.4 | 15.9 | 16.0 | 15.5 |
| Twin Falls | ROR | 12.0 | 25.6 | 8.2 | 11.4 | 20.6 | 21.7 | 10.2 | 0.0 | 0.0 | 6.6 | 8.3 | 9.5 | 11.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.9 | 18.9 | 13.6 | 15.9 | 18.5 | 18.1 | 13.5 | 8.5 | 14.1 | 15.7 | 14.6 | 14.5 | 15.1 |
| Upper Salmon 3&4 | ROR | 14.0 | 17.4 | 12.8 | 14.8 | 17.1 | 16.7 | 12.8 | 8.5 | 13.3 | 14.6 | 13.7 | 13.6 | 14.1 |
| **HCC Total** | | **580.9** | **616.9** | **599.2** | **712.2** | **871.7** | **703.6** | **514.5** | **350.7** | **432.3** | **416.1** | **363.6** | **487.5** | **554.1** |
| **ROR Total** | | **217.5** | **282.6** | **213.7** | **260.8** | **330.1** | **339.6** | **276.7** | **205.6** | **223.9** | **220.8** | **202.0** | **208.5** | **248.5** |
| **Total** | | **798.4** | **899.5** | **812.9** | **973.0** | **1201.8** | **1043.2** | **791.2** | **556.3** | **656.1** | **636.9** | **565.6** | **696.0** | **802.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 257.0 | 270.2 | 259.3 | 312.5 | 389.8 | 316.5 | 227.1 | 148.6 | 182.7 | 177.6 | 156.1 | 216.4 | 242.8 |
| Oxbow | HCC | 108.4 | 115.3 | 110.6 | 127.9 | 157.4 | 127.8 | 96.3 | 67.6 | 83.9 | 79.4 | 69.6 | 90.6 | 102.9 |
| Hells Canyon | HCC | 214.6 | 230.0 | 225.8 | 259.7 | 319.8 | 258.1 | 190.0 | 133.2 | 164.5 | 156.7 | 138.2 | 179.5 | 205.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 12.8 | 13.2 | 37.3 | 72.7 | 89.3 | 83.0 | 61.2 | 36.0 | 13.6 | 0.0 | 0.0 | 34.9 |
| Bliss | ROR | 38.5 | 41.7 | 36.0 | 37.8 | 42.4 | 40.4 | 34.4 | 27.4 | 36.4 | 39.1 | 37.4 | 37.2 | 37.4 |
| C .J. Strike | ROR | 49.8 | 54.7 | 47.4 | 52.0 | 52.6 | 46.8 | 36.2 | 28.6 | 43.5 | 49.8 | 48.1 | 48.8 | 46.5 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.2 | 28.5 | 21.9 | 24.1 | 28.5 | 28.1 | 22.3 | 15.5 | 23 | 25.4 | 23.8 | 23.7 | 24.1 |
| Milner | ROR | 8.9 | 22.2 | 2.4 | 6.2 | 18.2 | 18.2 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 7.7 |
| Shoshone Falls | ROR | 12 | 12 | 10.2 | 12 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.9 |
| Swan Falls | ROR | 16.3 | 17.9 | 15.7 | 17.1 | 17.3 | 15.5 | 12.7 | 10.1 | 14.6 | 16.3 | 15.9 | 16 | 15.5 |
| Twin Falls | ROR | 11.7 | 23.8 | 6.4 | 9.5 | 20.6 | 21.4 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 10.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.9 | 18.4 | 13.4 | 15.1 | 18.5 | 18.0 | 13.5 | 8.4 | 14.0 | 15.6 | 14.5 | 14.4 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.9 | 16.9 | 12.6 | 14.1 | 17.0 | 16.6 | 12.7 | 8.4 | 13.2 | 14.6 | 13.6 | 13.5 | 13.9 |
| **HCC Total** | | **580.0** | **615.5** | **595.7** | **700.1** | **867.0** | **702.4** | **513.4** | **349.4** | **431.0** | **413.7** | **363.9** | **486.5** | **551.6** |
| **ROR Total** | | **216.8** | **275.2** | **206.3** | **250.7** | **329.8** | **338.4** | **276.0** | **204.9** | **222.9** | **220.3** | **201.3** | **208.0** | **245.9** |
| **Total** | | **796.8** | **890.7** | **802.0** | **950.8** | **1196.8** | **1040.8** | **789.4** | **554.3** | **653.9** | **634.0** | **565.2** | **694.5** | **797.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 256.6 | 265.8 | 255.9 | 311.9 | 389.4 | 312.7 | 226.6 | 148.0 | 182.2 | 176.2 | 156.1 | 213.6 | 241.2 |
| Oxbow | HCC | 108.3 | 113.4 | 109.2 | 127.7 | 157.2 | 126.3 | 96.0 | 67.4 | 83.6 | 78.7 | 69.6 | 89.4 | 102.2 |
| Hells Canyon | HCC | 214.3 | 226.3 | 223.0 | 259.2 | 319.5 | 255.2 | 189.5 | 132.7 | 163.9 | 155.4 | 138.1 | 177.2 | 204.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 6 | 13 | 37.3 | 73.35 | 89.3 | 83.1 | 61.1 | 35.8 | 13.4 | 0 | 0 | 34.4 |
| Bliss | ROR | 38 | 39.7 | 35.9 | 37.6 | 42.1 | 40.3 | 34.3 | 27.2 | 36.2 | 39 | 37.3 | 37 | 37.1 |
| C .J. Strike | ROR | 49.7 | 52.5 | 47.3 | 51.9 | 52.5 | 46.6 | 36.1 | 28.4 | 43.3 | 49.5 | 47.9 | 48.6 | 46.2 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.9 | 24.6 | 21.9 | 23.9 | 28.4 | 28 | 22.1 | 15.3 | 22.9 | 25.2 | 23.7 | 23.5 | 23.6 |
| Milner | ROR | 8.9 | 11 | 2.4 | 6.4 | 18.2 | 18.2 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 6.7 |
| Shoshone Falls | ROR | 12 | 12 | 10.2 | 12 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.9 |
| Swan Falls | ROR | 16.3 | 17.3 | 15.8 | 17 | 17.3 | 15.4 | 12.7 | 10 | 14.6 | 16.3 | 15.8 | 15.9 | 15.4 |
| Twin Falls | ROR | 11.5 | 14.1 | 6.4 | 9.2 | 20.6 | 21 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 9.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.7 | 15.4 | 13.3 | 15.0 | 18.4 | 17.9 | 13.4 | 8.3 | 13.9 | 15.5 | 14.4 | 14.3 | 14.5 |
| Upper Salmon 3&4 | ROR | 13.8 | 14.4 | 12.6 | 14.0 | 17.0 | 16.5 | 12.6 | 8.3 | 13.1 | 14.5 | 13.5 | 13.4 | 13.6 |
| **HCC Total** | | **579.2** | **605.5** | **588.1** | **698.8** | **866.1** | **694.2** | **512.1** | **348.1** | **429.6** | **410.3** | **363.8** | **480.2** | **548.0** |
| **ROR Total** | | **215.4** | **233.3** | **205.9** | **249.8** | **329.9** | **337.3** | **275.5** | **203.9** | **222.1** | **219.3** | **200.6** | **207.1** | **241.7** |
| **Total** | | **794.6** | **838.8** | **794.0** | **948.6** | **1196.0** | **1031.5** | **787.6** | **552.0** | **651.7** | **629.6** | **564.4** | **687.3** | **789.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 256.2 | 264.3 | 255.9 | 310.0 | 389.1 | 310.8 | 226.1 | 147.4 | 181.6 | 167.5 | 156.0 | 211.0 | 239.7 |
| Oxbow | HCC | 108.1 | 112.8 | 109.2 | 126.9 | 157.1 | 125.5 | 95.8 | 67.1 | 83.3 | 78.0 | 69.4 | 88.3 | 101.8 |
| Hells Canyon | HCC | 214.0 | 225.0 | 223.0 | 257.8 | 319.2 | 253.7 | 189.1 | 132.2 | 163.4 | 153.5 | 137.9 | 175.0 | 203.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 12.5 | 36.6 | 73.3 | 89.2 | 83.1 | 60.6 | 35.2 | 13.7 | 0 | 0 | 33.7 |
| Bliss | ROR | 37.9 | 39.3 | 35.8 | 37.2 | 42 | 40.2 | 34.2 | 27.1 | 36.1 | 38.8 | 37 | 36.9 | 36.9 |
| C .J. Strike | ROR | 49.6 | 51.5 | 47.2 | 51.5 | 52.4 | 46.4 | 35.9 | 28.1 | 43 | 49.3 | 47.7 | 48.5 | 45.9 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.8 | 24.3 | 21.6 | 22.7 | 28.3 | 27.9 | 22.0 | 15.2 | 22.8 | 25.1 | 23.5 | 23.5 | 23.4 |
| Milner | ROR | 8.9 | 10.1 | 0.0 | 4.7 | 18.2 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 17.0 | 15.6 | 16.8 | 17.3 | 15.4 | 12.7 | 9.9 | 14.5 | 16.2 | 15.7 | 15.9 | 15.3 |
| Twin Falls | ROR | 11.5 | 13.3 | 5.4 | 8.5 | 20.6 | 21.0 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.6 | 15.1 | 13.1 | 14.0 | 18.3 | 17.8 | 13.3 | 8.2 | 13.8 | 15.4 | 14.2 | 14.3 | 14.3 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.1 | 12.4 | 13.2 | 16.9 | 16.5 | 12.6 | 8.2 | 13.0 | 14.4 | 13.4 | 13.4 | 13.5 |
| **HCC Total** | | **578.3** | **602.1** | **588.1** | **694.7** | **865.4** | **690.0** | **511.0** | **346.7** | **428.2** | **399.0** | **363.3** | **474.3** | **545.1** |
| **ROR Total** | | **214.8** | **223.0** | **199.7** | **242.7** | **329.3** | **336.7** | **275.0** | **202.6** | **220.7** | **218.8** | **199.5** | **206.9** | **239.1** |
| **Total** | | **793.1** | **825.1** | **787.8** | **937.4** | **1194.7** | **1026.7** | **786.0** | **549.3** | **648.9** | **617.8** | **562.8** | **681.2** | **784.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 255.7 | 262.7 | 255.8 | 308.3 | 388.7 | 309.5 | 225.5 | 146.8 | 180.9 | 166.0 | 156.4 | 208.4 | 238.7 |
| Oxbow | HCC | 107.9 | 112.1 | 109.1 | 126.2 | 156.9 | 125.0 | 95.6 | 66.8 | 83.0 | 77.2 | 69.6 | 87.2 | 101.4 |
| Hells Canyon | HCC | 213.6 | 223.7 | 222.9 | 256.5 | 319.0 | 252.8 | 188.6 | 131.7 | 162.8 | 152.0 | 138.1 | 172.9 | 202.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 11.6 | 36.9 | 73.3 | 89.1 | 83.1 | 60.5 | 35.2 | 13.7 | 0.0 | 0.0 | 33.6 |
| Bliss | ROR | 37.7 | 39.0 | 35.3 | 36.1 | 41.9 | 40.0 | 34.0 | 26.9 | 35.9 | 38.6 | 36.6 | 36.7 | 36.6 |
| C .J. Strike | ROR | 49.4 | 51.3 | 46.8 | 50.1 | 52.3 | 46.2 | 35.7 | 27.9 | 42.8 | 49.1 | 47.4 | 48.2 | 45.6 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.7 | 23.9 | 21.5 | 22.1 | 28.2 | 27.8 | 21.9 | 15.0 | 22.7 | 25.0 | 23.4 | 23.3 | 23.2 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 3.6 | 18.2 | 17.9 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.1 | 11.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.7 |
| Swan Falls | ROR | 16.2 | 17.0 | 15.5 | 16.5 | 17.3 | 15.3 | 12.6 | 9.9 | 14.5 | 16.2 | 15.7 | 15.8 | 15.2 |
| Twin Falls | ROR | 11.5 | 12.6 | 5.4 | 7.7 | 20.4 | 21.0 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.5 | 14.8 | 13.1 | 13.5 | 18.3 | 17.7 | 13.2 | 8.1 | 13.7 | 15.3 | 14.1 | 14.2 | 14.2 |
| Upper Salmon 3&4 | ROR | 13.6 | 13.9 | 12.4 | 12.8 | 16.9 | 16.4 | 12.5 | 8.1 | 12.9 | 14.3 | 13.3 | 13.3 | 13.4 |
| **HCC Total** | | **577.2** | **598.5** | **587.8** | **691.0** | **864.6** | **687.3** | **509.7** | **345.3** | **426.6** | **395.2** | **364.1** | **468.5** | **543.0** |
| **ROR Total** | | **214.1** | **219.9** | **197.8** | **236.5** | **328.8** | **335.5** | **274.2** | **201.7** | **219.9** | **218.1** | **198.5** | **205.9** | **237.6** |
| **Total** | | **791.3** | **818.4** | **785.6** | **927.5** | **1193.4** | **1022.8** | **783.9** | **547.0** | **646.5** | **613.3** | **562.6** | **674.4** | **780.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 255.2 | 260.1 | 255.7 | 306.4 | 388.4 | 307.9 | 224.8 | 146.1 | 180.1 | 165.9 | 156.1 | 212.9 | 238.3 |
| Oxbow | HCC | 107.7 | 111.0 | 109.1 | 125.5 | 156.8 | 124.4 | 95.3 | 66.5 | 82.6 | 77.1 | 69.5 | 89.1 | 101.2 |
| Hells Canyon | HCC | 213.1 | 221.6 | 222.9 | 255.0 | 318.7 | 251.5 | 188.1 | 131.1 | 162.1 | 151.9 | 138.0 | 176.6 | 202.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 10.3 | 35.6 | 73.3 | 88.9 | 83.0 | 60.4 | 35.0 | 13.7 | 0.0 | 0.0 | 33.3 |
| Bliss | ROR | 37.6 | 38.9 | 35.1 | 36.8 | 41.8 | 39.9 | 33.9 | 26.7 | 35.7 | 38.5 | 36.4 | 36.5 | 36.5 |
| C .J. Strike | ROR | 49.2 | 51.2 | 46.7 | 49.9 | 52.2 | 45.7 | 35.5 | 27.6 | 42.5 | 48.9 | 47.2 | 47.8 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.3 | 23.7 | 21.4 | 22.5 | 28.1 | 27.7 | 21.7 | 14.8 | 22.5 | 24.8 | 23.1 | 23.2 | 23.1 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 4.6 | 17.4 | 17.1 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.1 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.0 | 16.9 | 15.5 | 16.4 | 17.2 | 15.2 | 12.6 | 9.8 | 14.4 | 16.1 | 15.6 | 15.7 | 15.1 |
| Twin Falls | ROR | 11.5 | 12.6 | 5.4 | 8.1 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.2 | 14.7 | 13.0 | 13.9 | 18.2 | 17.6 | 13.1 | 8.0 | 13.6 | 15.2 | 13.9 | 14.1 | 14.1 |
| Upper Salmon 3&4 | ROR | 13.4 | 13.8 | 12.3 | 13.1 | 16.8 | 16.3 | 12.4 | 8.0 | 12.8 | 14.2 | 13.1 | 13.2 | 13.3 |
| **HCC Total** | | **576.0** | **592.7** | **587.7** | **686.9** | **863.9** | **683.8** | **508.2** | **343.7** | **424.8** | **394.9** | **363.6** | **478.6** | **542.1** |
| **ROR Total** | | **212.7** | **219.2** | **195.9** | **238.4** | **327.1** | **333.1** | **273.4** | **200.6** | **218.7** | **217.3** | **197.3** | **204.9** | **236.6** |
| **Total** | | **788.7** | **811.9** | **783.6** | **925.3** | **1191.0** | **1016.9** | **781.6** | **544.3** | **643.5** | **612.2** | **560.9** | **683.5** | **778.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 254.7 | 259.7 | 255.7 | 305.5 | 388.0 | 307.1 | 224.2 | 145.5 | 179.5 | 164.3 | 156.2 | 209.3 | 237.5 |
| Oxbow | HCC | 107.4 | 110.8 | 109.1 | 125.1 | 156.7 | 124.1 | 95.0 | 66.2 | 82.3 | 76.3 | 69.4 | 87.6 | 100.8 |
| Hells Canyon | HCC | 212.7 | 221.2 | 222.8 | 254.3 | 318.4 | 250.9 | 187.5 | 130.5 | 161.5 | 150.4 | 137.9 | 173.6 | 201.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 10.1 | 35.6 | 73.3 | 88.9 | 83.1 | 60.3 | 34.85 | 13.6 | 0 | 0 | 33.3 |
| Bliss | ROR | 37.5 | 38.6 | 35 | 36.6 | 41.7 | 39.7 | 33.7 | 26.5 | 35.5 | 38.3 | 36.2 | 36.4 | 36.3 |
| C .J. Strike | ROR | 49.1 | 50.7 | 46.6 | 49.6 | 52 | 45.5 | 35.2 | 27.4 | 42.3 | 48.7 | 46.9 | 47.6 | 45.1 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.1 | 23.6 | 21.3 | 22.3 | 28.1 | 27.5 | 21.6 | 14.7 | 22.3 | 24.6 | 22.9 | 23.1 | 22.9 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 2.7 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 11.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.6 |
| Swan Falls | ROR | 16.0 | 16.8 | 15.5 | 16.3 | 17.2 | 15.4 | 12.5 | 9.7 | 14.3 | 16.0 | 15.5 | 15.7 | 15.1 |
| Twin Falls | ROR | 11.5 | 12.6 | 4.8 | 7.1 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.1 | 14.6 | 12.9 | 13.7 | 18.2 | 17.5 | 12.9 | 7.8 | 13.4 | 15.1 | 13.8 | 14.0 | 14.0 |
| Upper Salmon 3&4 | ROR | 13.2 | 13.7 | 12.2 | 12.9 | 16.8 | 16.2 | 12.3 | 7.9 | 12.7 | 14.1 | 13.0 | 13.1 | 13.2 |
| **HCC Total** | | **574.8** | **591.7** | **587.6** | **684.9** | **863.1** | **682.1** | **506.7** | **342.2** | **423.2** | **391.0** | **363.5** | **470.5** | **540.1** |
| **ROR Total** | | **212.0** | **218.0** | **194.1** | **233.3** | **326.4** | **332.4** | **272.5** | **199.6** | **217.6** | **216.3** | **196.3** | **204.3** | **235.2** |
| **Total** | | **786.8** | **809.7** | **781.7** | **918.2** | **1189.5** | **1014.5** | **779.2** | **541.8** | **640.8** | **607.3** | **559.8** | **674.8** | **775.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 254.2 | 259.4 | 255.6 | 304.3 | 387.6 | 306.6 | 223.5 | 144.8 | 178.9 | 162.6 | 156.6 | 205.8 | 236.7 |
| Oxbow | HCC | 107.2 | 110.7 | 109.0 | 124.6 | 156.5 | 123.9 | 94.7 | 65.9 | 82.1 | 75.4 | 69.5 | 86.1 | 100.5 |
| Hells Canyon | HCC | 212.3 | 221.0 | 222.7 | 253.3 | 318.1 | 250.5 | 187.0 | 129.9 | 161.0 | 148.7 | 138.1 | 170.7 | 201.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 9.1 | 36.0 | 73.3 | 88.9 | 83.1 | 60.3 | 34.8 | 13.6 | 0.0 | 0.0 | 33.3 |
| Bliss | ROR | 37.3 | 37.6 | 34.9 | 35.8 | 41.6 | 39.6 | 33.5 | 26.3 | 35.3 | 38.1 | 36.0 | 36.2 | 36.0 |
| C .J. Strike | ROR | 48.6 | 49.7 | 46.5 | 49.3 | 51.9 | 45.3 | 35.0 | 27.1 | 42.0 | 48.5 | 46.6 | 46.8 | 44.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.0 | 23.5 | 21.3 | 21.8 | 28.0 | 27.3 | 21.4 | 14.5 | 22.1 | 24.5 | 22.7 | 22.8 | 22.7 |
| Milner | ROR | 8.9 | 8.7 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 8.1 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.4 |
| Swan Falls | ROR | 15.9 | 16.3 | 15.3 | 16.3 | 17.2 | 15.3 | 12.4 | 9.7 | 14.2 | 16.0 | 15.4 | 15.5 | 15.0 |
| Twin Falls | ROR | 11.5 | 11.8 | 4.8 | 4.4 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.0 | 14.5 | 12.9 | 13.3 | 18.1 | 17.4 | 12.8 | 7.7 | 13.3 | 14.9 | 13.6 | 13.8 | 13.9 |
| Upper Salmon 3&4 | ROR | 13.2 | 13.6 | 12.2 | 12.6 | 16.7 | 16.1 | 12.2 | 7.8 | 12.6 | 14.0 | 12.8 | 13.0 | 13.1 |
| **HCC Total** | | **573.7** | **591.1** | **587.3** | **682.2** | **862.2** | **681.0** | **505.2** | **340.6** | **421.9** | **386.7** | **364.2** | **462.6** | **538.2** |
| **ROR Total** | | **211.0** | **214.0** | **192.7** | **223.1** | **325.9** | **331.6** | **271.6** | **198.7** | **216.6** | **215.5** | **195.1** | **202.5** | **233.2** |
| **Total** | | **784.7** | **805.1** | **780.0** | **905.3** | **1188.1** | **1012.6** | **776.8** | **539.3** | **638.4** | **602.2** | **559.3** | **665.1** | **771.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 253.7 | 259.0 | 255.5 | 302.0 | 387.2 | 305.9 | 222.9 | 144.2 | 178.6 | 161.3 | 156.7 | 203.7 | 235.9 |
| Oxbow | HCC | 107.0 | 110.5 | 109.0 | 123.7 | 156.3 | 123.6 | 94.5 | 65.6 | 81.9 | 74.7 | 69.5 | 85.2 | 100.1 |
| Hells Canyon | HCC | 211.9 | 220.6 | 222.7 | 251.6 | 317.8 | 250.0 | 186.5 | 129.3 | 160.7 | 147.4 | 138.0 | 168.9 | 200.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 8.0 | 35.6 | 73.3 | 88.9 | 83.1 | 60.2 | 34.8 | 13.5 | 0.0 | 0.0 | 33.1 |
| Bliss | ROR | 37.2 | 37.5 | 34.8 | 35.5 | 41.5 | 39.4 | 33.4 | 26.1 | 35.1 | 38.0 | 35.8 | 35.9 | 35.9 |
| C .J. Strike | ROR | 47.8 | 49.4 | 46.5 | 48.2 | 51.8 | 45.2 | 34.8 | 26.9 | 41.7 | 48.3 | 46.4 | 46.6 | 44.5 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.8 | 23.4 | 21.0 | 20.9 | 27.9 | 27.2 | 21.3 | 14.3 | 22.0 | 24.4 | 22.5 | 22.6 | 22.5 |
| Milner | ROR | 8.2 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 4.8 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.7 | 16.2 | 15.3 | 16.0 | 17.1 | 15.3 | 12.4 | 9.6 | 14.1 | 15.9 | 15.4 | 15.5 | 14.9 |
| Twin Falls | ROR | 11.5 | 11.2 | 4.8 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.8 | 14.4 | 12.7 | 12.7 | 18.0 | 17.2 | 12.7 | 7.6 | 13.2 | 14.9 | 13.5 | 13.6 | 13.7 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.5 | 12.0 | 12.0 | 16.7 | 16.0 | 12.1 | 7.7 | 12.5 | 13.9 | 12.7 | 12.8 | 12.9 |
| **HCC Total** | | **572.6** | **590.1** | **587.2** | **677.3** | **861.3** | **679.5** | **503.9** | **339.1** | **421.1** | **383.4** | **364.2** | **457.8** | **536.5** |
| **ROR Total** | | **208.6** | **212.2** | **190.7** | **211.2** | **325.2** | **330.9** | **271.0** | **197.7** | **215.6** | **214.8** | **194.3** | **201.4** | **231.1** |
| **Total** | | **781.2** | **802.3** | **777.9** | **888.5** | **1186.5** | **1010.4** | **774.9** | **536.8** | **636.7** | **598.2** | **558.5** | **659.2** | **767.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 253.2 | 258.4 | 255.4 | 297.3 | 386.9 | 305.3 | 222.2 | 143.5 | 178.1 | 159.6 | 156.9 | 203.1 | 235.0 |
| Oxbow | HCC | 106.8 | 110.3 | 109.0 | 121.9 | 156.2 | 123.4 | 94.2 | 65.3 | 81.7 | 73.8 | 69.6 | 84.9 | 99.8 |
| Hells Canyon | HCC | 211.5 | 220.2 | 222.6 | 247.9 | 317.5 | 249.6 | 185.9 | 128.8 | 160.2 | 145.7 | 138.1 | 168.5 | 199.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 8.0 | 35.5 | 73.3 | 88.8 | 83.0 | 60.2 | 34.8 | 13.5 | 0.0 | 0.0 | 33.1 |
| Bliss | ROR | 36.7 | 37.4 | 34.7 | 34.8 | 41.4 | 39.3 | 33.2 | 25.9 | 34.9 | 37.8 | 35.6 | 35.8 | 35.6 |
| C .J. Strike | ROR | 47.6 | 49.3 | 46.2 | 48.0 | 51.7 | 45.0 | 34.6 | 26.7 | 41.4 | 48.0 | 46.1 | 46.2 | 44.2 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.7 | 23.3 | 21 | 20.7 | 27.8 | 27 | 21.2 | 14.2 | 21.8 | 24.3 | 22.4 | 22.5 | 22.4 |
| Milner | ROR | 8.2 | 8.3 | 0 | 0 | 17 | 17 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12 | 12 | 8.5 | 4.8 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.1 |
| Swan Falls | ROR | 15.6 | 16.2 | 15.3 | 15.9 | 17.1 | 15.2 | 12.3 | 9.5 | 14.1 | 15.9 | 15.3 | 15.4 | 14.8 |
| Twin Falls | ROR | 11.5 | 11.2 | 4.8 | 0 | 19.9 | 20.6 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.8 | 14.3 | 12.6 | 12.5 | 18.0 | 17.2 | 12.6 | 7.5 | 13.0 | 14.8 | 13.4 | 13.5 | 13.6 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.5 | 12.0 | 11.9 | 16.6 | 15.9 | 12.0 | 7.6 | 12.4 | 13.9 | 12.6 | 12.7 | 12.8 |
| **HCC Total** | | **571.5** | **588.9** | **587.0** | **667.1** | **860.6** | **678.3** | **502.3** | **337.6** | **419.9** | **379.1** | **364.6** | **456.5** | **534.5** |
| **ROR Total** | | **207.7** | **211.8** | **190.2** | **209.6** | **324.8** | **330.1** | **270.1** | **196.9** | **214.6** | **214.1** | **193.4** | **200.5** | **230.3** |
| **Total** | | **779.2** | **800.7** | **777.2** | **876.7** | **1185.4** | **1008.4** | **772.4** | **534.5** | **634.5** | **593.2** | **558.0** | **657.0** | **764.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 252.3 | 257.9 | 255.2 | 297.0 | 386.5 | 304.7 | 221.6 | 142.9 | 177.5 | 157.9 | 157.0 | 203.0 | 234.5 |
| Oxbow | HCC | 106.4 | 110.1 | 108.9 | 121.7 | 156.1 | 123.1 | 93.9 | 65.0 | 81.4 | 73.0 | 69.5 | 84.9 | 99.5 |
| Hells Canyon | HCC | 210.8 | 219.8 | 222.4 | 247.7 | 317.3 | 249.1 | 185.4 | 128.2 | 159.7 | 144.1 | 138.1 | 168.4 | 199.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.8 | 83.0 | 60.1 | 34.8 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.5 | 37.3 | 34.6 | 34.7 | 41.3 | 39.2 | 33.0 | 25.7 | 34.7 | 37.7 | 35.4 | 35.6 | 35.5 |
| C .J. Strike | ROR | 47.4 | 49.1 | 45.9 | 47.9 | 51.6 | 44.8 | 34.4 | 26.4 | 41.2 | 47.8 | 45.9 | 46.1 | 44.0 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 23.2 | 20.9 | 20.7 | 27.8 | 26.9 | 21.0 | 14.0 | 21.6 | 24.2 | 22.2 | 22.3 | 22.3 |
| Milner | ROR | 7.6 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.6 | 16.1 | 15.2 | 15.8 | 17.1 | 15.2 | 12.2 | 9.4 | 14.1 | 15.8 | 15.2 | 15.3 | 14.8 |
| Twin Falls | ROR | 10.6 | 11.2 | 4.8 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 14.3 | 12.6 | 12.4 | 17.9 | 17.0 | 12.5 | 7.3 | 12.9 | 14.7 | 13.2 | 13.4 | 13.5 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.4 | 12.0 | 11.8 | 16.6 | 15.8 | 11.9 | 7.5 | 12.2 | 13.8 | 12.5 | 12.7 | 12.8 |
| **HCC Total** | | **569.5** | **587.8** | **586.5** | **666.4** | **859.9** | **676.9** | **500.9** | **336.1** | **418.6** | **375.0** | **364.6** | **456.3** | **533.2** |
| **ROR Total** | | **205.2** | **211.2** | **188.6** | **209.0** | **324.5** | **329.4** | **269.2** | **195.7** | **213.7** | **213.4** | **192.4** | **199.8** | **229.3** |
| **Total** | | **774.7** | **799.0** | **775.1** | **875.4** | **1184.4** | **1006.3** | **770.1** | **531.8** | **632.3** | **588.4** | **557.0** | **656.1** | **762.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 200.7 | 199.7 | 244.5 | 251.3 | 294.0 | 213.0 | 214.2 | 150.3 | 152.4 | 156.4 | 158.7 | 194.2 | 202.5 |
| Oxbow | HCC | 83.5 | 82.9 | 101.7 | 104.6 | 119.0 | 88.3 | 90.4 | 68.4 | 70.1 | 71.0 | 69.7 | 80.9 | 85.9 |
| Hells Canyon | HCC | 165.2 | 165.0 | 205.8 | 212.3 | 241.6 | 177.7 | 177.7 | 134.2 | 137.5 | 140.0 | 138.1 | 159.9 | 171.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.7 | 71.0 | 86.4 | 83.8 | 56.4 | 25.7 | 9.1 | 0.0 | 0.0 | 30.2 |
| Bliss | ROR | 35.3 | 35.3 | 33.9 | 32.7 | 38.8 | 37.6 | 33.7 | 30.4 | 35.3 | 37.8 | 36.1 | 35.8 | 35.2 |
| C .J. Strike | ROR | 44.7 | 44.3 | 43.8 | 42.1 | 45.1 | 41.1 | 33.0 | 32.4 | 40.6 | 45.8 | 45.5 | 44.4 | 41.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.6 | 22.8 | 20.8 | 20.3 | 26.1 | 25.5 | 22.0 | 18.4 | 22.5 | 24.4 | 23.3 | 23.0 | 22.6 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 14.2 | 14.2 | 5.9 | 6.7 | 0.0 | 0.0 | 1.7 | 5.0 | 5.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 8.8 | 11.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.1 | 15.0 | 14.9 | 14.4 | 15.4 | 14.3 | 11.9 | 11.4 | 13.7 | 15.4 | 15.4 | 15.2 | 14.3 |
| Twin Falls | ROR | 9.4 | 9.0 | 3.8 | 0.0 | 17.0 | 17.8 | 10.0 | 11.0 | 0.0 | 5.2 | 7.1 | 8.8 | 8.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.5 | 12.2 | 16.7 | 16.0 | 13.2 | 10.7 | 13.6 | 14.9 | 14.0 | 13.9 | 13.8 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.1 | 11.9 | 11.6 | 15.5 | 14.9 | 12.5 | 10.3 | 12.8 | 14.0 | 13.2 | 13.1 | 13.0 |
| **HCC Total** | | **449.4** | **447.6** | **552.0** | **568.2** | **654.6** | **479.0** | **482.3** | **352.9** | **360.0** | **367.4** | **366.5** | **435.0** | **459.6** |
| **ROR Total** | | **198.4** | **197.8** | **176.0** | **192.5** | **301.3** | **310.8** | **270.5** | **236.2** | **205.4** | **204.1** | **191.3** | **197.8** | **223.5** |
| **Total** | | **647.8** | **645.4** | **728.0** | **760.7** | **955.9** | **789.8** | **752.8** | **589.1** | **565.4** | **571.5** | **557.8** | **632.8** | **683.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 200.2 | 198.4 | 243.1 | 251.0 | 293.7 | 212.4 | 213.6 | 149.6 | 151.7 | 155.3 | 158.9 | 193.6 | 201.8 |
| Oxbow | HCC | 83.3 | 82.4 | 101.1 | 104.5 | 118.9 | 88.0 | 90.2 | 68.0 | 69.8 | 70.4 | 69.7 | 80.6 | 85.6 |
| Hells Canyon | HCC | 164.8 | 163.9 | 204.6 | 212.0 | 241.4 | 177.2 | 177.2 | 133.6 | 136.9 | 138.9 | 138.1 | 159.4 | 170.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.9 | 71.0 | 86.0 | 83.8 | 56.4 | 25.6 | 9.0 | 0.0 | 0.0 | 30.1 |
| Bliss | ROR | 35.2 | 35.2 | 33.7 | 32.5 | 38.3 | 37.1 | 33.6 | 30.3 | 35.2 | 37.6 | 35.9 | 35.7 | 35.0 |
| C .J. Strike | ROR | 44.6 | 44.1 | 43.4 | 41.9 | 45.1 | 40.7 | 32.8 | 32.2 | 40.5 | 45.6 | 45.3 | 44.3 | 41.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 22.5 | 20.7 | 20.1 | 25.7 | 25.4 | 21.8 | 18.2 | 22.3 | 24.3 | 23.1 | 22.9 | 22.5 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 12.6 | 12.6 | 5.9 | 6.7 | 0.0 | 0.0 | 1.7 | 4.9 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 8.8 | 10.7 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.0 | 15.0 | 14.8 | 14.3 | 15.3 | 14.1 | 11.9 | 11.2 | 13.7 | 15.3 | 15.3 | 15.1 | 14.3 |
| Twin Falls | ROR | 9.4 | 9.0 | 3.8 | 0.0 | 16.2 | 16.6 | 10.0 | 11.0 | 0.0 | 5.2 | 6.8 | 8.7 | 8.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.7 | 12.4 | 12 | 16.3 | 15.9 | 13.1 | 10.5 | 13.4 | 14.8 | 13.9 | 13.8 | 13.6 |
| Upper Salmon 3&4 | ROR | 12.8 | 12.9 | 11.8 | 11.5 | 15.2 | 14.8 | 12.4 | 10.2 | 12.7 | 13.8 | 13.1 | 13 | 12.9 |
| **HCC Total** | | **448.3** | **444.7** | **548.8** | **567.5** | **654.0** | **477.6** | **481.0** | **351.2** | **358.4** | **364.6** | **366.7** | **433.6** | **458.0** |
| **ROR Total** | | **197.9** | **196.8** | **175.0** | **191.7** | **297.1** | **306.2** | **269.8** | **235.2** | **204.6** | **203.1** | **189.8** | **197.0** | **222.0** |
| **Total** | | **646.2** | **641.5** | **723.8** | **759.2** | **951.1** | **783.8** | **750.8** | **586.4** | **563.0** | **567.7** | **556.5** | **630.6** | **680.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 200.9 | 198.7 | 245.8 | 251.4 | 294.2 | 212.6 | 213.6 | 149.4 | 151.5 | 156.3 | 158.5 | 193.9 | 202.2 |
| Oxbow | HCC | 83.5 | 82.5 | 102.2 | 104.6 | 119.1 | 88.1 | 90.2 | 68.0 | 69.7 | 70.9 | 69.6 | 80.8 | 85.8 |
| Hells Canyon | HCC | 165.3 | 164.2 | 206.8 | 212.4 | 241.8 | 177.4 | 177.2 | 133.5 | 136.7 | 139.8 | 137.9 | 159.7 | 171.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.7 | 71.2 | 87.6 | 84.4 | 58.9 | 25.9 | 10.1 | 0.0 | 0.0 | 31.3 |
| Bliss | ROR | 35.2 | 35.4 | 33.9 | 32.8 | 39.6 | 38.3 | 33.5 | 30.2 | 35.2 | 37.7 | 35.9 | 35.6 | 35.3 |
| C .J. Strike | ROR | 44.5 | 44.1 | 43.9 | 41.9 | 46.6 | 42.3 | 32.8 | 32.1 | 40.5 | 46.0 | 45.2 | 44.6 | 42.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 22.7 | 20.8 | 20.3 | 26.8 | 25.8 | 21.8 | 18.1 | 22.3 | 24.5 | 23.3 | 22.9 | 22.7 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 15.5 | 15.5 | 5.9 | 6.7 | 0.0 | 0.0 | 2.4 | 5.0 | 5.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 9.7 | 11.4 | 12.0 | 10.2 |
| Swan Falls | ROR | 15.1 | 14.9 | 14.9 | 14.3 | 15.8 | 14.5 | 11.9 | 11.2 | 13.7 | 15.4 | 15.3 | 15.2 | 14.4 |
| Twin Falls | ROR | 9.4 | 9.2 | 3.8 | 0.0 | 18.3 | 19.1 | 10.0 | 11.0 | 0.0 | 6.0 | 7.5 | 8.9 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.5 | 12.2 | 17.1 | 16.2 | 13.1 | 10.5 | 13.5 | 15.0 | 14.1 | 13.8 | 13.8 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.1 | 11.9 | 11.6 | 15.9 | 15.1 | 12.4 | 10.2 | 12.7 | 14.0 | 13.2 | 13.0 | 13.0 |
| **HCC Total** | | **449.7** | **445.4** | **554.8** | **568.4** | **655.1** | **478.1** | **481.0** | **350.9** | **357.9** | **367.0** | **366.0** | **434.4** | **459.1** |
| **ROR Total** | | **197.9** | **197.8** | **183.0** | **193.4** | **308.3** | **317.4** | **270.3** | **237.4** | **205.0** | **207.1** | **192.3** | **197.6** | **225.6** |
| **Total** | | **647.6** | **643.2** | **737.8** | **761.8** | **963.4** | **795.5** | **751.3** | **588.3** | **562.9** | **574.1** | **558.3** | **632.0** | **684.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 200.5 | 199.1 | 245.2 | 251.1 | 293.9 | 212.1 | 213.1 | 136.5 | 150.8 | 155.4 | 158.7 | 193.4 | 200.8 |
| Oxbow | HCC | 83.4 | 82.7 | 102.0 | 104.5 | 118.9 | 87.9 | 89.9 | 61.9 | 69.4 | 70.4 | 69.7 | 80.5 | 85.1 |
| Hells Canyon | HCC | 165.0 | 164.5 | 206.3 | 212.1 | 241.6 | 177.0 | 176.7 | 122.0 | 136.0 | 139.0 | 138.0 | 159.3 | 169.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.5 | 71.3 | 87.6 | 84.3 | 55.9 | 27.5 | 10.2 | 0.0 | 0.0 | 31.2 |
| Bliss | ROR | 35.1 | 35.4 | 33.8 | 32.7 | 39.6 | 38.3 | 33.5 | 26.5 | 35.2 | 37.6 | 35.8 | 35.5 | 34.9 |
| C .J. Strike | ROR | 44.4 | 44.0 | 43.9 | 41.4 | 46.5 | 42.2 | 32.7 | 27.3 | 40.4 | 45.8 | 45.1 | 44.5 | 41.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 22.8 | 20.7 | 20.3 | 26.8 | 25.7 | 21.7 | 14.9 | 22.3 | 24.4 | 23.2 | 22.8 | 22.3 |
| Milner | ROR | 6.3 | 7.3 | 0.0 | 0.0 | 15.5 | 15.5 | 5.9 | 0.0 | 0.0 | 0.0 | 2.5 | 5.1 | 4.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.8 | 11.5 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.9 | 15.0 | 14.1 | 15.8 | 14.5 | 11.8 | 9.7 | 13.6 | 15.4 | 15.3 | 15.2 | 14.2 |
| Twin Falls | ROR | 9.4 | 9.7 | 3.8 | 0.0 | 18.3 | 19.2 | 10.0 | 0.0 | 0.0 | 6.1 | 7.5 | 9.0 | 7.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 13.9 | 12.4 | 12.2 | 17.2 | 16.1 | 13.0 | 8.0 | 13.4 | 14.9 | 14.0 | 13.7 | 13.5 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 11.8 | 11.6 | 15.9 | 15.0 | 12.3 | 8.1 | 12.7 | 13.9 | 13.1 | 13.0 | 12.8 |
| **HCC Total** | | **448.9** | **446.3** | **553.5** | **567.7** | **654.4** | **477.0** | **479.7** | **320.4** | **356.2** | **364.8** | **366.4** | **433.2** | **455.7** |
| **ROR Total** | | **197.3** | **199.3** | **182.7** | **192.4** | **308.4** | **317.1** | **269.7** | **193.5** | **206.3** | **206.8** | **192.0** | **197.4** | **221.9** |
| **Total** | | **646.2** | **645.6** | **736.2** | **760.1** | **962.8** | **794.1** | **749.4** | **513.9** | **562.5** | **571.6** | **558.4** | **630.6** | **677.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 200.1 | 198.8 | 244.6 | 250.8 | 293.6 | 211.6 | 212.6 | 136.0 | 150.2 | 154.4 | 159.0 | 192.9 | 200.4 |
| Oxbow | HCC | 83.2 | 82.6 | 101.7 | 104.4 | 118.8 | 87.7 | 89.7 | 61.7 | 69.1 | 69.9 | 69.8 | 80.4 | 84.9 |
| Hells Canyon | HCC | 164.7 | 164.2 | 205.8 | 211.9 | 241.4 | 176.6 | 176.3 | 121.5 | 135.5 | 138.0 | 138.2 | 158.9 | 169.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 30.5 | 71.1 | 87.1 | 84.3 | 55.9 | 27.7 | 10.1 | 0.0 | 0.0 | 31.1 |
| Bliss | ROR | 35.0 | 35.2 | 33.8 | 32.7 | 39.3 | 38.0 | 33.3 | 26.3 | 35.1 | 37.5 | 35.7 | 35.4 | 34.8 |
| C .J. Strike | ROR | 44.3 | 43.9 | 43.7 | 41.1 | 46.4 | 42.1 | 32.5 | 27.1 | 40.3 | 45.8 | 44.9 | 44.4 | 41.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.3 | 22.7 | 20.7 | 20.2 | 26.5 | 25.6 | 21.6 | 14.8 | 22.1 | 24.3 | 23.0 | 22.7 | 22.2 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 15.0 | 15.0 | 5.9 | 0.0 | 0.0 | 0.0 | 2.5 | 5.2 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.8 | 11.5 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.9 | 14.9 | 14.2 | 15.7 | 14.4 | 11.8 | 9.6 | 13.5 | 15.4 | 15.2 | 15.1 | 14.1 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 17.9 | 18.3 | 10.0 | 0.0 | 0.0 | 6.1 | 7.5 | 9.0 | 7.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.9 | 12.4 | 12.1 | 17.0 | 16.0 | 12.9 | 7.9 | 13.3 | 14.8 | 13.9 | 13.7 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 11.8 | 11.6 | 15.7 | 14.9 | 12.3 | 8.0 | 12.6 | 13.9 | 13.1 | 12.9 | 12.7 |
| **HCC Total** | | **448.0** | **445.6** | **552.1** | **567.1** | **653.8** | **475.9** | **478.6** | **319.2** | **354.8** | **362.3** | **367.0** | **432.2** | **454.7** |
| **ROR Total** | | **197.0** | **197.4** | **182.5** | **191.9** | **306.1** | **314.4** | **269.1** | **192.7** | **205.8** | **206.4** | **191.3** | **197.0** | **221.0** |
| **Total** | | **645.0** | **643.0** | **734.6** | **759.0** | **959.9** | **790.3** | **747.7** | **511.9** | **560.6** | **568.7** | **558.3** | **629.2** | **675.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 199.5 | 197.4 | 242.0 | 250.4 | 293.4 | 211.1 | 212.0 | 135.3 | 149.5 | 153.6 | 158.9 | 192.5 | 199.6 |
| Oxbow | HCC | 83.0 | 82.0 | 100.6 | 104.2 | 118.7 | 87.5 | 89.5 | 61.3 | 68.8 | 69.6 | 69.7 | 80.2 | 84.6 |
| Hells Canyon | HCC | 164.2 | 163.1 | 203.7 | 211.6 | 241.2 | 176.2 | 175.9 | 120.9 | 134.9 | 137.3 | 138.0 | 158.6 | 168.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 31.4 | 70.9 | 86.2 | 84.3 | 55.8 | 27.6 | 10.1 | 0.0 | 0.0 | 31.1 |
| Bliss | ROR | 34.9 | 35.2 | 33.7 | 32.6 | 38.8 | 37.3 | 33.1 | 26.1 | 34.8 | 37.3 | 35.4 | 35.2 | 34.5 |
| C .J. Strike | ROR | 44.1 | 43.7 | 43.6 | 41.1 | 45.8 | 41.3 | 32.3 | 26.9 | 40.2 | 45.7 | 44.6 | 44.3 | 41.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.2 | 22.5 | 20.6 | 20.1 | 26.3 | 25.4 | 21.4 | 14.6 | 21.9 | 24.2 | 22.9 | 22.5 | 22.1 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 13.9 | 13.9 | 5.9 | 0.0 | 0.0 | 0.0 | 2.6 | 5.0 | 4.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.6 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.8 | 14.8 | 14.1 | 15.4 | 14.1 | 11.7 | 9.5 | 13.4 | 15.3 | 15.1 | 15.1 | 14.0 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 16.8 | 17.4 | 10.0 | 0.0 | 0.0 | 5.7 | 7.6 | 8.9 | 7.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.7 | 12.3 | 12.0 | 16.8 | 15.9 | 12.8 | 7.8 | 13.1 | 14.7 | 13.7 | 13.6 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.9 | 11.8 | 11.5 | 15.6 | 14.8 | 12.2 | 7.9 | 12.4 | 13.8 | 12.9 | 12.8 | 12.6 |
| **HCC Total** | | **446.7** | **442.5** | **546.3** | **566.2** | **653.3** | **474.8** | **477.4** | **317.5** | **353.2** | **360.5** | **366.6** | **431.3** | **453.0** |
| **ROR Total** | | **196.5** | **196.5** | **181.9** | **192.3** | **301.8** | **309.3** | **268.2** | **191.7** | **204.6** | **205.0** | **190.4** | **196.0** | **219.5** |
| **Total** | | **643.2** | **639.0** | **728.2** | **758.5** | **955.1** | **784.1** | **745.6** | **509.2** | **557.8** | **565.5** | **557.0** | **627.3** | **672.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 199.1 | 197.1 | 240.6 | 250.1 | 293.0 | 210.6 | 211.5 | 134.7 | 148.9 | 152.2 | 159.2 | 192.0 | 199.1 |
| Oxbow | HCC | 82.8 | 81.8 | 100.0 | 104.1 | 118.6 | 87.3 | 89.3 | 61.1 | 68.5 | 68.9 | 69.8 | 79.9 | 84.3 |
| Hells Canyon | HCC | 163.9 | 162.8 | 202.6 | 211.4 | 240.9 | 175.8 | 175.4 | 120.4 | 134.4 | 136.0 | 138.2 | 158.1 | 168.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.2 | 30.2 | 70.5 | 85.9 | 84.2 | 55.8 | 27.4 | 10.3 | 0.0 | 0.0 | 31.0 |
| Bliss | ROR | 34.8 | 35.1 | 33.6 | 32.5 | 38.6 | 37.1 | 32.9 | 25.9 | 34.7 | 37.2 | 35.3 | 35.1 | 34.4 |
| C .J. Strike | ROR | 43.9 | 43.6 | 43.5 | 40.9 | 44.9 | 40.8 | 32.1 | 26.7 | 40.0 | 45.5 | 44.4 | 43.8 | 40.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.1 | 22.4 | 20.6 | 20.0 | 26.1 | 25.3 | 21.3 | 14.5 | 21.7 | 24.1 | 22.6 | 22.4 | 21.9 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 12.7 | 12.7 | 5.9 | 0.0 | 0.0 | 0.0 | 2.0 | 5.0 | 4.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.3 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.8 | 14.8 | 14.1 | 15.4 | 13.9 | 11.6 | 9.5 | 13.4 | 15.3 | 15.0 | 14.9 | 14.0 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 15.9 | 16.5 | 10.0 | 0.0 | 0.0 | 5.7 | 7.4 | 8.9 | 7.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.6 | 12.3 | 12.0 | 16.7 | 15.8 | 12.7 | 7.7 | 13.0 | 14.6 | 13.5 | 13.4 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.9 | 11.7 | 11.4 | 15.5 | 14.7 | 12.1 | 7.8 | 12.3 | 13.7 | 12.8 | 12.7 | 12.5 |
| **HCC Total** | | **445.8** | **441.7** | **543.2** | **565.6** | **652.5** | **473.7** | **476.2** | **316.2** | **351.8** | **357.1** | **367.2** | **430.0** | **451.8** |
| **ROR Total** | | **196.0** | **196.1** | **181.9** | **190.6** | **297.8** | **305.7** | **267.3** | **191.0** | **203.7** | **204.6** | **188.3** | **194.8** | **218.1** |
| **Total** | | **641.8** | **637.8** | **725.1** | **756.2** | **950.3** | **779.4** | **743.5** | **507.2** | **555.5** | **561.7** | **555.5** | **624.8** | **669.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 198.0 | 196.6 | 240.2 | 249.8 | 292.7 | 210.0 | 210.9 | 134.1 | 148.3 | 150.7 | 159.1 | 191.9 | 198.5 |
| Oxbow | HCC | 82.4 | 81.6 | 99.9 | 104.0 | 118.5 | 87.0 | 89.0 | 60.8 | 68.2 | 68.1 | 69.7 | 79.9 | 84.1 |
| Hells Canyon | HCC | 163.0 | 162.4 | 202.3 | 211.1 | 240.6 | 175.3 | 174.9 | 119.8 | 133.8 | 134.6 | 138.0 | 158.0 | 167.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.2 | 70.3 | 85.8 | 84.2 | 55.8 | 27.1 | 10.3 | 0.0 | 0.0 | 30.9 |
| Bliss | ROR | 34.7 | 34.8 | 33.5 | 32.4 | 38.4 | 36.8 | 32.8 | 25.8 | 34.5 | 37.2 | 35.1 | 34.9 | 34.2 |
| C .J. Strike | ROR | 43.8 | 43.4 | 43.4 | 40.8 | 44.7 | 40.4 | 31.9 | 26.4 | 39.9 | 45.4 | 44.2 | 43.6 | 40.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.0 | 22.2 | 20.5 | 20.0 | 25.8 | 25.1 | 21.1 | 14.3 | 21.5 | 23.9 | 22.4 | 22.2 | 21.8 |
| Milner | ROR | 6.3 | 5.8 | 0.0 | 0.0 | 12.3 | 12.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.3 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.0 | 15.3 | 13.8 | 11.6 | 9.4 | 13.3 | 15.2 | 15.0 | 14.9 | 13.9 |
| Twin Falls | ROR | 9.5 | 8.9 | 3.8 | 0.0 | 15.1 | 15.8 | 10.0 | 0.0 | 0.0 | 5.7 | 7.4 | 8.8 | 7.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.3 | 11.9 | 16.4 | 15.7 | 12.6 | 7.5 | 12.8 | 14.5 | 13.4 | 13.3 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.8 | 11.7 | 11.4 | 15.2 | 14.6 | 12.0 | 7.7 | 12.2 | 13.6 | 12.6 | 12.6 | 12.4 |
| **HCC Total** | | **443.4** | **440.6** | **542.4** | **564.9** | **651.8** | **472.3** | **474.8** | **314.7** | **350.3** | **353.4** | **366.8** | **429.8** | **450.4** |
| **ROR Total** | | **195.3** | **194.3** | **181.3** | **190.2** | **295.0** | **303.3** | **266.6** | **190.0** | **202.5** | **204.0** | **187.2** | **193.9** | **217.0** |
| **Total** | | **638.7** | **634.9** | **723.7** | **755.1** | **946.8** | **775.6** | **741.4** | **504.7** | **552.8** | **557.4** | **554.0** | **623.7** | **667.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 197.5 | 196.1 | 239.9 | 249.4 | 292.3 | 209.3 | 210.2 | 133.5 | 147.5 | 148.5 | 159.3 | 191.2 | 197.9 |
| Oxbow | HCC | 82.2 | 81.4 | 99.7 | 103.8 | 118.3 | 86.7 | 88.7 | 60.5 | 67.8 | 67.0 | 69.7 | 79.6 | 83.8 |
| Hells Canyon | HCC | 162.6 | 162.1 | 202.0 | 210.7 | 240.4 | 174.7 | 174.4 | 119.3 | 133.1 | 132.5 | 138.1 | 157.4 | 167.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.8 | 30.8 | 70.3 | 85.6 | 84.1 | 55.3 | 26.9 | 9.9 | 0.0 | 0.0 | 30.8 |
| Bliss | ROR | 34.5 | 34.8 | 33.4 | 32.4 | 38.1 | 36.6 | 32.6 | 25.6 | 34.2 | 37.1 | 34.8 | 34.8 | 34.1 |
| C .J. Strike | ROR | 43.6 | 43.3 | 43.3 | 40.8 | 44.5 | 40.0 | 31.7 | 26.2 | 39.7 | 45.1 | 43.8 | 43.4 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.9 | 22.1 | 20.4 | 19.9 | 25.6 | 25.0 | 21.0 | 14.1 | 21.3 | 23.7 | 22.2 | 22.1 | 21.6 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 12.3 | 12.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.8 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.4 | 11.1 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.7 | 14.1 | 15.2 | 13.7 | 11.5 | 9.3 | 13.3 | 15.2 | 14.9 | 14.8 | 13.9 |
| Twin Falls | ROR | 9.5 | 9.0 | 3.8 | 0.0 | 15.5 | 16.6 | 10.0 | 0.0 | 0.0 | 5.7 | 7.2 | 8.8 | 7.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.4 | 12.2 | 11.8 | 16.3 | 15.6 | 12.5 | 7.4 | 12.7 | 14.3 | 13.2 | 13.2 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.7 | 11.6 | 11.3 | 15.1 | 14.5 | 11.9 | 7.6 | 12.0 | 13.5 | 12.5 | 12.5 | 12.3 |
| **HCC Total** | | **442.3** | **439.6** | **541.6** | **563.9** | **651.0** | **470.7** | **473.3** | **313.3** | **348.4** | **348.0** | **367.1** | **428.2** | **449.0** |
| **ROR Total** | | **194.6** | **194.4** | **180.6** | **190.6** | **294.3** | **302.9** | **265.7** | **188.6** | **201.3** | **202.6** | **185.5** | **193.1** | **216.2** |
| **Total** | | **636.9** | **634.0** | **722.2** | **754.5** | **945.3** | **773.6** | **739.0** | **501.9** | **549.7** | **550.6** | **552.6** | **621.3** | **665.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 196.9 | 195.6 | 238.9 | 248.9 | 292.0 | 208.7 | 209.5 | 132.7 | 146.8 | 146.8 | 159.5 | 190.5 | 197.2 |
| Oxbow | HCC | 81.9 | 81.2 | 99.3 | 103.6 | 118.2 | 86.5 | 88.4 | 60.1 | 67.5 | 66.2 | 69.8 | 79.3 | 83.5 |
| Hells Canyon | HCC | 162.1 | 161.7 | 201.2 | 210.4 | 240.1 | 174.2 | 173.8 | 118.6 | 132.5 | 131.0 | 138.2 | 156.9 | 166.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.6 | 70.0 | 85.5 | 84.2 | 55.3 | 26.9 | 9.9 | 0.0 | 0.0 | 30.7 |
| Bliss | ROR | 34.4 | 34.6 | 33.3 | 32.1 | 38.1 | 36.2 | 32.3 | 25.4 | 34.0 | 37.0 | 34.7 | 34.7 | 33.9 |
| C .J. Strike | ROR | 43.4 | 43.1 | 43.0 | 40.7 | 44.4 | 39.5 | 31.4 | 25.9 | 39.5 | 44.9 | 43.5 | 43.2 | 40.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.8 | 22.0 | 20.3 | 19.5 | 25.4 | 24.7 | 20.8 | 14.0 | 21.1 | 23.5 | 22.0 | 22.0 | 21.4 |
| Milner | ROR | 6.3 | 5.8 | 0.0 | 0.0 | 12.2 | 12.2 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.9 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.7 | 14.0 | 15.2 | 13.6 | 11.4 | 9.2 | 13.2 | 15.1 | 14.8 | 14.8 | 13.8 |
| Twin Falls | ROR | 9.5 | 8.9 | 3.8 | 0.0 | 15.0 | 16.0 | 10.0 | 0.0 | 0.0 | 5.2 | 7.0 | 8.8 | 7.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.0 | 13.3 | 12.1 | 11.5 | 16.1 | 15.4 | 12.3 | 7.3 | 12.5 | 14.2 | 13.1 | 13.1 | 12.8 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.6 | 11.6 | 11.1 | 15.0 | 14.3 | 11.7 | 7.5 | 11.9 | 13.4 | 12.4 | 12.4 | 12.2 |
| **HCC Total** | | **440.9** | **438.5** | **539.4** | **562.9** | **650.3** | **469.4** | **471.7** | **311.4** | **346.8** | **344.0** | **367.5** | **426.7** | **447.5** |
| **ROR Total** | | **193.9** | **193.2** | **179.8** | **189.0** | **292.9** | **300.4** | **264.5** | **187.7** | **200.3** | **200.7** | **184.1** | **192.5** | **214.9** |
| **Total** | | **634.8** | **631.7** | **719.2** | **751.9** | **943.2** | **769.8** | **736.2** | **499.1** | **547.1** | **544.7** | **551.6** | **619.2** | **662.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 196.1 | 195.2 | 239.1 | 248.6 | 291.6 | 208.1 | 208.9 | 131.9 | 146.2 | 146.3 | 159.4 | 190.1 | 196.8 |
| Oxbow | HCC | 81.5 | 81.1 | 99.4 | 103.5 | 118.0 | 86.2 | 88.2 | 59.8 | 67.2 | 66.0 | 69.7 | 79.1 | 83.3 |
| Hells Canyon | HCC | 161.4 | 161.3 | 201.4 | 210.1 | 239.8 | 173.8 | 173.3 | 117.9 | 131.9 | 130.5 | 138.1 | 156.5 | 166.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.5 | 69.8 | 85.2 | 84.3 | 55.1 | 26.9 | 10.1 | 0.0 | 0.0 | 30.7 |
| Bliss | ROR | 34.3 | 34.5 | 33.2 | 32.0 | 38.0 | 35.9 | 32.1 | 25.2 | 33.8 | 36.9 | 34.5 | 34.5 | 33.7 |
| C .J. Strike | ROR | 43.1 | 43.0 | 43.0 | 40.7 | 44.2 | 38.8 | 31.2 | 25.7 | 39.2 | 44.6 | 43.3 | 43.0 | 40.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.7 | 21.9 | 20.2 | 19.4 | 25.2 | 24.4 | 20.6 | 13.8 | 20.9 | 23.3 | 21.9 | 21.9 | 21.3 |
| Milner | ROR | 6.2 | 5.8 | 0.0 | 0.0 | 11.3 | 11.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 11.1 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.6 | 13.9 | 15.0 | 13.3 | 11.4 | 9.1 | 13.2 | 15.0 | 14.7 | 14.7 | 13.7 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0.0 | 14.0 | 15.1 | 10.0 | 0.0 | 0.0 | 5.2 | 7.2 | 8.8 | 6.9 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.3 | 12.1 | 11.5 | 15.9 | 15.1 | 12.2 | 7.2 | 12.3 | 14.1 | 13.0 | 13.0 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.6 | 11.5 | 11.0 | 14.8 | 14.1 | 11.6 | 7.4 | 11.8 | 13.2 | 12.3 | 12.3 | 12.1 |
| **HCC Total** | | **439.0** | **437.6** | **539.9** | **562.2** | **649.4** | **468.1** | **470.4** | **309.6** | **345.3** | **342.8** | **367.2** | **425.7** | **446.4** |
| **ROR Total** | | **193.1** | **192.9** | **179.4** | **188.5** | **289.6** | **296.2** | **263.8** | **186.6** | **199.3** | **199.9** | **183.7** | **191.7** | **213.7** |
| **Total** | | **632.1** | **630.5** | **719.3** | **750.7** | **939.0** | **764.3** | **734.2** | **496.2** | **544.6** | **542.7** | **550.9** | **617.4** | **660.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 195.5 | 194.7 | 238.8 | 248.2 | 283.1 | 207.5 | 208.3 | 131.2 | 145.5 | 144.8 | 159.3 | 189.9 | 195.6 |
| Oxbow | HCC | 81.3 | 80.8 | 99.3 | 103.3 | 117.9 | 86.0 | 87.9 | 59.4 | 66.9 | 65.2 | 69.6 | 79.0 | 83.1 |
| Hells Canyon | HCC | 160.9 | 160.9 | 201.1 | 209.8 | 241.3 | 173.3 | 172.8 | 117.2 | 131.3 | 129.1 | 137.9 | 156.4 | 166.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 6.6 | 30.2 | 69.35 | 85.1 | 84.3 | 54.5 | 26.8 | 9.9 | 0 | 0 | 30.6 |
| Bliss | ROR | 34.2 | 34.4 | 33.1 | 31.9 | 38 | 35.8 | 32 | 25 | 33.6 | 36.7 | 34.3 | 34.3 | 33.6 |
| C .J. Strike | ROR | 43 | 42.8 | 42.9 | 40.4 | 44 | 38.5 | 31 | 25.4 | 39 | 44.4 | 43 | 42.8 | 39.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7 | 10.3 | 6.45 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.6 | 21.8 | 20.2 | 19.3 | 25.1 | 24.2 | 20.4 | 13.6 | 20.7 | 23.2 | 21.7 | 21.7 | 21.1 |
| Milner | ROR | 6.0 | 5.8 | 0.0 | 0.0 | 10.9 | 10.9 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.9 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.6 | 14.6 | 14.6 | 13.9 | 14.9 | 13.2 | 11.2 | 9.0 | 13.2 | 15.0 | 14.6 | 14.6 | 13.6 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0.0 | 13.7 | 14.7 | 10.0 | 0.0 | 0.0 | 5.2 | 7.0 | 8.8 | 6.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.2 | 12.0 | 11.4 | 15.9 | 15.0 | 12.0 | 7.0 | 12.2 | 13.9 | 12.8 | 12.9 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.5 | 11.5 | 10.9 | 14.8 | 14.0 | 11.5 | 7.3 | 11.6 | 13.1 | 12.2 | 12.2 | 12.0 |
| **HCC Total** | | **437.7** | **436.4** | **539.2** | **561.3** | **642.3** | **466.8** | **469.0** | **307.8** | **343.7** | **339.1** | **366.8** | **425.3** | **444.6** |
| **ROR Total** | | **192.4** | **192.2** | **179.1** | **187.5** | **288.1** | **294.4** | **262.8** | **184.9** | **198.3** | **198.9** | **182.2** | **190.8** | **212.6** |
| **Total** | | **630.1** | **628.6** | **718.3** | **748.8** | **930.4** | **761.2** | **731.8** | **492.7** | **542.0** | **538.0** | **549.0** | **616.1** | **657.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 195.0 | 194.1 | 238.3 | 247.7 | 282.7 | 206.9 | 207.6 | 130.4 | 144.8 | 143.6 | 159.4 | 189.4 | 195.0 |
| Oxbow | HCC | 81.1 | 80.6 | 99.1 | 103.1 | 117.7 | 85.7 | 87.6 | 59.1 | 66.5 | 64.6 | 69.7 | 78.8 | 82.8 |
| Hells Canyon | HCC | 160.5 | 160.4 | 200.8 | 209.4 | 241.1 | 172.8 | 172.2 | 116.5 | 130.7 | 127.9 | 138.0 | 155.9 | 165.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.0 | 69.2 | 85.0 | 84.4 | 54.4 | 26.8 | 9.8 | 0.0 | 0.0 | 30.5 |
| Bliss | ROR | 34.0 | 34.2 | 33.0 | 31.8 | 37.8 | 35.7 | 31.7 | 24.8 | 33.4 | 36.5 | 34.1 | 34.2 | 33.4 |
| C .J. Strike | ROR | 43.0 | 42.7 | 42.8 | 40.3 | 43.1 | 37.8 | 30.8 | 25.2 | 38.7 | 44.3 | 42.8 | 42.6 | 39.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.5 | 21.7 | 20.1 | 19.2 | 25 | 24.1 | 20.3 | 13.5 | 20.5 | 23.1 | 21.5 | 21.6 | 21.0 |
| Milner | ROR | 6 | 5.8 | 0 | 0 | 10.7 | 10.7 | 5.9 | 0 | 0 | 0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12 | 12 | 7.3 | 3.9 | 12 | 12 | 12 | 6.6 | 6.5 | 8.8 | 10.8 | 12 | 9.7 |
| Swan Falls | ROR | 14.6 | 14.6 | 14.6 | 13.8 | 14.7 | 13 | 11.2 | 8.9 | 13.1 | 14.9 | 14.5 | 14.6 | 13.5 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0 | 13.5 | 14.5 | 10 | 0 | 0 | 5.2 | 6.9 | 8.8 | 6.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.8 | 13.1 | 12.0 | 11.3 | 15.8 | 14.9 | 11.9 | 6.9 | 12.0 | 13.9 | 12.7 | 12.8 | 12.5 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.4 | 11.4 | 10.9 | 14.7 | 13.9 | 11.4 | 7.2 | 11.5 | 13.1 | 12.0 | 12.1 | 11.9 |
| **HCC Total** | | **436.6** | **435.1** | **538.2** | **560.2** | **641.5** | **465.4** | **467.4** | **306.0** | **342.0** | **336.1** | **367.1** | **424.1** | **443.3** |
| **ROR Total** | | **191.9** | **191.6** | **178.7** | **186.8** | **285.9** | **292.6** | **262.1** | **184.0** | **197.2** | **198.3** | **181.0** | **190.2** | **211.7** |
| **Total** | | **628.5** | **626.7** | **716.9** | **747.0** | **927.4** | **758.0** | **729.5** | **490.0** | **539.2** | **534.4** | **548.1** | **614.3** | **655.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 194.2 | 193.2 | 237.5 | 247.4 | 282.4 | 206.3 | 207.0 | 129.8 | 144.1 | 142.0 | 159.9 | 188.5 | 194.4 |
| Oxbow | HCC | 80.7 | 80.2 | 98.7 | 103.0 | 117.6 | 85.5 | 87.3 | 58.8 | 66.2 | 63.9 | 69.8 | 78.4 | 82.5 |
| Hells Canyon | HCC | 159.9 | 159.7 | 200.1 | 209.2 | 240.8 | 172.3 | 171.7 | 116.0 | 130.0 | 126.5 | 138.3 | 155.2 | 165.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 29.9 | 68.8 | 84.6 | 84.4 | 54.4 | 26.7 | 9.6 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.7 | 34.2 | 32.9 | 31.7 | 37.3 | 35.4 | 31.5 | 24.6 | 33.2 | 36.4 | 33.9 | 34.1 | 33.2 |
| C .J. Strike | ROR | 42.9 | 42.5 | 42.7 | 40.2 | 42.1 | 37.6 | 30.6 | 24.9 | 38.5 | 44.1 | 42.5 | 42.4 | 39.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.3 | 21.5 | 20.0 | 19.1 | 24.4 | 23.7 | 20.2 | 13.3 | 20.3 | 23.0 | 21.4 | 21.4 | 20.8 |
| Milner | ROR | 6.0 | 5.8 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.8 | 14.6 | 12.9 | 11.1 | 8.9 | 13.1 | 14.8 | 14.4 | 14.5 | 13.5 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.7 | 12.9 | 11.9 | 11.3 | 15.3 | 14.6 | 11.8 | 6.8 | 11.9 | 13.8 | 12.6 | 12.7 | 12.4 |
| Upper Salmon 3&4 | ROR | 12 | 12.3 | 11.4 | 10.8 | 14.3 | 13.7 | 11.3 | 7.1 | 11.4 | 13 | 12 | 12.1 | 11.8 |
| **HCC Total** | | **434.8** | **433.1** | **536.3** | **559.6** | **640.8** | **464.1** | **466.0** | **304.6** | **340.3** | **332.4** | **368.0** | **422.1** | **441.8** |
| **ROR Total** | | **191.0** | **190.7** | **178.2** | **186.3** | **282.4** | **290.7** | **261.3** | **183.1** | **196.3** | **197.4** | **180.0** | **189.5** | **210.6** |
| **Total** | | **625.8** | **623.8** | **714.5** | **745.9** | **923.2** | **754.8** | **727.3** | **487.7** | **536.6** | **529.8** | **548.0** | **611.6** | **652.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

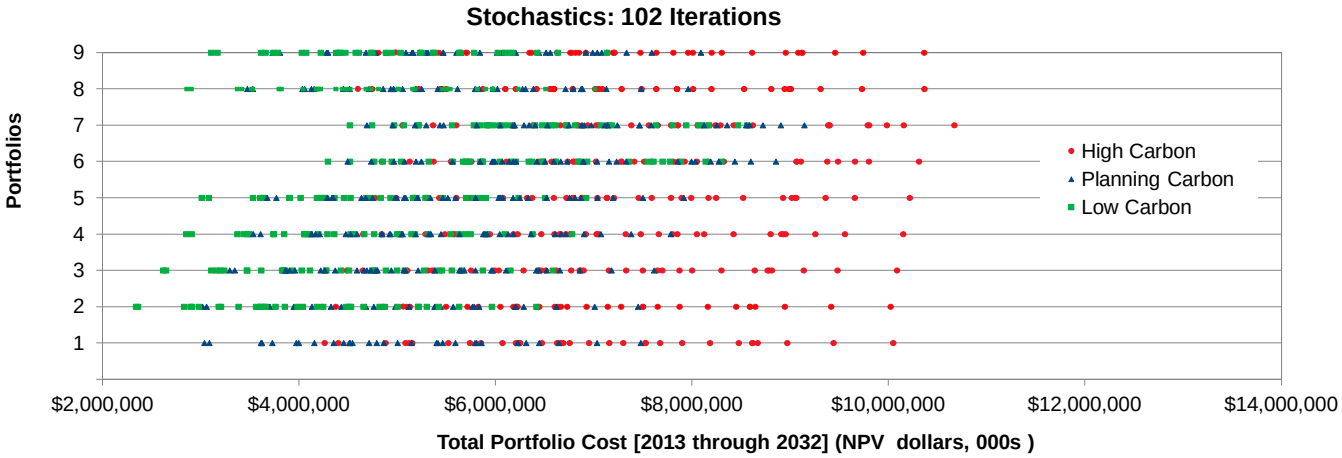
*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

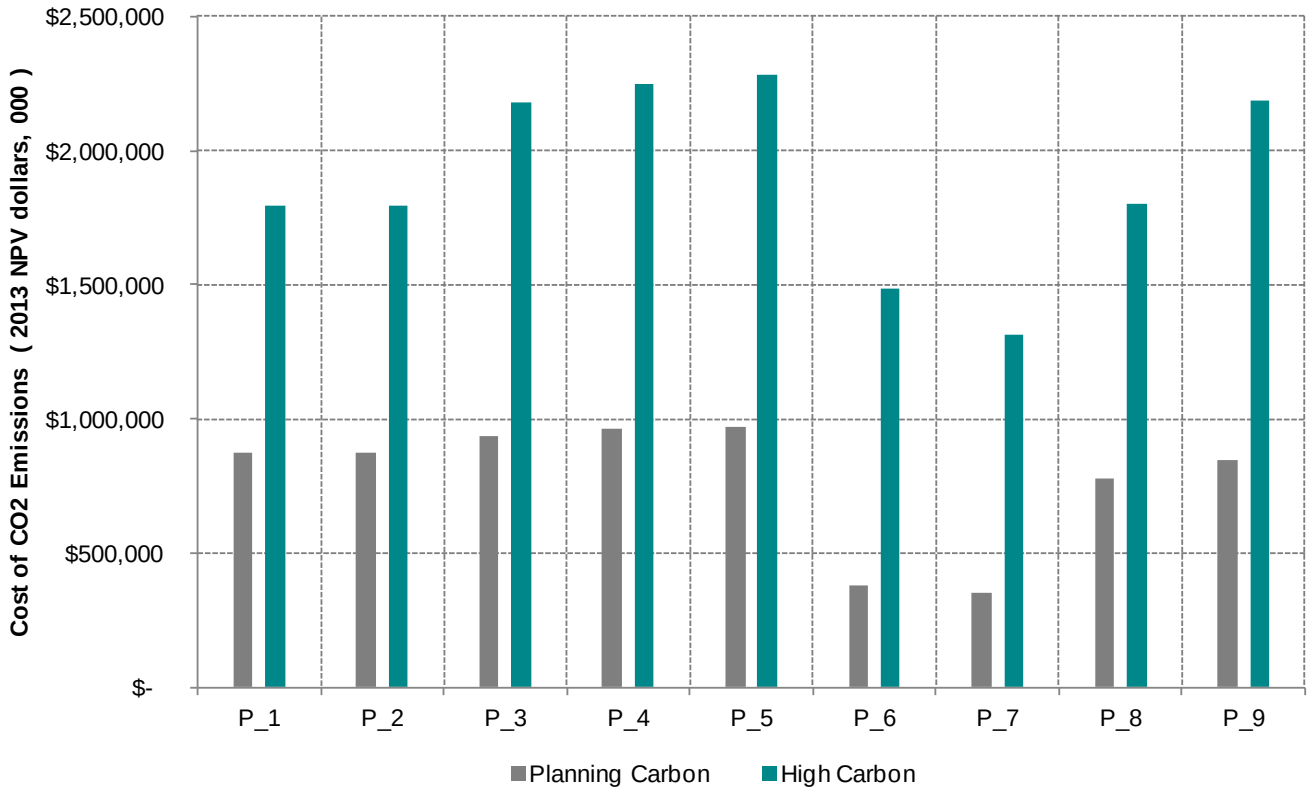
# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

## Stochastic Dispersion Plot




## Regulatory Environmental Compliance Costs

### *Portfolio Analysis Cost of $CO_2$ Emissions*




**Note**: Instead of assuming NOx, Hg, and $SO_2$ emissions adders, the 2013 IRP used the Idaho Power coal study to calculate the variable and fixed environmental compliance costs attributed to these emission types.

# Loss of Load Expectation Analysis

**Loss of Load Expectation Summary Data*–Portfolio 1**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2027 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.13 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2028 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 2**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2027 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2028 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 3**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.74 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.69 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2014 | 1.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.21 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.44 | 0.30 | 0.18 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2019 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.36 | 0.57 | 0.37 | 0.08 | 0.00 | 0.00 | 0.01 |
| 2020 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.26 | 1.19 | 1.68 | 0.04 | 0.00 | 0.00 | 0.02 |
| 2021 | 2.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 | 0.25 | 1.59 | 0.52 | 0.11 | 0.00 | 0.00 | 0.07 |
| 2022 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.06 | 0.14 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2023 | 0.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.28 | 0.06 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2024 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.69 | 0.08 | 0.09 | 0.00 | 0.00 | 0.01 |
| 2025 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.86 | 0.06 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2026 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 1.83 | 0.10 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2027 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.22 | 0.05 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2028 | 2.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.14 | 2.06 | 0.05 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2029 | 1.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.98 | 0.01 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2030 | 2.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 2.45 | 0.02 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2031 | 6.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 6.67 | 0.03 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2032 | 3.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 3.15 | 0.02 | 0.00 | 0.00 | 0.00 | 0.02 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 4**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.07 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.12 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.24 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.19 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2022 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.06 | 0.16 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2023 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.32 | 0.06 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2024 | 1.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.76 | 0.08 | 0.09 | 0.00 | 0.00 | 0.01 |
| 2025 | 2.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 2.03 | 0.06 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2026 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.25 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.30 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.51 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 3.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 3.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.69 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 5**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.07 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.12 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.24 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.25 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.30 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.51 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 3.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 3.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.69 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 6**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 2.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 2.29 | 0.04 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.06 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2021 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2022 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.06 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.22 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.15 | 0.01 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.39 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.38 | 0.02 | 0.00 | 0.00 | 0.00 | 0.03 |
| 2027 | 0.34 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.27 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 |
| 2028 | 0.55 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2029 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.76 | 0.01 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2030 | 2.18 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 2.03 | 0.02 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2031 | 3.97 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 3.85 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2032 | 2.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.85 | 0.01 | 0.00 | 0.00 | 0.00 | 0.11 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 7**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.75 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2016 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2022 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.05 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.18 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.12 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.31 | 0.02 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2027 | 0.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.21 | 0.01 | 0.00 | 0.00 | 0.00 | 0.04 |
| 2028 | 0.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.36 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 |
| 2029 | 0.73 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2030 | 1.68 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.55 | 0.01 | 0.01 | 0.00 | 0.00 | 0.05 |
| 2031 | 3.95 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 3.81 | 0.02 | 0.00 | 0.00 | 0.00 | 0.08 |
| 2032 | 2.20 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.97 | 0.02 | 0.00 | 0.00 | 0.00 | 0.14 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 8**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.05 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.14 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.47 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 1.70 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.49 | 0.06 | 0.01 | 0.00 | 0.00 | 0.09 |
| 2027 | 0.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2028 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.39 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2030 | 0.98 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2031 | 3.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.96 | 0.01 | 0.00 | 0.00 | 0.00 | 0.03 |
| 2032 | 1.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.24 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 9**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.44 | 0.30 | 0.18 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2019 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.36 | 0.57 | 0.37 | 0.08 | 0.00 | 0.00 | 0.01 |
| 2020 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.26 | 1.19 | 1.68 | 0.04 | 0.00 | 0.00 | 0.02 |
| 2021 | 2.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 | 0.25 | 1.59 | 0.52 | 0.11 | 0.00 | 0.00 | 0.07 |
| 2022 | 1.14 | 0.05 | 0.01 | 0.00 | 0.00 | 0.28 | 0.17 | 0.42 | 0.15 | 0.03 | 0.00 | 0.00 | 0.03 |
| 2023 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.25 | 0.81 | 0.17 | 0.05 | 0.00 | 0.00 | 0.03 |
| 2024 | 2.56 | 0.01 | 0.00 | 0.00 | 0.00 | 0.03 | 0.20 | 1.82 | 0.22 | 0.25 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.62 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2026 | 1.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 1.70 | 0.11 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2027 | 1.37 | 0.03 | 0.00 | 0.00 | 0.00 | 0.05 | 0.05 | 1.14 | 0.05 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2028 | 2.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.12 | 1.90 | 0.06 | 0.02 | 0.00 | 0.00 | 0.03 |
| 2029 | 3.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.21 | 3.12 | 0.05 | 0.03 | 0.00 | 0.00 | 0.03 |
| 2030 | 2.37 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 2.26 | 0.02 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2031 | 6.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 5.97 | 0.03 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2032 | 3.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 2.87 | 0.03 | 0.00 | 0.00 | 0.00 | 0.02 |

* With CBM@330 MW

# STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Integrated Resource Planning. | )<br>)<br>)<br>)<br>)<br>)<br>) | ERRATA ORDER |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 0 9 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# Compliance with State of Oregon IRP Guidelines

| Oregon Order 07-047 Action Items | 2013 IRP |
|---|---|
| **Guideline 1: Substantive Requirements** | |
| a. All resources must be evaluated on a consistent and comparable basis.<br>• All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response.<br>• Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.<br>• Consistent assumptions and methods should be used for evaluation of all resources.<br>• The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. | a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3. Idaho Power Today, section *Existing Supply-Side Resources*, pages 25–36. Demand-side options for meeting the utility's load are discussed in Chapter 4. Demand-Side Resources, pages 37–45.<br>a-2) Different resource alternatives results are compared in Chapter 7. Resource Alternatives Analysis, Table 7.1 on page 84. Different resource portfolios results are compared in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98.<br>a-3) The consistent modeling method for evaluating all resource alternatives is explained in Chapter 7. Resource Alternatives Analysis, pages 83-85. The consistent modeling method for evaluating all resource portfolios are explained in Chapter 9. Modeling Analysis and Results, pages 97–99.<br>a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9. Modeling Analysis and Results, in Table 9.1 Financial Assumptions, on page 97. |
| b. Risk and uncertainty must be considered.<br>• At a minimum, utilities should address the following sources of risk and uncertainty:<br>1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.<br>2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.<br>• Utilities should identify in their plans any additional sources of risk and uncertainty. | b-1) Electric utility risk and uncertainty factors (carbon, NG and water conditions) for resource alternatives are considered in Chapter 7. Resource Alternatives Analysis, section *Risk Analysis and Results,* pages 86–87.<br>Electric utility risk and uncertainty factors (load, carbon, NG and water conditions) for resource alternatives are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis*, pages 103–105 (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). An additional analysis for $CO_2$ emissions costs can be found in the *2013 IRP Technical Appendix*, section *Regulatory Environmental Compliance Costs,* page 131.<br>Note: Plant forced outages for resource alternatives and resource portfolios are not discussed in the IRP document or *2013 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis.<br>b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2. Political, Regulatory, and Operational Issues the following sections: *FERC Relicensing*, page 12; *Idaho Water Issues*, page 13; *Northwest Power Pool Energy Imbalance Market*, page 17; and *Federal Energy Legislation*, page 19. Also, the uncertainty in transmission planning process is described in Chapter 6. Transmission Planning, pages 72–73.<br>A tipping-point analyses for carbon adder and dispatch cost is analyzed in Chapter 5. Planning Period Forecasts, section *Carbon Adder Generation Dispatch Analysis,* pages 69–70. |
| c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.<br>• The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.<br>• Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.<br>• To address risk, the plan should include, at a minimum:<br>1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.<br>2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.<br>• The utility should explain in its plan how its resource choices appropriately balance cost and risk. | c-1) The IRP methodology and its' subsequent planning horizon of 20 years are discussed in Chapter 1. Summary, section *IRP Methodology,* fourth paragraph on page 4.<br>c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the expected NPV for resource alternative costs are found in Chapter 7. Resource Alternative Analysis, Table 7.1 on page 84. The summary of the expected NPV for total portfolio costs are found in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98. |
| d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | |

| Oregon Order 07-047 Action Items | 2013 IRP |
|---|---|
| | c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. A plot of stochastic dispersion is shown in the *2013 IRP Technical Appendix*, S*tochastic Dispersion Plot* on page 131.<br>c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1. Summary, in the last paragraph of section Introduction, on page 2. Idaho Power explains how its resource choices appropriately balance cost and risk in a twofold process:<br>Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87.<br>For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96.<br>d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2. Political, Regulatory, and Operational Issues, beginning pages 11–19 as well as in Chapter 1. Summary, section *Public Advisory Process*, pages 2–3. |
| **Guideline 2: Procedural Requirements.**<br>a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.<br>b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.<br>c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. | As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011 and 2013 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the 2004, 2006, 2009, 2011 and 2013 IRPs. The IRP Advisory Council meetings are open to the public, on a limited basis due to space constraints. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan.<br>As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2013 IRP, the 2013 Load and Sales Forecast and in the 2013 Technical Appendix.<br>As set forth in Guideline 2, part c., Idaho Power provided a draft 2013 IRP for public review on Friday, June 6, 2013, via a hard copy to members of IRP Advisory Committee and public attendees of the 2013 IRP Advisory Committee meetings. June 17, 2013 was the deadline for getting IRP Advisory Committee and public comments back on the draft plan. |

| Oregon Order 07-047 Action Items | 2013 IRP |
|---|---|
| **Guideline 3: Plan Filing, Review, and Updates.**<br>a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.<br>b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.<br>c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.<br>d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.<br>e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.<br>f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.<br>g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:<br>• Describes what actions the utility has taken to implement the plan;<br>• Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and<br>• Justifies any deviations from the acknowledged action plan. | a. The OPUC acknowledged Idaho Power's 2011 IRP on May 21, 2012 in Order 12-177. Idaho Power plans to file the 2013 IRP on June 28, 2013.<br>b. Idaho Power will schedule a public meeting at the OPUC after the 2013 IRP has been filed.<br>c. No action needed.<br>d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan.<br>e. In ORDER NO. 12-013, the OPUC provided direction on IRP flexible resource guidelines for EV. In ORDER NO. 12-177, the OPUC noted 12 action items regarding Idaho Power's 2011 IRP. Idaho Power has addressed these action items in the 2013 IRP.<br>f. Idaho Power submitted an update to the 2011 IRP in February 2013.<br>g. No action needed. |

| Oregon Order 07-047 Action Items | 2013 IRP |
|---|---|
| **Guideline 4: Plan Components.**<br>At a minimum, the plan must include the following elements:<br>a. An explanation of how the utility met each of the substantive and procedural requirements;<br>b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;<br>c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;<br>d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;<br>e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;<br>f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;<br>g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;<br>h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;<br>i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;<br>j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;<br>k. Analysis of the uncertainties associated with each portfolio evaluated;<br>l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;<br>m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and<br>n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff.<br>b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 5. Planning Period Forecasts, section *Load Forecast,* beginning on page 47. High- and low-growth scenarios in addition to stochastic load risk analysis are discussed in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>c. Peaking capacity and energy capability for each year of the plan are discussed in Chapter 5. Planning Period Forecasts, sections *Average Monthly Energy Planning* and *Peak-Hour Planning,* pages 60–61. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios,* beginning on page 80.<br>d. Not applicable.<br>e. Supply-side resources and their levelized costs and technologies are covered in Chapter 5. Planning Period Forecasts on figures 5.7 and 5.8, pages 66 and 67 respectively. Demand-side resources and their levelized costs and technologies are covered in Chapter 4. Demand-Side Resources, in Table 4.2 on page 43.<br>f. Resource reliability is covered in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* on pages 110111.<br>g. Fuel price forecasts are discussed in Chapter 5. Planning Period Forecasts, section *Coal Resources* (coal price forecast and environmental compliance cost analysis), pages 5859, section *Natural Gas Price Forecast,* on page 62. Environmental compliance costs are also discussed in section *Emissions Adders for Fossil Fuel-Based Resources,* pages 63–64. Alternative scenarios are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>h. Construction of resource portfolios are made in a twofold process:<br>1) Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87. 2) For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96.<br>i. The resource portfolios are evaluated against various risks in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>j. The portfolios are evaluated and ranked in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.<br>k. The uncertainties associated with each portfolio are evaluated in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98 and Figure 9.6 on page *104*.<br>m. No inconsistencies were identified.<br>n. An annual near-term action plan is described in Chapter 1. Summary, section *Near-Term Action Plan*, starting on page 9. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 5: Transmission.**<br>Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. | The transmission required for each resource being considered is described in the *2013 IRP Technical Appendix*, section *Transmission Cost Assumptions* on page 86. The transmission required for each resource portfolio being considered is also described in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios*, pages 80–81. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. Transmission facilities were analyzed as a resource option in Chapter 7. Resource Alternatives Analysis, pages 83–84. All the resource portfolios contained the Boardman to Hemingway Transmission Line as a resource option as discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96. |
| **Guideline 6: Conservation.**<br>a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.<br>b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.<br>c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:<br>• Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and<br>• Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | a. Idaho Power periodically studies conservation potential and a summary of the company's conservation (DSM) philosophy is described in Chapter 4. Demand-Side Resources, pages 37–38.<br>b. Cost-effectiveness of energy efficiency programs are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Performances,* pages 38–44.<br>c. As described in Chapter 4. Demand-Side Resources, third paragraph of page 37, due to the indirect nature of savings from regional market transformation activities, Idaho Power's outside party administrator Northwest Energy Efficiency Alliance (NEEA) impacts are not accounted for in the 2013 IRP. |
| **Guideline 7: Demand Response.**<br>Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). | Demand response resources are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Resources* on page 44. |
| **Guideline 8: Environmental Costs.**<br>Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO^2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable. | Idaho Power discusses the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources,* pages 63–64. The costs are shown in the *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131.<br>Idaho Power performed a base case, upper case, and zero-cost case and for the compliance cost of $CO_2$ and is discussed in Chapter 5. Planning Period Forecasts, section *Carbon Adder,* pages 68–69.<br>Idaho Power discusses the sensitivity analysis on a range of reasonably possible cost adders (low and high case) for nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources* on page 64. The costs are shown in *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131. |
| **Guideline 9: Direct Access Loads.**<br>An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2013 IRP 20-year planning period. |
| **Guideline 10: Multi-state Utilities.**<br>Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers. | Idaho Power intends to file the 2013 IRP in both the Idaho and Oregon jurisdictions. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 11: Reliability.**<br>Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives. | Idaho Power discussed the capacity planning margin in Chapter 9. Modeling Analysis and Results, section *Capacity Planning Margin*, pages 106–108, and the loss of load probability in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* pages 110–111. |
| **Guideline 12: Distributed Generation.**<br>Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation. | Idaho Power evaluated distributed generation technologies in the following sections:<br>Load shed, grid sync, and distributed PV: in Chapter 5. Planning Period Forecasts, Figure 5.7 and 5.8, pages 66 and 67, respectively.<br>Distributed PV: in Chapter 7. Resource Alternatives, pages 83–87. |
| **Guideline 13: Resource Acquisition.**<br>a. An electric utility should, in its IRP:<br>• Identify its proposed acquisition strategy for each resource in its action plan.<br>• Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.<br>• Identify any Benchmark Resources it plans to consider in competitive bidding.<br>b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment. | Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order 06-446 issued on August 10, 2006.<br>Idaho Power discussed asset ownership in Chapter 10 Action Plan, section *Acton Plan (2013–2032)*, last paragraph on page 114.<br>In the next 10 years, the Boardman to Hemingway Transmission Line is the only new IRP resource identified. Idaho Power is currently permitting this project and plans to contract the construction work. |

# STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1461

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation of matters related to Electric Vehicle Charging. | ORDER |

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

## I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

*2. Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

**D. Integrated Resource Planning Flexible Resources Guidelines**

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

*1. Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

### *2. Resolution*

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

ORDER NO. 12 013

2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

# Compliance with EV Guidelines

| Oregon Order 12-013 Guideline | 2013 IRP |
|---|---|
| **Guideline 1: Forecast the Demand for Flexible Capacity.**<br>Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period; | Forecasting the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |
| **Guideline 2: Forecast the Supply for Flexible Capacity.**<br>Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; | Forecasting the balancing reserves available at different time intervals from existing generating resources is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |
| **Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis**<br>In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis. | Evaluating all resource options, including the use of EVs, is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2011 IRP

ORDER NO. 12 177

ENTERED MAY 21 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

LC 53

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| In the Matter of<br>IDAHO POWER COMPANY<br>2011 Integrated Resource Plan. | ORDER |

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

## I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

## II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be

[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

## III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a public meeting. A technical workshop was held for parties on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

## IV. DISCUSSION

### A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected–case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

ORDER NO. 12 177

Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

## B. Objections to Idaho Power's 2011 IRP

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

### *1. Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)*

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as

well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

*Resolution*

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

### *2. Boardman to Hemingway Transmission (Action Item 7)*

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

*Resolution*

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

### *3. Conservation Voltage Reduction (Action Item 4)*

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

ORDER NO. 12 177

*Resolution*

We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:

> Action Item 4 – Conservation Voltage Reduction – The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

***4. Demand Response (Action Item 3)***

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

*Resolution*

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

***5. Energy Efficiency (Action Items 1 and 2)***

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

*Resolution*

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

ORDER NO. 12 177

### 6. *Alternative Portfolio (Action Items 8 and 9)*

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

*Resolution*

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

### 7. *Long Term Action Items (Action Item 12)*

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

*Resolution*

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

### 8. *Load Forecast*

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

*Resolution*

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

ORDER NO. 12 177

*9 Risk Analysis*

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

*Resolution*

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

*10. Wind Integration Study*

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

*Resolution*

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

*11. Solar Photovoltaic Analysis*

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

*Resolution*

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

ORDER NO. 12 177

### *12. Adherence of Plan to Integrated Resource Planning Guidelines*

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

*Resolution*

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

[4] IRP Guideline 1(c) prescribes the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future enviromnental compliance costs.

ORDER NO. 12 177

## IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 21 day of May, 2012, at Salem, Oregon.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

# Compliance with State of Oregon Action Items Regarding Idaho Power's 2011 IRP

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 1: Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)**<br>Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation.<br>CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years. CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.<br>Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.<br>Staff shares CUB's and RNP 's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement. | Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman Plant in Oregon that is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*.<br>In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98. |
| **Action Item 2: Boardman to Hemingway Transmission (Action Item 7)**<br>RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines. | Idaho Power analyzed Boardman to Hemingway as uncommitted resource in two ways:<br>1) Resource Alternatives: eight resources were analyzed side-by-side to achieve a 200-MW capacity of peak-hour contribution. The Resource Alternatives analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87.<br>2) Resource Portfolios: Boardman to Hemingway was in all nine portfolios. The results of the Resource Portfolio analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.<br>Progress on Boardman to Hemingway was discussed in the *Boardman to Hemingway* section of Chapter 6. Transmission Planning, pages 77–78. |
| **Action Item 3: Conservation Voltage Reduction (Action Item 4)**<br>Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management. We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:<br>Action Item 4 - Conservation Voltage Reduction- The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts. | Idaho Power included an assessment of the available cost-effective CVR resource potential in its service area. This can be found in the *Conservation Voltage Reduction* section of Chapter 4 Demand-Side Resources on page 45. |

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 4: Demand Response (Action Item 3)**<br>In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount. | Chapter 4. Demand-Side Resources, pages 37–45. provides a detailed discussion and analysis of the company's DSM programs. All nine resource portfolios include Demand Response. Resource portfolios are described in the *Portfolio Design and Selection* section of Chapter 8. Planning Criteria And Portfolio Selection, pages 90–96. |
| **Action Item 5: Energy Efficiency (Action Items 1 and 2)**<br>Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers. | Energy efficiency performance is discussed in Chapter 4 Demand-Side Resources, section Energy Efficiency Performance, pages 38-39. New energy efficiency programs are discussed in Chapter 4 Demand-Side Resources, section New Energy Efficiency Resources, pages 41-44. |
| **Action Item 6: Alternative Portfolio (Action Items 8 and 9)**<br>RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances. | Eight resources, including four renewable resources, were analyzed side-by-side to achieve 200 MW of peak-hour contribution. The analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87.<br>Four resource portfolios were constructed where Idaho Power ceased operations at some or all of the Idaho Power coal-fired generation facilities. One of the portfolios was jointly designed by the Idaho Conservation League and Boise State University. Portfolio design is discussed in the *Portfolio Design and Selection* section of Chapter 8. Planning, pages 90–96. |
| **Action Item 7: Long Term Action Items (Action Item 12)**<br>In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP. | Idaho Power provides its action plan in Chapter 10. Action Plan, pages 113–115. |
| **Action Item 8: Load Forecast**<br>Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staffs concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation. | Idaho Power's load forecast is discussed in detail in Chapter 5. Planning Period Forecasts, section *Load Forecast*, pages 47–55. Lingering economic conditions are discussed in detail, pages 48–50. |
| **Action Item 9: Risk Analysis**<br>Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation. | Idaho Power incorporated hydro generation variability as a risk factor. Idaho Power also used the AURORA model to perform stochastic risk analyses. Stochastic analysis is discussed in the *Stochastic Analysis* section of Chapter 9. Modeling Analysis and Results, pages 103–105. |
| **Action Item 10: Wind Integration Study**<br>RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback. | Idaho Power filed a wind integration study in February 2013. The wind integration study included an independent technical review. The wind integration study can be found on the Idaho Power website: www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf |
| **Action Item 11: Solar Photovoltaic Analysis**<br>RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects. | Idaho Power evaluated the performance of solar PV generation as a class. The PV analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87. |

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 12: Adherence of Plan to Integrated Resource Planning Guidelines**<br>Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1 (c) and 4(g), 4 because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.<br>In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented.<br>According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.<br>Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities. | Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman plant in Oregon which is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*.<br>In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.The OPUC is currently reviewing the Idaho Power coal study as part of Oregon Docket No. LC 57.<br>1. Idaho Power provides a concise listing of action items in Chapter 10. Action Plan, pages 113–114. |

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# ATTACHMENT N-4
# IDAHO POWER COMPANY'S 2015 INTEGRATED RESOURCE PLAN (DOCKET LC 63)

IDAHO POWER®
An IDACORP Company

June 2015

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

IDAHO POWER®
An IDACORP Company

June 2015

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

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# TABLE OF CONTENTS

Table of Contents ..... i

List of Tables ..... vi

List of Figures ..... viii

List of Appendices ..... x

Glossary of Acronyms ..... xi

1. Summary ..... 1

Introduction ..... 1

Public Advisory Process ..... 2

IRP Methodology ..... 3

Greenhouse Gas Emissions ..... 4

Proposed Pilot Projects ..... 6

Solar Photovoltaic to Address Distribution Feeder Voltage Loss ..... 6

Ice-Based Thermal Energy Storage ..... 6

Community Solar ..... 6

Portfolio Analysis Summary ..... 8

North Valmy and Jim Bridger Coal Unit Early Retirement and CAA Section 111(d) Regulation ..... 8

Uncertainty Related to PURPA Solar ..... 9

Boardman to Hemingway Transmission ..... 9

Selection of the Preferred Portfolio ..... 10

Action Plan ..... 10

Action plan (2015–2018) ..... 10

2. Political, Regulatory, and Operational Issues ..... 13

Idaho Energy Plan ..... 13

Idaho Strategic Energy Alliance ..... 13

FERC Relicensing ..... 14

Idaho Water Issues ..... 15

Renewable Integration Study ..... 18
Northwest Power Pool Energy Imbalance Market ..... 19
Renewable Energy Certificates ..... 20
Renewable Portfolio Standard ..... 21
REC Management Plan ..... 21
Federal Energy Legislation CAA Section 111(d) ..... 21
3. Idaho Power Today ..... 23
Customer Load and Growth ..... 23
2014 Energy Sources ..... 25
Existing Supply-Side Resources ..... 27
Hydroelectric Facilities ..... 28
Coal Facilities ..... 32
Natural Gas Facilities ..... 32
Solar Facilities ..... 33
Power Purchase Agreements ..... 34
Public Utility Regulatory Policies Act ..... 35
Wholesale Contracts ..... 37
Market Purchases and Sales ..... 38
4. Demand-Side Resources ..... 39
Introduction ..... 39
Demand-Side Management Program Overview ..... 39
DSM Planning Changes from the 2013 IRP ..... 40
Program Screening ..... 41
DSM Program Performance ..... 41
Energy Efficiency Performance ..... 41
Demand Response Performance ..... 42
Committed Energy Efficiency Forecast ..... 43
Committed Demand Response Resources ..... 46

Non-Cost-Effective DSM Resource Options....46
Additional Demand Response....47
Energy Efficiency Working Group....47
Conservation Voltage Reduction....48
5. Supply-Side Generation and Storage Resources....49
Renewable Resources....49
Solar....49
Geothermal....51
Hydroelectric....52
Wind....53
Biomass....53
Conventional Resources....53
Natural Gas-Fired Resources....54
Nuclear Resources....56
Coal Resources....56
Storage Technologies....57
Battery Storage....58
Ice-Based Thermal Energy Storage....58
Pumped Storage....59
6. Transmission Planning....61
Past and Present Transmission....61
Transmission Planning Process....62
Local Transmission Planning Process....62
Regional Transmission Planning....63
Interconnection-Wide Transmission Planning....63
Existing Transmission System....63
Idaho–Northwest Path....64
Brownlee East Path....64

Idaho–Montana Path ....65
Borah West Path ....65
Midpoint West Path ....65
Idaho–Nevada Path ....65
Idaho–Wyoming Path ....66
Idaho–Utah Path....66
Boardman to Hemingway ....66
Gateway West ....69
Gateway West Need Analysis....70
Transmission Assumptions in the IRP Portfolios ....71
7. Planning Period Forecasts....73
Load Forecast....73
Weather Effects....74
Economic Effects ....74
Peak-Hour Load Forecast ....76
Average-Energy Load Forecast ....78
Additional Firm Load ....79
Generation Forecast for Existing Resources....80
Hydroelectric Resources ....80
Coal Resources....83
Coal Analysis ....83
Natural Gas Resources ....84
Natural Gas Price Forecast....84
Resource Cost Analysis ....85
Resource Cost Analysis II—Resource Stack....86
Levelized Capacity (Fixed) Cost ....86
Levelized Cost of Production....86
Supply-Side Resource Costs ....90

Load and Resource Balance ..... 92
8. Portfolio Selection ..... 97
Portfolio Design ..... 97
Portfolio Design and Selection ..... 98
Status Quo Portfolio ..... 98
Maintain Coal Capacity Portfolios ..... 99
North Valmy Retirement Year-End 2019 Portfolios ..... 100
North Valmy Retirement Year-End 2025 Portfolios ..... 103
North Valmy Staggered Retirement Year-End 2019 (Unit 1) and Year-End 2025 (Unit 2) Portfolios ..... 104
Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2) Portfolios ..... 105
Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2028 (Unit 2) Portfolio ..... 106
Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2), North Valmy Retirement Year-End 2025 Portfolio ..... 107
Alternative to B2H Portfolios ..... 107
North Valmy Staggered Retirement Year-End 2021 (Unit 1) and Year-End 2025 (Unit 2) Portfolio ..... 110
Portfolio Design Summary ..... 111
9. Modeling Analysis and Results ..... 113
CAA Section 111(d) Sensitivity Analysis ..... 114
Null Sensitivity (no CAA Section 111(d)) ..... 114
State-by-State Mass-Based Compliance ..... 114
System-Wide Mass-Based Compliance ..... 115
Emissions-Intensity Compliance Using the EPA's Compliance Building Blocks ..... 115
Baseline CAA Section 111(d) ..... 116
CAA Section 111(d) Sensitivity Analysis Results ..... 118
Stochastic Risk Analysis ..... 121
Portfolio Cost-Assessment of Year-to-Year Variability ..... 123

Tipping-Point Analysis ....124
Portfolio Emissions ....125
Qualitative Risk Analysis ....125
Existing Generation ....126
New Generation ....127
Preferred Portfolio ....130
Analysis of Shoshone Falls Upgrade ....130
Capacity Planning Margin ....131
Flexible Resource Needs Assessment ....135
Loss of Load Expectation ....139
10. Preferred Portfolio and Action Plan ....141
Preferred Portfolio (2015–2034) ....141
Action Plan (2015–2018) ....141
Conclusion ....143

## LIST OF TABLES

Table 1.1 Community solar model comparison ....7
Table 1.2 Action plan (2015–2018) ....11
Table 2.1 Phase I measures included in the ESPA CAMP ....17
Table 3.1 Historical capacity, load, and customer data ....24
Table 3.2 Existing resources ....28
Table 3.3 Net metering service customer count and generation capacity as of May 1, 2015 ....33
Table 4.1 Current demand response programs 2014 performance ....42
Table 4.2 Total energy efficiency portfolio forecasted effects (2015–2034) (aMW) ....45
Table 4.3 Total energy efficiency portfolio cost-effectiveness summary ....45
Table 5.1 Solar capacity credit values ....51
Table 6.1 Available transmission import capacity ....66

Table 6.2 B2H capacity and permitting cost allocation ..... 67

Table 6.3 Transmission assumptions ..... 72

Table 7.1 Load forecast—peak hour (MW) ..... 77

Table 7.2 Load forecast—average monthly energy (aMW) ..... 79

Table 7.3 July monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources ($70^{th}$-percentile water and $70^{th}$-percentile load) ..... 95

Table 7.4 December monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources ($70^{th}$-percentile water and $70^{th}$-percentile load) ..... 95

Table 7.5 July monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources ($90^{th}$-percentile water and $95^{th}$-percentile load) ..... 96

Table 7.6 December monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources ($90^{th}$-percentile water and $95^{th}$-percentile load) ..... 96

Table 8.1 Fixed-cost impacts of coal retirement ..... 98

Table 8.2 Resource portfolio P1 ..... 99

Table 8.3 Resource portfolio P2(a) ..... 99

Table 8.4 Resource portfolio P2(b) ..... 99

Table 8.5 Resource portfolio P2(c) ..... 100

Table 8.6 Resource portfolio P3 ..... 100

Table 8.7 Resource portfolio P4(a) ..... 101

Table 8.8 Resource portfolio P4(b) ..... 101

Table 8.9 Resource portfolio P4(c) ..... 102

Table 8.10 Resource portfolio P5 ..... 102

Table 8.11 Resource portfolio P6 ..... 103

Table 8.12 Resource portfolio P6(b) ..... 103

Table 8.13 Resource portfolio P7 ..... 104

Table 8.14 Resource portfolio P8 ..... 104

Table 8.15 Resource portfolio P9 ..... 105

Table 8.16 Resource portfolio P10 ....105
Table 8.17 Resource portfolio P11 ....106
Table 8.18 Resource portfolio P12 ....107
Table 8.19 Resource portfolio P13 ....107
Table 8.20 Resource portfolio P14 ....108
Table 8.21 Resource portfolio P15 ....108
Table 8.22 Resource portfolio P16 ....109
Table 8.23 Resource portfolio P17 ....109
Table 8.24 Resource portfolio P18 ....110
Table 8.25 Resource portfolio scenario summary ....111
Table 9.1 Financial assumptions ....114
Table 9.2 Proposed target reductions for state-by-state mass-based compliance (IPC share) ....115
Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis) ....117
Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) ....119
Table 9.5 First peak-hour capacity deficit effects of removing 141 MW of solar PURPA ....128
Table 9.6 Capacity planning margin ....133
Table 10.1 Action plan (2015–2018) ....142

## LIST OF FIGURES

Figure 1.1 $CO_2$ emissions intensity of the largest 100 utilities ....4
Figure 1.2 $CO_2$ emissions of the largest 100 utilities ....5
Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow ....18
Figure 3.1 Historical capacity, load, and customer data ....24
Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power) ....26
Figure 3.3 2014 energy by source ....26

Figure 3.4 2014 power purchases by fuel type....27
Figure 3.5 PURPA contracts by resource type....36
Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW)....42
Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW)....43
Figure 6.1 Idaho Power transmission system map....64
Figure 6.2 B2H routes with the agency-preferred alternative....68
Figure 6.3 Gateway West Map....69
Figure 6.4 Midpoint West Historical Utilization....71
Figure 7.1 Peak-hour load-growth forecast (MW)....77
Figure 7.2 Average monthly load-growth forecast (aMW)....78
Figure 7.3 Brownlee historical and forecast inflows....82
Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)....85
Figure 7.5 30-year levelized capacity (fixed) costs....88
Figure 7.6 30-year levelized cost of production (at stated capacity factors)....89
Figure 7.7 Capacity cost of new supply-side resources, online 2020....90
Figure 7.8 Energy cost of new supply-side resources....91
Figure 9.1 Portfolio stochastic analysis....122
Figure 9.2 Exceedance graph of standard deviations....124
Figure 9.3 Tipping-point analysis results....125
Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood)....135
Figure 9.5 System regulation....136
Figure 9.6 Regulation violations, spring 2012....137
Figure 9.7 Regulation violations, summer 2012....137
Figure 9.8 Regulation violations, fall 2011....138
Figure 9.9 Regulation violations, winter 2011/2012....138
Figure 9.10 LOLE (hours per year)....140

# LIST OF APPENDICES

Appendix A—Sales and Load Forecast

Appendix B—Demand-Side Management 2014 Annual Report

Appendix C—Technical Appendix

# GLOSSARY OF ACRONYMS

AC—Alternating Current

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

AgI—Silver Iodide

akW—Average Kilowatt

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

ANSI—American National Standards Institute

ATC—Available Transmission Capacity

B2H—Boardman to Hemingway

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CAA—*Clean Air Act of 1970*

CAMP—Comprehensive Aquifer Management Plan

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

CERCLA—*Comprehensive Environmental Response, Compensation and Liability Act of 1980*

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CHQ—Corporate headquarters

Clatskanie PUD—Clatskanie People's Utility District

$CO_2$—Carbon Dioxide

CREP—Conservation Reserve Enhancement Program

CSPP—Cogeneration and Small-Power Producers

CVR—Conservation Voltage Reduction

CWA— *Clean Water Act of 1972*

DC—Direct Current

DOE—Department of Energy

DSM—Demand-Side Management

EEAG—Energy Efficiency Advisory Group

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

EPA—Environmental Protection Agency

ESA—*Endangered Species Act of 1973*

ESPA—Eastern Snake River Plain Aquifer

ESPAM—Enhanced Snake River Plain Aquifer Model

F—Fahrenheit

FCRPS—Federal Columbia River Power System

FERC—Federal Energy Regulatory Commission

FLA—Final License Agreement

FPA—*Federal Power Act of 1920*

FWS—US Fish and Wildlife Service

GWh—Gigawatt-Hour

HCC—Hells Canyon Complex

Hg—Mercury

HRSG—Heat Recovery Steam Generator

IGCC—Integrated Gasification Combined Cycle

INL—Idaho National Laboratory

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—IRP Advisory Council

IWRB—Idaho Water Resource Board

kV—Kilovolt

kW—Kilowatt

kWh—Kilowatt-Hour

LED—Light-Emitting Diode

LOLE—Loss of Load Expectation

LTP—Local Transmission Plan

LOLP—Loss of Load Probability

$m^2$—Square Meters

MOU—Memorandum of Understanding

MSA—Metropolitan Statistical Area

MW—Megawatt

MWh—Megawatt-Hour

NEEA—Northwest Energy Efficiency Alliance

NEPA—*National Environmental Policy Act of 1969*

NERC—North American Electric Reliability Corporation

$NO_x$—Nitrogen Oxide

NTTG—Northern Tier Transmission Group

NPV—Net Present Value

NWPCC—Northwest Power and Conservation Council

NWPP—Northwest Power Pool

NREL—National Renewable Energy Laboratory

O&M—Operation and Maintenance

OATT—Open Access Transmission Tariff

ODEQ—Oregon Department of Environmental Quality

ODOE—Oregon Department of Energy

OER—Idaho Governor's Office of Energy Resources

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statue

pASC—Preliminary Application for Site Certificate

PCA—Power Cost Adjustment

PM&E—Protection, Mitigation, and Enhancement

PGE—Portland General Electric

PPA—Power Purchase Agreement

PURPA—*Public Utility Regulatory Policies Act of 1978*

PV—Photovoltaic

Q/A—Quality Assurance

QF—Qualifying Facility

RAAC—Resource Adequacy Advisory Committee

RCRA—*Resource Conservation and Recovery Act of 1976*

REC—Renewable Energy Certificate

RES—Renewable Electricity Standard

RFP—Request for Proposal

RH BART—Regional Haze Best Available Retrofit Technology

ROI—Return on Investment

ROR—Run-of-River

RPS—Renewable Portfolio Standard

SCCT—Simple-Cycle Combustion Turbine

SCED—Security-Constrained Economic Dispatch

SCR—Selective Catalytic Reduction

SNCR—Selective Non-Catalytic Reduction

$SO_2$—Sulfur Dioxide

SPE—Special-Purpose Entity

SRBA—Snake River Basin Adjudication

SRPM—Snake River Planning Model

TEPPC—Transmission Expansion Planning Policy Committee

TES—Thermal Energy Storage

TRC—Total Resource Cost

TSCA—*Toxic Substances Control Act of 1976*

USACE—United States Army Corps of Engineers

UAMPS—Utah Associated Municipal Power Systems

US—United States

USBR—Bureau of Reclamation

USFS—United States Forest Service

VRB—Vanadium Redox-Flow Battery

WECC—Western Electricity Coordinating Council

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# 1. SUMMARY

## Introduction

The *2015 Integrated Resource Plan* (IRP) is Idaho Power's 12th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). Idaho Power's resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period.

2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.

3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

The 2015 IRP evaluates the 20-year planning period from 2015 through 2034. During this period, load is forecasted to grow by 1.2 percent per year for average energy demand and 1.5 percent per year for peak-hour demand. Total customers are expected to increase to 711,000 by 2034 from 515,000 in 2014. Additional company-owned resources will be needed to meet these increased demands.

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Hydroelectric generation is a large part of Idaho Power's generation fleet; however, hydroelectric plants are subject to variable water and weather conditions. Public and regulatory input encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP. Idaho Power continues to develop more conservative streamflow projections and planning criteria for use in resource adequacy planning. Idaho Power has an obligation to serve customer loads regardless of water and weather conditions. Further discussion of Idaho Power's IRP planning criteria can be found in Chapter 7.

Other resources used in the planning include demand-side management (DSM) and transmission lines. The goal for DSM programs is to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response programs. Idaho Power also strives to provide customers with tools and information to help them manage their own energy usage. The company achieves these objectives through the implementation and careful management of incentive programs and through outreach and education.

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and their planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG). Idaho Power coordinates local transmission planning with the regional forums as well as the

Federal Energy Regulatory Commission (FERC). Idaho Power is obligated under FERC regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers[1] and Idaho Power retail customers.[2] Timing of new transmission projects is subject to complex permitting, siting, and regulatory and partner coordination.

IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the *Energy Risk Management Policy and Standards*. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The *Energy Risk Management Policy and Standards* specifies an 18-month period, and Idaho Power assesses the resulting operations plan monthly.

## Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the resource plan, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2015 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2015 IRP, Idaho Power conducted 12 IRPAC meetings, including a resource portfolio design workshop. Public working group meetings to address the specific topics of energy efficiency, solar resources, and the study of coal resources were also held.



The IRPAC visits Swan Falls Dam.

In addition, Idaho Power hosted a field trip to the Swan Falls Hydroelectric Project (Swan Falls Project) for participants of the IRP process. Idaho Power personnel leading the field trip shared information on many topics,

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

including high-voltage transmission, recreation, avian biology, archaeology, and Snake River water supply. Field trip participants were led on a tour of the Swan Falls power plant and the Swan Falls museum.

Idaho Power believes working with members of the IRPAC and the public improves the IRP. Idaho Power and the members of the IRPAC recognize that final decisions on the resource plan are made by Idaho Power. However, Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2015 IRP and the resource planning process in general.

Following the filing of the final resource plan, Idaho Power presents the resource plan at public meetings in various communities around the company's service area. In addition, Idaho Power staff present the plan and discuss the planning process with various civic groups and at educational seminars as requested.

## IRP Methodology

Preparation of the Idaho Power 2015 IRP began with the forecast of future customer demand. Existing generation resources, demand-side resources, and transmission import capacity were combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated new energy efficiency programs and the expansion of existing programs to revise energy and capacity deficits. Finally, Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits.

Idaho Power evaluates resources and resource portfolios using a financial analysis. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), transmission upgrades, and anticipated environmental controls and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy certificates (REC).

Idaho Power is part of the larger northwestern and western regional energy markets, and market prices are an important component of evaluating energy purchases and sales. Idaho Power faces transmission import constraints and at times of peak customer load must rely on its own generation resources regardless of regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds customer demand and the transmission export capacity, and the company must curtail generation on its system.

An additional transmission connection to the Pacific Northwest has been part of the Idaho Power preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line, and since 2009 the addition has been called the Boardman to Hemingway (B2H) Transmission Line Project. Idaho Power again evaluated the B2H transmission line in the 2015 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Similar to the 2013 IRP, Idaho Power analyzed various resource portfolios over the entire 20-year planning period in the 2015 IRP. The analyzed portfolios in the 2015 IRP add resources

under certain scenarios as early as 2020; consequently, Idaho Power determined it is practical to again consider the 20-year planning period in total.

## Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide ($CO_2$) emission levels have historically been well below the national average for the 100 largest electric utilities in the United States (US), both in terms of total $CO_2$ emissions (tons) and $CO_2$ emissions intensity (pounds per megawatt-hour [MWh] generation). According to a May 2014 collaborative report using publicly reported 2012 generation and emissions data, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 38th lowest emitter of $CO_2$ per MWh produced and the 36th lowest emitter of $CO_2$ by tons of emissions among the nation's 100 largest electricity producers (figures 1.1 and 1.2).[3] According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 52nd largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

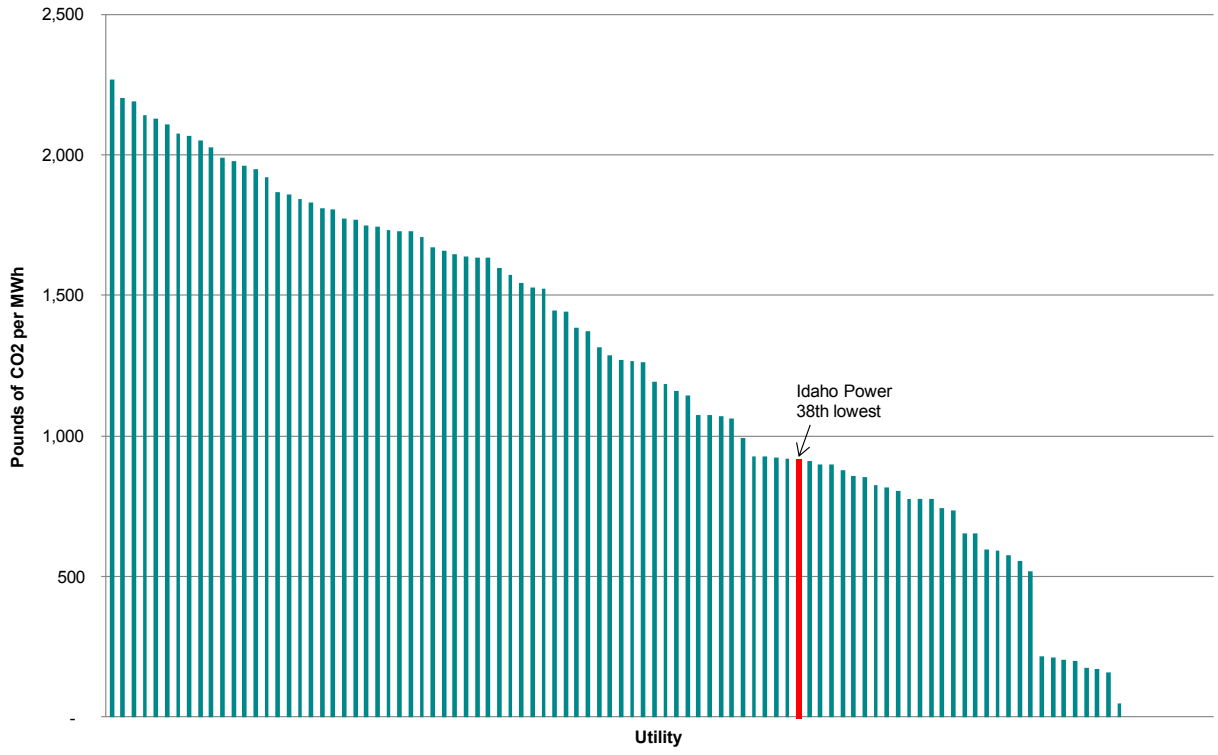


**Figure 1.1 $CO_2$ emissions intensity of the largest 100 utilities**

[3] M. J. Bradley & Associates. 2014. Benchmarking air emissions of the 100 largest electric power producers in the United States.

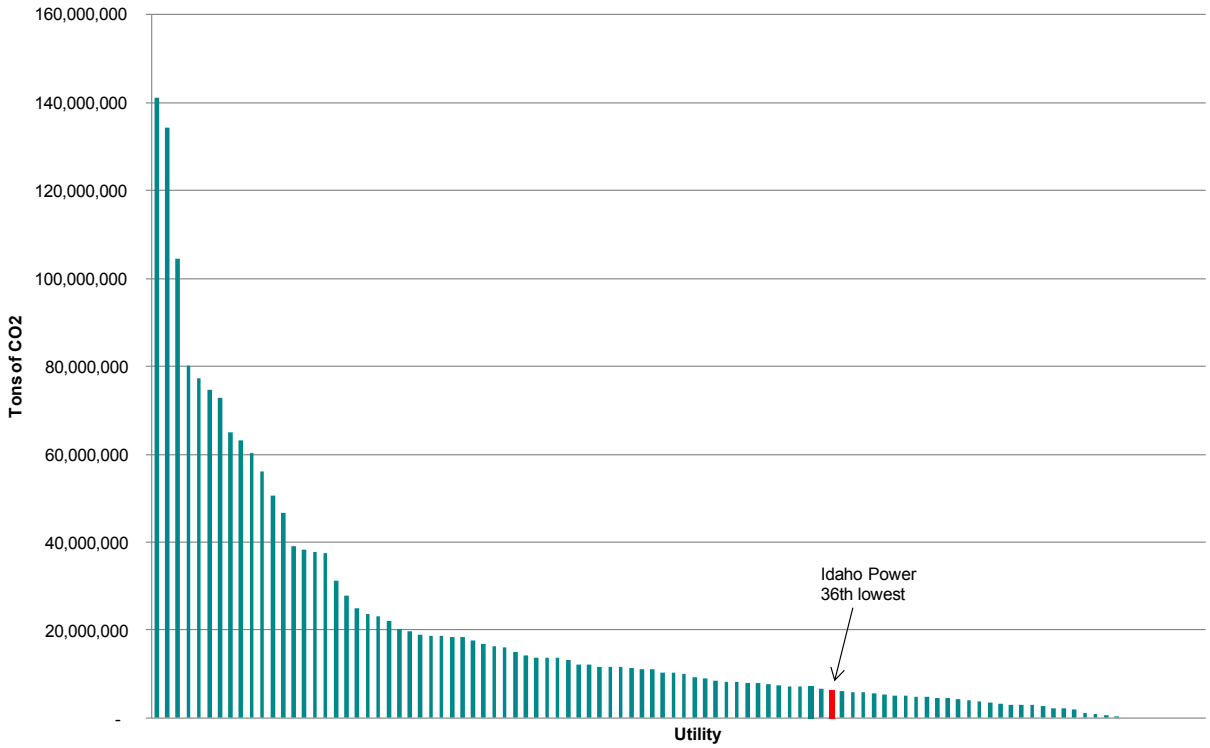


**Figure 1.2 $CO_2$ emissions of the largest 100 utilities**

In September 2009, Idaho Power's Board of Directors approved guidelines to reduce Idaho Power's resource portfolio average $CO_2$ emissions intensity from 2010 through 2013 to 10 to 15 percent below the company's 2005 $CO_2$ emissions intensity of 1,194 pounds per MWh. Because Idaho Power's $CO_2$ emissions intensity fluctuates with streamflows and production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

Currently, generation and emissions from company-owned resources are included in the $CO_2$ intensity calculation. The company's progress toward achieving this intensity reduction goal and additional information on Idaho Power's $CO_2$ emissions are reported on the company's website at idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm.

Information related to Idaho Power's $CO_2$ emissions is also available through the Carbon Disclosure Project at cdproject.net.

In November 2012, the Board of Directors approved the extension of the company's 2010 to 2013 goal for reducing $CO_2$ emission intensity. The goal as restated in 2012 is to achieve $CO_2$ emission intensity 10 to 15 percent below the 2005 $CO_2$ emission intensity from 2010 to 2015. A second extension of the goal approved by the Board of Directors in May 2015 sets a target $CO_2$ emission intensity of 15 to 20 percent below the 2005 $CO_2$ emission intensity for 2016 to 2017.

For the first time in several cycles, the 2015 IRP does not use a carbon adder to estimate the future cost of carbon emissions. The 2015 IRP incorporates the cost and long-term effects of carbon regulation by modeling several scenarios based on the Environmental Protection Agency's (EPA) proposed *Clean Air Act* (CAA) Section 111(d) regulations and the impact it

would have on the company's operations. A more complete discussion of climate change and the regulation of greenhouse gas emissions is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K at idacorpinc.com/pdfs/10K/10k2014a.pdf.

# Proposed Pilot Projects

## *Solar Photovoltaic to Address Distribution Feeder Voltage Loss*

A small-scale proof-of-concept photovoltaic (PV) and battery system pilot project is being considered for feeders with low voltage near the end of the feeder. The purpose of the pilot project is to evaluate its operational performance and its cost-effectiveness. The system will be designed to maintain the feeder voltage within +/- 5 percent of nominal voltage (American National Standards Institute [ANSI] C84.1) and be cost competitive with other options. During 2015 and 2016 the physical and economic feasibility will be examined. If feasible, a pilot system will be constructed and monitored. The results of the work will be reported in the 2017 IRP.

## *Ice-Based Thermal Energy Storage*

Idaho Power proposes a pilot project to investigate the benefits of using ice-based thermal energy storage (TES) to shift peak-hour air conditioning (A/C) load to off-peak periods. The initial phase of the pilot project would involve identifying a customer, designing the system, and putting together a detailed cost estimate. The second phase would be purchasing and installing the equipment, followed by data collection to determine the effectiveness of the concept. The ice-based TES technology is discussed further in Chapter 5.

# Community Solar

In the 2009 IRP, Idaho Power proposed a solar PV pilot project. At the time, a downward trend in the cost of solar PV was identified, and that trend has continued over the past few years. In addition, the energy shape of solar generation has been seen as a much better fit with Idaho Power's customer needs when compared to other variable and intermittent renewable resources. For these reasons, the company was interested in gaining experience and data related to solar generation, and a small pilot project was proposed.

In August 2010, the IPUC commented in Order No. 32042 (Case No. IPC-E-09-33) on the proposed solar pilot project, stating:

> Solar power has been identified as a resource that should be pursued by the Company. The recently announced Boise City solar project, we find, will provide Idaho Power that opportunity to assess the merits of such a resource.

Since the issuance of Order No. 32042, a number of unique circumstances have arisen that caused Idaho Power to reassess the appropriate timing and nature of its involvement in solar research and related projects. First, the solar project referenced in the IPUC order did not ultimately provide the assessment opportunity envisioned by the IPUC, as the developers chose not to pursue completion of the project. Further, three months after Order No. 32042 was issued, in November 2010 Idaho Power had 80 megawatts (MW) of *Public Utility Regulatory Policies Act of 1978* (PURPA) wind contracts pending approval at the IPUC, and the company had received another 570 MW of requests for new contracts. It was at that time the company

filed a joint petition to address PURPA policy and pricing issues at the state level, and Case No. GNR-E-10-04 was opened. A short time later, Idaho Power filed an application to modify its net metering service offering, and the IPUC opened Case No. IPC-E-12-27. In this case, the commission considered policy issues related to net metering, specifically in the areas of pricing and equitable cost assignment. Because of the broad scope of policy issues involving renewable generation under consideration by the IPUC in each of these cases, Idaho Power felt it was appropriate to postpone the development of any solar research project or customer-focused program pending the outcome of those cases.

Customer interest in central station and distributed solar generation was the subject of many 2015 IRP discussions, both among IRPAC members and Idaho Power leadership. Late in the 2015 IRP public process, Idaho Power was approached by several interested parties and asked to consider sponsoring a community solar project. The US Department of Energy (DOE) defines "community shared solar" as a solar-electric system that provides power and/or financial benefit to multiple community members.[4] The DOE further states the primary goal of community solar is to increase access to solar energy and to reduce up-front costs for participants. Secondary goals include: 1) improved economies of scale, 2) optimal project siting, 3) increased public understanding of solar energy, and 4) local job generation.

Several models have been used to facilitate community-shared solar projects, including utility-sponsored, special-purpose entity (SPE), and non-profit. Table 1.1 from the DOE compares various community solar models.[5]

**Table 1.1 Community solar model comparison**

| | Utility | SPE | Non-Profit |
|---|---|---|---|
| ***Owned By*** | Utility or third party | SPE members | Non-profit |
| ***Financed By*** | Utility, grants, customer subscriptions | Member investments, grants, incentives | Memberships, donor contributions, grants |
| ***Hosted By*** | Utility or third party | Third party | Non-profit |
| ***Subscriber Profile*** | Electric customers of the utility | Community investors | Donors, members |
| ***Subscriber Motive*** | Offset personal electricity use | Return on investment (ROI); offset personal electricity use | ROI; philanthropy |
| ***Long-term Strategy of Sponsor*** | Offer solar options; add solar generation (possibly for a renewable portfolio standard [RPS]) | Sell system to host; retain for electricity production | Retain for electricity production for life of the system |
| ***Examples*** | • Sacramento Municipal Utility District—SolarShares Program<br>• Tucson Electric Power—Bright Tucson Program | • University Park Community Solar, LLC<br>• Clean Energy Collective, LLC<br>• Island Community Solar, LLC | • Winthrop Community Solar Project<br>• Solar for Sakai |

[4] US Department of Energy. 2012. A guide to community shared solar: Utility, private, and nonprofit project development. http://www.nrel.gov/docs/fy12osti/54570.pdf.

[5] Ibid.

Several possibilities exist for the structure of a solar pilot project. One option Idaho Power is interested in pursuing would be to develop a PV project at a substation near existing load. This concept would not require the addition of new transmission resources and would have economy-of-scale advantages over distributed rooftop installations. The cost of the project could be subsidized by allowing participating customers to voluntarily buy the output from the project to invest in renewable energy.

The interested parties have asked Idaho Power to sponsor a community-based solar project to satisfy the solar pilot project proposed by the company in the 2009 IRP. For an example of this concept, there are several utility-sponsored projects whereby utility customers volunteer by contributing either an up-front or ongoing payment to support a solar project. In exchange, customers receive a payment or credit on their electric bills that is proportional to 1) their contribution and 2) how much electricity the solar project produces. Usually, the utility or an identified third-party owns the solar system itself. The participating customer has no ownership stake in the solar system. Rather, the customer buys rights to the benefits of the energy produced by the system.

It is important to note that Idaho Power's load and resource balance indicates an investment in any new generation, including solar generation, is neither needed nor economic to pursue at this time or during the four-year action plan horizon. However, as regulations governing carbon emissions mature, additional renewable generation may be warranted, and community-shared solar could be a viable option to help satisfy some future carbon intensity targets.

Given the quickly changing regulatory, technological, and economic landscape, the company will explore the risks and opportunities of, and potential designs for, a community-based solar project by continuing to work with interested parties. Because there is no identified resource need in the near-term, a project of this nature would be pursued outside the traditional needs-based regulatory framework and would focus on meeting changing customer preferences with regard to where and how the energy they use is produced.

## Portfolio Analysis Summary

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The preferred portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost, risk, and environmental factors over the 2015 to 2034 planning period. Several key factors create uncertainty regarding the selection of a preferred portfolio in the 2015 IRP. These factors include consideration of North Valmy and Jim Bridger coal unit early retirement, the EPA's proposed CAA Section 111(d) regulation, large contracted amounts of unbuilt PURPA solar projects, and the timing of the B2H transmission line.

### *North Valmy and Jim Bridger Coal Unit Early Retirement and CAA Section 111(d) Regulation*

The 2015 IRP examines the EPA's proposed CAA Section 111(d) regulation and the future of Idaho Power's ownership share of the Jim Bridger and North Valmy coal-fired power plants. With the exception of the Status Quo portfolio, all other portfolios analyzed evaluate alternatives to continued investment in the coal units and/or the impact of reducing generation from

fossil-fueled power plants to comply with uncertain environmental regulations. The optimization of coal unit shutdown alternatives using computer modeling tools will not be possible until the proposed CAA Section 111(d) regulation is finalized sometime in the second half of 2015. It is possible to identify trends in the modeling results that indicate a portfolio with an earlier North Valmy unit shutdown coupled with the completion of the B2H project performs well on a 20-year net-present-value (NPV) basis.

The early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years in exchange for longer-term savings. This is conceptually similar to repaying a home mortgage early. Over the shortened life of a loan, the total payments will be less, but in the near term the monthly payment will be higher. The same is true when contemplating early retirement of North Valmy or Jim Bridger units. For example, a North Valmy 2019 early shutdown will cost approximately $95 million more between 2015 and 2019 but save approximately $181 million in fixed O&M, capital investment, and finance costs compared to a 2031 to 2034 retirement (in nominal dollars). Unlike the home mortgage example, a coal unit will have little value at the decommissioning date, and it is likely another resource investment will be required.

## Uncertainty Related to PURPA Solar

Power supply planning is complicated by the inability of a utility to control the timing, type, and quantity of PURPA resources being added to the Idaho Power generation portfolio. Under PURPA, a utility is obligated to sign energy sales agreements with all qualifying facilities (QF) that request to sell energy to Idaho Power. Changes in PURPA regulations, resource incentives, and technology can and do continuously change the quantity and MWs of projects being proposed or contracted for under PURPA. In addition, even after a PURPA QF agreement is executed with a proposed project, there is still uncertainty whether the project will be built. The result is increased planning uncertainty to the timing and type of company-owned resources needed. Current PURPA regulations also do not consider Idaho Power energy needs or impacts on system reliability, which creates challenging integration issues and is contrary to the company's desire to develop a reliable system as efficiently and cost-effectively as possible.

The IRP load and resource balance includes 461 MW of solar PV from PURPA projects scheduled to be on-line by year-end 2016. The energy and peak-hour capacity of these projects was included in the PURPA forecast at the time the forecast was prepared. The risk of relying on these signed contracts is exemplified by the fact that 141 MW of the 461 MW were recently terminated due to inaction by the PURPA developers. The removal of the 141 MW of solar capacity increases peak-hour capacity deficits by approximately 75 MW. Because the schedule for completing the IRP would not allow the PURPA generation forecast to be updated, the removal of the 141 MW of solar PV generation is addressed in a qualitative manner in the risk analysis section of Chapter 9.

## Boardman to Hemingway Transmission

Portfolio analysis for the 2015 IRP indicates portfolios with the B2H transmission line consistently outperform those in which the transmission line is excluded. This result is consistent with analyses of past IRPs, which have shown the B2H project is a valuable supply-side resource that will allow Idaho Power to meet future system needs. Regional growth in renewable energy

resources, such as wind and solar, makes B2H increasingly valuable as it provides increased system flexibility critical to the reliability of interconnected systems with high penetration levels of variable and intermittent resources.

### Selection of the Preferred Portfolio

As previously noted, portfolios with early North Valmy unit retirements performed well in the 2015 IRP analysis; analyses show favorable economics for portfolios with the retirement of North Valmy Unit 1 as early as 2019. However, these portfolios carry considerable risk associated with the following factors:

- Uncertainty related to the proposed CAA Section 111(d) regulation, particularly the effect of the final rule on operations at existing coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020
- Uncertainty related to retirement planning for a jointly owned power plant, specifically the challenges associated with arriving at a retirement date that is feasible to both owners of the plant
- Uncertainty related to PURPA solar and the effect of further project cancellations on capacity additions in the early 2020s
- Uncertainty related to the completion date of the B2H project due to permitting issues and the needs of project partners
- Uncertainty of regulatory acceptance of early coal unit retirement and rate impacts associated with accelerated cost recovery

Given these risks, the preferred portfolio selected is portfolio P6(b), which includes the retirement of the North Valmy plant at year-end 2025 and the completion of the B2H project in 2025. The close linking of these resource actions suggests an earlier completion date of the B2H project could accelerate the decommissioning of the North Valmy plant. Portfolio P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, portfolio P6(b) also adds a 300 MW combined-cycle combustion turbine (CCCT). These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With the expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

## Action Plan

### Action plan (2015–2018)

Table 1.2 provides the schedule of action items Idaho Power anticipates over the next four years. Additional details regarding actions related to the Shoshone Falls Hydroelectric Project (Shoshone Falls Project) are presented in chapters 5 and 9 of the IRP.

**Table 1.2 Action plan (2015–2018)**

| Year(s) | Resource | Action | Action Number |
|---|---|---|---|
| 2015–2018 | B2H | Ongoing permitting, planning studies, and regulatory filings | 1 |
| 2015–2018 | Gateway West | Ongoing permitting, planning studies, and regulatory filings | 2 |
| 2015–2019 | Energy efficiency | Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand. | 3 |
| 2015–2016 | N/A | Coordinate with government agencies on implementation planning for CAA Section 111(d). | 4 |
| 2015 | Shoshone Falls | File to amend FERC license regarding 50-MW expansion | 5 |
| 2015 | Jim Bridger Unit 3 | Complete installation of selective catalytic reduction (SCR) emission-control technology | 6 |
| 2015–2016 | Shoshone Falls | Study options for a smaller upgrade ranging in size up to approximately 4 MW | 7 |
| 2016 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | 8 |
| 2016 | North Valmy units 1 and 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | 9 |
| 2017 | Shoshone Falls | Commence construction of smaller upgrade | 10 |
| 2017 | Jim Bridger units 1 and 2 | Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP | 11 |
| 2019 | Shoshone Falls | On-line date for smaller upgrade during first quarter | 12 |

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# 2. Political, Regulatory, and Operational Issues

## Idaho Energy Plan

In 2007, the Idaho Legislature's Interim Committee on Energy, Environment, and Technology prepared, and the Idaho Legislature approved, a new Idaho Energy Plan for the first time in 25 years. With rapid changes in energy resources and policies, the committee recommended the legislature revisit the Idaho Energy Plan every five years to reflect the interests of Idaho citizens and businesses. In keeping with this recommendation, the plan was reviewed and updated by the Interim Committee and approved by the legislature in 2012. The Idaho Governor's Office of Energy Resources (OER) and the Idaho Strategic Energy Alliance assisted the Interim Committee in updating the energy plan.

The 2012 update finds that Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy, despite the potential economic and political vulnerability caused by Idaho's reliance on energy imports. Idaho currently lacks significant commercial natural gas and oil wells and only generates about half the electricity it uses. Yet the state has abundant hydropower, wind, biomass, and other renewable energy sources.

Ongoing changes in energy generation and consumption provide an opportunity for economic growth within the state. While the Idaho Energy Plan acknowledges the risks attributed to advances in energy generation, transmission, and end-use technologies, it also recognizes the prospective benefits. With this recognition, the 2012 Idaho Energy Plan emphasizes five core objectives:

1. Ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho.

2. Maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans.

3. Protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources.

4. Promote sustainable economic growth, job creation, and rural economic development.

5. Provide the means for Idaho's energy policies and actions to adapt to changing circumstances.

Because the OER was charged with coordinating and cooperating with federal and state agencies on issues concerning the State's energy requirement, Governor C. L. "Butch" Otter asked the OER to coordinate the State of Idaho's response to the EPA Clean Power Plan on behalf of all relevant state agencies.

## Idaho Strategic Energy Alliance

Under the umbrella of the OER, the Idaho Strategic Energy Alliance allows various stakeholders to have representation and participate in developing energy plans and strategies for Idaho's

energy future. The Idaho Strategic Energy Alliance is Idaho's primary mechanism for advancing energy production, energy efficiency, and energy business in the State of Idaho.

The purpose of the Idaho Strategic Energy Alliance is to develop a sound energy portfolio for Idaho that includes diverse energy resources and production methods, that provides the highest value to the citizens of Idaho, that ensures quality stewardship of environmental resources, and that functions as an effective, secure, and stable energy system.

Idaho Power representatives serve on both the Idaho Strategic Energy Alliance board of directors and a number of the volunteer task forces that work in the following areas:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

## FERC Relicensing

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years, depending on the size, complexity, and cost of the project.

Idaho Power filed a final license application (FLA) for the Swan Falls Project with FERC in June 2008, and the new license for the Swan Falls Project was issued by FERC on September 8, 2012, for a 30-year term expiring September 1, 2042.

Idaho Power's remaining and most significant ongoing relicensing effort is the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 34 percent of the company's total generating capacity. The current license for the HCC expired in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1973* (ESA); and other applicable federal laws.

Administrative work on relicensing the HCC is expected to continue until a new license is issued. After a new license is issued, further costs will be incurred to comply with the terms of the new license. Because the new license for the HCC has not been issued, and discussions on the protection, mitigation, and enhancement (PM&E) packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include the following:

1. Coordinating the relicensing process
2. Consulting with regulatory agencies, tribes, and interested parties
3. Preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites
4. Preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
5. Studying and analyzing data
6. Preparing all necessary reports, exhibits, and filings responding to requests for additional information from FERC
7. Consulting on legal matters

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental PM&E measures imposed as a condition of relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2015 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

## Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues is expected to affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative

water-right proceedings. Idaho Power's ongoing participation in water-right issues is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.



Snake River below Bliss.

Idaho Power, along with other Snake River Basin water-right holders, was engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA. As a result of the SRBA, the company's water rights were adjudicated, resulting in the issuance of partial water-right decrees. The Final Unified Decree for the SRBA was signed on August 25, 2014.

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power over the company's water rights at the Swan Falls Project. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The Swan Falls Agreement placed the portion of the company's water rights beyond the minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked the court to resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the State of Idaho are actively involved in those discussions. The settlement also recognizes

water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties are working with water users and other stakeholders in the development of water-management measures through the implementation of the Eastern Snake River Plain Aquifer (ESPA) *Comprehensive Aquifer Management Plan* (CAMP) as approved by the Idaho Water Resource Board (IWRB) and the 2009 Swan Falls Reaffirmation Agreement.

Given the high degree of interconnection between the ESPA and Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River. The company continues to emphasis implementation of the ESPA CAMP to improve aquifer levels and tributary spring flows to the Snake River. While some of the Phase I recommendations outlined in Table 2.1 were slow to develop due to limited initial funding, House Bill 547 signed into law by Governor Otter in 2014 provides $5 million annually to the IWRB for aquifer stabilization projects, with the ESPA having first priority.

While there have been two practices—recharge and weather modification—that have received funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

During the winter of 2014 to 2015, weather and canal maintenance conditions allowed for an extended wintertime recharge season from October 27, 2014, to March 24, 2015, resulting in a volume recharged of 72,325 acre-feet. This volume significantly exceeded the combined recharge of the two previous seasons and exceeded the average annual recharge of the previous five seasons by 4,500 acre-feet.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program in the upper Snake River Basin and, through the cooperative effort, has greatly expanded the existing weather modification operational program, along with forecasting and meteorological data support. The company has an established, long-term plan to continue the expansion of this program. In 2014, Idaho Power expanded its cloud-seeding program to the Boise and Wood River basins, in collaboration with basin water users and the IWRB. Wood River cloud seeding, along with the upper Snake activities, will benefit the ESPA CAMP implementation through additional water supply.

**Table 2.1 Phase I measures included in the ESPA CAMP**

| Measure | Target (acre-feet) | Estimated to Date (acre-feet) |
|---|---|---|
| Groundwater to surface-water conversions | 100,000 | 30,300 |
| Managed aquifer recharge | 100,000 | 78,000* |
| Demand reduction | – | – |
| Surface-water conservation | 50,000 | 26,000 |
| Crop-mix modification | 5,000 | 0 |
| Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP) | 40,000 | 34,000 |
| Weather modification | 50,000 | 250,000 |

*Average annual recharge from 2009 to 2014.

For the 2015 IRP, Idaho Power forecasted flows similar to those in the 2013 IRP, with declines in reach gains extending through the end of the IRP planning period. Based on modeling under the 90-percent exceedance forecast, declining flows at Swan Falls drop to 4,030 cfs, which is slightly higher than the Swan Falls minimum of 3,900 cfs. Figure 2.1 provides the yearly April through July inflow to Brownlee Reservoir as forecasted for the 2015 IRP.

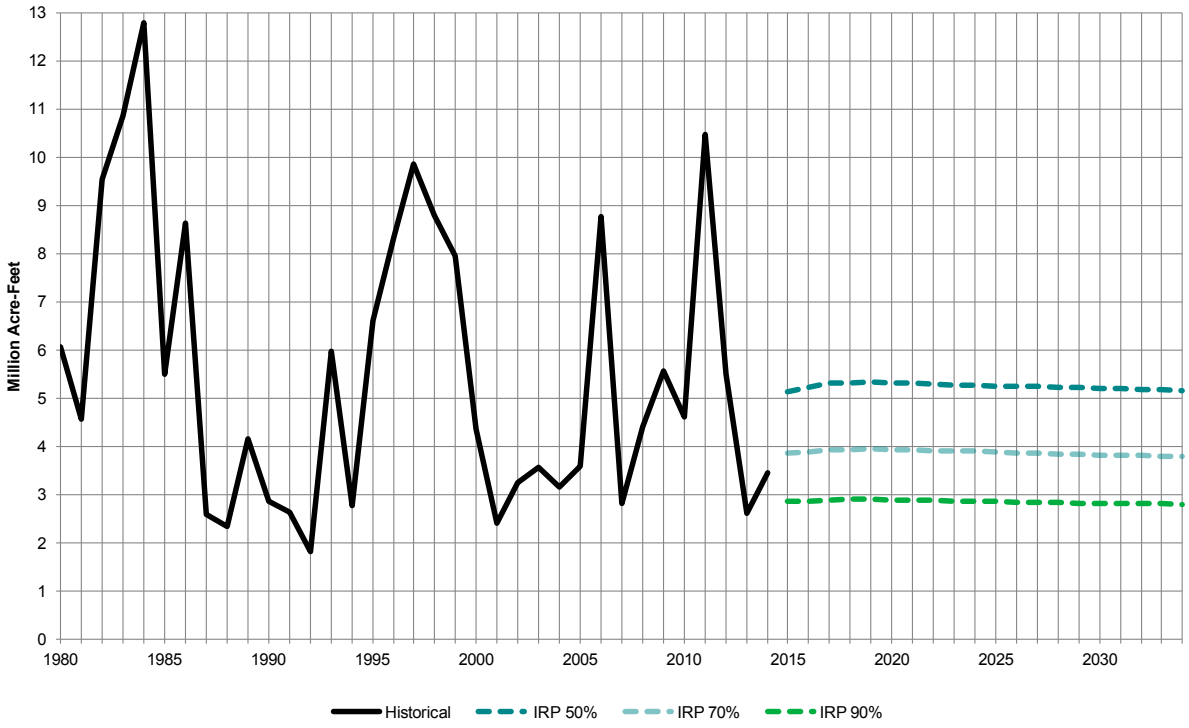



**Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow**

## Renewable Integration Study

Idaho Power has completed two wind integration studies and one solar integration study since the mid-2000s. These studies increased the company's understanding of the impacts and costs associated with integrating variable and intermittent resources without compromising reliability. The variable and uncertain production from wind and solar resources requires Idaho Power to provide additional balancing reserves from existing dispatchable generating resources, which results in lost opportunity costs and corresponding increases in power supply expenses.

Idaho Power completed the most recent wind integration study in 2013, which was the basis for a tariff schedule of wind integration costs proposed to the IPUC by Idaho Power. The IPUC approved the proposal as Schedule 87 in Order No. 33150 in October 2014.

The first Idaho Power solar integration study was completed in 2014, and the subsequent revision to Schedule 87 was approved by the IPUC in Order No. 33227 in February 2015 as part of a settlement stipulation between Idaho Power and intervening parties. The solar integration

settlement stipulation includes provisions requiring Idaho Power to initiate a second solar integration study by January 2015 and to complete the second study within 12 months. Idaho Power has formed a Technical Review Committee of renewable energy experts for the second solar integration study, which is in progress but will not be finished prior to the completion of the 2015 IRP.

The results of the integration studies show periods of low customer demand to be the most difficult to cost-effectively integrate variable resources. During low demand periods, other existing resources are often already running at minimum levels or may already be shut off. Under these conditions, curtailment of the variable resources may be necessary to keep generation balanced with customer load. The integration studies also demonstrate the frequency of curtailment events are expected to increase as additional variable resources are added to the system.

For the IRP, integration costs for existing wind and solar resources are common to all the portfolios analyzed and are not included in the portfolio cost accounting. However, portfolios with new wind or solar resources do include costs consistent with Schedule 87 for the new resources. A copy of Schedule 87 is provided in *Appendix C—Technical Appendix*.

## Northwest Power Pool Energy Imbalance Market

Since 2012, the Northwest Power Pool (NWPP) has evaluated energy imbalance markets (EIM), sometimes referred to as a security-constrained economic dispatch (SCED). A second phase of the effort was focused on refining the design elements of a SCED to suit the unique issues present in the NWPP. A third phase just completed developed a number of operational tools to facilitate a more robust and reliable system operation. The NWPP is now moving into a fourth phase to continue to refine design elements of an SCED to develop additional low-cost/high-value tools to enhance system operation. Many institutional issues remain before an SCED can be implemented in the Pacific Northwest.

For Idaho Power, there are several principle benefits to an EIM:

1. The market would provide greater access to balancing energy to accommodate intermittent generation variations within Idaho Power's balancing area.

2. There would be a slight improvement in real-time dispatch costs.

3. The market would provide better real-time pricing for power imbalances that occur in real-time for wholesale power customers.

Idaho Power supports, and will continue to participate in, the NWPP discussions; however, participation by a majority of the NWPP members will be required to realize the benefits of an EIM.

## Renewable Energy Certificates

RECs, also known as green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents the renewable attributes associated with the production of 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The purchase of a REC buys the renewable attributes, or "greenness," of that energy.

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hours (kWh), or 1 MWh, of electricity produced. RECs and the electricity produced by a certified renewable resource can either be sold together (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level RPS. An RPS is a policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy.

A certifying tracking system gives each REC a unique identification number to facilitate tracking purchases, sales, and retirements. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used (retired), held (banked), or traded (sold).

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- REC supply/demand
- Whether the REC is certified for RPS compliance
- The generation type (e.g., wind, solar, geothermal)
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds are returned to Idaho Power customers through the power cost adjustment (PCA) as directed by the IPUC in Order No. 32002 and by the OPUC in Order No. 11-086. Because the RECs were sold, Idaho Power cannot claim the renewable attributes associated with those RECs. The new REC owner has purchased the rights to claim the renewable attributes of that energy.

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, every dollar contributed by a customer brings about the delivery of 118 kWh of renewable energy to the region's power grid, providing the contributing customer associated claims for the renewable energy. The entire amount designated is used to purchase green power from renewable projects in the Northwest and to support Solar 4R Schools. On behalf of program participants, Idaho Power obtains and retires RECs. For the 2014 Green Power Program, Idaho Power purchased and subsequently retired 19,318 RECs on behalf of Green Power participants.

# Renewable Portfolio Standard

Idaho Power anticipates that existing hydroelectric facilities will not be included in RPS calculations. However, hydroelectric upgrades on existing facilities, such as the Shoshone Falls upgrade, will likely be included in RPS calculations.

Under the Oregon RPS, Idaho Power is classified as a smaller utility because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 5- or 10-percent RPS requirement beginning in 2025.

While the State of Idaho does not have an RPS, a federal renewable energy standard (RES) is a possibility. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to position the company's resource and REC portfolio to minimize the potential effect on customers if a federal RES is implemented.

## *REC Management Plan*

In December 2009, Idaho Power filed a REC management plan with the IPUC that detailed the company's plans to continue acquiring long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near term and return to customers their 95-percent share of the proceeds as defined under the PCA mechanism. In June 2010, the IPUC accepted Idaho Power's REC management plan in Order No. 32002 (Case No. IPC-E-08-24).

# Federal Energy Legislation CAA Section 111(d)

Idaho Power is subject to a broad range of federal, state, regional, and local environmental laws and regulations. Current and pending environmental legislation relates to climate change, greenhouse gas emissions and air quality, mercury (Hg) and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species. The legislation includes the CAA, the *Clean Water Act of 1972* (CWA); the *Resource Conservation and Recovery Act of 1976* (RCRA); the *Toxic Substances Control Act of 1976* (TSCA); the *Comprehensive Environmental Response, Compensation and Liability Act of 1980* (CERCLA); and the ESA.

The utility industry will continue to respond to changes in environmental legislation associated with utility operations, including emissions regulations associated with the operation of coal and natural gas-fired generating facilities.

On June 2, 2014, the EPA, under President Obama's Climate Action Plan, released its long-anticipated proposal to regulate $CO_2$ emissions from existing power plants under CAA Section 111(d). EPA's proposed Clean Power Plan includes ambitious, mandatory $CO_2$ reduction targets for each state designed to achieve nationwide 30-percent $CO_2$ emission reductions over 2005 levels by 2030. The EPA has proposed a novel approach, extending regulations beyond the stationary source itself, which is where the EPA has traditionally confined its authority. Each state's rate-based goal, namely pounds of $CO_2$ per MWh was calculated using four building blocks:

1. Building Block 1—Improve efficiency in existing coal-fired power plants.

2. Building Block 2—Re-dispatch generation from existing coal-fired power plants to natural gas combined-cycle plants.

3. Building Block 3—Increase generation from non-$CO_2$-emitting resources.

4. Building Block 4—Increase end-use energy efficiency programs.

A combination of the four building blocks was used to calculate an interim goal (average of years 2020–2029) and a final 2030 goal. Each state would then implement the goals through a state plan, which will need to be approved by the EPA. Each rate-based goal would be legally binding on each state.

With new comprehensive federal energy legislation, a utility's resource portfolio will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes. Because the EPA's proposed regulation will not be finalized until sometime after the completion of the 2015 IRP, the IRP analysis examines several compliance sensitivities that represent possible outcomes of the final regulation. Additional information on these sensitivities is presented in Chapter 9 and in *Appendix C—Technical Appendix*.

# 3. IDAHO POWER TODAY

## Customer Load and Growth

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 515,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,400 MW. On July 2, 2013, the peak-hour load reached 3,407 MW—the system peak-hour record.



Construction in downtown Boise.

Average firm load increased from 1,200 aMW in 1990 to 1,739 aMW in 2014 (load calculations exclude the load from the former special-contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,594 MW. The 959-MW increase in capacity represents enough generation to serve nearly 175,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 318-MW Langley Gulch CCCT. This highly efficient, natural gas-fired power plant is located in the western Treasure Valley in Payette County, Idaho. Construction of the plant began in August 2010, and the plant became commercially available in June 2012.

The data in Table 3.1 suggests each new customer adds approximately 5.5 kilowatts (kW) to the peak-hour load and about 2.5 average kilowatts (akW) to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to the average load; industrial customers generally have a more consistent load shape.

Since 1990, Idaho Power has added about 225,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 225,000 customers require 1,237 MW of additional peak-hour capacity and about 560 aMW of energy.

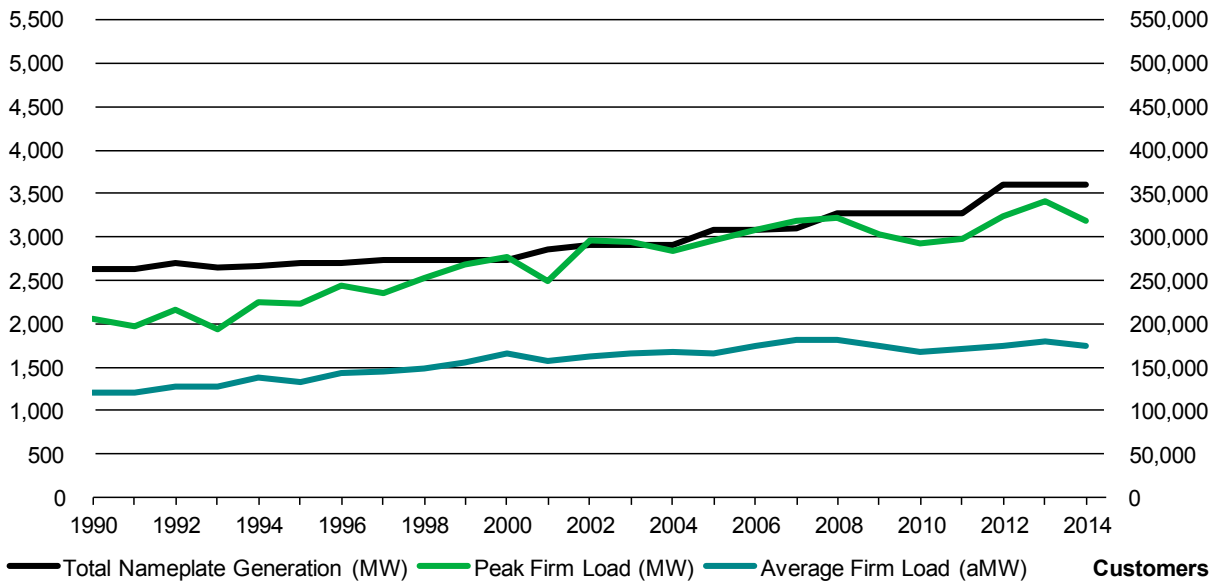



**Figure 3.1 Historical capacity, load, and customer data**

**Table 3.1 Historical capacity, load, and customer data**

| Year | Total Nameplate Generation (MW) | Peak Firm Load (MW) | Average Firm Load (aMW) | Customers[1] |
|---|---|---|---|---|
| 1990 | 2,635 | 2,052 | 1,205 | 290,492 |
| 1991 | 2,635 | 1,972 | 1,206 | 296,584 |
| 1992 | 2,694 | 2,164 | 1,281 | 306,292 |
| 1993 | 2,644 | 1,935 | 1,274 | 316,564 |
| 1994 | 2,661 | 2,245 | 1,375 | 329,094 |
| 1995 | 2,703 | 2,224 | 1,324 | 339,450 |
| 1996 | 2,703 | 2,437 | 1,438 | 351,261 |
| 1997 | 2,728 | 2,352 | 1,457 | 361,838 |
| 1998 | 2,738 | 2,535 | 1,491 | 372,464 |
| 1999 | 2,738 | 2,675 | 1,552 | 383,354 |
| 2000 | 2,738 | 2,765 | 1,653 | 393,095 |
| 2001 | 2,851 | 2,500 | 1,576 | 403,061 |
| 2002 | 2,912 | 2,963 | 1,622 | 414,062 |
| 2003 | 2,912 | 2,944 | 1,657 | 425,599 |
| 2004 | 2,912 | 2,843 | 1,671 | 438,912 |
| 2005 | 3,085 | 2,961 | 1,660 | 456,104 |
| 2006 | 3,085 | 3,084 | 1,745 | 470,950 |
| 2007 | 3,093 | 3,193 | 1,808 | 480,523 |
| 2008 | 3,276 | 3,214 | 1,815 | 486,048 |
| 2009 | 3,276 | 3,031 | 1,742 | 488,813 |
| 2010 | 3,276 | 2,930 | 1,679 | 491,368 |
| 2011 | 3,276 | 2,973 | 1,711 | 495,122 |
| 2012 | 3,594 | 3,245 | 1,745 | 500,731 |
| 2013 | 3,594 | 3,407 | 1,801 | 508,051 |
| 2014 | 3,594 | 3,184 | 1,739 | 515,262 |

[1] Year-end residential, commercial, and industrial count plus the maximum number of active irrigation customers

Idaho Power anticipates adding approximately 9,800 customers each year throughout the 20-year planning period. The expected-case load forecast predicts summer peak-hour load requirements will grow at about 62 MW per year, and the average-energy requirement is forecast to grow at 24 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

The simple peak-hour load-growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 318-MW Langley Gulch CCCT plant every five years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The plan to meet the requirements of Idaho Power's load growth is discussed in Chapter 10.

The generation costs per kW included in Chapter 7 provide some perspective on customer growth. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,145 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch Power Plant, and peak-hour generation capital costs are about $800 per kW for a natural gas-fired simple-cycle combustion turbine (SCCT), such as the Danskin and Bennett Mountain projects. These capital-cost estimates are in 2015 dollars and do not include fuel or any other O&M expenses.

Based on the capital-cost estimates, each new residential customer requires over $1,700 of capital investment for 1.5 kW of baseload generation, plus an additional $4,400 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of over $6,100. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $6,100 capital generation requirement. A residential customer growth rate of 9,800 new customers per year translates into almost $60 million of new generation plant capital each year to serve the baseload and peak energy requirements of new residential customers.

## 2014 Energy Sources

Idaho Power's system receives energy from a variety of fuel types and integrates energy from more than 100 PURPA projects and three power purchase agreements (PPA) in addition to company-owned generation. Figure 3.2 shows the nameplate capacity of resources delivering to Idaho Power's system from company-owned resources, PURPA contracts, and long-term PPAs.

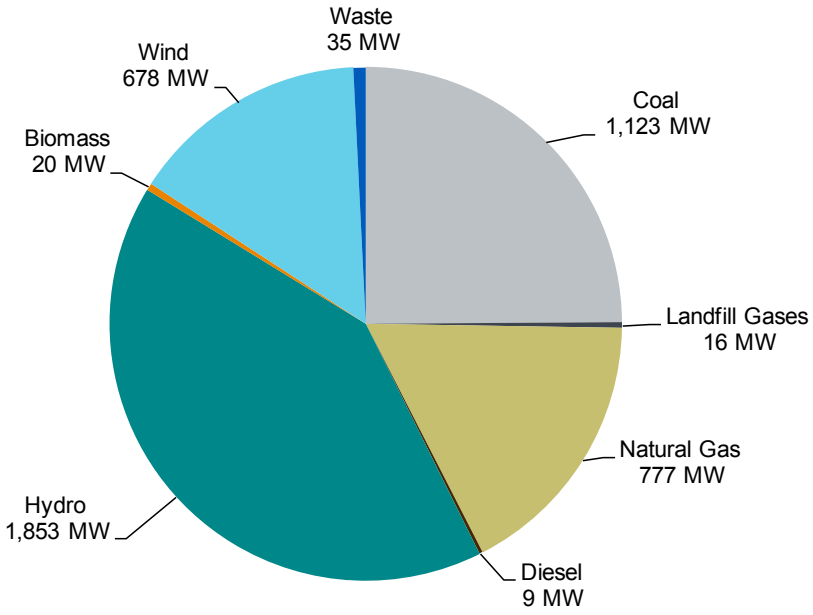



**Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power)**

Idaho Power's electricity sources for 2014 are shown in Figure 3.3. Idaho Power generated 77 percent of the total energy requirement. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Purchased power provides the remaining 23 percent of the energy requirement and includes power purchased from PURPA projects, market purchases, and PPAs, the need for which has been identified in past IRPs.

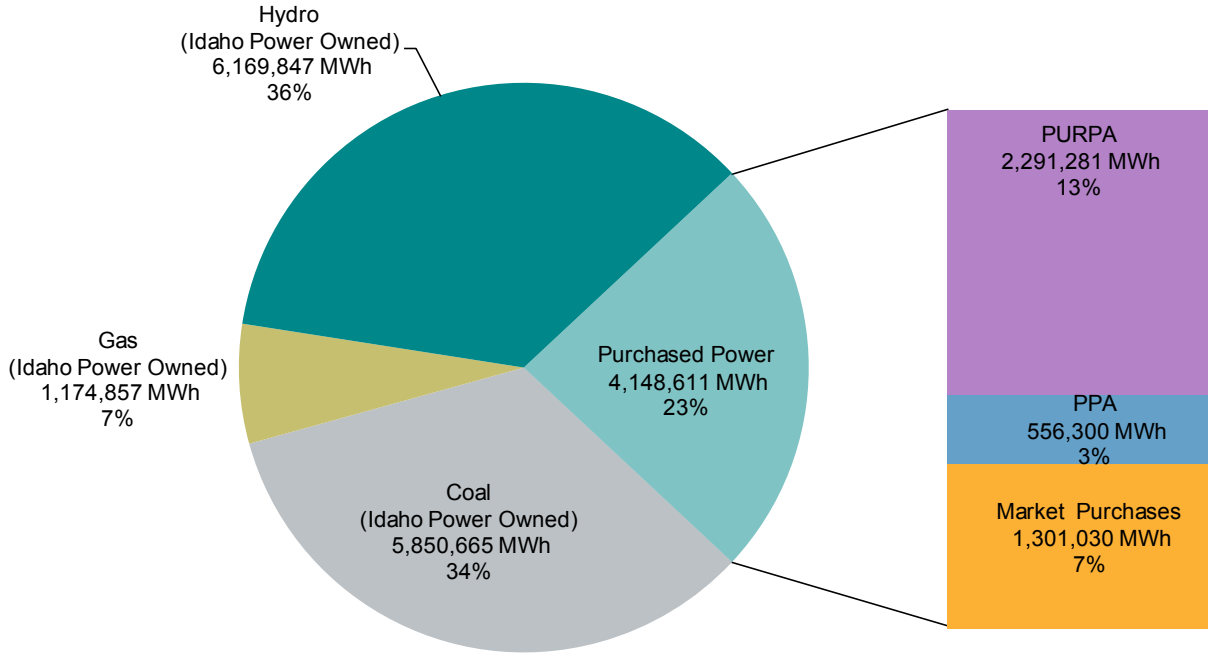



**Figure 3.3 2014 energy by source**

In 2014, Idaho Power purchased 4,148,611 MWh of electricity through PURPA contracts, market purchases, and long-term PPAs. Figure 3.4 provides a percentage breakdown by fuel type for the PPA and PURPA purchases. Market purchases are shown in total but not identified by fuel type since the original resource is not known. Idaho Power receives RECs from the Elkhorn Valley Wind Project, the Raft River Geothermal Project, and the Neal Hot Springs Geothermal Project. However, as noted in Chapter 2, Idaho Power is required to sell these RECs, and none of the renewable generation is represented as being delivered to Idaho Power retail customers in 2014.

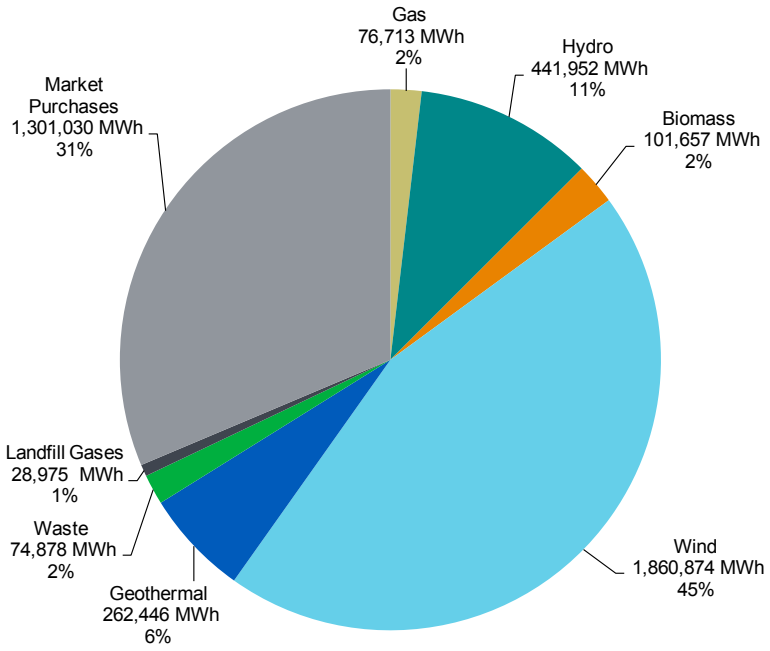



**Figure 3.4 2014 power purchases by fuel type**

## Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are presented in *Appendix C—Technical Appendix*. Table 3.2 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

**Table 3.2 Existing resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydroelectric | 92.3 | Upper Snake |
| Bliss | Hydroelectric | 75.0 | Mid-Snake |
| Brownlee | Hydroelectric | 585.4 | Hells Canyon |
| C. J. Strike | Hydroelectric | 82.8 | Mid-Snake |
| Cascade | Hydroelectric | 12.4 | North Fork Payette |
| Clear Lake | Hydroelectric | 2.5 | South Central Idaho |
| Hells Canyon | Hydroelectric | 391.5 | Hells Canyon |
| Lower Malad | Hydroelectric | 13.5 | South Central Idaho |
| Lower Salmon | Hydroelectric | 60.0 | Mid-Snake |
| Milner | Hydroelectric | 59.4 | Upper Snake |
| Oxbow | Hydroelectric | 190.0 | Hells Canyon |
| Shoshone Falls | Hydroelectric | 12.5 | Upper Snake |
| Swan Falls | Hydroelectric | 27.2 | Mid-Snake |
| Thousand Springs | Hydroelectric | 8.8 | South Central Idaho |
| Twin Falls | Hydroelectric | 52.9 | Mid-Snake |
| Upper Malad | Hydroelectric | 8.3 | South Central Idaho |
| Upper Salmon A | Hydroelectric | 18.0 | Mid-Snake |
| Upper Salmon B | Hydroelectric | 16.5 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| North Valmy | Coal | 283.5 | North Central Nevada |
| Langley Gulch | Natural Gas—CCCT | 318.5 | Southwest Idaho |
| Bennett Mountain | Natural Gas—SCCT | 172.8 | Southwest Idaho |
| Danskin | Natural Gas—SCCT | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | Eastern Idaho |
| **Total existing nameplate capacity** | | **3,594.4** | |

The following sections describe Idaho Power's existing supply-side generation resources and long-term PPAs.

## Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 970 aMW, or 8.5 million MWh under median water conditions.

## Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the HCC in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 70 percent of Idaho Power's annual hydroelectric generation and approximately 30 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability.

Idaho Power operates the HCC to comply with the existing annual FERC license as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the Fall Chinook Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon (*Oncorhynchus tshawytscha*) below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

Brownlee Reservoir is the main HCC reservoir and Idaho Power's only reservoir with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately 1 million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used for system flood control, recreation, and the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood-control directions received from the US Army Corps of Engineers (USACE) as outlined in Article 42 of the existing FERC license.

After flood-control requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River basin above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake River (mid-Snake) projects, with all of the flow augmentation eventually passing through the HCC before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the Fall Chinook Program adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook

operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

### Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C. J. Strike, Bliss, Lower Salmon, Upper Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, and C. J. Strike projects. These three projects are operated within the FERC license requirements to coincide with daily system peak demand when load-following capacity is available.

Idaho Power completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail (*Taylorconcha serpenticola*), a threatened species under the ESA. The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to relicense the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power annually alternated operating the Bliss and Lower Salmon facilities under ROR and load-following operations. Study results indicated that while load-following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A *Bliss Rapids Snail Protection Plan* developed in consultation with the FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company has been able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has received a license amendment from FERC for both projects that allows load-following operations to resume.

### Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the water is needed are especially beneficial. Acquiring water through the water bank also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2014 with Water District 63 in the Boise River basin to rent 8,000 acre-feet of storage water released in January 2015. In August 2009, Idaho Power also entered into a five-year (2009–2013) water-rental agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. In 2011, the company extended the Shoshone–Bannock rental agreement for two additional years, 2014 and 2015.

Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of mainstem Snake River

hydroelectric projects. The company typically scheduled delivery of the water between July and October each year during the term of the agreement. The Shoshone–Bannock agreement was executed in part to offset the effect of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. The company is reviewing the potential to renegotiate the Shoshone–Bannock agreement for future years. Idaho Power intends to continue to pursue water-rental opportunities as part of its regular operations.

## Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River Basin above Milner Dam. Idaho Power has continued to work with the stakeholders in the upper Snake River to expand the program and has recently collaborated with irrigators in the Boise and Wood River Basins to expand the target to include those watersheds.

Idaho Power seeds clouds by introducing silver iodide (AgI) into winter storms. Cloud seeding increases precipitation from passing winter-storm systems. If a storm has the right combination of abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation.



Remote cloud-seeding generator.

Idaho Power uses two methods to seed clouds:

1. Remotely operated ground generators at high elevations
2. Modified aircraft burning flares containing AgI

Benefits of either method vary by storm, and the combination of both methods provides the most flexibility to successfully place AgI into passing storms. Minute water particles within the clouds freeze on contact with the AgI particles and eventually grow and fall to the ground as snow.

AgI is a very efficient ice nuclei that allows it to be used in minute quantities. It has been used as a seeding agent in numerous western states for decades without any known harmful effects (weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 28 percent annually with an annual average of 14 percent. Idaho Power estimates cloud seeding currently provides an additional 250,000 acre-feet from the upper Snake River and 269,000 acre-feet from the Payette River. At program build-out, Idaho Power estimates that additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,000,000 acre-feet. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2014 to 2015 winter season, the program included 23 remote-controlled, ground-based generators and 2 aircraft for operations in the west central mountains (Payette, Boise, and Wood River basins. The Upper Snake River Basin program included 21 remote-controlled, ground-based generators operated by Idaho Power and 25 manual, ground-based generators operated by the coalition of stakeholders in the Upper Snake. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

## Coal Facilities

### Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

### North Valmy

Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

### Boardman

Idaho Power owns 10 percent, or 64.2 MW (generator nameplate rating), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. Portland General Electric (PGE) has 90 percent ownership and is the operator of the Boardman facility.

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the EPA related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide ($SO_2$), and nitrogen oxide ($NO_x$) emissions. At the end of 2014, the net-book value of Idaho Power's share of the Boardman facility was approximately $20.9 million.

## Natural Gas Facilities

### Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens STG-5000F4 combustion turbine and one 131.5-MW Siemens SST-700/SST-900 reheat steam turbine. The Langley Gulch plant, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012.

### Danskin

Idaho Power owns and operates the 271-MW Danskin natural gas-fired SCCT facility. The facility consists of one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse

W251B12A combustion turbines. The Danskin facility is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

### Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173-MW Siemens–Westinghouse 501F natural gas-fired SCCT located east of the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant is also dispatched as needed to support system load.

### Salmon Diesel

Idaho Power owns and operates two diesel generation units in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are operated during emergency conditions, primarily for voltage and load support.

## *Solar Facilities*

In 1994, a 25-kW solar PV array with 90 panels was installed on the rooftop of Idaho Power's corporate headquarters (CHQ) in Boise, Idaho. The 25-kW solar array is still operational, and Idaho Power uses the hourly generation data from the solar array for resource planning.

Idaho Power also uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring streamflows, and operating cloud-seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program and owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events.

### Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. The majority of net metering customers use solar PV systems. As of May 1, 2015, there were 479 solar PV systems interconnected through the company's net metering service with a total capacity of 3.316 MW. At that time, the company had received completed applications for an additional 48 net metered solar PV systems representing an incremental capacity of 0.498 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.3.

**Table 3.3 Net metering service customer count and generation capacity as of May 1, 2015**

| | Number of Customers | | | Generation Capacity (MW) | | |
|---|---|---|---|---|---|---|
| **Resource Type** | **Active** | **Pending** | **Total** | **Active** | **Pending** | **Total** |
| Solar PV | 479 | 48 | 527 | 3.316 | 0.498 | 3.8140 |
| Wind | 70 | 2 | 72 | 0.557 | 0.010 | 0.5670 |
| Other/hydroelectric | 10 | – | 10 | 0.147 | 0.000 | 0.0147 |
| **Total** | 559 | 50 | 609 | – | 0.508 | 4.5280 |

### Oregon Solar Photovoltaic Pilot Program and Oregon Solar Photovoltaic Capacity Standard

In 2009, the Oregon Legislature passed Oregon Revised Statute (ORS) 757.365 as amended by House Bill 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to customers in Oregon. Under the pilot program, Idaho Power acquired 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW were allocated, and the remaining 200 kW were offered during an enrollment period in October 2011. However, because some PV systems were not completed from the 2011 enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In 2013, the Oregon Legislature passed House Bill 2893, which increased Idaho Power's required capacity amount by 55 kW. An enrollment period was held in April 2014, and all capacity was allocated, bringing Idaho Power's total capacity in the program to 455 kW.

Under the Oregon Solar PV Capacity Standard as stated in ORS 757.370, Idaho Power is required to either own or purchase the generation from a 500-kW utility-scale solar PV facility by 2020. Under the rules, if the utility-scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the State of Oregon RPS. Idaho Power does not plan to build or acquire the generation from a 500-MW solar facility in Oregon prior to 2016, as the company already has sufficient RECs to meet the Oregon RPS requirement and no near-term needs for additional generation. The company will further evaluate this requirement in the 2017 IRP and determine the best method of meeting the 2020 compliance deadline.

## *Power Purchase Agreements*

### Elkhorn Valley Wind Project

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn Valley Wind Project was constructed during 2007 and began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project.



Elkhorn Valley Wind Project, Union County, Oregon

### Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that

was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. The Raft River geothermal project has rarely exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is currently receiving negligible RECs from the Raft River project. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of all RECs generated by the project.

### Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project.

### Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

## *Public Utility Regulatory Policies Act*

In 1978, the US Congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. The acronym CSPP (cogeneration and small-power producers) is often used in association with PURPA. Individual states were tasked with establishing PPA terms and conditions, including the price each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in Idaho and the OPUC rules and regulations for all PURPA facilities located in Oregon. The rules and regulations are similar but not identical for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2015 IRP was completed in October 2014.

As of March 31, 2015, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,302 MW of nameplate capacity. These PURPA contracts are for low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities,

and various other small, renewable-power generation facilities. Of the 133 contracts, 105 were on-line as of March 31, 2015, with a cumulative nameplate rating of approximately 781 MW. Figure 3.5 shows the percentage of the total PURPA capacity of each resource type under contract.

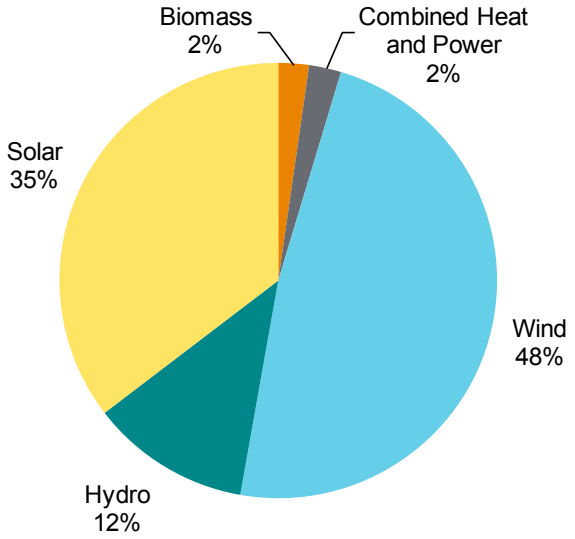



**Figure 3.5 PURPA contracts by resource type**

## Published Avoided Cost Rates

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided cost. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost rate Idaho Power is required to include in PURPA contracts. Some of the general guidelines are outlined below.

### *Published Avoided Cost Eligibility*

- *Idaho*—Wind and solar projects with a nameplate rating of less than 100 kW and all other projects with less than 10 aMW calculated on a monthly basis

- *Oregon*—All projects with a nameplate rating of less than 10 MW

For all projects not eligible for the published avoided cost rate, a unique negotiated avoided cost is calculated for each project. The basis for this negotiated avoided cost rate is the commission approved incremental cost IRP avoided cost methodology. In Idaho and Oregon, the published avoided cost is different based on the resource type (i.e. wind, solar, hydro, base load).

### *REC Ownership*

- *Idaho*—Projects that contract with Idaho Power using the published avoided cost rate will retain all RECs associated with the project. If the PURPA contract contains negotiated rates, IPUC Order No. 32697, issued December 18, 2012, stipulates the RECs will be equally shared between Idaho Power and the project owner.

- *Oregon*—The project owner retains all rights to the RECs associated with the project.

On January 30, 2015, Idaho Power filed a petition with the IPUC requesting the required contract term within new Idaho PURPA contracts be revised from 20 to 2 years. The IPUC opened case IPC-E-15-01 to address this matter, and a hearing is scheduled for June 29, 2015. IPUC Order No. 33222, issued February 6, 2015, temporarily revised the contract term from 20 to 5 years during the processing of the case.

In April 2012, the OPUC issued Order No. 12-146, which opened OPUC Docket UM 1610. Docket UM 1610 addresses many of the same PURPA issues identified in the recent Idaho PURPA cases as well as unique PURPA issues associated with Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013. This case is moving into its second and third phases, continuing to review and address numerous PURPA-related issues.

On December 18, 2012, the IPUC issued Order No. 32697. Order No. 32697 included new rules and regulations in regard to the numerous PURPA issues presented in the various cases that began in November 2010. Some highlights are as follows:

- The published avoided cost rate is available only for wind and solar projects with a nameplate rating of less than 100 kW.
- For all other resource types, the eligibility cap remains at 10 aMW.
- Idaho Power's proposed incremental cost IRP methodology was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A unique published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project owner retains the RECs associated with the project for QF contracts containing published avoided cost rates.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that contain negotiated rates.

On May 6, 2013, the IPUC issued Order No. 32802 concerning the reconsideration of Case No. GNR-E-11-03. Order No. 32802 affirms many of the commission rulings in Order No. 32697. PURPA contracting continues to be an issue in Idaho, and approximately 200 MW of various QF projects currently have some form of a filed dispute in regard to PURPA contracts with Idaho Power.

## Wholesale Contracts

Idaho Power currently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts). The Elkhorn, Raft River Geothermal, Neal Hot Springs, and Clatskanie Exchange contracts were described previously in the Power Purchase Agreements section in this chapter.

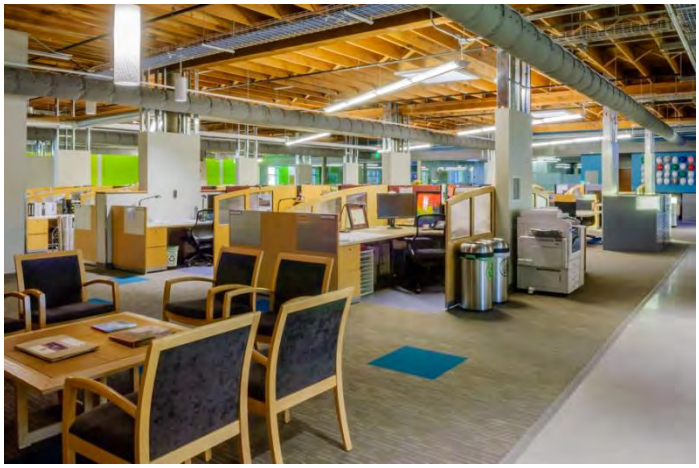
## Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power is especially dependent on the regional markets during peak-load periods, and the existing transmission system is used to import the energy purchases. A reliance on regional markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

# 4. DEMAND-SIDE RESOURCES

## Introduction

Demand-side resources have been the first resource choice in every IRP since 2004. No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. In the 2015 IRP, demand response will provide 390 MW of peak summer reduction, while energy efficiency will reduce average annual loads by 301 aMW and 473 MW of peak reduction by the year 2034.



CSHQA's new offices received the City of Boise Building Excellence awards for Best Sustainable Commercial Project and Best Overall Project for 2014. CSHQA participated in Idaho Power's Building Efficiency program.

## Demand-Side Management Program Overview

DSM programs are an essential part of Idaho Power's resource strategy, and its portfolio of programs consists of demand response, energy efficiency, and market transformation programs. The three program categories provide different system benefits. Demand response programs reduce peak loads through customer behavior or automations that respond during periods of extreme loads when all other resources, including market purchases, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side base load resources. Market transformation targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations and funded Northwest Energy Efficiency Alliance (NEEA) market transformation activities since 1997. Energy efficiency, demand response, and market transformation programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial. Education programs and services are also offered to customers to support, promote, and encourage efficiency efforts.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs to administer them along with the costs incurred by participants, are published annually. The most recent analysis can be found in the *Demand-Side Management 2014 Annual Report Supplement 1: Cost-Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their load impact over the 20-year IRP planning horizon as part of the IRP process. Additionally, in 2014 Idaho Power contracted with Applied Energy Group (AEG) to conduct an energy efficiency potential study that resulted in a forecast of energy savings over the 20-year IRP planning period. The resulting AEG forecast and program history were analyzed against the load forecast to ensure the energy efficiency

forecasted by AEG was credited with offsetting future loads. Details on the integration of the energy efficiency forecast are found in *Appendix A—Sales and Load Forecast*, *Appendix B—Demand-Side Management 2014 Annual Report*, and *Appendix C—Technical Appendix*.

## DSM Planning Changes from the 2013 IRP

Demand response and market transformation were considered differently in the 2015 IRP than the previous 2013 plan. Since market transformation was included in the 2014 AEG study, market transformation savings are considered a demand-side resource in the 2015 IRP, whereas in the past market transformation savings have been excluded from resource planning. In the 2015 IRP, demand response was treated as both a committed resource based on cost-effectiveness and as a potential new future resource addition beyond the committed resource level in select portfolios.

The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. As a consequence, Idaho Power temporarily suspended two of its three demand response programs for summer 2013 under IPUC Case No. IPC-E-12-29 and Tariff Advice No. 13-04 with the OPUC. Through IPUC Case No. IPC-E-13-14 (Order No. 32923) and OPUC Case No. UM 1653 (Order No. 13-482), Idaho Power and interested parties reached a settlement agreement to continue the company's demand response programs for 2014 and beyond.

In the 2015 IRP, 390 MW of demand response capacity are included in every portfolio, and up to an additional 60 MW are in some portfolios as needed. In 2014, these programs cost $10.6 million; had the programs been used for the maximum number of hours, the cost would have been approximately $13.8 million. These costs represent approximately $6 million dollars in savings compared to 2012 ($21.2 million) and are significantly less than the annual value of $16.7 million agreed on in the settlement agreement. Another result of the settlement was guidance on how to operate the programs in years where they may not be short-term peak capacity deficits. To maintain the engagement of participants in demand response programs, Idaho Power will conduct a minimum of three events, even when extreme loads, low water, and extreme temperatures that demand response programs were designed to meet do not occur. In addition to helping retain participants, these three events will allow Idaho Power to evaluate and improve operations of the programs. Since demand response is considered a committed resource to the company, the potential load reduction of 390 MW from demand response was applied to future peak summer loads prior to the selection of additional resources to meet future peak deficits.

Market transformation achieves energy efficiency savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improve their energy efficiency. Idaho Power achieves market transformation savings primarily through its participation in NEEA. Idaho Power has been a funding member of NEEA since its inception in 1997.

Historically, Idaho Power has treated the savings reported by NEEA separately from savings from company run and administered efficiency programs. While the company has been supporting market transformation since the regional collaborative started, the value in the

programs for Idaho Power was to promote new potential energy-savings technologies and to look for new opportunities to be adopted into Idaho Power's program offerings. Examples of this include residential energy-efficient lighting that started out as a NEEA initiative to promote compact fluorescent technologies and transitioned to utility programs across the Northwest, including Idaho Power. Another reason affecting how market transformation savings were used in resource planning was related to how savings were attributed to utilities. Until 2010, NEEA primarily apportioned savings by how much each regional funder utility contributed to their various initiatives and put very little effort into assigning savings to geographic locations. This made it difficult to count on NEEA savings that may or may not be actually reducing Idaho Power loads while reducing regional system loads.

Since 2010, NEEA has been working on and continuously improving its ability to verify savings at the service-area level of its funders through evaluation and increased data collection. This allows Idaho Power to include market transformation savings as part of the company's efforts to meet IRP energy-savings targets. Another consideration to fully integrate market transformation into the IRP is that the AEG potential study that determines the energy efficiency forecast is agnostic to where the savings for any potential measure or technology come from or who provides them. The forecasted future savings can come from market transformation efforts done on a regional basis or from a traditional utility-administered program.

## Program Screening

All DSM programs and measures included in Idaho Power's current portfolio of programs and the forecast have been screened for cost-effectiveness. Cost-effectiveness analyses of DSM forecasts for the 2015 IRP are presented in more detail in *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2014 Annual Report* contains a detailed description of Idaho Power's 2014 energy efficiency program portfolio along with historical program performance. A complete review of Idaho Power's DSM programs, evaluations, and cost-effectiveness can be found in the 2014 annual report filing, *Demand-Side Management 2014 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*, which are available on Idaho Power's website at idahopower.com/EnergyEfficiency/reports.cfm.

## DSM Program Performance

While the IRP planning process primarily looks forward, it is also important to review historical DSM performance to understand the effects on system load. Accumulated annual savings from energy efficiency investments grow over time based on measure lives of the efficient equipment and measures adopted and installed by customers each year. Additionally, past performance of demand response programs has changed over time as the design and use of the programs have evolved.

### *Energy Efficiency Performance*

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 167 aMW or over 1.4 million MWh of reduced supply-side energy production to customers through 2014. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 13-year period from 2002 through 2014, along with the associated IRP targets developed as part of the IRP process since 2004.

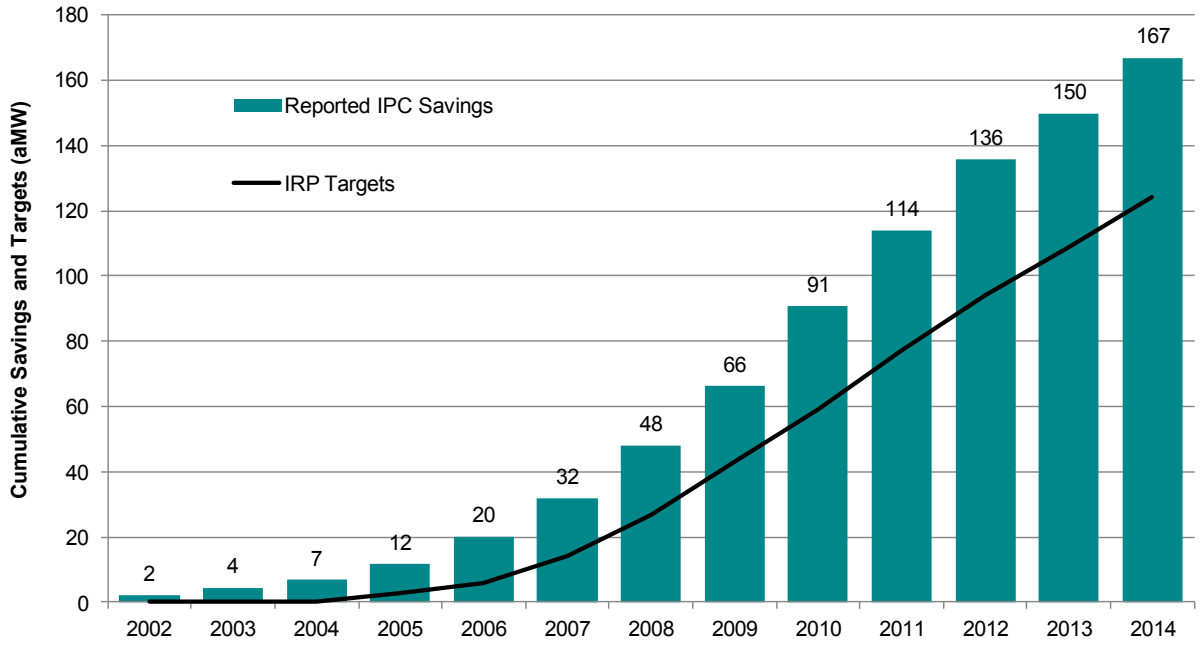



**Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW)**

## *Demand Response Performance*

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three distinct programs that work together as one resource. Each program targets a different customer class. Table 4.1 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2014 summer season, participating irrigation program customers contributed 78 percent of the total potential demand reduction, or 295 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2014 Annual Report.*

**Table 4.1 Current demand response programs 2014 performance**

| Program | Customer Class | Reduction Technology | 2014 Peak Performance (MW) | Percent of Total 2014 Peak Performance |
|---|---|---|---|---|
| A/C Cool Credit | Residential | Central A/C | 44 | 12% |
| Irrigation Peak Rewards | Irrigation | Pumps | 295 | 78% |
| FlexPeak Management | Commercial, industrial | Various | 40 | 11% |
| | | **Total** | **378** | |

Figure 4.2 shows the historical annual demand response program capacity between 2004 and 2014 along with associated IRP targets between 2004 and 2012. There were no targets for 2013 to 2014 in the 2013 IRP. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards

program to a dispatchable program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity, respectively, from the Irrigation Peak Rewards program, which was not used based on the lack of need and the variable cost to dispatch the program. The reported capacity value was lower in 2013 because of the one-year suspension of the irrigation and residential programs.

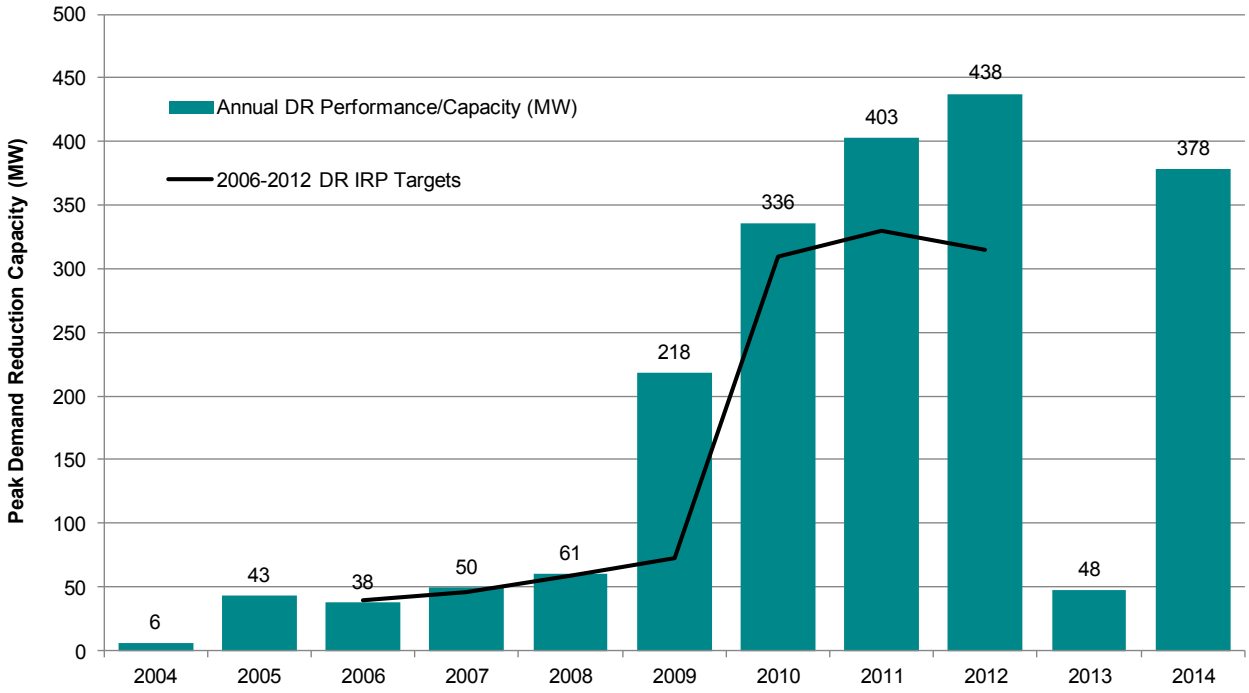



**Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW)**

## Committed Energy Efficiency Forecast

For the 2015 IRP, AEG was retained to update the previous study from 2012 and provide an updated 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the 2014 potential study were as follows:

- Incorporate the rapid changes in residential lighting potential based on the impacts from light-emitting diode (LED) lighting.
- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 20 years (2015–2034) within the Idaho Power service area.
- Assess potential energy savings and peak demand associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide a dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2015 through 2034.

Because the potential study's market characterization process bundles industries and building types into homogenous groupings, Idaho Power's special-contract customers were treated outside of the potential study model. Forecasts for these unique customers, who tend to be very active in efficiency, were based on the combined customer group's history of participation along the near-term pipeline of projected projects.

In the AEG study, the energy efficiency potential estimates represent gross savings developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described below.

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every other applicable measure available. The retrofit measures are phased in over a number of years, which is greater for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market-adoption factors to the economic potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The potential study followed a standard approach in developing the achievable potential. First, the market was characterized by customer class. The classification phase included segmenting the market by housing type for residential and understanding the various industries and building types within the commercial and industrial customer classes. Saturations of end-use technologies within customer segments are assessed to help determine which technologies are available for efficient upgrades. The next phase included screening measures and technologies for cost-effectiveness, then assessing the adoption rates of technologies to determine the forecast of achievable potential. More detailed information about cost-effectiveness methodologies and approaches can be found in *Appendix C—Technical Appendix*.

The annual savings potential forecast is provided to Idaho Power in gigawatt-hours (GWh), where it is converted to hourly, then monthly, demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are shaped by end-use load shapes that spread the forecasted savings across all hours of the year. The load shapes used to allocate savings by end-use were provided by AEG as part of the study deliverables. All reported energy efficiency and demand response forecasts are expressed at generation level and therefore include line losses of 9.6 percent for energy and 9.7 percent for peak demand to account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the meter level.

Table 4.2 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2015 to 2034 in five-year blocks in terms of cumulative average annual energy reduction (aMW) by customer class. In 2019, the forecast reduction for 2015 to 2019 programs is forecast to be 84.3 aMW; by 2024 (halfway through the planning period), the cumulative reduction across all customer classes increases to 169.4 aMW. By the end of the IRP planning horizon in 2034, 300.8 aMW of reduction are forecast to come from the energy efficiency portfolio, with 55 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed annual forecast values can be found in *Appendix C—Technical Appendix*.

**Table 4.2 Total energy efficiency portfolio forecasted effects (2015–2034) (aMW)**

| | 2015 | 2019 | 2024 | 2029 | 2034 |
|---|---|---|---|---|---|
| Industrial/commercial/special contracts | 8 | 46 | 93 | 138 | 167 |
| Residential | 3 | 28 | 55 | 85 | 111 |
| Irrigation | 1 | 11 | 22 | 23 | 23 |
| **Total*** | **12** | **84** | **169** | **246** | **301** |

*Totals may not add exactly due to rounding.

Table 4.3 shows the cost-effectiveness summary from the potential study. The table shows the NPV analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs or program benefits. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficiency technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing marginal resources.

**Table 4.3 Total energy efficiency portfolio cost-effectiveness summary**

| | 2034 Load Reduction (aMW) | 2034 Peak Load Reduction (MW) | Resource Costs ($000s) (20-Year NPV) | Total Benefits ($000s) (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs (cents/kWh) |
|---|---|---|---|---|---|---|
| Residential | 111 | 175 | $425,360 | $691,151 | 1.6 | 9.8 |
| Industrial/commercial/ special contract | 167 | 226 | $253,982 | $618,633 | 2.4 | 3.3 |
| Irrigation | 23 | 72 | $139,206 | $222,009 | 1.6 | 10.3 |
| **Total** | **301** | **473** | **$818,548** | **$1,531,793** | **1.9** | **6.1** |

The value of avoided energy over the 20-year investment in the energy efficiency measures was almost twice the TRC when comparing benefits and costs resulting in an overall benefit/cost ratio of two. The levelized cost to reduce energy demand by 301 aMW and peak demand by 473 MW is 6.1 cents per kWh from a TRC perspective.

Once the energy efficiency forecast is complete, the forecasted energy efficiency is included in the IRP planning horizon and the load and resource balance analysis. Planning assumptions in the energy efficiency potential forecast include new programs, technology, known changes to codes and standards, customer adoption behavior, and cost-effectiveness that are explicitly incorporated into the potential study and reflect differences between the energy efficiency forecast and the amount of efficiency accounted for in the load forecast. A key difference between the two views of efficiency is that the load forecast accounts for energy efficiency effects based on previous years' program performance while the forecast from the potential study is a more prospective approach. The amount of energy efficiency not captured by the load forecast trends is accounted for in the load and resource balance analysis.

## Committed Demand Response Resources

Under the current program design and participation levels, demand response from all programs is forecast to provide 390 MW of peak reduction during July throughout the IRP planning period with additional program potential available during June and August. The committed demand response included in the IRP has a capacity cost of $33 per annual kW per year.



Typical irrigation pivot supplied by a pump participating in the Irrigation Peak Rewards demand response program.

## Non-Cost-Effective DSM Resource Options

AEG provided an additional potential study analysis to model additional achievable potential that would occur if the cost-effectiveness benefit/cost ratio requirements of a TRC test were changed from the standard requirement of one or greater down to a value of 0.8. The revised assumptions in the model produced a non-cost-effective energy-savings potential of 16 aMW and 24 MW of peak reduction over the 20-year IRP planning horizon. The 20-year present value cost of the additional efficiency was determined to have a levelized cost of 9.1 cents per kWh, which is 3.0 cents higher than the 20-year levelized cost of the achievable potential within the normal parameters of the TRC test. The additional DSM amount was made available as a resource in three of the analyzed portfolios.

## Additional Demand Response

An additional 60 MW of demand response were made available for peak summer reduction in some portfolios. If Idaho Power were to pay increased incentive amounts to customers, there would be added available capacity to expand the Irrigation Peak Rewards program in future years. While the current demand response portfolio cost is $33 per kW per year, this additional demand response capacity would cost approximately $51 per kW per year. This additional demand response capacity is included in some portfolios beginning in the year 2021 and is included in the preferred portfolio in 2030.

## Energy Efficiency Working Group

On November 4, 2014, the IPUC issued Order No. 33161 (Case No. IPC-E-14-04) finding that Idaho Power's 2013 DSM expenses were prudently incurred. On November 7, 2014, the IPUC issued Errata to Order No. 33161, stating in relation to issues raised in the case:

> The Commission agrees that the issues raised by Staff and other parties are significant and warrant a more in-depth review. We direct the parties to do so in the context of the Company's next Integrated Resource Plan filing.

In response to the Errata, Idaho Power organized an Energy Efficiency Working Group inviting members of the IRPAC, public participants in the IRP process, and the Energy Efficiency Advisory Group (EEAG). The Energy Efficiency Working Group held two public meetings in December 2014.

The first Energy Efficiency Working Group meeting included a discussion of a broad range of energy efficiency and resource planning issues that can be classified into two general categories: 1) strategies related to energy-efficiency program delivery and 2) the treatment of energy efficiency in the resource planning process. The second Energy Efficiency Working Group meeting focused on how energy efficiency as a resource should be treated in the IRP. Topics discussed at the second working group meeting included the following:

- A comparison presented by AEG of potential studies from other regional utilities
- A comparison presented by IPUC staff of Idaho Power's inclusion of energy efficiency in the IRP to the inclusion of energy efficiency by other regional utilities
- An Idaho Power-led discussion of the inclusion of transmission and distribution investment deferral into the benefits in the DSM cost-effectiveness analysis.

Through correspondence with working group participants, Idaho Power expressed the view that its current treatment of energy efficiency in the resource planning process appropriately balances the need for responsible and effective resource planning and the desire to pursue all cost-effective and achievable energy efficiency. Idaho Power also recognizes that achieving those balanced objectives on an ongoing basis requires continued review and evaluation of the planning process, as well as an awareness of related industry best practices.

Idaho Power has committed to continuing to investigate the extent to which transmission and/or distribution benefits result from energy efficiency measures and programs, as well as the approximate value of such benefits. Idaho Power presented a status update of this investigation at the May 7, 2015, IRPAC meeting. In the May 7, 2015, IRPAC meeting, Idaho Power indicated the study of transmission and distribution investment deferment is ongoing. Actions to be taken as part of the ongoing study include a review of transmission and distribution investments related to growth, an evaluation of the effectiveness of energy efficiency measures and programs in deferring transmission and distribution investment, and an estimate of the deferral value for those cases with the potential for transmission and/or distribution investment deferment.

Idaho Power is also committed to continuing to discuss the program delivery issues identified by working group participants, by IPUC staff, and by some intervenors in comments filed in Case No. IPC-E-14-04. The company plans to use EEAG as the forum to provide customers, regulatory staff, and other interested stakeholders an opportunity to provide advice and recommendations to Idaho Power on formulating, implementing, and evaluating energy efficiency and demand response programs and activities.

## Conservation Voltage Reduction

The goal of conservation voltage reduction (CVR) is to reduce electrical demand and energy by minimizing the distribution feeder voltage while providing service voltage within the standard operation range. Idaho Power participated in a northwest CVR pilot and implemented CVR on a few distribution feeders. In the 2013 IRP, Idaho Power proposed to validate the energy savings and reduced peak demand of CVR using new technologies and methods of measurement. Idaho Power included the validation plan (*Conservation Voltage Reduction Enhancements Project*) in its *2014 Smart Grid Report*. The project scope includes the following:

- Validate the energy and demand savings associated with CVR at the customer level
- Quantify the costs and benefits associated with implementing CVR
- Determine methods for expanding the CVR program to additional feeders
- Pilot methods for making Idaho Power's CVR program more dynamic
- Determine methods for the ongoing measurement and validation of the CVR program's effectiveness

The CVR measurement and verification process has been identified. Idaho Power has installed the infrastructure to evaluate CVR energy savings and demand reduction at seven substations in six different weather zones. In addition, new technology has been deployed on test feeders to evaluate its effectiveness in making CVR more dynamic. Hourly customer usage data will be collected from the Advanced Metering Infrastructure (AMI) system throughout 2015. This usage data will be analyzed to determine how CVR impacts the customer classes in weather zones across Idaho Power's service area. Idaho Power expects to complete the CVR analysis in 2016. Extending CVR measures to other Idaho Power facilities will then be evaluated.

# 5. SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. As discussed in Chapter 4, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources and storage technologies considered when Idaho Power developed the resource portfolios for the 2015 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.

The primary source of cost information for the 2015 IRP is a report titled *Lazard's Levelized Cost of Energy Analysis*.[6] Lazard, a leading independent financial advisory and asset management firm, issued the levelized cost report in September 2014. Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the age of the information. For a full list of all the resources considered and cost information, see figures 7.5 and 7.6 in Chapter 7. All cost information presented is in 2015 dollars.

## Renewable Resources

Renewable resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. In the 2015 IRP, renewable resources were included in many of the portfolios analyzed as part of meeting the EPA's proposed CAA Section 111(d) regulation. Renewable resources are discussed in general terms in the following sections.

### *Solar*

The primary types of solar technology are utility-scale PV and distributed PV. In general, PV technology absorbs solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons and creates an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy is passed through an inverter, converting it to alternating current (AC) that can then be used on-site or sent to the grid. Even on cloudy days, a PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter ($m^2$) per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the desert southwest has the highest solar potential in the US.

In designing initial portfolios that included solar resources, Idaho Power chose the utility-scale PV technology because of its compliance to EPA's proposed CAA Section 111(d) regulation,

[6] Lazard. 2014. Lazard's levelized cost of energy analysis. http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.

its flexibility, and its lower overall cost. Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPSs, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2015 IRP for utility-scale PV resources is based on the 2014 Lazard report, which estimates a cost of $1,500 per kW for fixed panels and $1,750 per kW for PV with a single-axis tracking system. The 20-year levelized cost of production for fixed panels is $118 per MWh based on a 21.5-percent annual capacity factor and $109 per MWh for PV with a single-axis tracking system and a 26.8-percent annual capacity factor. In attempting to capture the decreasing cost of solar, Idaho Power used the 2017 forecast provided by Lazard of $1,250 per kW for PV with a single-axis tracking system.

To account for the decreasing cost trend seen in PV resources over the past few years, the 2015 IRP assumes solar PV costs remain fixed over the 20-year planning period. In comparison, other resource costs are escalated at 2.2 percent over the same 20 years. Therefore, in real-dollar terms, solar PV costs decline over the 20-year planning period. Idaho Power will continue to closely follow the decreasing price trend of solar PV as this technology continues to become more cost competitive with more traditional resource alternatives.

### Solar Capacity Credit

Idaho Power reviewed the solar capacity credit calculations due to comments received during the 2013 IRPAC meetings as well as comments received after filing the 2013 IRP. Idaho Power, interested members of the IRPAC, and interested members of the public formed a study group separate from the IRPAC to evaluate solar peak-hour capacity factors. The group formally met in September and October, and Idaho Power had additional informal meetings and conversations with members of the study group. Idaho Power updated the solar PV peak-hour capacity factors based on guidance from the members of the solar work group.

Idaho Power simulated solar generation for water years 2011 through 2013 as part of the solar integration study (data for the period October 1, 2010, through September 30, 2013). Idaho Power used the simulated solar generation combined with actual load data from the same time period to estimate the solar peak-hour capacity factors. In essence, the estimation used the system load data to identify the highest 150 load hours, used the simulated solar generation data to estimate the time-coincident simulated solar generation, and calculated a weighted average of the solar peak-hour capacity factor where the frequency of the hour was used as the weight in the weighted average calculation. The steps of the process are as follows:

1. Identify the 150 highest load hours from 2011 through 2013 (all are summer hours).

2. Determine the simulated solar generation during each of the 150 highest load hours. Solar generation simulation is from the Idaho Power solar integration study and is simulated at five-minute intervals at a set of utility-scale solar generation sites across Idaho Power's service area. The five-minute data was compiled into an average for the hour.

3. Group the solar generation by clock hour for the 150 highest load hours (e.g., a list of all the solar generation values for the clock hour from 2:00 p.m. to 3:00 p.m. during the 150 highest load hours).

4. Estimate the 90$^{th}$ percentile exceedance for each clock hour represented in the 150 highest load hours (among the highest 150 load hours, during the clock hour starting at xx:00, 9 times out of 10, the solar generation was simulated to be at least xx percent of the maximum possible delivered solar generation).

5. Calculate a weighted average of the solar generation for the series of clock hours; the clock hours are weighted by the proportion the clock hour is represented in the top 150 load hours.

Idaho Power used the same process for estimating fixed-panel generation systems and solar tracking generation.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to the Idaho Power system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2015 resource plan are reported in Table 5.1.

**Table 5.1 Solar capacity credit values**

| PV System Description | Peak-Hour Capacity Credit |
|---|---|
| South orientation | 28.4% |
| Southwest orientation | 45.5% |
| Tracking | 51.3% |

## Geothermal

Potential commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary-cycle technologies. Based on exploration to date in southern Idaho, binary-cycle geothermal development is more likely than flashed steam within Idaho Power's service area. The flashed steam technology requires higher water temperatures. Most optimal locations for potential geothermal development are believed to be in the southeastern part of the state; however, the potential for geothermal generation in southern Idaho remains somewhat uncertain. The time required to discover and prove geothermal resource sites is highly variable and can take years or even decades.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300º Fahrenheit (F) or greater. Binary-cycle technology is used for lower-temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low-boiling-point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine/generator. After driving the generator, the secondary fluid is

condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters used for binary-cycle geothermal generation in the 2015 IRP are based on data from independent geothermal developers and cost information from a PPA Idaho Power has with U.S. Geothermal, Inc., for the generation from the Raft River Geothermal Project located in southern Idaho. The capital-cost estimate used in the 2015 IRP for geothermal resources is $4,021 per kW, and the 25-year levelized cost of production is $101 per MWh based on a 90-percent annual capacity factor.

## *Hydroelectric*

Hydroelectric power is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. Idaho Power believes the development of new, large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydroelectric sites have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PURPA contracts with Idaho Power.

### Small Hydroelectric

Because small hydroelectric projects, such as ROR and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects, the IRPAC expressed an interest in evaluating small hydroelectric in the 2015 IRP. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital-cost estimate used in the IRP for small hydroelectric resources is $3,600 per kW, and the 75-year levelized cost of production is $159 per MWh.

### Shoshone Falls Expansion Project

In August 2006, Idaho Power filed a license amendment application with FERC to expand the Shoshone Falls Project from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The expansion project involves replacing the two smaller units with a single 50-MW unit that will result in a net expansion of 49 MW.

In July 2010, FERC issued a license amendment for the project allowing two years to begin construction and five years to complete the project. Idaho Power has received two extensions from FERC since the issuance of the license amendment. The latest extension, granted by FERC in May 2014, allows Idaho Power until July 2022 to complete the project. Construction associated with renovations at the intake structure, the new scenic flow structure, and the replacement of the gated spillway at Shoshone Falls commenced in 2014 and is scheduled to be completed in December 2015. Idaho Power continues to analyze the costs and benefits of the generator/turbine expansion segment of the project.

For the 2015 IRP, Idaho Power is considering the Shoshone Falls generator/turbine expansion a resource option. The expansion is expected to produce on average about 200 GWh annually of incremental energy above the existing power plant configuration, with nearly 75 percent of the incremental energy occurring during the January through June period. The incremental energy is assumed to be REC eligible. A cost-benefit analysis of the generator/turbine expansion is provided in Chapter 9.

### Wind

A typical wind project consists of an array of wind turbines ranging in size from 1 to 3 MW each. The majority of potential wind sites in southern Idaho lie between the south-central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles per hour are prime locations for wind development.

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain regions, as evidenced by the number of existing projects. Wind resources present a problem for utilities due to the variable and intermittent nature of wind generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2015 IRP, Idaho Power used an annual average capacity factor of 28 percent and a capacity factor of 5 percent for peak-hour planning. The capital-cost estimate used in the IRP for wind resources is $1,800 per kW, and the 25-year levelized cost of energy is $135 per MWh, which includes a wind integration cost of $15.39 per MWh.

### Biomass

Biomass resource types considered in the 2015 IRP include wood-burning resources and anaerobic digesters. Wood burning resources typically rely on a steady supply of woody residue collected from forested areas. Therefore, fuel supply can be an issue for these types of plants as the radius of the area used to collect fuel is expanded. Several anaerobic digesters have been built in southern Idaho due to the size of the dairy industry and the quantity of fuel available. However, these digesters are limited in size and would be difficult to develop on a utility scale.

The capital-cost estimate used in the IRP for a 35-MW wood-burning biomass project is $2,622 per kW, and $4,761 per kW for a 3-MW anaerobic digester project. The wood-burning unit is expected to have an annual capacity factor of 85 percent, while the anaerobic digester is expected to operate at 75 percent. Based on the annual capacity factors, the 30-year levelized cost of production is $102 per MWh for the wood-burning unit and $119 per MWh for the anaerobic digester.

## Conventional Resources

While much attention has been paid to renewable resources over the past few years, conventional generation resources continue to be needed to provide dispatchable capacity, which is critical in maintaining the reliability of an electrical system. These conventional generation technologies include natural gas-fired resources, nuclear, and coal.

## Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine to generate electricity. CCCTs are typically used for baseload energy, while less-efficient SCCT are used to generate electricity during peak-load periods. Additional details on the characteristics of both types of natural gas resources are presented in the following sections.

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2015 IRP assumes new natural gas resources would require building additional pipeline capacity. This additional cost is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

### Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits fewer emissions when compared to coal, therefore requiring fewer pollution controls.

A traditional CCCT plant consists of a gas turbine/generator equipped with a heat recovery steam generator (HRSG) to capture waste heat from the turbine exhaust. The HRSG uses waste heat from the combustion turbine to drive a steam-turbine generator to produce additional electricity. In a CCCT plant, heat that would otherwise be wasted is used to produce additional power beyond that typically produced by an SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined-cycle units by adding an HRSG.

Several CCCT plants, similar to Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the IRP for a CCCT resource is $1,145 per kW, and the 30-year levelized cost of production at a 70-percent annual capacity factor is $79 per MWh.

### Simple-Cycle Combustion Turbines

Simple-cycle, natural gas-turbine technology involves pressurizing air that is then heated by burning gas in fuel combustors. The hot, pressurized air expands through the blades of the turbine that connects by a shaft to the electric generator. Designs range from larger, industrial machines at 80 to 200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are not typically economical to operate other than to meet peak-hour load requirements.

Several natural gas-fired SCCTs have been brought on-line in the region in recent years, primarily in response to the regional energy crisis of 2000–2001. High electricity prices combined with persistent drought conditions during 2000–2001, as well as continued summertime peak load growth, created interest in generation resources with low capital costs and relatively short construction lead times.

Idaho Power currently has approximately 430 MW of SCCT capacity. As peak summertime electricity demand continues to grow within Idaho Power's service area, SCCT generating resources remain a viable option to meet peak load during critical high-demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest.

The 2015 IRP evaluated two SCCT technologies: 1) a 47-MW small, aeroderivative unit and 2) a 170-MW industrial-frame unit. The capital-cost estimate used in the IRP for the small, aeroderivative unit is $1,000 per kW, and an industrial-frame unit is $800 per kW. Both the aeroderivative unit and the industrial-frame unit are expected to have an annual capacity factor of 10 percent.

Based on the annual capacity factor, the 35-year levelized cost of production is $250 per MWh for the small, aeroderivative unit and $219 per MWh for the industrial-frame unit. These levelized costs are close to the same as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If needed, Idaho Power would evaluate these two technologies in greater detail prior to issuing a request for proposal (RFP) to determine which technology would provide the greatest benefit.

### Reciprocating Engines

Reciprocating engine generation sets are typically natural gas-fired engines connected to a generator through a flywheel and coupling. Because they are mounted on a common baseframe, the entire unit can be assembled, tuned, and tested in the factory before being delivered to the power plant location, which minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple, identical units, which allows each unit to run at its best efficiency point once started. As more generation is needed, additional units are started. This configuration also allows for relatively inexpensive future expansion of the plant capacity.

For the IRP, Idaho Power modeled a reciprocating engine similar to the 34SG model manufactured by Wärtsilä with a nameplate rating of 18.8 MW. The capital-cost estimate used for a reciprocating engine resource is $500 per kW, and the 40-year levelized cost of production at a 10-percent annual capacity factor is $136 per MWh.

### Combined Heat and Power

Combined heat and power (CHP), or cogeneration, typically refers to simultaneous production of both electricity and useful heat from a single plant. CHP plants are typically located at, or near, commercial or industrial facilities capable of using the heat generated in the process. These facilities are sometimes referred to as a steam host. Generation technologies frequently used in CHP projects are gas turbines or engines with a heat-recovery unit.

The main advantage of CHP is that higher overall efficiencies can be obtained because the steam host is able to use a large portion of the waste heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, building additional transmission capacity can also often be avoided. In addition, reduced costs

for the steam host provide a competitive advantage that would ultimately help the local economy.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different.

Recognizing the actual cost of a CHP resource may vary depending on the specific facility being considered, the capital-cost estimate used in the IRP for CHP is $2,123 per kW, and the 40-year levelized cost of production evaluated at an annual capacity factor of 80 percent is $81 per MWh.

## Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for some time, and Idaho Power has continued to evaluate various technologies in the IRP. Due to the Idaho National Laboratory (INL) site in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor could be built on the site. For the 2015 IRP, high capital costs coupled with a great amount of uncertainty in waste disposal issues prevented a nuclear resource from being included in the portfolio analysis. In addition, the recent earthquake and tsunami in Japan, and the impact on the Fukushima nuclear plant, created a global concern over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to know the full impact this disaster will have on the future of nuclear power generation.

For the 2015 IRP, a 1,100-MW advanced nuclear resource and a 600-MW small modular plant were analyzed; however, for both types of plants, it was assumed that Idaho Power would only be a part owner in either type of facility by taking 250 MW of the total plant capacity. The capital-cost estimate used in the IRP for an advanced nuclear resource is $4,350 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 90 percent, is $119 per MWh. For the small modular reactor technology, the capital-cost estimate is $5,000 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 95 percent, is $343 per MWh.

## Coal Resources

Conventional coal resources have been a part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over global warming and climate change have made it impractical to consider building any new conventional coal resources; however, integrated gasification combined cycle (IGCC) and IGCC coupled with carbon sequestration are two technologies that were still evaluated in the IRP.

IGCC is an evolving coal-based technology designed to substantially reduce $CO_2$ emissions. As the regulation of $CO_2$ emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of the country's coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow $CO_2$ to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or "syngas" that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

The addition of $CO_2$-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. $CO_2$ has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of $CO_2$ produced would require the development of underground sequestration methods.

Carbon sequestration involves taking captured $CO_2$ and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. The capital-cost estimate used in the IRP for IGCC is $3,257 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $116 per MWh. The capital-cost estimate used for IGCC with carbon sequestration is $6,390 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 75 percent, is $184 per MWh.

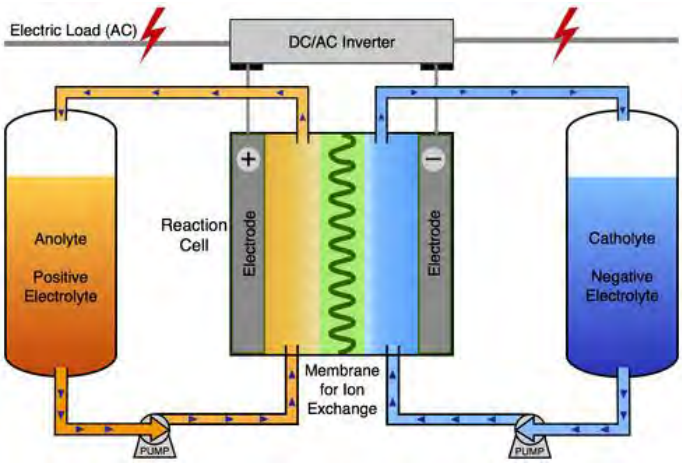
## Storage Technologies

RPSs have spurred the development of renewable resources in the Pacific Northwest to the point where there is an oversupply of energy. Recently, Mid-Columbia wholesale market prices for electricity are typically one-third to one-half lower than just a few years ago. At the same time, retail rates for electricity continue to grow as utilities have to pass the cost of building these resources on to customers. The oversupply issue has grown to the point where at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to go negative.

As more intermittent renewable resources like wind and solar continue to be built within the region, the need for energy storage is amplified. While there are many storage technologies at various stages of development, such as hydrogen storage, compressed air, and flywheels, the 2015 IRP considered and evaluated three specific storage technologies: 1) battery storage, 2) ice-based TES, and 3) pumped storage.

## Battery Storage

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery storage technologies at various stages of development. The 2015 IRP focused on one specific type of battery technology; the vanadium redox-flow battery (VRB).




Basic illustration of a flow battery.[7]

Advantages of the VRB technology include its low cost, long life, and easy scalability to utility/grid applications. Most battery technologies are not a good fit for utility-scale applications because they cannot be easily or economically scaled to much larger sizes. The VRB overcomes much of this issue because the capacity of the battery can be increased just by increasing the size of the tanks that contain the electrolytes, which also helps keep the cost relatively low.

VRB technology also has an advantage in maintenance and replacement costs, as only certain components need replaced about every 10 years, whereas other battery technologies require a complete replacement of the battery and more frequently depending on how they are used. For the IRP, the capital-cost estimate for the VRB is $3,000 per kW, and the 10-year levelized cost of production, evaluated at an annual capacity factor of 25 percent, is $240 per MWh.

## Ice-Based Thermal Energy Storage

Ice-based TES is a concept developed to take advantage of the A/C needs of mid-sized to large commercial buildings. The general concept is to create ice during low-load/low-price times (light load hours), then to use the ice for A/C needs during the high-load/higher-price times (heavy load hours). While this concept does not specifically store electricity, it does shift the time the energy is consumed, with the overall goal of reducing peak daytime demand.

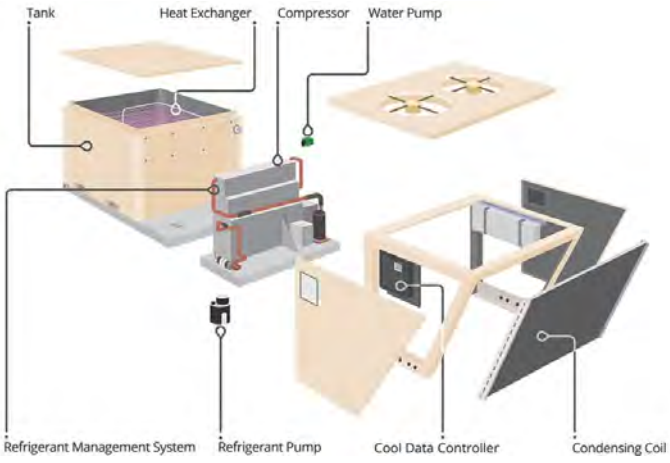



Illustration of an ice-based TES system.[8]

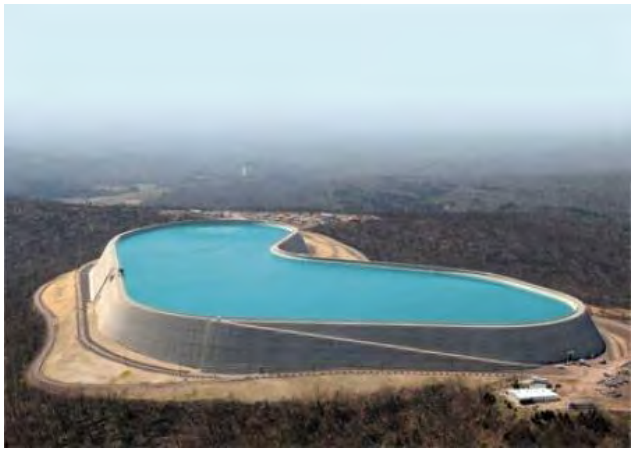
[7] Source: http://strategy.sauder.ubc.ca/antweiler/blog.php?item=2014-09-28.

[8] Source: http://www.ice-energy.com/technology/ice-bear-energy-storage-system.

One company currently commercializing the ice-based TES technology is Ice Energy with their *Ice Bear Energy Storage System*. Requirements in California to develop energy storage have allowed several utilities to begin installing and testing this technology, with several installations of 5 MW to 15 MW in size. For the IRP, the capital-cost estimate used for this technology is $1,500 per kW, and the 20-year levelized cost of production, evaluated at an annual capacity factor of 10.4 percent, is $224 per MWh.

## Pumped Storage

Pumped storage is a type of hydroelectric power generation used to change the "shape" or timing when electricity is produced. The technology stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.



Pumped-storage facility.[9]

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change. The capital-cost estimate used in the IRP for pumped storage is $5,000 per kW, and the 50-year levelized cost of production is $346 per MWh.

[9] Source: http://www.renewableenergyworld.com/rea/news/article/2010/10/worldwide-pumped-storage-activity.

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# 6. TRANSMISSION PLANNING

## Past and Present Transmission



Idaho Power's double-circuit 230-kilovolt (kV) transmission line traversing Hells Canyon.

High-voltage transmission lines are vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that serve the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three coal-fired power plants located in neighboring states that supply approximately one-third of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric and intermittent resources with access to wholesale energy markets.

Idaho Power's regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of the difference in peak seasons, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load, and Idaho Power sells excess energy to Pacific Northwest utilities during the winter and spring. New regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers through the following:

- The construction of additional peaking resources to serve summer peak load is delayed or avoided.
- Revenue from off-system sales during the winter and spring is credited to customers through the PCA.
- Revenue from others' use of the transmission system is credited to Idaho Power customers.
- System reliability is increased.
- Capacity is added to help integrate intermittent resources, such as wind and solar.
- Flexibility is provided to respond to the proposed CAA Section 111(d) requirements.
- The ability to more efficiently implement advanced market tools, such as EIMs or SCED.

# Transmission Planning Process

In recent years, FERC mandated several aspects of the transmission planning process. FERC Order No. 1000 requires Idaho Power to participate in transmission planning on a local, regional, and interregional basis, as described in Attachment K of the Idaho Power Open-Access Transmission Tariff (OATT) and summarized in the following sections.

## *Local Transmission Planning Process*

The expansion planning of Idaho Power's transmission network occurs through a local-area transmission advisory process and the biennial local transmission planning process.

### Local-Area Transmission Advisory Process

Idaho Power develops long-term, local-area transmission plans with community advisory committees. The community advisory committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for the full development of the area. The plans account for land-use limits and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for the following five load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Treasure Valley
5. West Central Mountains

Recently, the *Treasure Valley Electric Plan* was divided into two plans:

1. *Western Treasure Valley Electrical Plan*—The western plan was completed in 2011 and encompasses Malheur County in Oregon and Canyon, Gem, Owyhee, Payette, and Washington counties in Idaho.
2. *Eastern Treasure Valley Electric Plan*—The eastern plan was completed in 2012 and encompasses all or portions of Ada, Elmore, and Owyhee counties in Idaho.

### Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the planned supply-side resources identified in the IRP process, the transmission upgrades identified in the local-area transmission advisory process, the forecasted network customer load (e.g., Bonneville Power Administration [BPA] customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and third-party transmission customer requirements. By identifying potential resources,

potential resource locations, and load-center growth, the required transmission system capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

### *Regional Transmission Planning*

Idaho Power is active in regional transmission planning through the Northern Tier Transmission Group (NTTG). The NTTG was formed in early 2007 to improve the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). Biennially, the NTTG develops a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers.

### *Interconnection-Wide Transmission Planning*

The WECC Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three functions:

1. Oversee data management for the western interconnection.
2. Provide policy and management of the planning process.
3. Guide the analyses and modeling for Western Interconnection economic transmission expansion planning.

In addition to providing the means to model the transmission implications of various load and resource scenarios at an interconnection-wide level, the TEPPC coordinates planning between transmission owners, transmission operators, and regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. WECC activities include resource adequacy analyses and corresponding North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission line rating process.

## Existing Transmission System

Idaho Power's transmission system extends from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

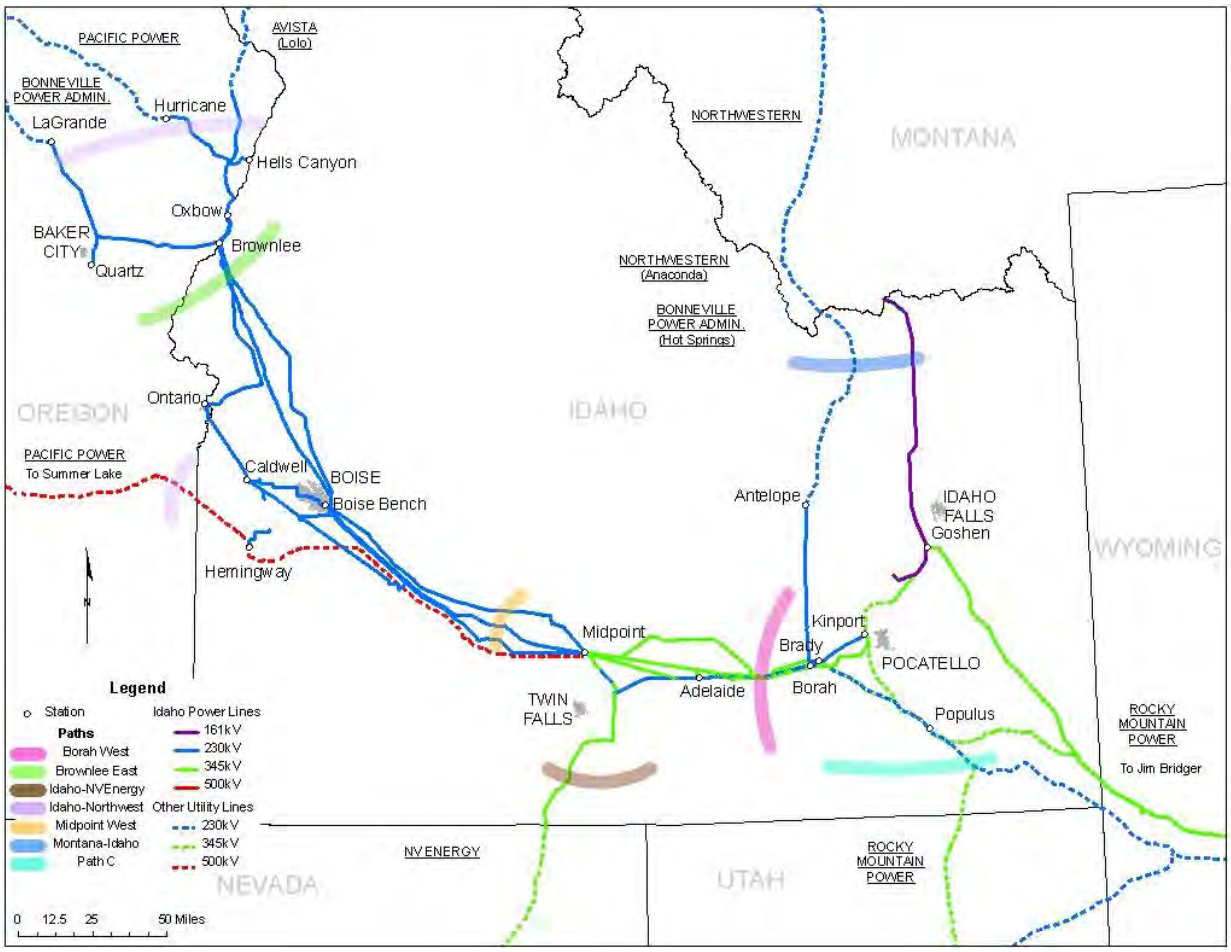



**Figure 6.1 Idaho Power transmission system map**

The transmission paths identified on the map are described in the following sections, along with the conditions that result in capacity limitations.

## Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney Substation near Burns, Oregon. The Idaho–Northwest path is capacity-limited during summer months due to transmission-wheeling obligations for the BPA eastern Oregon and southern Idaho load and due to energy imports from the Pacific Northwest to serve Idaho Power retail load. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's service area.

## Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the

Brownlee East Total path. The capacity limitation on the Brownlee East transmission path occurs between Brownlee and the Treasure Valley.

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the HCC as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

## Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy south from Montana into Idaho.

## Borah West Path

The Borah West transmission path is internal to the Idaho Power system. The path is comprised of 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation located near American Falls, Idaho. Idaho Power's one-third share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric energy and energy imports from Montana, Wyoming, and Utah. PacifiCorp's two-thirds share of energy from the Jim Bridger plant also flows across this path to load centers in the Pacific Northwest. The Borah West path is capacity-limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production move east to west across the system to the Pacific Northwest. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Borah West path.

## Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. The Midpoint West path is capacity-limited due to east-side Idaho Power resources, PURPA resources, and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

## Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the North Valmy Power Plant was built in northern Nevada. Idaho Power is allocated

100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

### Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

### Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path owner and operator of all of the transmission lines. The path effectively feeds into Idaho Power's Borah West path when power is moving from east to west; consequently, the import capability of Path C is limited by Borah West path capacity limitations.

**Table 6.1 Available transmission import capacity**

| | Total Transmission Capacity* | | |
|---|---|---|---|
| **Transmission Path** | **Import Direction** | **Capacity (MW)** | **ATC (MW)**** |
| Idaho–Northwest | West to east | 1,200 | 0 |
| Idaho–Nevada | South to north | 262 | 0 |
| Idaho–Montana | North to south | 383 | 0 |
| Brownlee East | West to east | 1,915 | 0 |
| Midpoint West | East to west | 1,027 | 0 |
| Borah West | East to west | 2,557 | 0 |
| Idaho–Wyoming (Bridger West) | East to west | 2,400 | 60 |
| Idaho–Utah (Path C) | South to north | 1,250 | 0*** |

*Total transmission capacity and available transmission capacity (ATC) as of April 1, 2015.

** The ATC of a specific path may change based on changes in the transmission service and generation interconnection request queue (i.e., the end of a transmission service, granting of transmission service, or cancelation of generation projects that have granted future transmission capacity).

***Idaho Power-estimated value; actual ATC managed by PacifiCorp.

## Boardman to Hemingway

In the 2006 IRP process, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a line interconnecting at the McNary Substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including different terminus locations and sizing the project to economically meet projected demand. The project identified in 2006 has evolved into what is currently the B2H project. The project currently involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long

between the proposed Longhorn Station in the Boardman, Oregon, area and the Hemingway Substation in southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and reduced capacity limitations on the regional transmission system as demands on the system continue to grow
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon
- Flexibility to integrate renewable resources, respond to pending carbon legislation and more efficiently implement advanced market tools
- Flexibility to respond to the proposed CAA Section 111(d) requirements

The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, and 2013 IRPs.

In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the B2H project. Table 6.2 shows each party's B2H capacity and permitting cost allocation.

**Table 6.2 B2H capacity and permitting cost allocation**

| | Idaho Power | BPA | PacifiCorp |
|---|---|---|---|
| Capacity (MW) west to east ..... | 350<br>200 winter/500 summer | 400<br>550 winter/250 summer | 300 |
| Capacity (MW) east to west ..... | 85 | 97 | 818 |
| Permitting cost allocation ..... | 21% | 24% | 55% |

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the B2H project.

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), the US Forest Service (USFS), and the Oregon Department of Energy (ODOE). The federal permitting process is dictated primarily by the *Federal Land Policy Management Act* and *National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On December 19, 2014, BLM published the Draft Environmental Impact Statement (Draft EIS). Figure 6.2 shows the proposed transmission line routes included in the Draft EIS with the agency preferred route. Idaho Power expects the BLM to issue a Final EIS in 2016.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE as part of the state siting process. Idaho Power intends to submit an amended pASC in late 2015 or 2016.

In light of the permitting delays and siting impediments that have occurred and may occur, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2021 or beyond. Additional project information is available at boardmantohemingway.com.

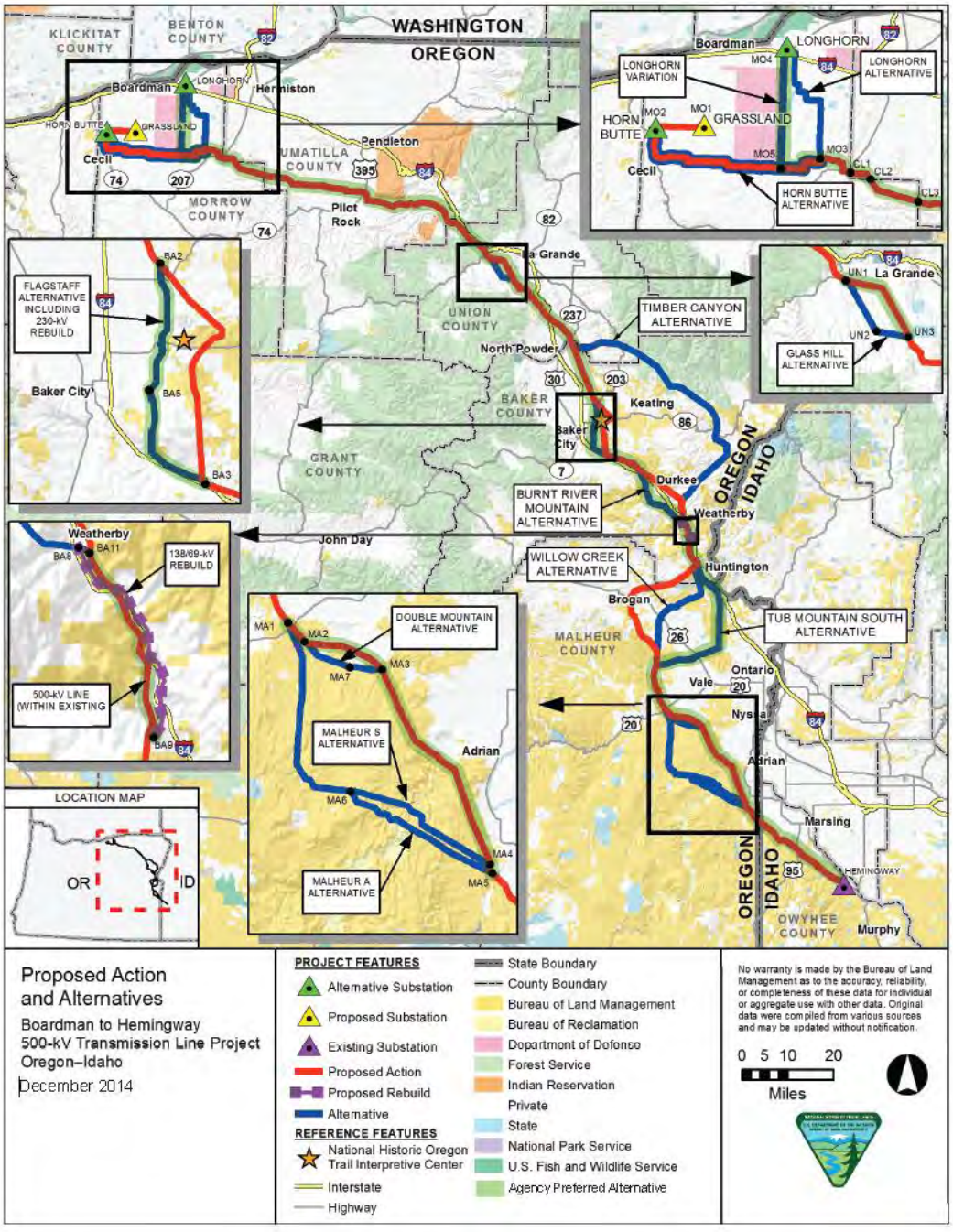



**Figure 6.2 B2H routes with the agency-preferred alternative**

# Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho. Rocky Mountain Power has been designated the permitting project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 6.3 shows a map of the project identifying the routes studied in the federal permitting process and depicts the BLM's preferred route. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint (segment 6), which is an existing transmission line operated at 345-kV but constructed at 500-kV.




**Figure 6.3 Gateway West Map**

The Gateway West project will provide many benefits to Idaho Power customers, including the following:

1. Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's "core" transmission system, connecting two major Idaho Power load pockets.

2. Provide the option to locate future generation resources east of the Treasure Valley.

3. Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation.

4. Transmission capability is needed to meet the transmission needs of the future, including transmission needs associated with intermittent resources.

Phase 1 of Gateway West is expected to provide up to 1,500 MW of additional transfer capacity between Midpoint and Hemingway. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Idaho Power has a one-third interest in these capacity additions.

The two transmission projects, B2H and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah.

Under the federal permitting process established by NEPA, the BLM has completed the EIS for all segments of the Gateway West project except segment 8 (Midpoint to Hemingway) and segment 9 (Cedar Hill to Hemingway). The BLM is conducting a supplemental environmental analysis on these two segments. A final record of decision for these two segments is expected by late 2016, subject to permitting completion.

More information about the Gateway West project can be found at gatewaywestproject.com.

## Gateway West Need Analysis

Idaho Power has two internal transmission paths between the Magic Valley and Treasure Valley:

- Boise East
- Midpoint West

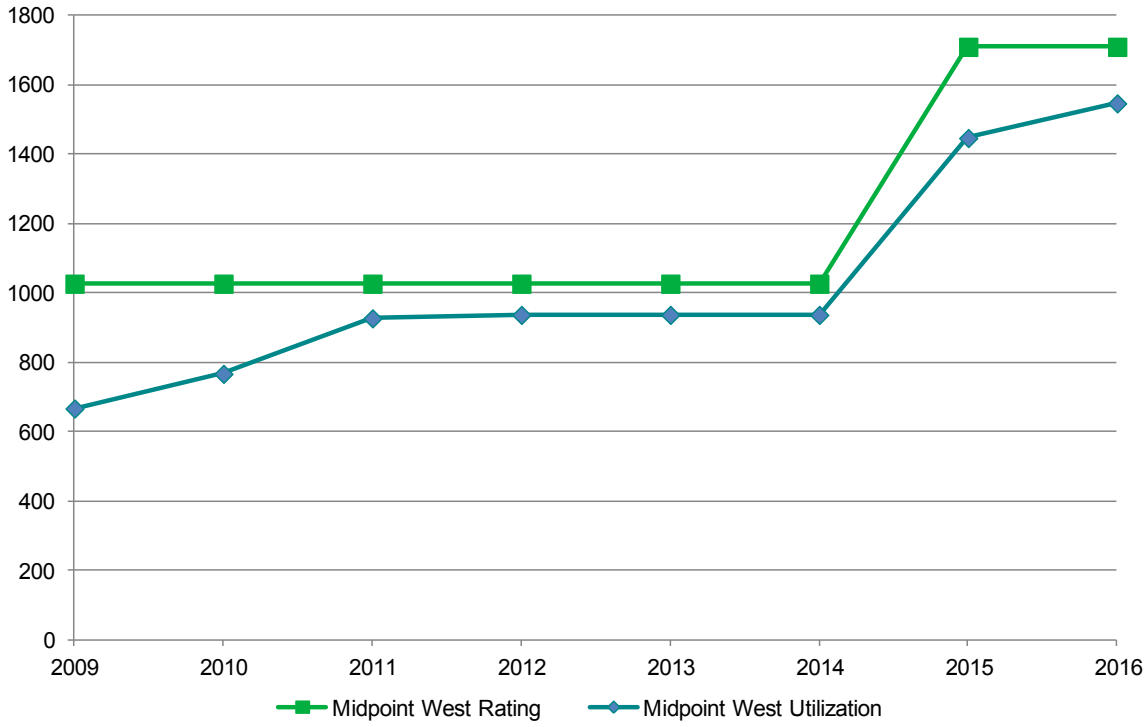
The Boise East transmission path consists of 230-kV, 138-kV and 69-kV transmission lines connecting the Mountain Home area to the Boise/Nampa/Caldwell area. This transmission path is currently being studied due to large amounts of solar generation proposed to be sited in and around the Mountain Home area. Gateway West will increase the capability of the Boise East path.

The Midpoint West transmission path consists of 230-kV and 138-kV transmission lines connecting the Magic Valley area to the Mountain Home area. The Midpoint West transmission path has a rating of 1,027 MW which will increase to 1,710 MW following two initiatives currently underway:

1. Idaho Power will expand the Midpoint West rating from 1,027 MW to 1,300 MW through incremental upgrades to existing transmission assets (230 kV and below). These upgrades are expected to be in service by the end of 2015.

2. Idaho Power has made arrangements to acquire an ownership share of the PacifiCorp-owned Midpoint–Hemingway 500-kV line, pending regulatory approval. Idaho Power's ownership share will equate to 410 MW of the 1,500-MW line rating. This is expected to be finalized by the end of 2015.

Over the past several years, Idaho Power's use of the Midpoint West transmission path has steadily increased. Figure 6.4 illustrates this increasing use.




**Note**: Large increases to the use of Midpoint West occurred in 2010 (PURPA Wind), 2011 (PURPA Wind), and 2015 (third-party transmission service). Use is also projected to increase in 2016 with the interconnection of 100 MW of solar in eastern Idaho.

**Figure 6.4 Midpoint West Historical Utilization**

The Midpoint West path will continue to be constrained following the upgrades described above. As the Boise East and Midpoint West paths become further used, Idaho Power will continue to invest in new transmission facilities to reinforce the transmission system. Gateway West is the planned upgrade that will increase the capability of the Midpoint West path.

## Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 6.3.



The Hemingway Substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

**Table 6.3 Transmission assumptions**

| Resource Type | Geographic Area | Resource Levels (incremental amounts) | Additional Transmission Requirements |
|---|---|---|---|
| B2H line | Hemingway Substation | 500 MW (summer)/ 200 MW (winter) | New 230-kV line from Hemingway to the Treasure Valley. |
| Gas turbine (SCCT) | Elmore County | 170 MW | New 230-kV substation and new 230-kV line to the Treasure Valley. |
| Gas turbine (CCCT) | Elmore County | 300 MW | New 230-kV substation and new 230-kV line to the Treasure Valley. |
| CHP | Canyon County | 45 MW | New 138-kV substation and new 138-kV line to existing 138-kV system. |
| Geothermal | Cassia County | 30 MW | New 138-kV line from resource to existing 138-kV substation. |
| Reciprocating engines | Distributed | 18 MW | No new transmission. New distribution upgrades assumed for each engine location. |
| PV | Elmore/Owyhee County | 10 MW | New 138-kV substation and new 138-kV line to existing 138-kV system. |
| Pumped storage hydro | Above Brownlee Reservoir | 300 MW | New 230-kV line from Oxbow to Treasure Valley, new 138-kV tap from site to existing 138-kV system. |

The assumptions about the geographic area where particular supply-side resources are developed determine the transmission upgrades required.

# 7. Planning Period Forecasts

The IRP process requires Idaho Power to prepare numerous forecasts and estimates, which can be grouped into four main categories:

1. Load forecasts
2. Generation forecast for existing resources
3. Natural gas price forecast
4. Resource cost estimates



Forecasting load growth is essential for Idaho Power to meet future needs of customers.

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2015 IRP.

## Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and A/C in June, July, and August. For a number of years, the growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. However, both measures are important in planning future resources and are part of the load forecast prepared for the 2015 IRP.

The expected case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future retail electricity sales will not precisely follow the path suggested by the expected case forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with abnormal weather. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecasts were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The sales forecast is heavily influenced by the most recent economic forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2014 macroeconomic forecast strongly influenced the 2015 IRP load forecast results. The national, state, metropolitan statistical area (MSA) and county economic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., are also used in developing the 2015 IRP load forecast. The forecasts of

households, population, employment, output, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

## Weather Effects

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50-percent chance loads will be higher or lower than the expected-case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were analyzed to address load variability due to weather—70$^{th}$-percentile and 90$^{th}$-percentile load forecasts. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal basis. Over the longer-term, economic conditions, demographic conditions, and changing technologies influence the load forecast.

## Economic Effects

The national recession that began in 2008 affected the local economy and energy use in Idaho Power's service area. The severity of the recession resulted in a decline in new customer growth. Idaho Power added less than 2,500 new residential customers in 2011. Recently, the number of new residential customers added each year has increased to over 6,500.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by a 0.9-percent decline in 2010 and a slight decline in 2011. The 2009 through 2011 time period was the first time overall energy use had declined since the energy crisis of 2000 to 2001. In 2012, 2013, and 2014, system electricity sales increased by 1.7 percent, 0.5 percent, and 1.0 percent, respectively. The sales increases were due to economic recovery in the service area and higher irrigation sales.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period, and the population increase is included in the load forecast models. Idaho Power also continues to receive requests from prospective large-load customers attracted to southern Idaho due to the positive business climate and relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of residential customers in Idaho Power's service area is expected to increase 1.6 percent annually from 428,000 at the end of 2014 to nearly 591,000 by the end of the planning period in 2034. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.3-percent average residential load-growth rate.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*. For example, the expected annual average system load growth of 1.2 percent (over the period

2015 through 2034) is comprised of a residential load growth of 1.3 percent, a commercial load growth of 1.0 percent, an irrigation load growth of 0.5 percent, an industrial load growth of 2.0 percent, and an additional firm load growth of 0.6 percent.

The 2015 IRP average annual system load forecast reflects the continued improvement in the service-area economy. While economic conditions during the development of the 2013 IRP were positive, they were less optimistic than the actual performance experienced in the interim period leading up to the 2015 IRP. The improved economic and demographic variables driving the 2015 forecast are reflected by a more positive sales outlook throughout the planning period. The stalled recovery in the national and, to a lesser extent, service area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic time series. Retail electricity price projections for the 2015 IRP are lower relative to the 2013 IRP, serving to increase the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2015 IRP load forecast include the following:

- The load forecast used for the 2015 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, since 2011, residential and commercial customer growth along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2017, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions assumed for the 2013 IRP. When compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yields lower future prices. The retail prices are most evident in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand

response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the entire forecast period due to the significant growth in the dairy industry, higher commodity prices, and changing crop-planting patterns. Following the dairy industry growth, there has been a trend toward more water-intensive crops, primarily alfalfa and corn. Farmers have also taken advantage of the commodities market by planting increasing levels of acreage. Additionally, the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

- Updated loss factors were determined by Idaho Power's Customer Operations Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that, on average, the loss coefficients are lower than those used in the 2013 IRP. This resulted in a permanent reduction of nearly 20 aMW to the load forecast annually.

## Peak-Hour Load Forecast

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts. Idaho Power uses the 95$^{th}$-percentile forecast as the basis for peak-hour planning in the IRP. The 95$^{th}$-percentile forecast is based on the 95$^{th}$-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,407 MW—was recorded on July 2, 2013, at 4:00 p.m. The previous summer peak demand record was 3,245 MW on July 12, 2012, at 4:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011, the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also had a significant effect on reducing peak demand. The 2015 IRP load forecast projects peak-hour load to grow by approximately 63 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance as a supply-side resource.

Figure 7.1 and Table 7.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90$^{th}$ percentile, and 95$^{th}$ percentile. The 95$^{th}$-percentile forecast uses the 95$^{th}$-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

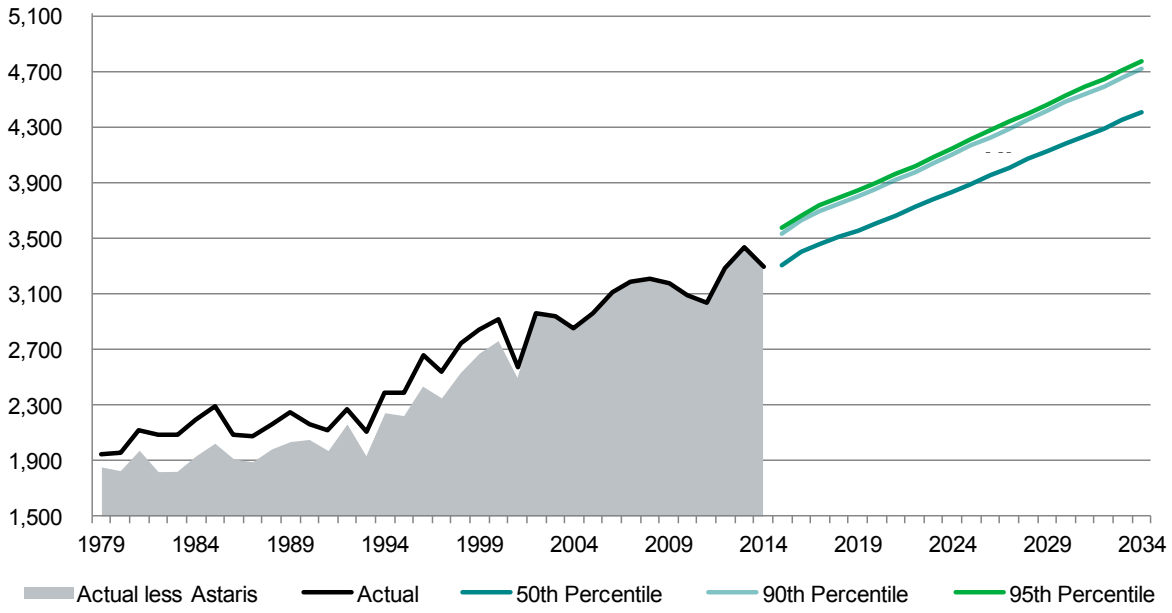



**Figure 7.1 Peak-hour load-growth forecast (MW)**

**Table 7.1 Load forecast—peak hour (MW)**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2014 (Actual) | 3,184 | 3,184 | 3,184 |
| 2015 | 3,313 | 3,537 | 3,576 |
| 2016 | 3,401 | 3,630 | 3,669 |
| 2017 | 3,463 | 3,696 | 3,736 |
| 2018 | 3,514 | 3,752 | 3,793 |
| 2019 | 3,562 | 3,805 | 3,847 |
| 2020 | 3,615 | 3,862 | 3,905 |
| 2021 | 3,670 | 3,922 | 3,965 |
| 2022 | 3,725 | 3,981 | 4,026 |
| 2023 | 3,780 | 4,041 | 4,086 |
| 2024 | 3,839 | 4,105 | 4,151 |
| 2025 | 3,897 | 4,168 | 4,215 |
| 2026 | 3,956 | 4,231 | 4,278 |
| 2027 | 4,013 | 4,293 | 4,341 |
| 2028 | 4,071 | 4,355 | 4,404 |
| 2029 | 4,130 | 4,419 | 4,469 |
| 2030 | 4,187 | 4,481 | 4,531 |
| 2031 | 4,242 | 4,540 | 4,592 |
| 2032 | 4,296 | 4,599 | 4,651 |
| 2033 | 4,352 | 4,659 | 4,713 |
| 2034 | 4,407 | 4,719 | 4,773 |
| **Growth rate (2015–2034)** | **1.5%** | **1.5%** | **1.5%** |

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,313 MW in 2015 to 4,407 MW in 2034—an average annual compound growth rate of 1.5 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.5 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,576 MW in 2015 to 4,773 MW in 2034. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 7.1.

Idaho Power's winter peak-hour load record is 2,528 MW, recorded on December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

## Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 7.2 and Table 7.2 show the results of the three forecasts used in the 2015 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70th-percentile forecast, and a 10-percent probability of exceeding the 90th-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 1.2 percent.

Idaho Power uses the 70th-percentile forecast as the basis for monthly average-energy planning in the IRP. The 70th-percentile forecast is based on 70th-percentile weather to forecast average monthly load, 70th-percentile water to forecast hydroelectric generation, and 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

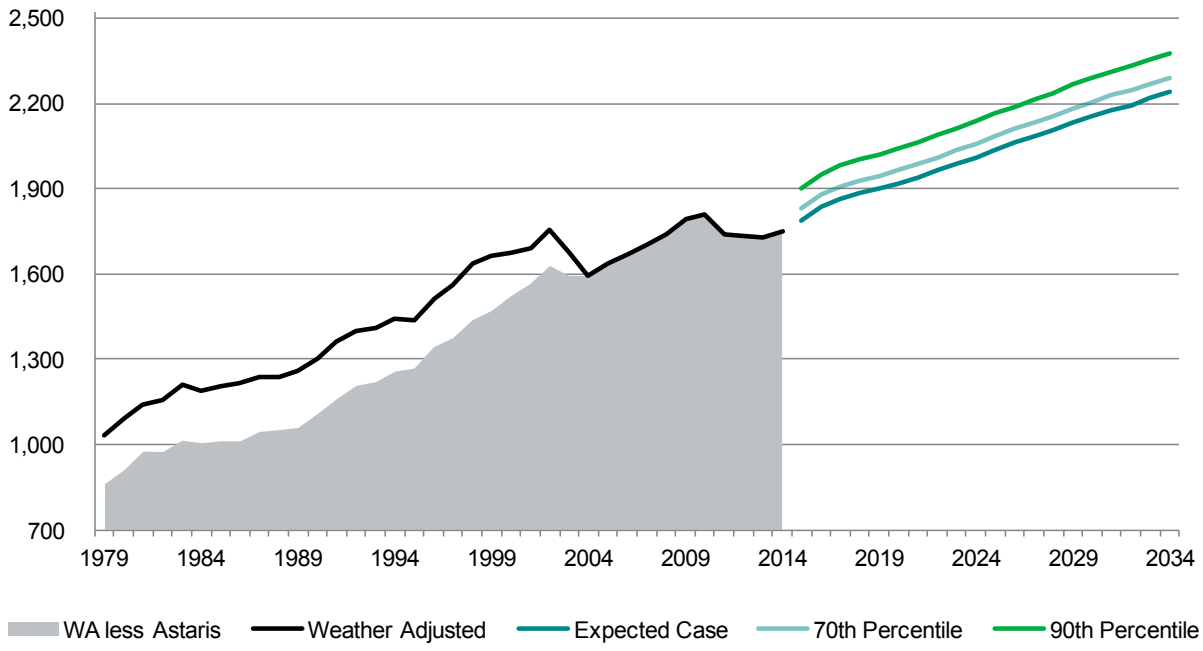



**Figure 7.2 Average monthly load-growth forecast (aMW)**

**Table 7.2 Load forecast—average monthly energy (aMW)**

| Year | Median | 70th Percentile | 90th Percentile |
|---|---|---|---|
| 2015 | 1,786 | 1,829 | 1,900 |
| 2016 | 1,835 | 1,878 | 1,950 |
| 2017 | 1,864 | 1,908 | 1,981 |
| 2018 | 1,883 | 1,928 | 2,002 |
| 2019 | 1,900 | 1,946 | 2,021 |
| 2020 | 1,918 | 1,964 | 2,040 |
| 2021 | 1,941 | 1,987 | 2,064 |
| 2022 | 1,964 | 2,011 | 2,088 |
| 2023 | 1,988 | 2,035 | 2,113 |
| 2024 | 2,012 | 2,059 | 2,139 |
| 2025 | 2,037 | 2,085 | 2,165 |
| 2026 | 2,061 | 2,110 | 2,190 |
| 2027 | 2,085 | 2,134 | 2,215 |
| 2028 | 2,107 | 2,156 | 2,238 |
| 2029 | 2,133 | 2,183 | 2,266 |
| 2030 | 2,156 | 2,206 | 2,290 |
| 2031 | 2,177 | 2,228 | 2,312 |
| 2032 | 2,195 | 2,246 | 2,331 |
| 2033 | 2,219 | 2,271 | 2,356 |
| 2034 | 2,240 | 2,292 | 2,378 |
| **Growth rate (2015–2034)** | **1.2%** | **1.2%** | **1.2%** |

## *Additional Firm Load*

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company to serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has three special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, and the INL. The special-contract customers are described briefly as follows.

### Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support; quality assurance (Q/A); systems integration; and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

### Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

### Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2034 for the INL. The forecast calls for loads to slowly rise through 2021, rise dramatically through 2024, and stay near that higher level throughout the remainder of the forecast period.

## Generation Forecast for Existing Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are shown in *Appendix C—Technical Appendix*. The following sections provide a description of Idaho Power's hydroelectric, thermal, and transmission resources and how they are accounted for in the load and resource balance.



Swan Falls Dam.

### *Hydroelectric Resources*

For the 2015 IRP, Idaho Power continues using 70$^{th}$-percentile forecast streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70$^{th}$ percentile means basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90$^{th}$-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ percentile means streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse-than-median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50$^{th}$-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50$^{th}$-, 70$^{th}$-, and 90$^{th}$-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2015 IRP is included in *Appendix C—Technical Appendix*.

A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA CAMP includes demand-reduction and weather-modification measures that will add new water to the basin water budget. Idaho Power believes the positive effect of the new water associated with the CAMP measures is likely to be temporary. The current water-use practices driving the steady decline over recent years are expected to continue, resulting in declining basin outflows assumed to persist well into the 2030s. The declining basin outflows for this IRP are assumed to continue through the planning period.



Oxbow Dam, part of the Hells Canyon Complex.

A water-management practice affecting Snake River streamflows involves the release of water to augment flows during salmon outmigration. Various federal agencies involved in salmon migration studies have, in recent years, supported efforts to shift the delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to occur during worse-than-median water years. During 2013—a year with markedly worse-than-median water conditions—flow augmentation water from the Upper Snake River and Boise River basins was delivered during May. Because worse-than-median water is assumed in the IRP, and because of the importance of July as a resource-constrained month, Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2015 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August.

The monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating

constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived from historical operation data.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 7.3 shows historical April-to-July Brownlee inflow as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability but do include reductions related to declining base flows in the Snake River. As noted previously in this section, these declines are assumed to continue through the planning period.

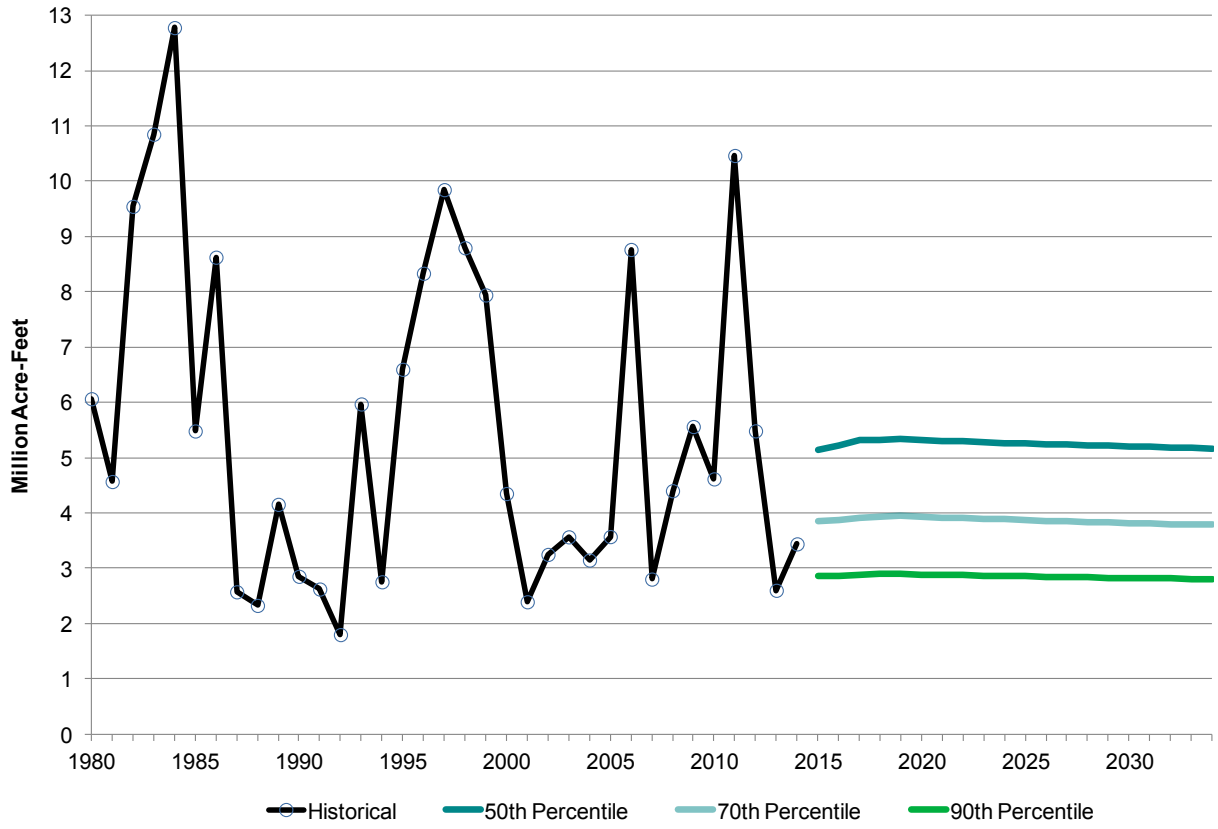



**Figure 7.3 Brownlee historical and forecast inflows**

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on a regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2015 IRP. A more complete discussion of climate change and expectations of possible effects on Snake River water supply is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K.

## Coal Resources

Idaho Power's coal-fired generating facilities have typically operated as baseload resources. Monthly average-energy forecasts in the load and resource balance for the coal-fired projects are based on typical baseload output levels. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the full-rated, maximum dependable capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C—Technical Appendix*.

Major plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Jim Bridger units in 2015, 2016, 2021, and 2022 due to the Regional Haze final rulemaking.

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available for coal-fired operations after December 31, 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with Regional Haze rules on particulate matter, $SO_2$, and $NO_x$ emissions.

## Coal Analysis

Idaho Power prepared an initial coal study as part of the *2011 IRP Update*, and the report was filed with the IPUC and OPUC in February 2013. The 2011 study evaluated several investment alternatives, including converting coal units to burn natural gas, installing SCR or selective non-catalytic reduction (SNCR), and scrubber additions. The study recommended installing SCR on Jim Bridger units 3 and 4 in 2015 and 2016, respectively. Since the completion of that initial coal study, the company has continued to monitor the costs and benefits associated with the SCR investments for Jim Bridger units 3 and 4 to ensure those investments remain cost-effective. An update to the economic analysis of the Bridger 3 and 4 SCR investments that supports the continued installation of the SCRs for those units is presented in *Appendix C—Technical Appendix* of the 2015 IRP.

There are no further environmental investment action items required by state or federal regulators prior to preparing and filing the 2017 IRP. In addition, there have been no material changes in the underlying forecast assumptions from the 2011 study. The company will evaluate investment alternatives for SCRs at Jim Bridger units 1 and 2 no later than the 2017 IRP.

Idaho Power seeks to balance the impacts of carbon regulation with the economic impact to customers, as well as customer needs for reliable service. For the 2015 IRP, the company applied a more dynamic economic analysis of the existing coal units compared to prior IRPs. The 2015 IRP evaluated numerous portfolios that included coal unit shutdowns on various dates. The company believes the termination of operations at its coal-fired plants in the very near future would lead to an increased risk of higher costs for customers in the near-term without a commensurate long-term economic benefit. The company is mindful that an early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years to achieve longer-term savings.

Idaho Power has been in discussions with the joint owner of the North Valmy plant regarding the future of that plant. State public utility commissions and Idaho Power's customers expect future costs to be mitigated and balanced with future risks. Cost and risk will continue to be important factors in the utilities' discussions and decision processes.

Idaho Power currently benefits from the diversity of its generation resources, and that diversity helps mitigate the power supply cost risk borne by customers as the company transitions to the new energy landscape.

### Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT. The SCCT units are typically operated during peak load events in summer and winter months. The monthly average-energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during January, June, July, August, and December and produce approximately 230 aMW of gas-fired generation for the five months. With respect to peak-hour output, the SCCTs are assumed capable of producing an on-demand peak capacity of 416 MW. While the peak dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power's CCCT, Langley Gulch, became commercially available in June 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. Langley Gulch is forecast to contribute approximately 165 aMW, with an on-demand peaking capacity of 318 MW.

## Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. For the 2015 IRP, Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast. Idaho Power also used the EIA as the source for the natural gas price forecast for the 2013 IRP and continues to use the EIA forecast for Idaho-jurisdiction avoided cost-calculation purposes. The natural gas price forecast was discussed during the first three monthly IRPAC meetings held in August through October 2014. During these discussions, Idaho Power provided comparisons of the EIA natural gas price forecast to an alternative forecast, as well as comparisons to observed settlement prices for futures trading in the natural gas market.

The *Annual Energy Outlook 2014*, published by the EIA in April 2014, is the source for the natural gas price forecast for the 2015 IRP. For the 2015 IRP, Idaho Power uses nominal prices, as published by the EIA, as inputs to the analysis performed. Figure 7.4 shows forecast Henry Hub natural gas prices. The low- and high-case natural gas price forecasts used for the 2015 IRP and shown on the chart correspond respectively to the high resource (high availability) and low resource (low availability) cases reported by the EIA in the *Annual Energy Outlook 2014*. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in *Appendix C—Technical Appendix*.

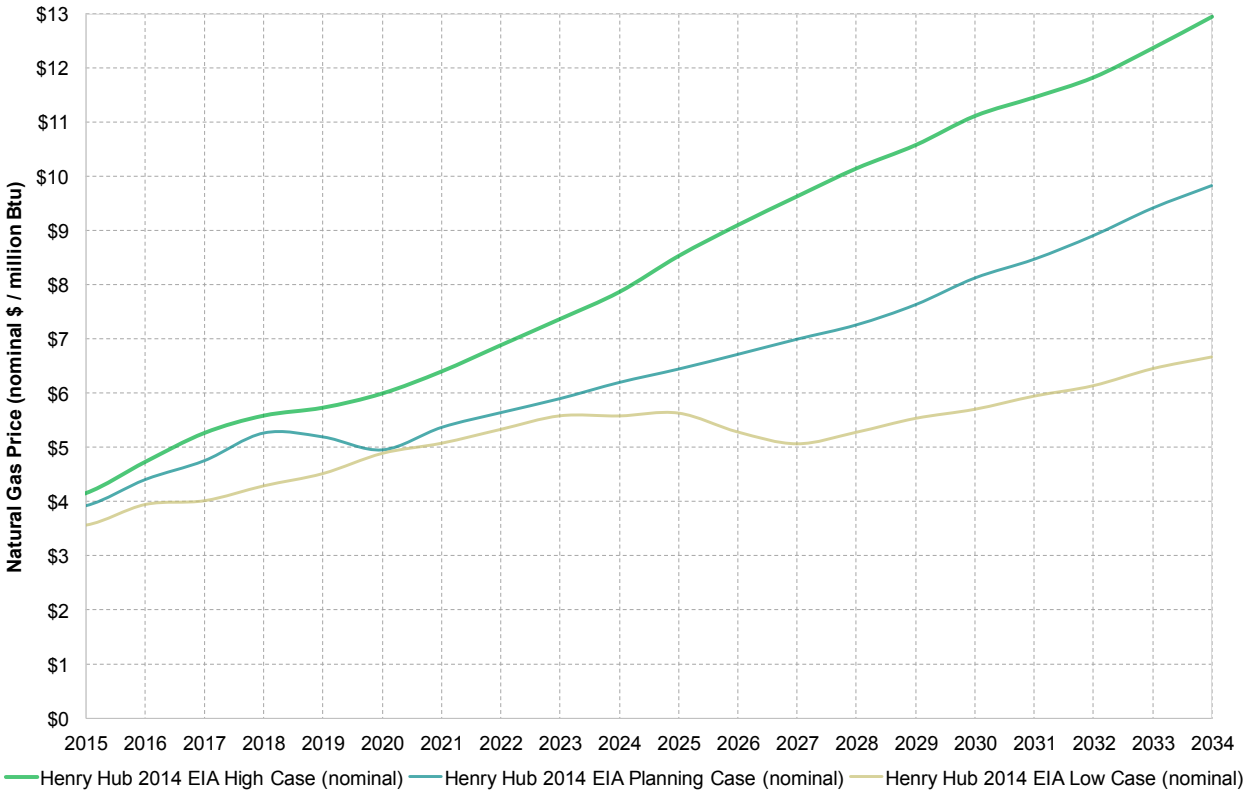



**Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)**

## Resource Cost Analysis

A comparative cost analysis of a variety of supply-side and demand-side resources was conducted as part of resource screening for the 2015 IRP. As described previously, cost inputs and operating data used to develop the resource cost analysis were derived from the September 2014 Lazard report, Idaho Power engineering studies and operating experience, and consultation with specific resource developers. Resource costs are presented as follows:

- *Levelized capacity (fixed) costs*—Levelized fixed cost per kW of installed (nameplate) capacity per month

- *Levelized cost of production (at stated capacity factors)*—Total levelized cost per MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

The capital cost of solar PV resources has been the subject of considerable IRPAC discussions over recent IRPs. As widely reported, solar PV costs have declined markedly over recent years, presenting unique challenges in determining appropriate costs for solar resources. For the 2015 IRP, Idaho Power used the Lazard report's projected 2017 capital cost of $1,250 per kW for utility-scale, single-axis tracking solar PV resources. To further capture reported trends in solar PV capital costs, the 2015 IRP capital cost of $1,250 per kW was not escalated according to the IRP's assumed level of inflation, as the capital costs for other considered resources were.

For the 2015 IRP, Idaho Power is including in resource cost calculations the assumption that potential IRP resources have varying economic life. Financial analyses for the IRP assume the annual depreciation expense of capital costs is based on an apportioning of the capital costs over the entire economic life of a given resource.

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs of supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, applicable balance of plant construction costs, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an allowance for funds used during construction (AFUDC) (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, an annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial effects resulting from the load-reduction programs.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are shown in *Appendix C—Technical Appendix*.

# Resource Cost Analysis II—Resource Stack

## *Levelized Capacity (Fixed) Cost*

The annual fixed-revenue requirements in nominal dollars for each resource were summed and levelized over the assumed economic life and are presented in terms of dollars per kW of plant nameplate capacity per month. Included in these levelized fixed costs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic life, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. Figure 7.5 provides a combined ranking of all the various resource options in order of lowest to highest levelized fixed cost per kW per month. The ranking shows that natural gas peaking resources and demand response are the lowest capacity-cost alternatives. The natural gas peaking resources have high operating costs, but operating costs are less important for resources intended for use only during a limited number of hours per year to meet peak-hour demand.

## *Levelized Cost of Production*

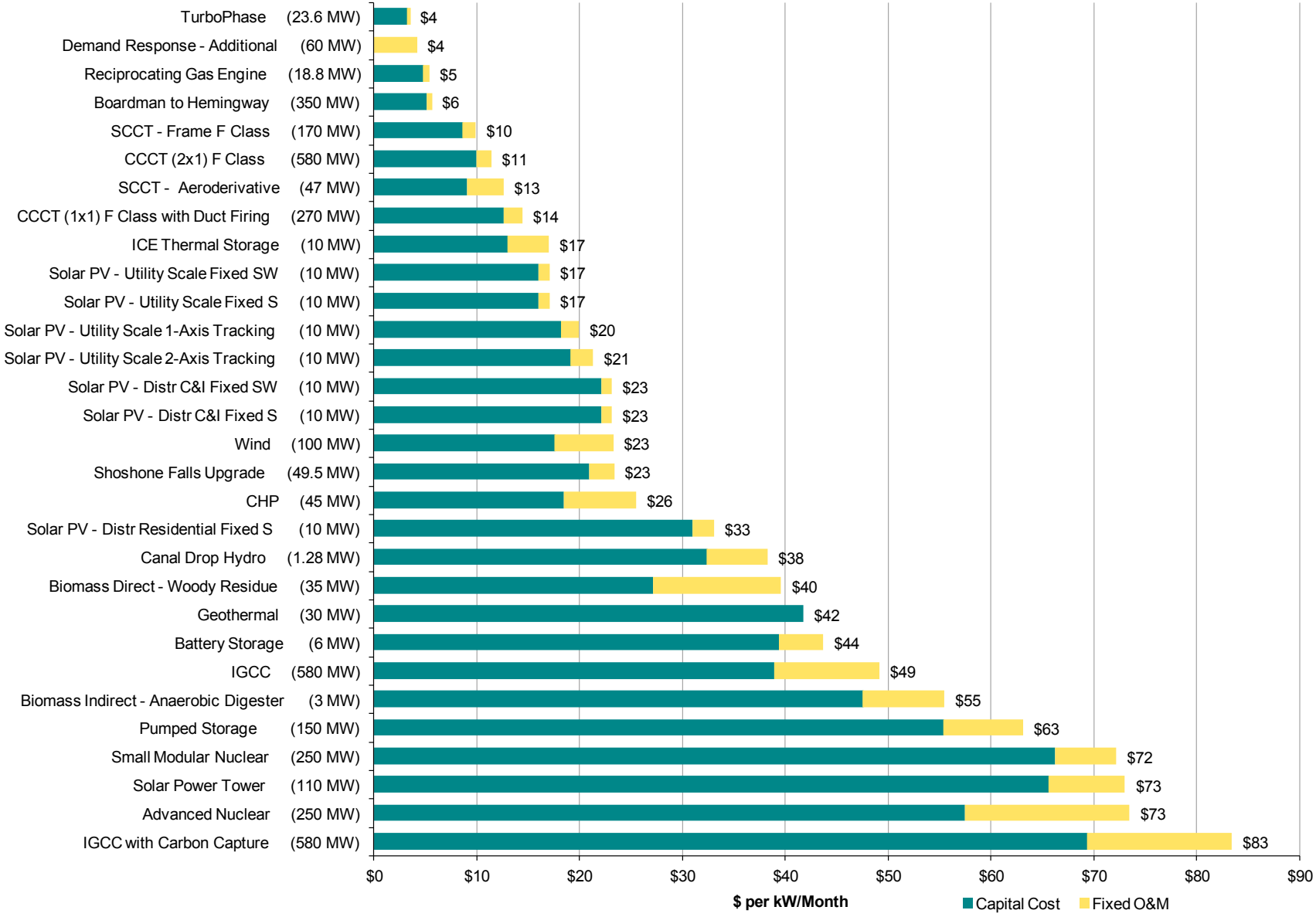
Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost-of-production measurement represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. The B2H transmission line is among the lowest-cost resources for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost-of-production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost-of-production calculation for a generation resource is the assumed level of annual capacity use over the life of the resource, referred to as the capacity factor. A capacity factor of 50 percent would suggest a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost would be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity-factor assumptions reduce the MWh, and the levelized cost would be higher.

For the portfolio cost analysis, fixed resource costs are annualized over the assumed economic life for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.


TurboPhase (23.6 MW) $4
Demand Response - Additional (60 MW) $4
Reciprocating Gas Engine (18.8 MW) $5
Boardman to Hemingway (350 MW) $6
SCCT - Frame F Class (170 MW) $10
CCCT (2x1) F Class (580 MW) $11
SCCT - Aeroderivative (47 MW) $13
CCCT (1x1) F Class with Duct Firing (270 MW) $14
ICE Thermal Storage (10 MW) $17
Solar PV - Utility Scale Fixed SW (10 MW) $17
Solar PV - Utility Scale Fixed S (10 MW) $17
Solar PV - Utility Scale 1-Axis Tracking (10 MW) $20
Solar PV - Utility Scale 2-Axis Tracking (10 MW) $21
Solar PV - Distr C&I Fixed SW (10 MW) $23
Solar PV - Distr C&I Fixed S (10 MW) $23
Wind (100 MW) $23
Shoshone Falls Upgrade (49.5 MW) $23
CHP (45 MW) $26
Solar PV - Distr Residential Fixed S (10 MW) $33
Canal Drop Hydro (1.28 MW) $38
Biomass Direct - Woody Residue (35 MW) $40
Geothermal (30 MW) $42
Battery Storage (6 MW) $44
IGCC (580 MW) $49
Biomass Indirect - Anaerobic Digester (3 MW) $55
Pumped Storage (150 MW) $63
Small Modular Nuclear (250 MW) $72
Solar Power Tower (110 MW) $73
Advanced Nuclear (250 MW) $73
IGCC with Carbon Capture (580 MW) $83
$0 $10 $20 $30 $40 $50 $60 $70 $80 $90
$ per kW/Month
Capital Cost
Fixed O&M

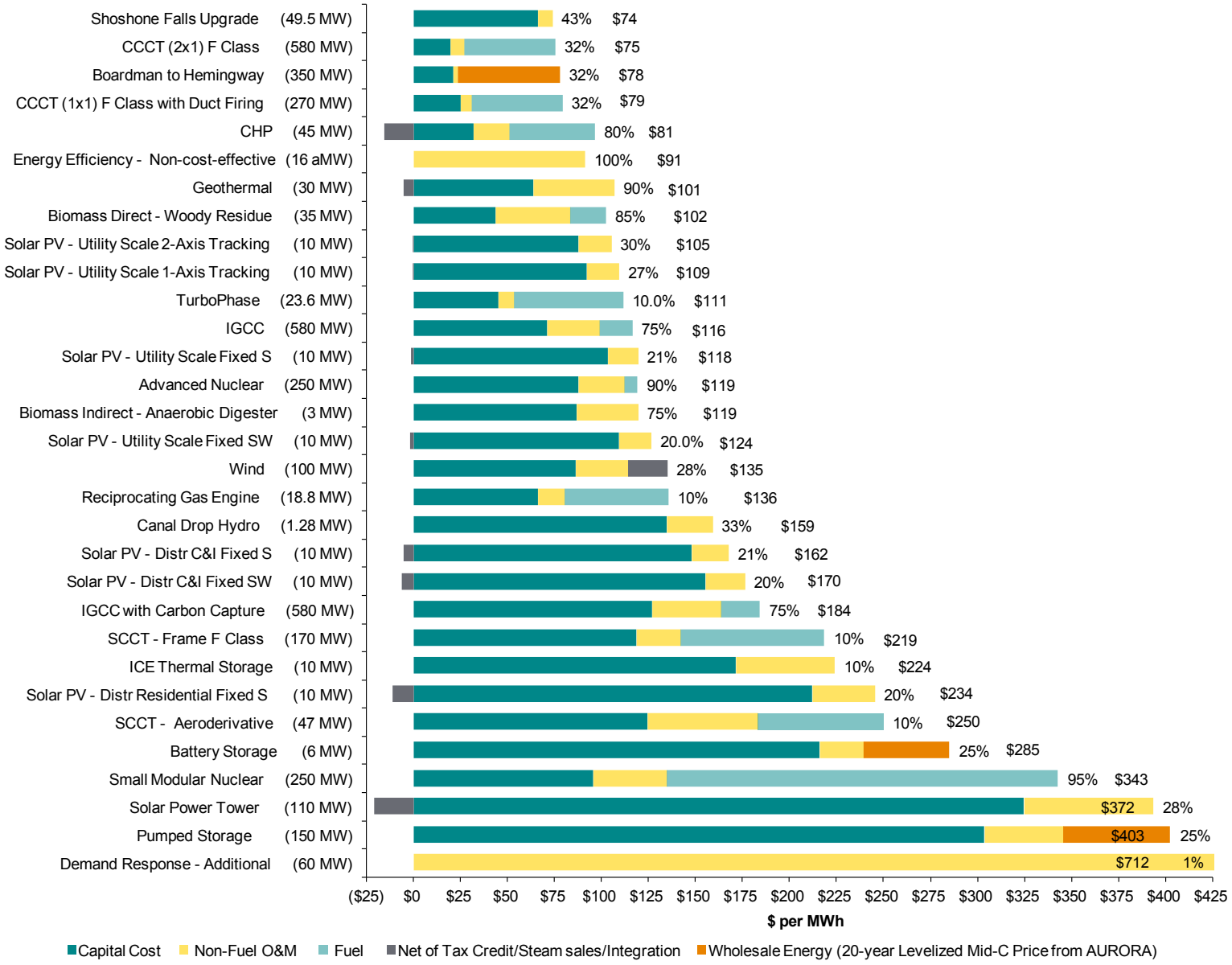



**Figure 7.6 30-year levelized cost of production (at stated capacity factors)**

## Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. For the 2015 IRP, Idaho Power used the 2014 Lazard report as the primary source for supply-side resource costs. Idaho Power engineering studies and plant operating experience were also used. Costs for select resources not provided by the Lazard report and for which Idaho Power has limited engineering and operating experience were determined through consultation with specific resource developers.

The 2015 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2015 IRP has identified periods of future system deficiencies. New resource costs are levelized estimates (based on expected annual generation) that include capital, fuel, and non-fuel O&M. Figure 7.7 shows the capital costs in nominal dollars per kW for a new resource with a 2020 online date plotted against peak-hour capacity for various supply-side resources considered in the 2015 IRP. The on-line date of 2020 is used because, depending on the coal-retirement scenario, the earliest date for new resources in the 2015 IRP is 2020. The use of the 2020 on-line date also allows projected 2015 to 2016 capital-cost declines in utility-scale PV solar to be captured in the plotted data.

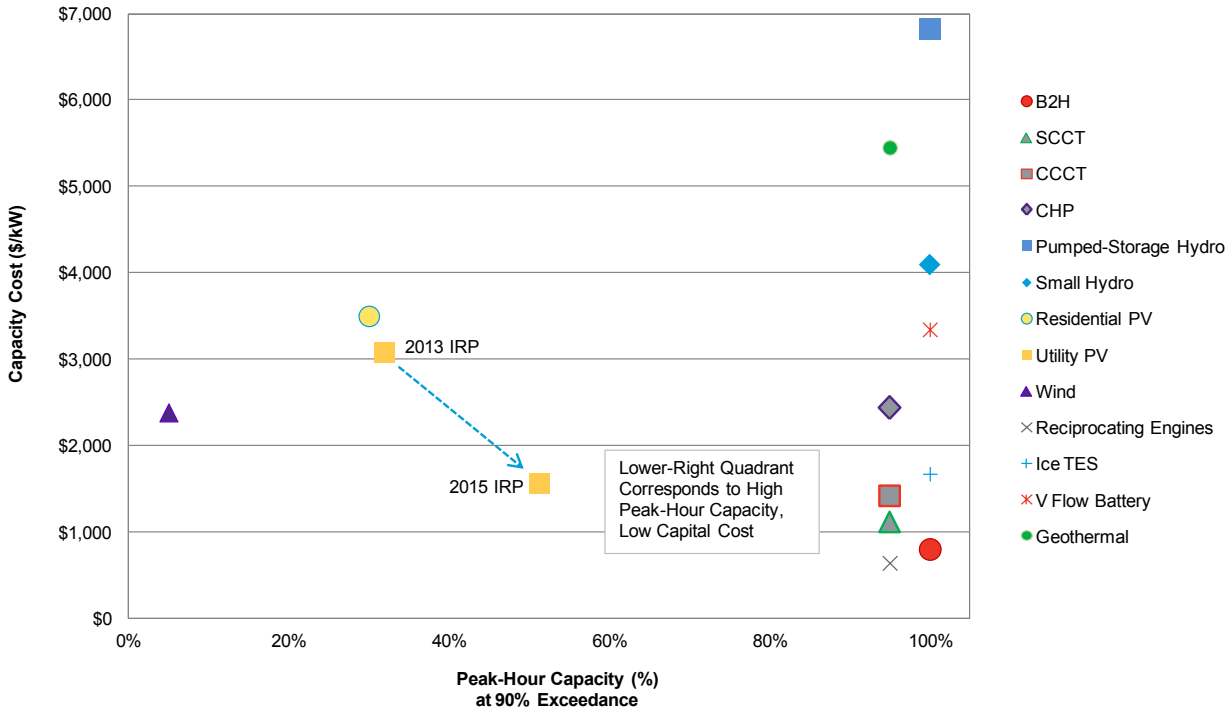



**Figure 7.7 Capacity cost of new supply-side resources, online 2020**

Resources in the lower-right portion of Figure 7.7 are considered to provide peak-hour capacity at a relatively low capital cost. Among the resources in the lower-right portion, the B2H transmission line and various natural-gas fired generating resources provide the highest peak-hour capacity at the lowest cost. Ice-based TES also appears in the lower-right portion as a relatively low-cost capacity resource. The dashed arrow on the figure represents the notable shift in assumptions since the 2013 IRP for utility-scale PV solar. The marked decline in PV solar

capital costs has been extensively reported over recent years. The shift in peak-hour capacity is based on an analysis performed for the 2015 IRP indicating peak-hour capacity slightly in excess of 50 percent of nameplate capacity for single-axis PV solar power plants. This analysis is described in Chapter 5.

While it is important to evaluate the costs presented in Figure 7.7, these costs represent only part of the TRC. In preparing the IRP, Idaho Power also considers the value each resource provides in conjunction with the existing resources in the company's generation portfolio; supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 7.8 shows the levelized cost of energy in dollars per MWh for various new supply-side resources considered in the 2015 IRP, where costs considered include those related to building and operating the resource for a 20-year period. The data used to create Figure 7.8 allows for resource alternatives to be compared based on the capacity cost and the total levelized cost of production.

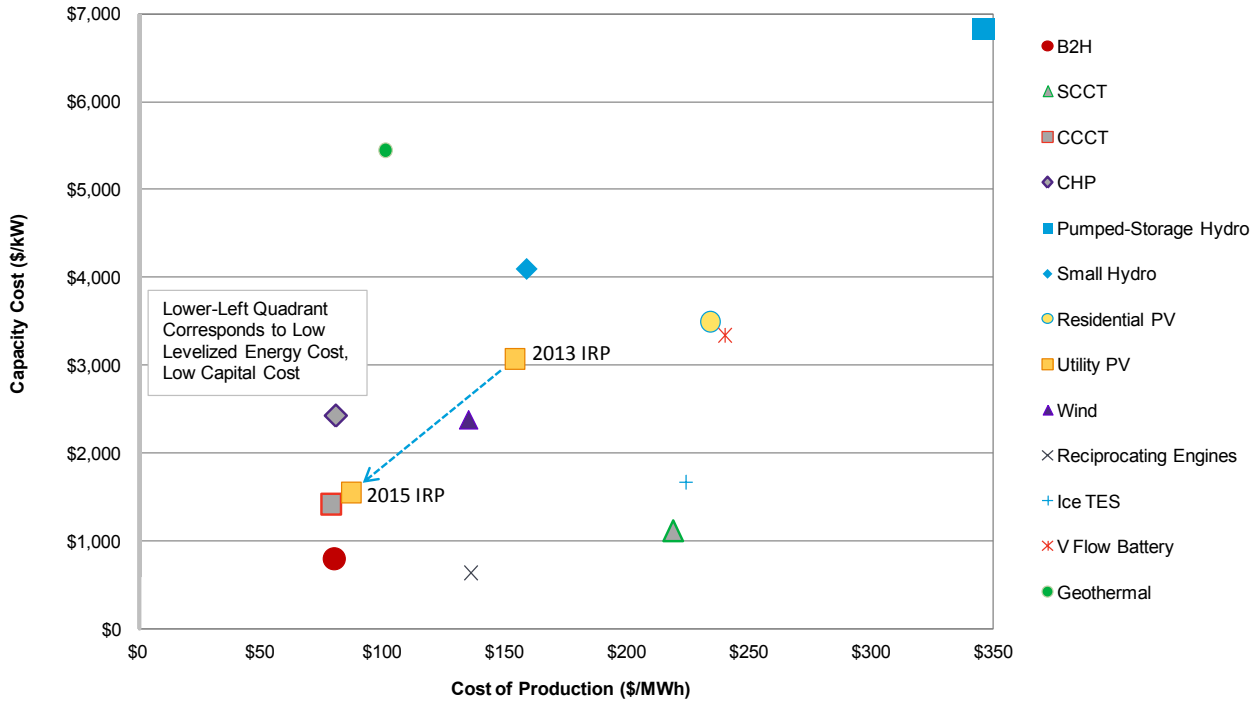



**Figure 7.8 Energy cost of new supply-side resources**

Resources in the lower-left portion of Figure 7.8 produce (or deliver) energy at a low levelized cost and have a relatively low capital cost. The B2H transmission line is among those resources having low levelized costs and low capital costs. Figures 7.7 and 7.8 respectively demonstrate that the B2H transmission line is attractive as a capacity resource (i.e., one needed relatively infrequently) and energy resource (i.e., one needed for frequent energy delivery). In contrast, a SCCT has competitive costs with respect to the relatively infrequent delivery of capacity (Figure 7.7) but is much less competitive when required to deliver energy (Figure 7.8). The dashed line represents the capital-cost decrease observed in utility-scale PV solar since the 2013 IRP.

## Load and Resource Balance

Idaho Power has adopted the practice of assuming drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources while using the conservative water and load conditions is considered comparable to requiring a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having a sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares the load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. Due to the uncertainty of the CAA Section 111(d) regulation, many different assumptions can be made for the future of Idaho Power's coal resources. To address these different coal futures, Idaho Power analyzed nine load and resource balance scenarios:

- **Status Quo:** The first scenario assumes Idaho Power makes no changes in the operations of its coal fleet. This scenario is very similar to the load and resource balance provided in the 2013 IRP and is designed to provide a basis for comparison.

- **Maintain Coal Capacity**: The second scenario assumes Idaho Power will maintain its coal fleet but reduce emissions output in compliance with the proposed CAA Section 111(d) regulation by limiting or capping the amount generators can run.

- **Retire North Valmy Coal Plant:** A third set of scenarios assumes varying timing dates for the retirement of units 1 and 2 of the North Valmy coal plant. There are four scenarios that reflect possible retirement dates for units 1 and 2 of North Valmy:

    - Retire units 1 and 2 by the end of 2019

    - Retire units 1 and 2 by the end of 2025

    - Retire Unit 1 by the end of 2019 and Unit 2 by the end of 2025

    - Retire Unit 1 by the end of 2021 and Unit 2 by the end of 2025

- **Retire units 1 and 2 of Jim Bridger Coal Plant:** Two sets of scenarios assume different retirement dates for units 1 and 2 of the Jim Bridger coal plant. There are a total of four units at Jim Bridger, and units 3 and 4 are not being considered for retirement.

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2028

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2032

- **Retire North Valmy Coal Plant and units 1 and 2 of Jim Bridger Coal Plant:** A final scenario assumes the retirement of units 1 and 2 of North Valmy coal plant by the end of 2025, retirement of Unit 1 of Jim Bridger coal plant by the end of 2023, and retirement of Unit 2 of Jim Bridger by the end of 2032.

Each scenario will include a load and resource balance using average monthly energy planning assumptions and peak-hour planning assumptions.

Average-energy surpluses and deficits are determined using 70$^{th}$-percentile water and 70$^{th}$-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using a reserved network capacity.

Peak-hour load deficits are determined using 90$^{th}$-percentile water and 95$^{th}$-percentile peak-hour load conditions. The hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

All load and resource balances, irrespective of the coal future under consideration, include the following:

- Existing demand reduction due to the demand response programs and the forecast effect of existing energy efficiency programs.

- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. Idaho Power's agreement with Elkhorn Valley Wind expires at the end of 2027. The other agreements do not expire within the planning period.

- Firm Pacific Northwest import capability. This does not include the import capacity from the B2H transmission line or the Gateway West transmission line.

- Expected generation from all Idaho Power-owned resources. The Boardman coal plant has a planned retirement date of 2020.

- Existing PURPA projects and contracts completed by October 31, 2014, including 461 MW of solar projects under contract but not yet operational. (Contracts for four solar projects totaling 141 MW of installed capacity were terminated on April 6, 2015. The relatively late termination date precludes the removal of these projects from the load and resource balance analysis for the 2015 IRP.) Idaho Power assumes all PURPA contracts, with the exception of wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. Wind projects are not expected to be renewed. There is a total of 627 MW of wind under contract. Wind contracts begin to expire in October 2025, and the total wind under contract drops to 130 MW at the end of the planning period.

At times of peak summer load, Idaho Power is using all ATC from the Pacific Northwest. If Idaho Power encountered a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has

committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Idaho Power's customers reach a maximum energy demand in the summer. From a resource adequacy perspective, July has historically been the month during which Idaho Power's system is most constrained. Based on projections for the 2015 IRP, July is likely to remain the most resource-constrained month. A secondary maximum energy demand occurs during the winter in the month of December. Tables 7.3 and 7.4 provide for July and December the monthly average-energy deficits for each of the coal futures considered in the 2015 IRP. Darker shading in the tables corresponds with larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data for only the period 2020 to 2034.

**Table 7.3 July monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | (1) | (52) | (121) | (145) |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | (3) | (69) | (135) | (186) | (255) | (279) |
| Valmy Retire Units 1 and 2 Year–End 2019 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Units 1 and 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Unit 1 Year–End 2019 and Unit 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Unit 1 Year–End 2021 and Unit 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2028 | – | – | – | – | – | (3) | (51) | (76) | (129) | (329) | (395) | (460) | (511) | (580) | (605) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032 | – | – | – | – | – | (3) | (51) | (76) | (129) | (166) | (232) | (298) | (349) | (580) | (605) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032, Valmy Retire Units 1 and 2 Year–End 2025 | – | – | – | – | – | (3) | (197) | (222) | (275) | (312) | (349) | (414) | (465) | (697) | (721) |

**Table 7.4 December monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Valmy Retire Units 1 and 2 Year-End 2019 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | – | – | – | – | – | (32) | (64) | (149) | (180) | (239) | (259) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | – | – | – | – | – | – | – | – | (17) | (239) | (259) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | (3) | (88) | (119) | (341) | (361) |

Tables 7.5 and 7.6 provide the peak-hour capacity deficits for July and December for the coal futures considered. Darker shading in the tables corresponds to larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data only for 2020 to 2034.

**Table 7.5 July monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | (14) | (61) | (136) | (175) | (224) | (316) | (352) | (426) | (491) | (523) |
| Maintain Coal Capacity | – | – | – | – | – | (14) | (61) | (136) | (175) | (224) | (316) | (352) | (426) | (491) | (523) |
| Valmy Retire Units 1 and 2 Year-End 2019 | (24) | (141) | (143) | (176) | (236) | (277) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | (14) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | (9) | (11) | (44) | (105) | (145) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | (11) | (44) | (105) | (145) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | (149) | (190) | (236) | (312) | (350) | (576) | (667) | (703) | (777) | (842) | (874) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | (149) | (190) | (236) | (312) | (350) | (400) | (491) | (527) | (601) | (842) | (874) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | (149) | (190) | (499) | (575) | (613) | (663) | (754) | (790) | (864) | (1,105) | (1,137) |

**Table 7.6 December monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Valmy Retire Units 1 and 2 Year-End 2019 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | – | – | – | – | – | (147) | (188) | (218) | (247) | (276) | (254) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | – | – | – | – | – | – | (12) | (42) | (71) | (276) | (254) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | (187) | (207) | (235) | (234) | (275) | (305) | (334) | (539) | (517) |

# 8. PORTFOLIO SELECTION

## Portfolio Design

In the 2015 IRP, Idaho Power continued the 2013 IRP's practice of analyzing a range of coal-retirement portfolios. The consideration of additional early coal retirement, or early shutdown portfolios is consistent with expectations expressed by the IPUC in its Acceptance of Filing order for the 2013 IRP (Case No. IPC-E-13-15, Order No. 32980). The 23 portfolios analyzed for the 2015 IRP can be grouped into the following 10 categories. All portfolios are assumed to have SCR installation for Jim Bridger units 3 and 4 completed by 2016.

1. **Status quo portfolio**—A single resource portfolio with no additional retirement of coal-fired generating units other than Boardman in 2020 and without output constraints related to the proposed CAA Section 111(d) regulation. The status quo portfolio relies on the B2H transmission line and reciprocating gas engines to meet future resource needs.

   All other portfolios considered in the 2015 IRP assume compliance with CAA Section 111(d) based on various assumptions regarding what the final regulation will contain.

2. **Maintain coal capacity portfolios**—A set of three portfolios with no retirement of coal capacity during the IRP planning period with the exception of the planned 2020 year-end Boardman shutdown.

3. **North Valmy retirement year-end 2019 portfolios**—A set of five portfolios with the retirement of both North Valmy units at year-end 2019.

4. **North Valmy retirement year-end 2025 portfolios**—A set of three portfolios with the retirement of both North Valmy units at year-end 2025.

5. **North Valmy staggered retirement year-end 2019 (Unit 1) and year-end 2025 (Unit 2) portfolios**—A set of two portfolios with retirement of North Valmy Unit 1 at year-end 2019 and Unit 2 at year-end 2025.

6. **North Valmy staggered retirement year-end 2021 (Unit 1) and year-end 2025 (Unit 2) portfolio**—A single portfolio with the retirement of North Valmy Unit 1 at year-end 2021 and Unit 2 at year-end 2025.

7. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2) portfolios**—A set of two portfolios with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2032. The early retirement of these portfolios is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

8. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2028 (Unit 2) portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028. The early retirement of this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

9. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2), North Valmy retirement year-end 2025 portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028, and the retirement of both North Valmy units at year-end 2025. The early Jim Bridger retirement in this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

10. **Alternative to B2H portfolios**—A set of four portfolios in which the B2H transmission line is replaced by alternative resources. Except for this set of portfolios, all other 2015 IRP portfolios have the B2H transmission line.

The coal-retirement portfolios include the additional cost of recovering the remaining investment in the coal units prior to retirement. In addition, resource retirement includes the accelerated decommissioning costs when estimating the resource portfolio costs.

The coal-retirement portfolios also include the cost savings associated with early investment recovery and shutdown. These savings include avoided future capital investments, fixed operating costs, and avoided ROI. Treatment of the fixed-cost accounting is summarized in Table 8.1.

**Table 8.1 Fixed-cost impacts of coal retirement**

| Fixed-Cost Description | Cost Impact |
|---|---|
| Accelerated recovery of depreciation expense on remaining investments | Cost |
| Utility rate of return applied over a shorter life | Savings |
| Accelerated recovery of decommissioning and demolition costs (net of salvage) | Cost |
| Avoidance of future incremental capital (including avoidance of environmental retrofit investments) | Savings |
| Avoidance of future fixed operating expenses | Savings |

## Portfolio Design and Selection

Idaho Power analyzed 23 resource portfolios for the 2015 IRP. All portfolios are designed to balance forecast load with available or additional resources to eliminate energy and capacity deficits according to the IRP planning criteria described in Chapter 7. The energy and capacity deficits for the considered coal-retirement futures are also provided in Chapter 7. The portfolios were designed in collaboration with the IRPAC and public participants in the IRP process.

### *Status Quo Portfolio*

The resource additions in the status quo portfolio are driven by the need to eliminate peak-hour capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. The status quo portfolio is designated as resource portfolio P1.

### P1

**Table 8.2 Resource portfolio P1**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

## *Maintain Coal Capacity Portfolios*

Resource additions of the set of portfolios with coal capacity maintained, excepting the planned Boardman shutdown, are driven by capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. These portfolios differ from P1 only in the assumed on-line date for B2H, ranging from 2021 to 2025. The portfolios are designated as resource portfolios P2(a), P2(b), and P2(c).

### P2(a)

**Table 8.3 Resource portfolio P2(a)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

### P2(b)

**Table 8.4 Resource portfolio P2(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

### P2(c)

**Table 8.5 Resource portfolio P2(c)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2021 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

## *North Valmy Retirement Year-End 2019 Portfolios*

Resource additions for portfolios with North Valmy retirement in 2019 are driven by capacity deficits beginning in July 2020 and reaching 786 MW by July 2034. These resource portfolios are designated as P3, P4(a), P4(b), P4(c), and P5. The P4 portfolios differ primarily in the assumed on-line date for B2H, ranging from 2021 to 2025.

### P3

The resource portfolio P3 adds 60 MW of ice-based TES and 330 MW of utility-scale, single-axis PV solar in the early 2020s and the B2H transmission line in 2025. In 2033, 75 MW of additional utility-scale, single-axis PV solar is added. P3 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study included in all portfolios. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.6 Resource portfolio P3**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Ice-based TES | 25 MW | 25 MW |
| 2021 | Ice-based TES | 35 MW | 35 MW |
| 2021 | Utility-scale solar PV 1-axis | 150 MW | 77 MW |
| 2023 | Utility-scale solar PV 1-axis | 180 MW | 92 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2033 | Utility-scale solar PV 1-axis | 75 MW | 38 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| 2020–34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 827 MW |
| | | Net peak-hour capacity | 550 MW |

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

## P4(a)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage and 198 MW of reciprocating engines in the early 2020s prior to the B2H transmission line in 2025. The 60 MW of battery storage are replaced in 2030 to 2031 with new battery storage, followed by the addition of 54 MW of reciprocating engines in 2033.

**Table 8.7 Resource portfolio P4(a)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | Reciprocating engines | 108 MW | 108 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2030 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |
| 2033 | Reciprocating engines | 54 MW | 54 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 872 MW |
| | | Net peak-hour capacity | 550 MW |

## P4(b)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage, 90 MW of reciprocating engines in 2020 to 2021, and the B2H transmission line in 2023. The 60 MW of battery storage is replaced in 2030 to 2031 with additional battery storage, followed by the addition of 162 MW of reciprocating engines in 2032 to 2034.

**Table 8.8 Resource portfolio P4(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2030 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |

**Table 8.8 Resource portfolio P4(b) (continued)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2032 | Reciprocating engines | 54 MW | 54 MW |
| 2033 | Reciprocating engines | 72 MW | 72 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 872 MW |
| | | Net peak-hour capacity | 550 MW |

## P4(c)

Portfolio P4(c) adds 25 MW of Vanadium redox flow battery storage in 2020 and the B2H transmission line in 2021. The portfolio also includes 35 MW of Vanadium redox flow battery storage added in 2029, with 25 MW of battery storage replacement in 2030. Reciprocating engines totaling 252 MW are added in the early 2030s.

**Table 8.9 Resource portfolio P4(c)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2029 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2030 | Reciprocating engines | 36 MW | 36 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2031 | Reciprocating engines | 108 MW | 108 MW |
| 2033 | Reciprocating engines | 108 MW | 108 MW |
| | | Total retired capacity | (287 MW) |
| | | Total added capacity | 837 MW |
| | | Net peak-hour capacity | 550 MW |

## P5

Resource portfolio P5 adds a 300-MW CCCT in 2020 and the B2H transmission line in 2025.

**Table 8.10 Resource portfolio P5**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | CCCT | 300 MW | 300 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

## North Valmy Retirement Year-End 2025 Portfolios

Portfolios with North Valmy retirement in 2025 experience capacity deficits beginning in July 2025 and reaching 786 MW by July 2034. These resource portfolios are designated as P6, P6(b), and P7.

### P6

Resource portfolio P6 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300-MW CCCT is added in 2030.

**Table 8.11 Resource portfolio P6**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

### P6(b)

Resource portfolio P6(b) is a variation of P6 that includes in 2030 60 MW of demand response and 20 MW of ice-based TES, allowing the 300-MW CCCT to be deferred by one year to 2031. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios.

**Table 8.12 Resource portfolio P6(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Demand response | 60 MW | 60 MW |
| 2030 | Ice-based TES | 20 MW | 20 MW |
| 2031 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 880 MW |
| | | Net peak-hour capacity | 618 MW |

### P7

Resource portfolio P7 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300 MW pumped-storage hydro project is added in 2030.

**Table 8.13 Resource portfolio P7**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Pumped-storage hydro | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

## *North Valmy Staggered Retirement Year-End 2019 (Unit 1) and Year-End 2025 (Unit 2) Portfolios*

Resource additions of portfolios with North Valmy retirement in 2019 (Unit 1) and 2025 (Unit 2) are driven by capacity deficits beginning in July 2021 and reaching 786 MW by July 2034. The portfolios of this set are designated P8 and P9.

### P8

Resource portfolio P8 adds 60 MW of ice-based TES and 70 MW of utility-scale, single-axis PV solar in 2021 to 2024 and the B2H transmission line in 2025. P8 adds 45 MW of canal hydro in 2031 and 126 MW of reciprocating engines in 2032 to 2033. Equivalent to resource portfolio P3, portfolio P8 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.14 Resource portfolio P8**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Ice-based TES | 15 MW | 15 MW |
| 2023 | Ice-based TES | 30 MW | 30 MW |
| 2024 | Utility-scale solar PV 1-axis | 70 MW | 36 MW |
| 2024 | Ice-based TES | 15 MW | 15 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Canal hydro | 45 MW | 45 MW |
| 2032 | Reciprocating engines | 72 MW | 72 MW |
| 2033 | Reciprocating engines | 54 MW | 54 MW |
| 2020-34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 791 MW |
| | | Net peak-hour capacity | 529 MW |

*Note: Extra energy efficiency beyond cost-effective amount determined by DSM potential study.

### P9

The resource portfolio P9 adds 60 MW of demand response in 2021-24. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P9 also adds 54 MW of reciprocating engines in 2024. The B2H transmission line is added in 2025, followed by 18 MW of reciprocating engines in 2031 and a 170-MW SCCT in 2032.

**Table 8.15 Resource portfolio P9**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Demand response | 15 MW | 15 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Reciprocating engines | 54 MW | 54 MW |
| 2024 | Demand response | 15 MW | 15 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Reciprocating engines | 18 MW | 18 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 802 MW |
| | | Net peak-hour capacity | 540 MW |

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2) Portfolios*

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2) are driven by peak-hour capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. These resource portfolios are designated as P10 and P11.

### P10

The resource portfolio P10 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P10 adds a 300-MW CCCT in 2033.

**Table 8.16 Resource portfolio P10**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 970 MW |
| | | Net peak-hour capacity | 617 MW |

### P11

Resource portfolio P11 adds 60 MW of ice-based TES, 155 MW of utility-scale, single-axis PV solar in 2024, and the B2H transmission line in 2025. P11 also adds 180 MW of reciprocating engines and a 45-MW CHP facility in 2033. Like portfolios P3 and P8, P11 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.17 Resource portfolio P11**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | Ice-based TES | 60 MW | 60 MW |
| 2024 | Utility-scale solar PV 1-axis | 155 MW | 80 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2032 | Reciprocating engines | 108 MW | 108 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CHP | 45 MW | 45 MW |
| 2033 | Reciprocating engines | 36 MW | 36 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| 2020-34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 889 MW |
| | | Net peak-hour capacity | 536 MW |

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2028 (Unit 2) Portfolio*

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2028 (Unit 2) are driven by capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. This resource portfolio is designated as P12.

### P12

The resource portfolio P12 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P12 also adds a 300-MW CCCT in 2029.

**Table 8.18 Resource portfolio P12**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2028 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2029 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 970 MW |
| | | Net peak-hour capacity | 617 MW |

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2), North Valmy Retirement Year-End 2025 Portfolio*

The resource additions to the portfolio with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2), and North Valmy retirement in 2025, are driven by capacity deficits beginning in July 2024 and reaching 1,137 MW by July 2034. This resource portfolio is designated as P13.

### P13

Resource portfolio P13 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P13 also adds a 300-MW CCCT in 2029 and a second CCCT in 2033.

**Table 8.19 Resource portfolio P13**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2029 | CCCT | 300 MW | 300 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (615 MW) |
| | | Total added capacity | 1,270 MW |
| | | Net peak-hour capacity | 655 MW |

## *Alternative to B2H Portfolios*

This set of four portfolios replaces the B2H transmission line with alternatives. Each B2H alternative portfolio assumes a different coal-retirement future. Resource portfolio P14 assumes coal capacity is maintained. Resource portfolio P15 assumes North Valmy retirement in 2019. Resource portfolio P16 assumes the staggered retirement of North Valmy units 1 and 2 in 2019 and 2025, respectively. Resource portfolio P17 assumes the staggered retirement of Jim Bridger units 1 and 2 in 2023 and 2032, respectively.

## P14

Resource portfolio P14 adds 60 MW of ice-based TES in 2025 to 2026, 18 MW of reciprocating engines in 2026, a 300-MW CCCT in 2027, and a 170-MW SCCT in 2032.

**Table 8.20 Resource portfolio P14**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | Ice-based TES | 15 MW | 15 MW |
| 2026 | Ice-based TES | 45 MW | 45 MW |
| 2026 | Reciprocating engines | 18 MW | 18 MW |
| 2027 | CCCT | 300 MW | 300 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 548 MW |
| | | Net peak-hour capacity | 548 MW |

## P15

Resource portfolio P15 adds 60 MW of Vanadium redox flow battery storage in 2020 to 2021 and 252 MW of reciprocating engines in 2020 to 2025. P15 also adds a 170-MW SCCT and a 300-MW CCCT in the second half of the 2020s, 60 MW of battery storage replacement, and 36 MW of reciprocating engines in 2034.

**Table 8.21 Resource portfolio P15**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | Reciprocating engines | 108 MW | 108 MW |
| 2025 | Reciprocating engines | 54 MW | 54 MW |
| 2026 | SCCT | 170 MW | 170 MW |
| 2029 | CCCT | 300 MW | 300 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2031 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 878 MW |
| | | Net peak-hour capacity | 556 MW |

## P16

Resource portfolio P16 adds 60 MW of demand response and 90 MW of reciprocating engines in 2021 to 2025. The 60 MW of demand response is beyond the 390 MW of summer demand

response included as an existing resource in all portfolios. P16 also adds a 300-MW CCCT and a 170-MW SCCT in the second half of the 2020s. In the early 2030s, 18 MW of reciprocating engines and a 170-MW SCCT are added.

**Table 8.22 Resource portfolio P16**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Demand response | 15 MW | 15 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Demand response | 15 MW | 15 MW |
| 2024 | Reciprocating engines | 54 MW | 54 MW |
| 2025 | Reciprocating engines | 36 MW | 36 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2026 | CCCT | 300 MW | 300 MW |
| 2029 | SCCT | 170 MW | 170 MW |
| 2031 | Reciprocating engines | 18 MW | 18 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 808 MW |
| | | Net peak-hour capacity | 546 MW |

## P17

Resource portfolio P17 adds a variety of resources, including 250 MW of utility-scale, single-axis solar PV; 162 MW of reciprocating engines; 45 MW of CHP; 30 MW of geothermal; and 60 MW of ice-based TES in 2024 to 2029. In the 2030s, P18 adds a 300-MW CCCT and a 170-MW SCCT.

**Table 8.23 Resource portfolio P17**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | Ice-based TES | 60 MW | 60 MW |
| 2024 | Utility-scale solar PV 1-axis | 175 MW | 90 MW |
| 2025 | CHP | 45 MW | 45 MW |
| 2026 | Reciprocating engines | 54 MW | 54 MW |
| 2027 | Geothermal | 30 MW | 30 MW |
| 2027 | Utility-scale solar PV 1-axis | 75 MW | 38 MW |
| 2028 | Reciprocating engines | 54 MW | 54 MW |
| 2029 | Reciprocating engines | 54 MW | 54 MW |
| 2030 | CCCT | 300 MW | 300 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 895 MW |
| | | Net peak-hour capacity | 542 MW |

## North Valmy Staggered Retirement Year-End 2021 (Unit 1) and Year-End 2025 (Unit 2) Portfolio

After the April 2015 IRPAC meeting, Idaho Power received a submittal requesting the analysis of a portfolio with the retirement of North Valmy Unit 1 in 2021 from IRPAC member David Hawk (Oil and Gas Industry Advisor) in partnership with IRPAC member Ben Otto (Idaho Conservation League). New resources specified by the submittal included B2H, demand response, CHP, small hydro, geothermal, and residential PV solar. Idaho Power developed a resource portfolio using these specifications, adding the retirement of North Valmy Unit 2 in 2025. With the retirement of North Valmy Unit 1 in 2021 and Unit 2 in 2025, capacity deficits begin in July 2022 and reach 786 MW by July 2034. The resulting resource portfolio, designed to meet these deficits and the submitted request for specific resource actions, is designated as resource portfolio P18.

### P18

Resource portfolio P18 adds 20 MW of residential PV solar, 60 MW of demand response, a 45-MW CHP facility in 2022 to 2024, and the B2H transmission line in 2025. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P18 also adds 3 MW of residential PV solar per year in 2031 to 2034, 40 MW of geothermal in 2031, 45 MW of CHP in 2032, 60 MW of small hydro in 2033, and 18 MW of reciprocating engines in 2034.

**Table 8.24 Resource portfolio P18**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2021 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2022 | Residential PV solar | 5 MW | 2 MW |
| 2022 | Demand response | 10 MW | 10 MW |
| 2023 | Residential PV solar | 5 MW | 2 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Residential PV solar | 10 MW | 3 MW |
| 2024 | Demand response | 20 MW | 20 MW |
| 2024 | CHP | 45 MW | 45 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Residential PV solar | 10 MW | 3 MW |
| 2031 | Geothermal | 40 MW | 40 MW |
| 2032 | Residential PV solar | 10 MW | 3 MW |
| 2032 | CHP | 45 MW | 45 MW |
| 2033 | Residential PV solar | 10 MW | 3 MW |
| 2033 | Small hydro | 60 MW | 60 MW |
| 2034 | Residential PV solar | 10 MW | 3 MW |
| 2034 | Reciprocating engines | 18 MW | 18 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 766 MW |
| | | Net peak-hour capacity | 504 MW |

## Portfolio Design Summary

The 23 portfolios analyzed for the 2015 IRP consider a range of alternatives with regard to early coal retirement and the B2H transmission line. The following table provides a summary of the 2015 IRP portfolio scenarios on the basis of early coal retirement and the B2H transmission line.

**Table 8.25 Resource portfolio scenario summary**

| Coal | B2H | Alternative to B2H |
|---|---|---|
| No coal capacity retirement | 4 | 1 |
| Early retirement—North Valmy | 11 | 2 |
| Early retirement—Jim Bridger | 3 | 1 |
| Early retirement—North Valmy and Jim Bridger | 1 | – |

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# 9. MODELING ANALYSIS AND RESULTS

Idaho Power evaluated the costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to serve customer load using all resources in the portfolio. Portfolio costs are expressed in terms of NPV in the IRP's cost-comparison analysis of portfolios.

The IRP portfolio costs consist of fixed and variable components. The fixed component includes annualized capital costs for new portfolio resources, including transmission interconnection costs for new generating facilities, and fixed O&M costs and ROI. Capital costs for new resources are annualized over the resource's estimated economic life. Annualized capital costs beyond the IRP planning window (2015–2034) are not included in portfolio costs.

Coal-retirement portfolios include costs for the accelerated recovery of remaining depreciation expenses and accelerated recovery of decommissioning and demolition costs (net of salvage). The costs of coal-retirement portfolios are countered by savings from avoiding future coal plant capital upgrades, including environmental retrofit upgrades, and from avoiding future fixed operating expenses and ROI for the retired coal unit(s).

Idaho Power uses the AURORAxmp® (AURORA) electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data.

The AURORA software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, and regional pool pricing logic. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS, Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results. Updates to the database generally add additional hourly operational details and move away from flat generation output, de-rates, and fixed-capacity factors. The updates also incorporate detailed generating resource scheduling, which results in a model that is more deterministic in character and provides a more specific operational view of the WECC.

Portfolio costs are calculated as the NPV of the 20-year stream of annualized costs, fixed and variable, for each portfolio. The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

**Table 9.1 Financial assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount rate (weighted average capital cost) | 6.74% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 2.20% |
| Annual property tax escalation rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premium (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.75% |

# CAA Section 111(d) Sensitivity Analysis

Idaho Power developed multiple sensitivities for the EPA's proposed regulation for regulating $CO_2$ emissions from existing generating sources under CAA Section 111(d). The multiple sensitivities are a reflection of the considerable uncertainty related to the stipulations of the finalized regulation scheduled to be issued in summer 2015. Each sensitivity, with the exception of a null sensitivity in which no restrictions are assumed, is based on a set of assumptions on compliance stipulations for the final regulation. Analyzing multiple sensitivities allows the estimation of a range of possible cost impacts from CAA Section 111(d). The cost sensitivity analysis could provide information to state-level agencies tasked with the development of state plans for CAA Section 111(d) implementation.

The analyzed CAA Section 111(d) sensitivities are described by four categories:

1. Null sensitivity (no CAA Section 111(d))
2. State-by-state mass-based compliance
3. System-wide mass-based compliance
4. Emissions-intensity compliance using the EPA's compliance building blocks

## *Null Sensitivity (no CAA Section 111(d))*

Idaho Power analyzes a null sensitivity to provide a comparison with portfolios complying with regulations on $CO_2$ emissions for existing power plants. The only portfolio analyzed under the null sensitivity is the status quo portfolio (P1), which maintains coal capacity and meets planning-period deficits with B2H in 2025 and 36 MW of reciprocating engines in 2034.

## *State-by-State Mass-Based Compliance*

Under state-by-state mass-based compliance, CAA Section 111(d) proposed state-specific target reductions are the basis for compliance. The proposed regulation's treatment of Langley Gulch is

uncertain, as it was brought on-line midway through EPA's 2012 baseline year. Consequently, Langley Gulch is assumed to be constrained at one of three possible annual capacity factors: 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh). The proposed target reductions are defined in Table 9.2.

**Table 9.2 Proposed target reductions for state-by-state mass-based compliance (IPC share)**

| Affected Source | 2020–2029 Target MWh | 2030 and Beyond Target MWh |
|---|---|---|
| Jim Bridger | 3,914,502 MWh<br>(13.8% below 2012 MWh) | 3,675,608 MWh<br>(19.1% below 2012 MWh) |
| North Valmy | 574,382 MWh<br>(29.5% below 2012 MWh) | 533,343 MWh<br>(34.5% below 2012 MWh) |
| Boardman | 149,967 MWh<br>(43.2% below 2012 MWh) | 137,029 MWh<br>(48.1% below 2012 MWh) |
| Langley Gulch | Target 30%, 55%, or 70% annual capacity factor 2020–2034 | |

## System-Wide Mass-Based Compliance

Under system-wide mass-based compliance, CAA Section 111(d) compliance is based on adherence to $CO_2$ limits imposed at an individual-utility system level. The assumed Idaho Power system-level limits were derived to be consistent with EPA's proposed state-specific target reductions. Under this approach, system-wide emissions, which include emissions from Langley Gulch and Idaho Power's share of Jim Bridger and North Valmy, are constrained to 6,332,020 tons of $CO_2$ for 2020 to 2029 and to 5,925,874 tons of $CO_2$ for 2030 and beyond. Compared to 2012 system-wide emissions, these constraint levels are lower by 20 percent (2020 to 2029 constraint) and 25 percent (2030 and beyond constraint).

## Emissions-Intensity Compliance Using the EPA's Compliance Building Blocks

In its proposed regulation, the EPA describes building blocks to assist in developing a plan for achieving compliance. Keys to the building-block approach for achieving compliance are the reduction of $CO_2$ emissions through the re-dispatch of affected sources and the development of renewable energy and energy efficiency resources leading to a reduction in emissions intensity. Idaho Power makes the following assumptions in using the EPA's building blocks as the basis for CAA Section 111(d) compliance:

- Boardman coal plant is reduced to a zero production level and retired by year-end 2020.
- North Valmy coal plant is reduced to a zero production level and retired as early as year-end 2019 or as late as year-end 2025; until retirement, Idaho Power's share of North Valmy is assumed to have an annual production constraint equal to its 2012 production level (IPC share = 814,264 MWh).
- Jim Bridger coal plant is reduced to a production level 53,320 MWh less than its 2012 production level of 4,541,712 MWh (IPC share); the re-dispatch of Jim Bridger is to a new 95-MW CCCT under construction in Wyoming.

- The Langley Gulch natural gas-fired plant is limited to one of three levels based on annual capacity factors of 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh).

- Renewable energy and energy efficiency resources are developed in Idaho to the EPA's proposed target levels.

## *Baseline CAA Section 111(d)*

Among the sensitivities developed for the 2015 IRP, Idaho Power selected a baseline sensitivity for the initial portfolio cost analysis. The baseline CAA Section 111(d) portfolio cost analysis assumes state-by-state mass-based compliance with Langley Gulch constrained at a 30 percent annual capacity factor. The selection of these assumptions for the baseline analysis is not a reflection of Idaho Power's preference for CAA Section 111(d), nor is it an indication of the company's view of the most probable CAA Section 111(d) outcome. Rather, it is selected to provide information in comparing costs between portfolios. The baseline costs identify portfolios for further analysis under other CAA Section 111(d) sensitivities and for the stochastic risk analysis. The results of the baseline CAA Section 111(d) sensitivity analyses are provided in Table 9.3.

**Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis)**

| Portfolio[1] | | | | Variable Costs | Fixed Costs[3] | Summary | | |
|---|---|---|---|---|---|---|---|---|
| Portfolio Index (1) | Portfolio Description (2) | B2H (3) | Coal Capacity Retirement (4) | Operating[2] (AURORA) (5) | Total Fixed Costs (6) | Total Fixed + Variable Costs (7) (7) = (5) + (6) | Lowest Cost Rank (8) | Lowest Cost Relative Difference (9) |
| P1 | Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions) | ✓ | | $4,306,018 | $110,689 | $4,416,707 | 1 | $0 |
| P9* | Valmy19_25 w/ DR, recips, B2H_25, SCCT | ✓ | ✓ | $4,489,655 | $30,933 | $4,520,588 | 2 | $103,880 |
| P11* | Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,418,783 | $130,594 | $4,549,377 | 3 | $132,670 |
| P2(a)* | B2H_25, recips, (no coal capacity retirement) | ✓ | | $4,461,356 | $110,689 | $4,572,046 | 4 | $155,338 |
| P8* | Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,445,028 | $129,423 | $4,574,450 | 5 | $157,743 |
| P10* | Bridger23_32 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,505,955 | $75,219 | $4,581,175 | 6 | $164,467 |
| P2(b) | B2H_23, recips, (no coal capacity retirement) | ✓ | | $4,456,215 | $136,570 | $4,592,785 | 7 | $176,078 |
| P6(b)* | Valmy25_25 w/B2H_25, DR, ice TES, CCCT | ✓ | ✓ | $4,492,228 | $102,944 | $4,595,171 | 8 | $178,464 |
| P6 | Valmy25_25 w/ B2H_25, CCCT | ✓ | ✓ | $4,492,934 | $111,303 | $4,604,237 | 9 | $187,529 |
| P13* | Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,507,342 | $100,935 | $4,608,277 | 10 | $191,570 |
| P2(c) | B2H_21, recips, (no coal capacity retirement) | ✓ | | $4,452,737 | $164,124 | $4,616,861 | 11 | $200,154 |
| P3* | Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,311,661 | $309,467 | $4,621,128 | 12 | $204,421 |
| P12 | Bridger23_28 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,541,071 | $100,730 | $4,641,800 | 13 | $225,093 |
| P18* | Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips | ✓ | ✓ | $4,464,898 | $179,429 | $4,644,327 | 14 | $227,619 |
| P4(c) | Valmy19_19 w/ battery, recips, B2H_21 | ✓ | ✓ | $4,539,309 | $105,904 | $4,645,213 | 15 | $228,506 |
| P4(b) | Valmy19_19 w/ battery, recips, B2H_23 | ✓ | ✓ | $4,528,608 | $180,442 | $4,709,050 | 16 | $292,343 |
| P4(a) | Valmy19_19 w/ battery, recips, B2H_25 | ✓ | ✓ | $4,521,759 | $188,424 | $4,710,183 | 17 | $293,475 |
| P17* | Bridger23_32 w/ ice TES, PV, CHP, recips, geothermal, CCCT, SCCT | | ✓ | $4,380,138 | $332,652 | $4,712,790 | 18 | $296,083 |
| P16* | Valmy19_25 w/ DR, recips, CCCT, SCCT | | ✓ | $4,518,985 | $197,652 | $4,716,637 | 19 | $299,930 |
| P14 | Ice TES, recips, CCCT, SCCT, (no coal capacity retirement) | | | $4,477,547 | $263,236 | $4,740,783 | 20 | $324,075 |
| P5 | Valmy19_19 w/ CCCT, B2H_25 | ✓ | ✓ | $4,482,891 | $281,412 | $4,764,303 | 21 | $347,595 |
| P15 | Valmy19_19 w/ battery, recips, SCCT, CCCT | | ✓ | $4,493,671 | $311,829 | $4,805,500 | 22 | $388,793 |
| P7 | Valmy25_25 w/ B2H_25, pumped storage | ✓ | ✓ | $4,509,228 | $487,899 | $4,997,127 | 23 | $580,419 |

Notes:

[1] All portfolios assume CAA Section 111(d) implementation except for P1.

[2] AURORA simulates the variable fuel and O&M costs and REC sales (when applicable). This includes the existing system, the effects of coal plant shutdowns (when applicable), plus the new portfolio resources and compliance with CAA Section 111(d) (when applicable). The reservation charge for new and existing natural gas plants is calculated in AURORA.

[3] Fixed costs of existing resources are excluded except as needed in accounting for coal-retirement portfolios.

* Denotes portfolios that were studied in the stochastic risk analysis

The selection of portfolios for further analysis indicated in Table 9.3 is based on the results of the baseline CAA Section 111(d) analyses as well as discussions held at IRPAC meetings in which participants voiced a desire to further analyze a relatively broad spectrum of portfolio types (e.g., portfolios with and without B2H).

## *CAA Section 111(d) Sensitivity Analysis Results*

The analysis of portfolio costs under the different CAA Section 111(d) sensitivities indicates that portfolio relative performance does not change significantly across the sensitivities; low-cost portfolios under the baseline CAA Section 111(d) sensitivity tend to have low costs under the other sensitivities. Cost impacts of CAA Section 111(d) are greatest when individual coal-plant dispatch decisions are mandated under a state-by-state approach. Likewise, the more severely Langley Gulch generation is reduced, the higher the cost of compliance. Cost impacts are least when the EPA's building blocks are the basis for CAA Section 111(d) compliance and Langley Gulch is assumed to be permitted to run up to a capacity factor of 70 percent (approximately 1.95 million MWh annually). Under the building block approach, Idaho Power assumes North Valmy can be operated at 2012 production levels (annually) until retirement and Jim Bridger can be operated at annual production levels 53,320 MWh less than 2012 production levels. For reference, P1 costs under the null sensitivity are $4,417 million. Table 9.4 provides the results of the CAA Section 111(d) sensitivity analysis.

**Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions)**

| | | State-by-State Mass-Based Compliance | | | System-Wide Mass-Based Compliance | Emissions-Intensity Compliance with Building Blocks | | |
|---|---|---|---|---|---|---|---|---|
| Portfolio | Portfolio Description | Langley Gulch at 30% Annual CF* | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF | | Langley Gulch at 30% Annual CF | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF |
| P1 | Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) |
| P2(a) | B2H_25, recips, (no coal capacity retirement) | $4,572 | $4,541 | $4,536 | $4,518 | N/A | N/A | N/A |
| P2(b) | B2H_23, recips, (no coal capacity retirement) | $4,593 | $4,563 | $4,557 | $4,539 | N/A | N/A | N/A |
| P2(c) | B2H_21, recips, (no coal capacity retirement) | $4,617 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P3 | Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW | $4,621 | $4,563 | $4,558 | $4,512 | $4,518 | $4,490 | $4,488 |
| P4(a) | Valmy19_19 w/ battery, recips, B2H_25 | $4,710 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P4(b) | Valmy19_19 w/ battery, recips, B2H_23 | $4,709 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P4(c) | Valmy19_19 w/ battery, recips, B2H_21 | $4,645 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P5 | Valmy19_19 w/ CCCT, B2H_25 | $4,764 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P6 | Valmy25_25 w/ B2H_25, CCCT | $4,604 | $4,571 | $4,568 | $4,536 | $4,517 | $4,485 | $4,480 |
| P6(b) | Valmy25_25 w/B2H_25, DR, ice TES, CCCT | $4,595 | $4,564 | $4,561 | $4,527 | $4,509 | $4,478 | $4,473 |
| P7 | Valmy25_25 w/ B2H_25, pumped storage | $4,997 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P8 | Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW | $4,574 | $4,541 | $4,538 | $4,503 | $4,485 | $4,458 | $4,455 |
| P9 | Valmy19_25 w/ DR, recips, B2H_25, SCCT | $4,521 | $4,494 | $4,490 | $4,455 | $4,438 | $4,408 | $4,410 |
| P10 | Bridger23_32 w/ SCCT, B2H_25, CCCT | $4,581 | $4,551 | $4,545 | $4,545 | N/A | N/A | N/A |

**Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) (continued)**

| Portfolio | Portfolio Description | State-by-State Mass-Based Compliance | | | System-Wide Mass-Based Compliance | Emissions-Intensity Compliance with Building Blocks | | |
|---|---|---|---|---|---|---|---|---|
| | | Langley Gulch at 30% Annual CF* | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF | | Langley Gulch at 30% Annual CF | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF |
| P11 | Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW | $4,549 | $4,511 | $4,506 | $4,510 | N/A | N/A | N/A |
| P12 | Bridger23_28 w/ SCCT, B2H_25, CCCT | $4,642 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P13 | Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT | $4,608 | $4,577 | $4,572 | $4,570 | $4,535 | $4,505 | $4,498 |
| P14 | Ice TES, recips, CCCT, SCCT, (no coal capacity retirement) | $4,741 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P15 | Valmy19_19 w/ battery, recips, SCCT, CCCT | $4,806 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P16 | Valmy19_25 w/ DR, recips, CCCT, SCCT | $4,717 | $4,682 | $4,672 | $4,530 | $4,639 | $4,606 | $4,600 |
| P17 | Bridger23_32 w/ ice TES, PV, CHP, recips, geotherm, CCCT, SCCT | $4,713 | $4,657 | $4,649 | $4,665 | N/A | N/A | N/A |
| P18 | Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips | $4,644 | $4,615 | $4,610 | $4,578 | $4,560 | $4,533 | $4,528 |

Note: Gray shaded cells not analyzed because no Valmy retirement is assumed (N/A) and/or baseline costs are too high.

* Baseline CAA Section 111(d) sensitivity.

## Stochastic Risk Analysis

The stochastic analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and to the degree they can affect the analysis results (i.e., portfolio costs).

Idaho Power identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Natural gas prices follow a log-normal distribution centered on the planning case forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2014. The serial correlation factor is 0.65.

2. *Customer load*—Customer load follows a normal distribution and is correlated with Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) as part of research conducted for the 2013 IRP to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

3. *Hydroelectric variability*—Hydroelectric variability follows a normal distribution. Idaho Power-owned hydroelectric generation is correlated with the Pacific Northwest regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from 1928 through 2009.

The three selected stochastic variables are key drivers of variability in year-to-year power supply costs and therefore provide suitable stochastic shocks to allow differentiated results for analysis.

The stochastic analysis was performed under the system-wide mass-based limits on $CO_2$ emissions. This assumption was selected because all eleven portfolios can comply with CAA Section 111(d) under this compliance approach. Moreover, the objective of the stochastic analysis is to determine the cost impact when portfolios are stochastically shocked. The purpose of the analysis is to understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations), and how the ranges for portfolios differ.

Idaho Power created a set of 100 iterations based on the three stochastic variables. Idaho Power then calculated the portfolio cost for eleven portfolios, where the eleven portfolios were selected based on results of the initial cost analysis under the baseline CAA Section 111(d) sensitivity or to provide a wide range of resource types (e.g., with and without B2H). Each stochastic iteration was reduced to one numerical value—the NPV of the total cost to serve customer load over the 20-year planning period. Figure 9.1 shows the stochastic analysis results.

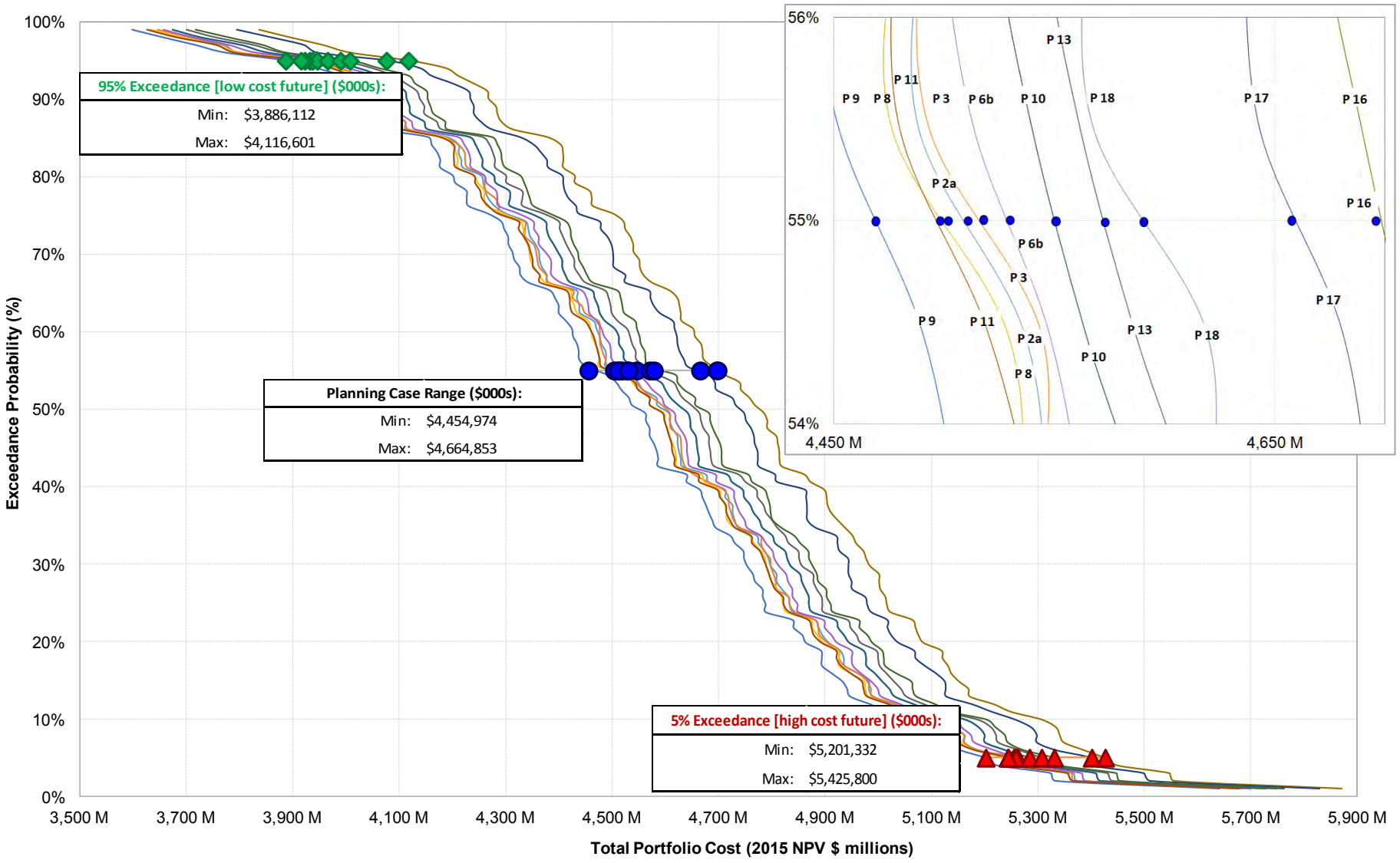


**Figure 9.1 Portfolio stochastic analysis**

In Figure 9.1, the horizontal axis is the portfolio cost (NPV) and the vertical axis is the exceedance probability. Each line on the figure corresponds to one of the eleven portfolios stochastically analyzed, and the line is the connection of ranked NPV observations for the 100 stochastic iterations. The figure illustrates portfolio costs at the 5-percent and 95-percent exceedance probabilities, as well as portfolio costs with planning case inputs for the three stochastic variables (natural gas, customer load, hydro condition). Reassuringly, the planning case results approximate well the 50-percent exceedance level.

Figure 9.1 illustrates portfolio P9, a North Valmy early retirement portfolio with B2H, is the least-cost portfolio for the full set of 100 iterations. Portfolios are relatively clustered across the top nine least-cost portfolios, with B2H alternative portfolios P16 and P17 somewhat set apart with higher costs.

While not easily discerned, there is some crossing of the portfolio-specific lines in Figure 9.1. Significant crossing of lines in the exceedance graph is an indication of substantial portfolio disparity; portfolio cost performance in this case is markedly different across the set of stochastic iterations. As an example, a portfolio consisting of exclusively natural gas-fired generation would be expected to conspicuously cross lines on Figure 9.1 as portfolio costs range greatly from low to high natural gas-price futures. Finally, the lack of significant crossing of lines is a testament to the resource diversity of Idaho Power's existing portfolio and the portfolios of new resources considered in the IRP; under no set of stochastic futures is a portfolio a clear and runaway cost winner, only to be countered by a different set of futures for which it is just as clearly a losing portfolio susceptible to significantly higher costs than other portfolios.

## *Portfolio Cost-Assessment of Year-to-Year Variability*

At the request of participants in the IRPAC process, Idaho Power expanded the stochastic analysis for the 2015 IRP to include an assessment of year-to-year portfolio cost variability. This assessment of year-to-year variability allows portfolios to be compared on the basis of their susceptibility to large year-to-year price swings. Idaho Power assesses the year-to-year variability by use of the standard deviation metric. For each stochastic iteration, the standard deviation of the 20-year stream of AURORA-determined variable costs (converted to base 2015 dollars) is calculated. Therefore, each of the eleven portfolios for which stochastic analysis is performed has 100 standard deviation measures corresponding to the 100 different stochastic iterations. Portfolios susceptible to large year-to-year price swings tend to have larger standard deviations.

An exceedance graph of the standard deviations for each of the eleven portfolios is shown as Figure 9.2. The exceedance graph indicates that P3, which adds just over 400 MW of utility-scale PV solar, is the least susceptible to large year-to-year swings. Portfolio P16, which adds more than 700 MW of natural gas-fired generating capacity, is the most susceptible to large year-to-year swings.

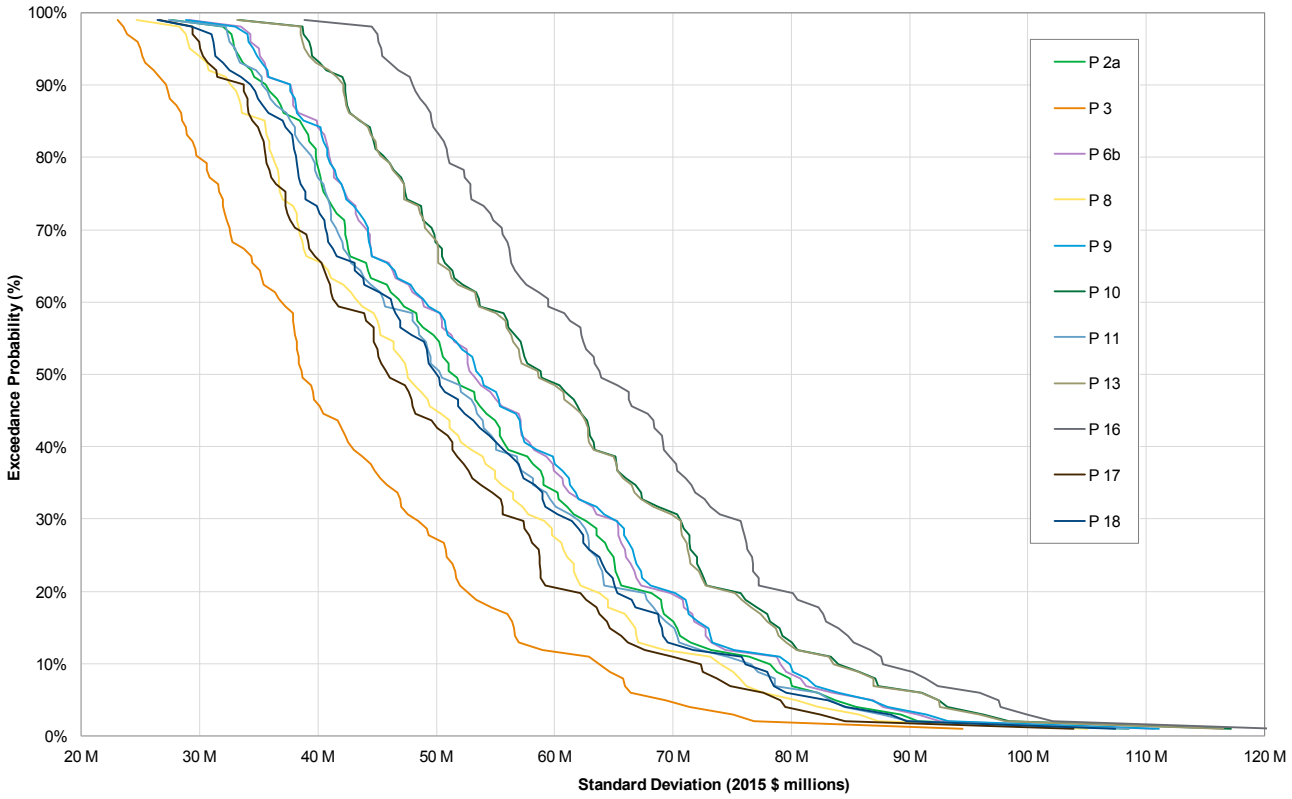


**Figure 9.2 Exceedance graph of standard deviations**

## Tipping-Point Analysis

To test the sensitivity of total portfolio cost to capital-cost estimates, Idaho Power conducted a tipping-point analysis for P3, which has a high penetration of utility-scale, single-axis PV solar, and P7, which has 300 MW of pumped-storage hydro. In the tipping-point analysis, the change in the total portfolio cost is determined as a function of change in the capital cost. The capital cost of the solar resource is varied for P3, and the capital cost of pumped-storage hydro is varied for P7. The percent change in the capital cost is relative to planning-case capital-cost estimates, where the solar resource under the planning case is estimated at $1,250 per kW (for capacity constructed in 2017 or later) and pumped-storage hydro is estimated at $5,000 per kW. A graph of the tipping-point analysis results is provided in Figure 9.3. As an example, the graph illustrates that a change in utility-scale, single-axis PV solar of -30 percent results in an estimated decrease in total portfolio costs for P3 of $50 million (NPV).

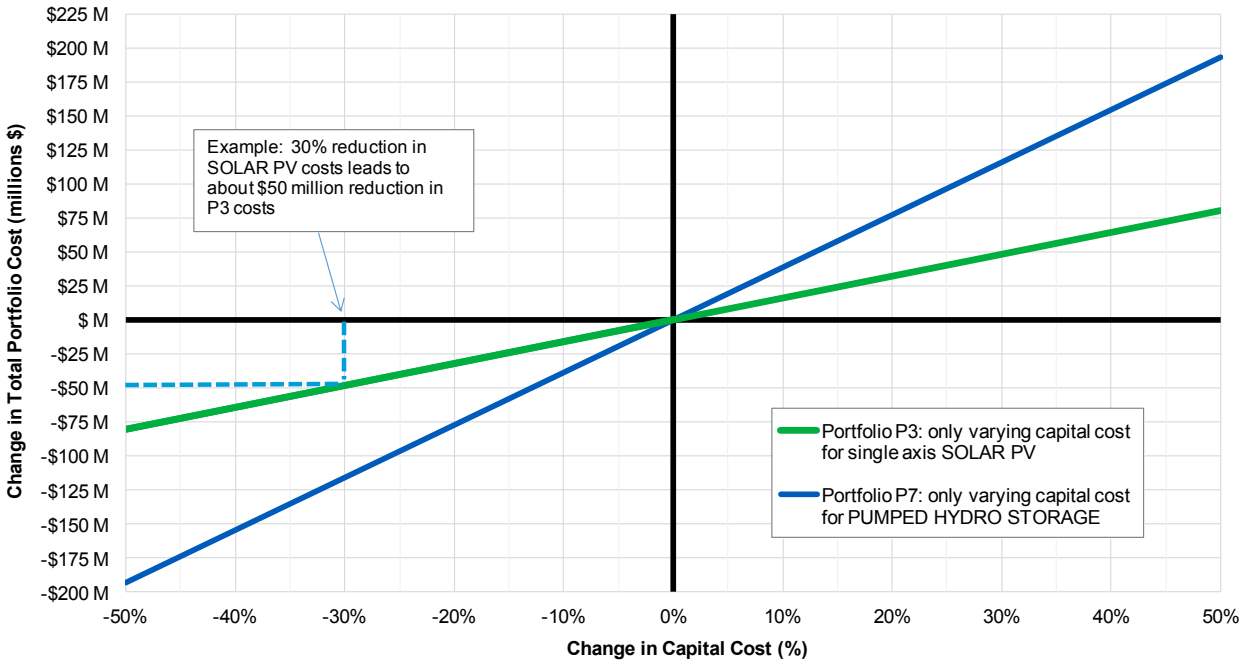


**Figure 9.3 Tipping-point analysis results**

## Portfolio Emissions

For the 2015 IRP, Idaho Power analyzed the total portfolio emissions for the 20-year planning period by the following four emission types:

1. $CO_2$—A greenhouse gas associated with climate change
2. $NO_x$—Contributes to regional haze
3. $SO_2$—Contributes to acid rain formation
4. Hg—A toxic element found in coal deposits

Total emissions by type were calculated using AURORA emissions modeling. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing resources. With the exception of portfolios retiring Jim Bridger units 1 and 2 without installation of $NO_x$-controlling environmental retrofits, all portfolios comply with environmental regulations. Illustrations of the four emission types for the eleven portfolios on which CAA Section 111(d) sensitivity and stochastic analyses were performed are provided in *Appendix C—Technical Appendix.*

## Qualitative Risk Analysis

The qualitative risks associated with the portfolios are more difficult to assess. The goal is to select a portfolio likely to withstand unforeseen events. The portfolios contain a diverse range of resource futures. Each future includes existing and new generating resources with different implementation, fuel, and technology risks. The following section highlights specific risks within

the portfolios, describes Idaho Power's interpretation of the risk profiles associated with each resource, and acknowledges that the portfolios may contain unique and differing risks.

## Existing Generation

### Hydro—Water-Supply Risk

The long-term sustainability of the Snake River Basin streamflows is important for Idaho Power to sustain hydro generation as a resource to meet future demand. Several assumptions related to the management of streamflows were made in developing the 20-year streamflow forecasts for the IRP. These assumptions include the following:

- The implementation of aquifer management practices on the ESPA, including aquifer recharge, system conversions, and the CREP
- Future irrigation demand and return flows
- Declines in reach gains tributary to the Snake River
- Expansion of weather-modification efforts (i.e., cloud seeding).

The assumptions used in developing the 20-year streamflow forecast are carefully planned and based on the current knowledge of Idaho Power staff in consultation with other stakeholders. Those assumptions are also subject to the limitations of the current models used in developing the twenty-year streamflow forecast for the 2015 IRP.

Additional risks to future hydro generation not included in the development of the 20-year streamflow outlook consist of the following:

- Changes in the timing and demand for irrigation water due to climate variability
- Changes to the sources of flow augmentation water and the potential for overestimation of flow augmentation availability in low-water years
- Long-term changes in the timing of flood control releases at Brownlee Reservoir in response to earlier snowmelt
- The potential for underestimation of the decline in reach gains within the Snake River Basin
- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

### Relicensing Risk

Working within the constraints of the original FERC licenses, the HCC has historically provided operational flexibility that has benefited Idaho Power's customers. The operational flexibility of the HCC is increasingly critical to the successful integration of variable energy resources. As a result of the FERC relicensing process, operational requirements, such as minimum

reservoir elevations, minimum flows, and limitations on ramping rates, may become more stringent. The loss of operational flexibility will limit Idaho Power's ability to optimally manage the HCC, making the integration of variable energy resources more challenging and ultimately increasing power supply costs.

### Fossil Fuel-Fired Power Generation and Proposed CAA Section 111(d) Regulation Risks

In 2014, the EPA released, under CAA Section 111(d), a proposed regulation for addressing greenhouse gas emissions from existing fossil fuel-fired electric generating units. The EPA's proposal requires states meet their goal by 2030, with interim goals from 2020 to 2029. The EPA stated it expects to finalize the rulemaking by summer 2015. State implementation plans would be due by June 20, 2016, subject to extensions for portions of the plan to June 30, 2017, for state plans or June 20, 2018, for multi-state plans, under certain circumstances. Since this is a proposed regulation, it is subject to interpretation and change. There is considerable uncertainty on the stipulations of the final regulation, and the resulting impact on fossil fuel-fired generation on Idaho Power's system and throughout the region.

### Regulatory risk

Idaho Power is a regulated utility with an obligation to serve customer load in its service area and is therefore subject to regulatory risk. Idaho Power expects that future resource additions and removals will be approved for inclusion in the rate base and that it will be allowed to earn a fair rate of ROIs related to resource actions of the IRP portfolios. Idaho Power includes public involvement in the IRP process through an IRPAC and by opening the IRPAC meetings to the public. The open public process allows a public discussion of the IRP and establishes a foundation of customer understanding and support for resource additions and removals when the plan is submitted for approval. The open public process reduces the regulatory risk associated with developing a resource plan.

### $NO_x$ Compliance Alternatives Risk

Portfolios with the early retirement of Jim Bridger units 1 and 2 assume these units are permitted to operate until retirement without installation of SCR retrofits necessary for compliance with EPA regional haze regulations. All other portfolios assume the SCR retrofits are installed on schedule in 2021 for Unit 2 and 2022 for Unit 1. The permitting associated with the Jim Bridger early retirement compliance alternatives is highly speculative at this point. An inability to successfully achieve permitting consistent with the assumptions of these compliance alternatives would likely have a significant effect on the costs and feasibility of portfolios with the early retirement of Jim Bridger units 1 and 2.

## *New Generation*

### Resource Commitment Risk

Idaho Power faces risk in the timing of, and commitment to, new resources. There are a number of factors that influence the actual timing of resource planning, including the pace of PURPA resource development, siting issues, partnership influences, and the performance of existing resources.

## PURPA Development

In the IRP's assessment of resource adequacy, Idaho Power assumes PURPA projects having signed contracts are part of system resources. The forecast of PURPA development is a unique challenge in the IRP's assessment of resource adequacy; PURPA development occurs independent of the IRP process and can abruptly alter resource adequacy. Idaho Power's practice is to include PURPA projects that are operational or under signed contract.

Since the 2015 IRP process began in late summer 2014, Idaho Power signed contracts for 461 MW of solar PURPA projects and has received inquiries for an additional 885 MW. Since including the 461 MW of solar contracts as part of committed system resources in the 2015 IRP, contracts for four solar PURPA projects totaling 141 MW have been terminated, leaving 320 MW still under contract. Table 9.5 illustrates the effect of removing the 141 MW of solar PURPA projects with terminated contracts on the 2015 IRP first deficit year.

**Table 9.5 First peak-hour capacity deficit effects of removing 141 MW of solar PURPA**

| Scenario | First deficit 2015 IRP | First deficit without 141 MW solar PURPA |
|---|---|---|
| Status quo | July 2025 | July 2024 |
| Maintain coal capacity | July 2025 | July 2024 |
| North Valmy retire units 1 and 2 year-end 2019 | July 2020 | July 2020 |
| North Valmy retire units 1 and 2 year-end 2025 | July 2025 | July 2024 |
| North Valmy retire Unit 1 year-end 2019 and Unit 2 year-end 2025 | July 2021 | July 2021 |
| North Valmy retire Unit 1 year-end 2021 and Unit 2 year-end 2025 | July 2022 | July 2022 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2028 | July 2024 | July 2024 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032 | July 2024 | July 2024 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032, North Valmy retire units 1 and 2 year-end 2025 | July 2024 | July 2024 |

As unbuilt resources, uncertainty persists in relation to the remaining 320 MW of solar PURPA projects. Further contract terminations will lead to earlier onsets of system deficiencies and may ultimately require Idaho Power to construct system resources earlier than expected and with larger capacities.

While uncertainty related to the potential over-forecasting of PURPA development is a critical risk element from the perspective of resource adequacy, PURPA development also carries the potential for under-forecasting. The potential for under-forecasting is evidenced by the October 13, 2014, filing of signed contracts for 401 MW of solar PURPA projects, out of the 461 MW in total; over the course of a day, the PURPA forecast grew by 401 MW. While under-forecasting does not jeopardize system resource adequacy, it does increase the likelihood that Idaho Power will encounter issues associated with energy oversupply during system operations. Issues associated with periodic energy oversupply have grown increasingly frequent over recent years. The expansion of variable and intermittent generation will increase this reliability challenge. The flexible-resource needs assessment performed for the 2015 IRP

corroborates concerns related to reliability impacts from periodic energy oversupply. The flexible resource needs assessment is described later in this chapter.

### Boardman to Hemingway transmission line

Significant challenges have been encountered during the permitting phase of the B2H transmission line. Environmental requirements related to siting of the transmission line have the potential to delay the project and increase permitting costs. The completion date of the project is subject to these siting, permitting, and regulatory approval requirements. The needs of the partners, PacifiCorp and BPA, also impact the in-service date.

### Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In July 2013, the NWPCC approved a charter for the Resource Adequacy Advisory Committee (RAAC). The RAAC's purpose is to assess power supply adequacy in the Northwest. Idaho Power has participated in the RAAC since its inception and also in the NWPCC's Resource Adequacy Forum, which preceded the RAAC.

The NWPCC adopted an adequacy standard used by the RAAC as a metric for assessing resource adequacy. The purpose of the resource adequacy standard is to provide an early warning should resource development fail to keep pace with demand growth. The analytical information generated with each resource adequacy assessment assists the regional utilities when preparing their individual IRPs. The statistic used to assess compliance with the adequacy standard is the likelihood of supply shortage, which is commonly known as the loss of load probability (LOLP). Under the adequacy standard, the LOLP is held to a maximum level of 5 percent.

The RAAC issued a draft report on an assessment of LOLP for the 2020 and 2021 operating years. The LOLP for the 2020 operating year is just under the 5 percent adequacy standard level. For the 2021 operating year, the LOLP increases to a little over 8 percent. The draft RAAC report indicates the increased LOLP for the 2021 operating year is the result of planned retirements of coal-fired generating capacity at Centralia, Washington, and the Boardman power plant. The RAAC adequacy assessment notes that the 2021 LOLP would be brought to below the 5 percent level by adding resources providing the equivalent of 1,150 MW of dispatchable generation. The RAAC also notes the LOLP analysis for both operating years does not include planned, new generating resources in the region, because these resources, while planned, have not yet been sited or licensed.

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2015 IRP analysis indicates Idaho Power resource deficits occur in the summer months, with July being the most critical month. The Northwest Regional Adequacy Assessment indicates that January, February, and to a lesser extent August are the most critical months for the overall Pacific Northwest region. The B2H transmission line is a regional resource that will assist Idaho Power and the larger Pacific Northwest in addressing their opposing seasonal capacity deficits.

The Idaho Power resource planning process is consistent with the NWPCC resource adequacy studies. The Idaho Power stochastic analysis indicates that even under high load,

high electricity/natural gas prices, and low water conditions, resource portfolios containing B2H are the lowest-cost portfolios.

### DSM implementation

While Idaho Power has considerable experience in DSM programs, there is always an implementation risk with a new program. The actual energy savings and peak reductions may vary significantly from the estimated amounts if customer participation rates are not achieved.

### New technologies

Many of the portfolios include technologies Idaho Power has limited experience in developing, building, or operating. This lack of direct experience increases the risk associated with the development of these resources, including the following:

- **Price Risk**: Cost estimates for solar are based on a 2014 Lazard report. While this report provides an objective, third-party estimate of resource costs, there is risk that trends in solar pricing may not be properly captured by the Lazard report.

- **Siting Risk**: Several of the technologies involve different risks associated with the type of resource being developed:

    - Fuel types, such as gas, may encounter public and political pressure against a project being located near load centers or being constructed at all.

    - Technologies, such as CHP and ice-based TES, would require a large commercial or industrial customer to partner with Idaho Power.

Geothermal, pumped storage, and canal drop hydro require the facility to be sited at the source of the motive force. These projects are often located in remote locations far from load centers, which increase the development and transmission costs associated with the resource.

## Preferred Portfolio

On the basis of the 2015 IRP's quantitative and qualitative analysis, the preferred portfolio selected by Idaho Power is P6(b). P6(b) balances the cost, risk, and environmental concerns identified in this IRP. The retirement of the North Valmy plant and the completion of B2H in 2025 balances the risks of CAA Section 111(d), increases in unplanned intermittent and variable generation, and is shown to be cost competitive. P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, P6(b) also adds a 300-MW CCCT. These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

## Analysis of Shoshone Falls Upgrade

For the 2015 IRP, Idaho Power analyzed the benefits and costs of the 50-MW expansion of the Shoshone Falls Power Plant. The incremental electrical generation the plant would produce with

the expansion is, on average, approximately 200 GWh annually. Using the AUROA model, an analysis was performed to determine the value this incremental hydro generation would provide to the system. The incremental generation is assumed to be eligible for RECs and the value of these certificates is included in the benefit calculation. The cost of the project was updated using 2015 IRP assumptions.

The analysis indicates that over the 20-year planning period, the incremental energy produced from the expansion is projected to yield a benefit to the preferred portfolio of approximately $13.8 million on an NPV basis under planning-case assumptions for natural gas price, customer load, and hydroelectric generation. However, as noted in Chapter 5, nearly 75 percent of the incremental energy in an average year will be produced during the six-month period from January through June, with substantially less production during July through September. Therefore, while the analysis indicates some economic benefit from the incremental energy, the 50-MW Shoshone Falls expansion cannot be linked to an IRP-determined resource need, as it provides little to no capacity or energy during peak summer load months.

As a result, Idaho Power will explore the construction of a smaller upgrade to more cost-effectively replace the aging 0.6 MW and 0.4 MW units at Shoshone Falls. The smaller upgrade will allow energy benefits to be realized through a much higher annual capacity factor and fulfill license requirements associated with the beneficial use of streamflow at the project location. Conceptual-level analysis indicates an upgrade having a capacity ranging in size from 1.7 MW to 4.0 MW is well suited for the hydraulic characteristics of the existing facilities. The cost analysis conducted as part of the conceptual-level study indicates energy from the smaller upgrade can be produced at a 40-year levelized cost of approximately $50 to $55 per MWh for the 4-MW upgrade and $60-$65 per MWh for the 1.7-MW upgrade. As indicated in the Action Plan in Chapter 10, Idaho Power will continue to study smaller-upgrade options and seek an amendment of the current FERC license to allow for the construction of a smaller-sized capacity upgrade to commence in 2017.

## Capacity Planning Margin

Idaho Power discussed planning criteria with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2015 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P6(b), the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources, assuming expected-case ($50^{th}$-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case ($50^{th}$-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio,

which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility or the loss of Langley Gulch. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin also results in the attainment of a loss-of-load expectation (LOLE) of roughly 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.6.

**Table 9.6 Capacity planning margin**

| | July 2015 | July 2016 | July 2017 | July 2018 | July 2019 | July 2020 | July 2021 | July 2022 | July 2023 | July 2024 | July 2025 | July 2026 | July 2027 | July 2028 | July 2029 | July 2030 | July 2031 | July 2032 | July 2033 | July 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | | | | | | | | | | | | | | | | | | | | |
| **Peak-Hour Forecast (50th%)** | (2,923) | (3,001) | (3,044) | (3,074) | (3,107) | (3,142) | (3,196) | (3,241) | (3,265) | (3,315) | (3,344) | (3,380) | (3,446) | (3,469) | (3,506) | (3,586) | (3,603) | (3,665) | (3,711) | (3,737) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | | | | | |
| Boardman | 55 | 55 | 55 | 55 | 55 | 55 | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Jim Bridger | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| North Valmy | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | 263 | – | – | – | – | – | – | – | – | – |
| **Coal Total** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Gas** | | | | | | | | | | | | | | | | | | | | |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Gas Total** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| **Hydroelectric** | | | | | | | | | | | | | | | | | | | | |
| Hydroelectric (50th%)—HCC | 1,192 | 1,194 | 1,199 | 1,199 | 1,202 | 1,199 | 1,196 | 1,193 | 1,190 | 1,187 | 1,184 | 1,181 | 1,178 | 1,175 | 1,172 | 1,169 | 1,167 | 1,164 | 1,161 | 1,158 |
| Hydroelectric (50th%)—Other | 295 | 295 | 295 | 295 | 295 | 295 | 294 | 293 | 293 | 292 | 291 | 290 | 289 | 289 | 288 | 287 | 287 | 286 | 285 | 284 |
| **Hydroelectric Total (50th%)** | 1,487 | 1,488 | 1,493 | 1,493 | 1,497 | 1,494 | 1,490 | 1,486 | 1,482 | 1,479 | 1,475 | 1,471 | 1,467 | 1,464 | 1,460 | 1,457 | 1,453 | 1,450 | 1,446 | 1,442 |
| **CSPP (PURPA) Total** | 156 | 220 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 404 | 404 | 404 | 401 | 400 | 390 | 389 | 380 | 380 |
| **PPAs** | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | – | – | – | – | – | – | – |
| Raft River Geothermal | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Neal Hot Springs Geothermal | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Clatskanie Exchange—Take | 10 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Clatskanie Exchange—Return | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| **PPAs Total** | 33 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |

**Table 9.6 Capacity planning margin (continued)**

| | July 2015 | July 2016 | July 2017 | July 2018 | July 2019 | July 2020 | July 2021 | July 2022 | July 2023 | July 2024 | July 2025 | July 2026 | July 2027 | July 2028 | July 2029 | July 2030 | July 2031 | July 2032 | July 2033 | July 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Pacific Northwest Import Capability Total** | 243 | 243 | 239 | 234 | 230 | 227 | 224 | 273 | 270 | 266 | 261 | 257 | 254 | 249 | 245 | 242 | 238 | 234 | 230 | 230 |
| **Existing Resource Subtotal** | 3,656 | 3,711 | 3,897 | 3,892 | 3,892 | 3,886 | 3,824 | 3,869 | 3,862 | 3,854 | 3,846 | 3,574 | 3,567 | 3,554 | 3,544 | 3,535 | 3,518 | 3,510 | 3,493 | 3,489 |
| **Monthly Surplus/Deficit** | 733 | 710 | 853 | 818 | 785 | 743 | 628 | 628 | 597 | 540 | 501 | 194 | 121 | 85 | 38 | (51) | (84) | (156) | (218) | (248) |
| **2013 IRP Resources** | | | | | | | | | | | | | | | | | | | | |
| 2025 B2H | – | – | – | – | – | – | – | – | – | – | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2030 Demand Response | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 60 | 60 | 60 | 60 | 60 |
| 2030 Ice-Based TES | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 20 | 20 | 20 | 20 | 20 |
| 2031 CCT | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | 500 | 500 | 500 | 500 | 500 | 580 | 880 | 880 | 880 | 880 |
| **Remaining Monthly Surplus/Deficit** | 733 | 710 | 853 | 818 | 785 | 743 | 628 | 628 | 597 | 540 | 1,001 | 694 | 621 | 585 | 538 | 529 | 796 | 724 | 662 | 632 |
| **Planning Margin** | 25% | 24% | 28% | 27% | 25% | 24% | 20% | 19% | 18% | 16% | 30% | 21% | 18% | 17% | 15% | 15% | 22% | 20% | 18% | 17% |

## Flexible Resource Needs Assessment

Idaho Power analyzed the need for flexible resources as directed by the OPUC in Order 12-013. Idaho Power determined there are adequate flexible resources to address up-regulation (up-regulation is required when intermittent generation is less than the quantity scheduled and Idaho Power generation must overcome the generation shortfall). Idaho Power determined there are likely to be insufficient down-regulation resources available at certain times of the year. Specifically, down-regulation deficiencies occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load.

Idaho Power analyzed the flexible resource needs using the data developed for the solar integration study. The data consisted of actual load, actual wind, and simulated PV solar generation for 500 MW of solar plant at six geographic locations throughout Idaho Power's service area. The data were developed at five-minute intervals over three water years from October 2010 through September 2013.

The first step in the analysis was to estimate the flexible resource requirement. Idaho Power calculated the flexible need requirement in 5-, 10-, 15-, 30-, 45-, and 60-minute intervals from the dataset, and the results are presented in Figure 9.4. The one-percent likelihood shown in Figure 9.4 is the total likelihood, composed of one-half percent up plus a one-half percent down.

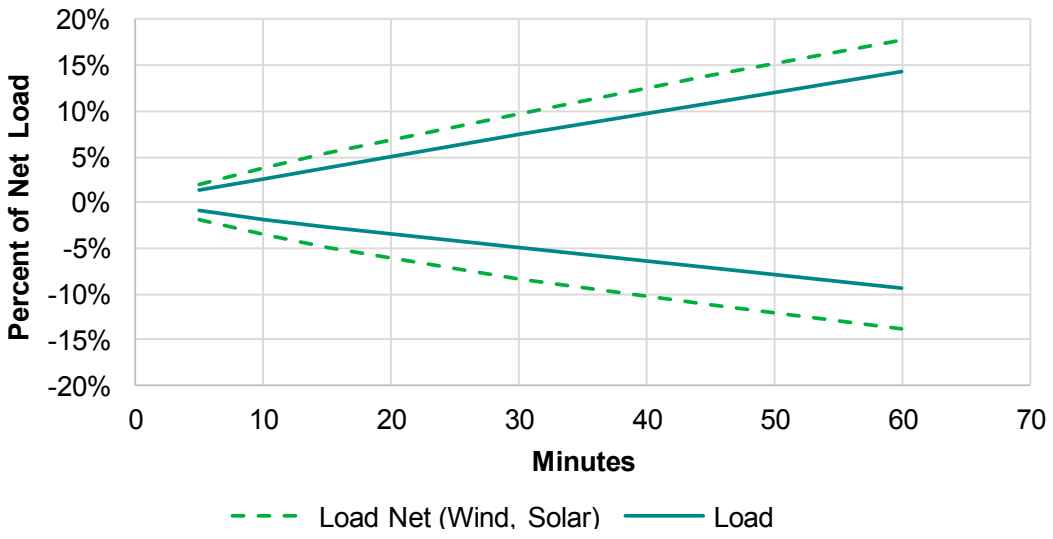


**Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood)**

Figure 9.4 shows that adding intermittent resources to the Idaho Power system increases the flexibility need, both up and down. Idaho Power has a second solar integration study underway to further analyze the effects of adding intermittent utility-scale solar PV generation to Idaho Power's system.

Idaho Power used a resource dispatch simulation of Idaho Power's system to forecast available system flexibility after adding 500 MW of solar PV to the generation mix. The purpose of the simulation was to assess both the regulation requirement and supply. The simulation was performed using a one-hour time step. Up-regulation and down-regulation quantities were assessed to determine the net result of flexible resource needs and flexible resource supply. A representative graph of system regulation during the spring is shown in Figure 9.5 (April 2012 historical data with the addition of 500 MW of solar PV on the system).

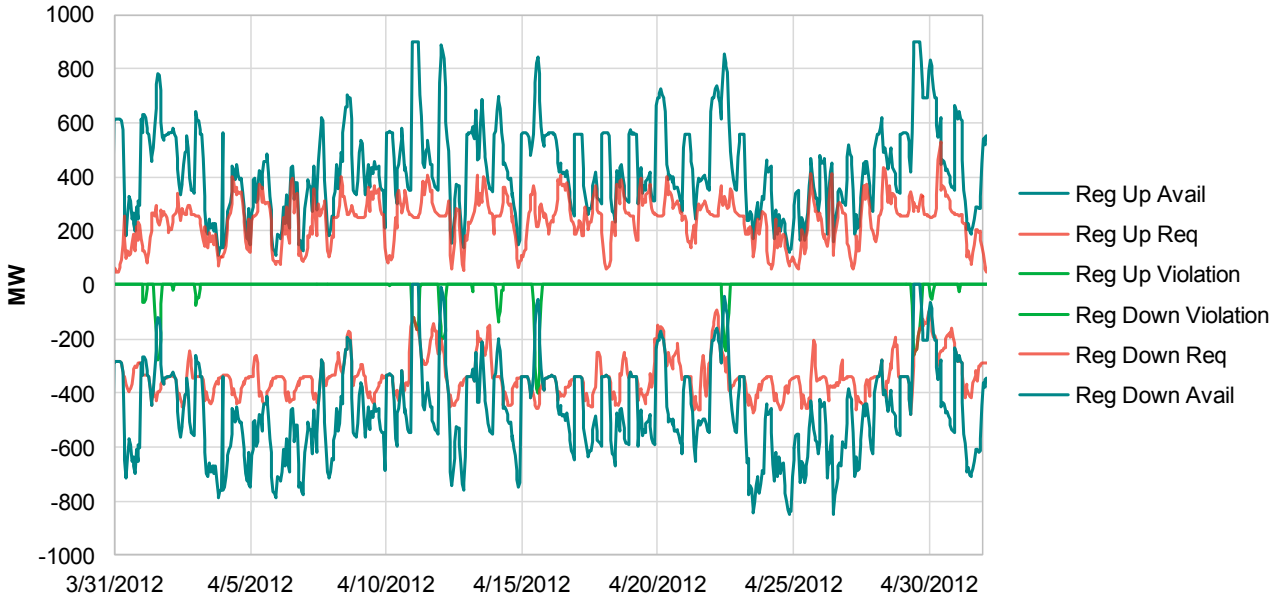


**Figure 9.5 System regulation**

Figure 9.5 shows the five quantities:

1. Up-regulation available
2. Up-regulation requirement
3. Regulation violation (both up and down)
4. Down-regulation requirement
5. Down-regulation available

Figure 9.6 is simplified to focus on the regulation violation by removing the lines showing the regulation requirement and the regulation available.

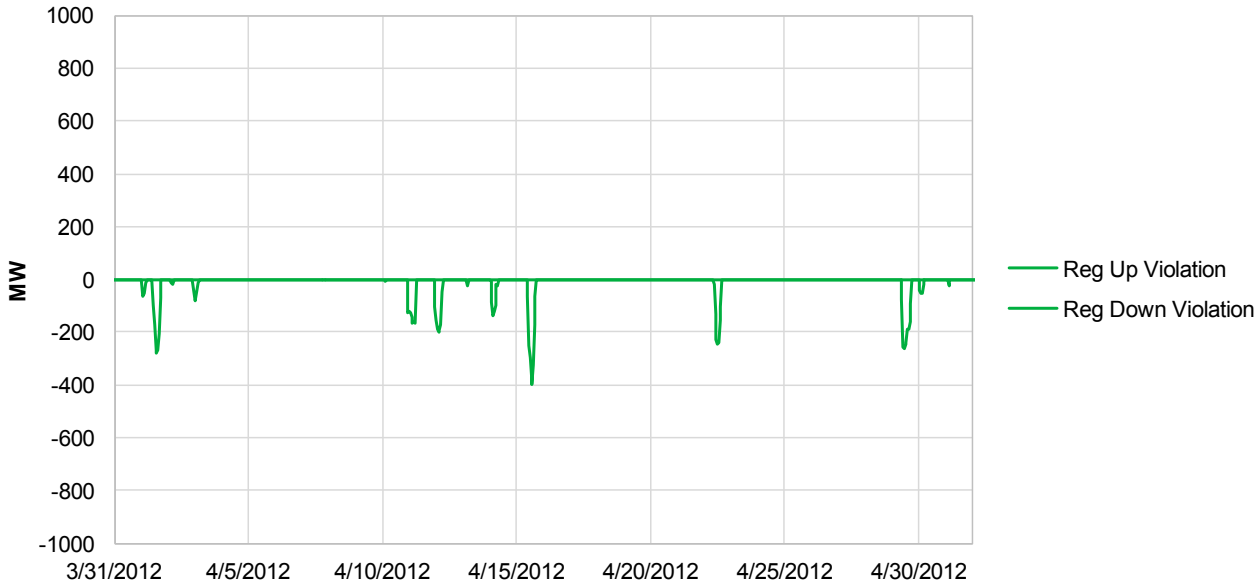


**Figure 9.6 Regulation violations, spring 2012**

Figure 9.6 shows significant down-regulation violations during certain hours of the spring. The down-regulation violations occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load. There are no up-regulation violations during the April study period.

Idaho Power analyzed the other three seasons of the year and determined that regulation is primarily an issue during the spring. The graphs for summer, fall, and winter are shown in figures 9.7 through 9.9.




**Figure 9.7 Regulation violations, summer 2012**




**Figure 9.8 Regulation violations, fall 2011**

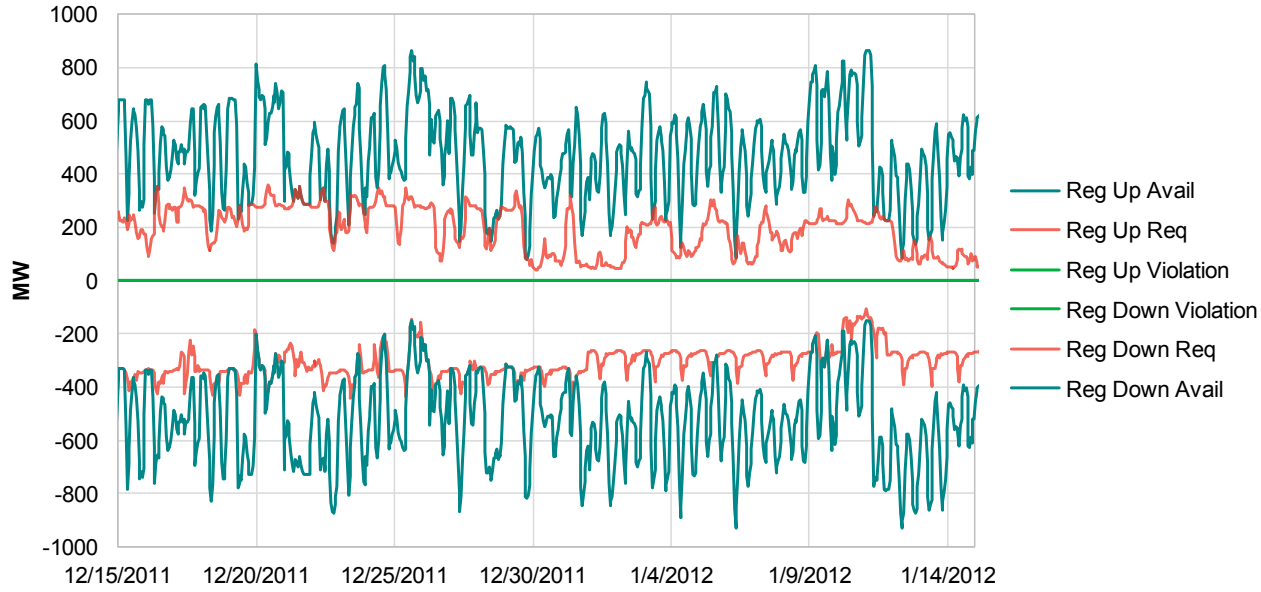


**Figure 9.9 Regulation violations, winter 2011/2012**

As shown in figures 9.7 through 9.9, zero violations are evident through the summer, fall, and winter seasons, except a single small down-regulation violation in one hour of the summer season. The summer down-regulation violation is less than 10 MW; however, down-regulation violations could become an issue during some summer hours. Several times during the four seasons, the regulation available equals the regulation requirement, indicating Idaho Power's system is operating at the regulation limits. The simulations show it is more likely for Idaho Power's system to face down-regulation limits than up-regulation limits.

Idaho Power is currently conducting a second solar integration study. Idaho Power anticipates additional regulation analysis will occur as part of the second solar integration study. Idaho Power expects to update the flexibility analysis with the results of the second solar integration study in the 2017 IRP. Down-regulation is a significant concern during periods of oversupply for Idaho Power and other utilities in the region. Idaho Power is currently investigating methods to address potential down-regulation violations.

## Loss of Load Expectation

Idaho Power used a spreadsheet model[10] to calculate the LOLE for the 11 portfolios studied in the stochastic risk analysis in the 2015 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the selected portfolios. As mentioned in the Capacity Planning Margin section, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require the use of the transmission capacity. The 2015 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator and purchase outage rates (equivalent demand forced outage rates), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load for the 10 peak days in a given year, although existing programs allow use up to 15 days. The 10-day assumption was chosen as a conservative reflection of reality where it is assumed some days will be left in reserve for unexpected extreme weather. Ice TES resources were modeled as a reduction to hourly load during afternoon/evening hours in summer months and an increase in hourly load during night hours in summer months. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a lack of fuel (water). Resource capacities are assumed to be constant for all hours each month with the exception of demand response and ice TES as explained above, as well as solar PV resources. PV resources are modeled with a capacity that varies by hour for each month according to changing daylight hours and sun position.

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power chose to calculate a LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5 to 1 hours per year.

The results of the LOLE probability analysis are shown in Figure 9.10. Several portfolios result in a LOLE greater than 2 hours per year, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The results indicate that resource portfolios 2(a), 6(b), 8, 10, 11, and 13 are the best performers with an LOLE under two hours per year over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

[10] Based on Roy Billinton's *Power System Reliability Evaluation*, chapters 2 and 3. 1970.

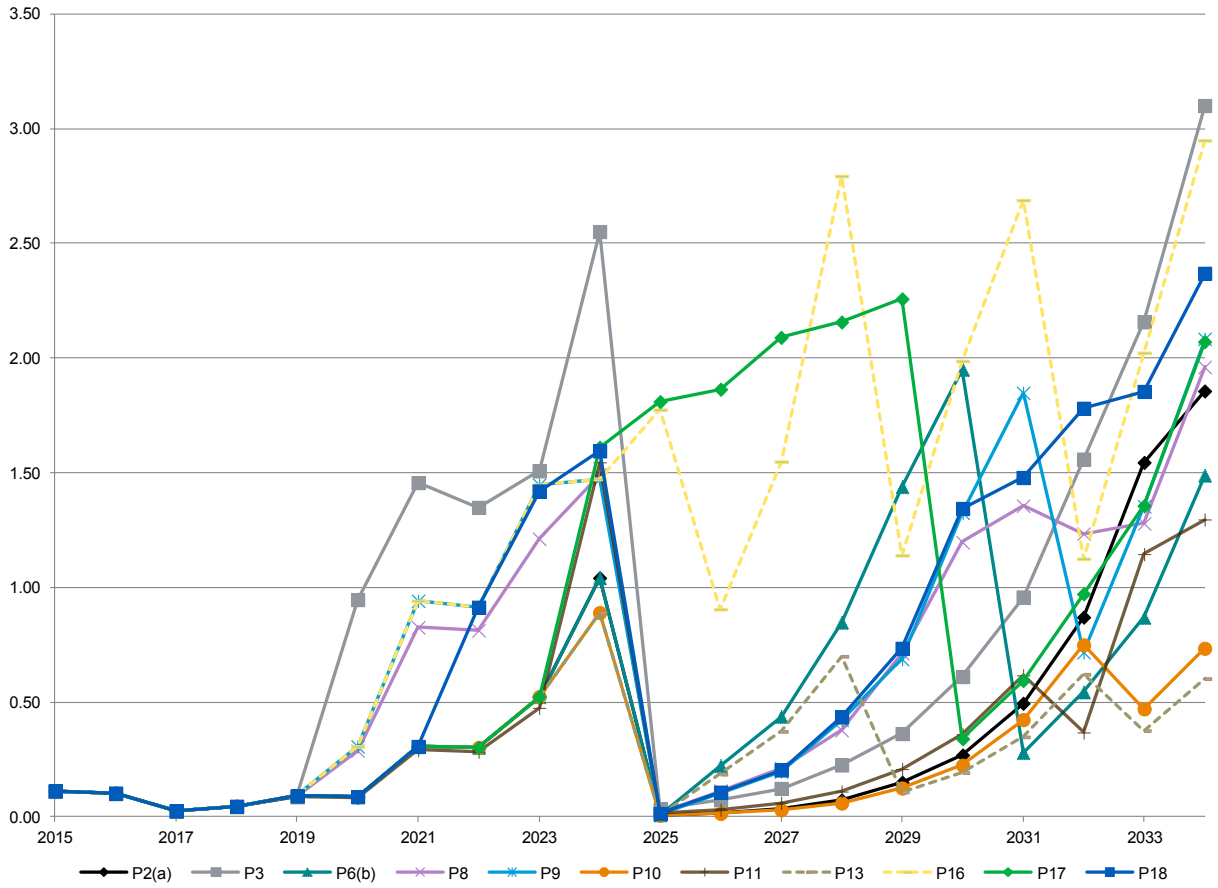


**Figure 9.10 LOLE (hours per year)**

# 10. Preferred Portfolio and Action Plan

## Preferred Portfolio (2015–2034)

Analysis for the 2015 IRP consistently indicates favorable economics associated with two significant resource actions: the B2H transmission line and the early retirement of the North Valmy Power Plant. IRP analysis suggests a strong connection between these resource actions, both of which are characterized by uncertain timetables. Specifically, an acceleration in the completion of the B2H line can be expected to provide the system reliability and access to markets allowing for a corresponding acceleration in the early retirement of North Valmy.

The B2H transmission line and early North Valmy retirement are two key resource actions of portfolio P6(b), the 2015 IRP's preferred resource portfolio. Portfolio P6(b) contains both actions in the year 2025, with the completion of the transmission line preceding the end-of-year coal plant retirement. Portfolio P6(b) contains no other resource actions through the end of the 2020s, adding 60 MW of demand response and 20 MW of ice-based TES in 2030 and a 300-MW CCCT in 2031.

The absence of resource needs in portfolio P6(b) prior to the 2025 retirement of North Valmy is noteworthy. The resource sufficiency through the early 2020s shields portfolio P6(b) from risk exposure associated with the following factors:

1. Uncertainty related to planned but yet-to-be-built PURPA solar; further project cancellations beyond those already observed will have a greater impact on portfolios requiring capacity additions in the early 2020s.

2. Uncertainty related to the EPA's proposed regulation of $CO_2$ emissions from existing power plants under CAA Section 111(d), particularly the effect of the final regulation on operations at coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020.

3. Uncertainty related to the completion date of the B2H line due to permitting issues and needs of project partners.

4. Uncertainty related to retirement planning for a jointly owned power plant (North Valmy), specifically the challenges associated with arriving at a mutually feasible retirement date.

Uncertainty is a common part of long-term integrated resource planning. Even with the increased uncertainty surrounding the 2015 IRP, the analysis indicates completion of the B2H line and early retirement of the North Valmy Power Plant are prudent actions. The timing of the actions can be appropriately adjusted as conditions related to the four factors listed above become actionable.

## Action Plan (2015–2018)

The action plan for the 2015 to 2018 period includes items specifically related to the preferred portfolio P6(b) and other items irrespective of the portfolio selected. The P6(b) action items

include continued permitting and planning for the B2H transmission line and investigation of North Valmy retirement in collaboration with plant co-owner NV Energy. The pursuit of these items over the action plan period is critical to the successful and timely implementation of the preferred portfolio.

The Gateway West transmission line remains a key future resource to Idaho Power and the region, promoting continued grid reliability in a time of expanding variable energy resources. Therefore, the plan includes continued permitting and planning associated with the Gateway West project.

CAA Section 111(d) will potentially have a pronounced impact on coal and natural gas-fired power plant operations on Idaho Power's system and throughout the nation. Idaho Power will remain involved as a stakeholder as CAA Section 111(d) moves toward finalization and implementation. As stipulations of the final regulation become clearer, and as implementation planning is developed, Idaho Power will assess the impacts of CAA Section 111(d) on the preferred portfolio.

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups such as NEEA
- Filing to amend the FERC license to adjust the 50-MW Shoshone Falls project expansion and efforts related to the study and construction a smaller upgrade of the project with a scheduled on-line date in the first quarter of 2019
- Completion of SCR retrofits for Jim Bridger units 3 and 4
- Begin economic evaluation of SCR retrofits for Jim Bridger units 1 and 2 (SCR installation required for Unit 1 in 2022 and for Unit 2 in 2021)

Table 10.1 provides actions with dates for the 2015 to 2018 period.

**Table 10.1 Action plan (2015–2018)**

| Year | Resource | Action | Action Number |
|---|---|---|---|
| 2015–2018 | B2H | Ongoing permitting, planning studies, and regulatory filings | 1 |
| 2015–2018 | Gateway West | Ongoing permitting, planning studies, and regulatory filings | 2 |
| 2015–2019 | Energy efficiency | Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand. | 3 |
| 2015–2016 | N/A | Coordinate with government agencies on implementation planning for CAA Section 111(d). | 4 |
| 2015 | Shoshone Falls | File to amend FERC license regarding 50-MW expansion | 5 |
| 2015 | Jim Bridger Unit 3 | Complete installation of SCR emission-control technology | 6 |
| 2015-2016 | Shoshone Falls | Study options for smaller upgrade ranging in size up to approximately 4 MW | 7 |
| 2016 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | 8 |

**Table 10.1 Action Plan (2015–2018) (continued)**

| Year | Resource | Action | Action Number |
|---|---|---|---|
| 2016 | North Valmy units 1 and 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | 9 |
| 2017 | Shoshone Falls | Commence construction of a smaller upgrade | 10 |
| 2017 | Jim Bridger units 1 and 2 | Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP | 11 |
| 2019 | Shoshone Falls | On-line date for smaller upgrade during first quarter | 12 |

Idaho Power has several choices when procuring long-term energy. It can develop and own generation assets, rely on PPA and market purchases, or use a combination of the two strategies. During the action plan period, Idaho Power expects to continue participating in the regional power market and enter into mid- and long-term PPAs. However, in the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate-of-return advantages inherent in a regulated electric utility.

## Conclusion

The 2015 IRP analysis indicates favorable results for the B2H transmission line and the early retirement of the North Valmy Power Plant. The analysis also suggests a linkage between the B2H line and the early retirement of North Valmy. Acceleration in the completion of the transmission line could bring about a corresponding acceleration in scheduling for North Valmy retirement.



View of the Hemingway Substation.

Idaho Power has treated the B2H transmission line as an uncommitted resource in every IRP beginning with the 2006 IRP. For every IRP, including the 2015 IRP, the B2H line has been a top-performing resource alternative. The consistency of these analyses indicates it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the B2H transmission line.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2015 IRP. The IRPAC discussed many technical aspects of the 2015 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to an Idaho Power facility. Idaho Power's resource plan is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2017. As described in this plan, the coming years are characterized by considerable uncertainty

associated with energy-related issues on the state, regional, and national levels. Idaho Power anticipates that as uncertainty related to these issues clears, the 2015 IRP preferred portfolio and action plan may be adjusted in the next IRP filed in 2017, or sooner if directed by the IPUC or OPUC.

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June 2015

# Integrated Resource Plan 2015

## APPENDIX A
## Sales and Load Forecast







## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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June 2015

# Integrated Resource Plan 2015

## APPENDIX A
## Sales and Load Forecast

## ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... ii
List of Figures ..... ii
List of Appendices ..... iii
Introduction ..... 1
2015 IRP Sales and Load Forecast ..... 3
Average Load ..... 3
Peak-Hour Demands ..... 4
Overview of the Forecast ..... 7
Fuel Prices ..... 8
Electric Vehicles ..... 10
Forecast Probabilities ..... 11
Load Forecasts Based on Weather Variability ..... 11
Load Forecasts Based on Economic Uncertainty ..... 12
Residential ..... 15
Commercial ..... 17
Irrigation ..... 21
Industrial ..... 23
Additional Firm Load ..... 25
Micron Technology ..... 26
Simplot Fertilizer ..... 26
Idaho National Laboratory ..... 26
Company System Peak ..... 27
Company System Load ..... 29
Contract Off-System Load ..... 31
Energy Efficiency and Demand Response ..... 33
Energy Efficiency ..... 33
Demand Response ..... 34

# LIST OF TABLES

Table 1. Residential fuel-price escalation (2015–2034) (average annual percent change) ....8
Table 2. Average load and peak-demand forecast scenarios ....12
Table 3. Forecast probabilities ....13
Table 4. System load growth (aMW) ....14
Table 5. Residential load growth (aMW) ....15
Table 6. Commercial load growth (aMW) ....17
Table 7. Irrigation load growth (aMW) ....21
Table 8. Industrial load growth (aMW) ....23
Table 9. Additional firm load growth (aMW) ....25
Table 10. System summer peak load growth (MW) ....27
Table 11. System winter peak load growth (MW) ....28
Table 12. System load growth (aMW) ....29

# LIST OF FIGURES

Figure 1. Forecast residential electricity prices (cents per kWh) ....9
Figure 2. Forecast residential natural gas prices (dollars per therm) ....10
Figure 3. Forecast system load (aMW) ....14
Figure 4. Forecast residential load (aMW) ....15
Figure 5. Forecast residential use per customer (weather-adjusted kWh) ....16
Figure 6. Forecast commercial load (aMW) ....17
Figure 7. Commercial building share ....18
Figure 8. Forecast commercial use per customer (weather-adjusted kWh) ....19
Figure 9. Commercial categories UPC, 2014 relative to 2010 ....19
Figure 10. Forecast irrigation load (aMW) ....21
Figure 11. Forecast industrial load (aMW) ....23
Figure 12. Industrial electricity consumption by industry group (based on 2014 sales) ....24
Figure 13. Forecast additional firm load (aMW) ....25
Figure 14. Forecast system summer peak (MW) ....27
Figure 15. Forecast system winter peak (MW) ....28

Figure 16. Forecast system load (aMW) ....29
Figure 17. Composition of system company electricity sales (thousands of MWh)....30

## LIST OF APPENDICES

Appendix A1. Historical and Projected Sales and Load ....35
Residential Load ....35
Historical Residential Sales and Load, 1974–2014 (weather adjusted)....35
Projected Residential Sales and Load, 2015–2034 ....36
Commercial Load....37
Historical Commercial Sales and Load, 1974–2014 (weather adjusted)....37
Projected Commercial Sales and Load, 2015–2034 ....38
Irrigation Load ....39
Historical Irrigation Sales and Load, 1974–2014 (weather adjusted)....39
Projected Irrigation Sales and Load, 2015–2034....40
Industrial Load....41
Historical Industrial Sales and Load, 1974–2014 (not weather adjusted) ....41
Projected Industrial Sales and Load, 2015–2034....42
Additional Firm Sales and Load* ....43
Historical Additional Firm Sales and Load, 1974–2014 ....43
Projected Additional Firm Sales and Load, 2015–2034 ....44
Company System Load (excluding Astaris) ....45
Historical Company System Sales and Load, 1974–2014 (weather adjusted) ....45
Projected Company System Sales and Load, 2015–2034....46

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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2015 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2015 through 2034.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. To account for inherent uncertainty and variability, four additional load forecasts were prepared—two that provide a range of possible load growths due to economic uncertainty and two that address the load variability associated with abnormal weather. The high and low economic growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

While the expected-case load forecast assumes median historical values (50$^{th}$ percentile) for temperatures and median rainfall, the weather scenarios are developed with a 70$^{th}$-percentile and a 90$^{th}$-percentile weather probability assumption. The 70$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time). Idaho Power uses the 70$^{th}$-percentile load forecast in IRP resource planning to account for the risk associated with weather impacts on load.

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,240 average megawatts (aMW) by 2034 from 1,786 aMW in 2015, representing an average yearly growth rate of 1.2 percent over the 20-year planning period (2015–2034). In the more critical 70$^{th}$-percentile load forecast used for resource planning, the system load is forecast to reach 2,292 aMW by 2034 (1.2% average annual growth).

The Idaho Power system peak load (95$^{th}$ percentile) is forecast to grow to 4,773 megawatts (MW) in 2034 from the actual system summer peak of 3,407 MW that occurred on Tuesday, July 2, 2013, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.5 percent per year over the 20-year planning period (2015–2034).

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc. The national, state, metropolitan statistical area (MSA) and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*. The number of Idaho Power active retail customers is expected to increase from the December 2014 level of 514,700 customers to nearly 710,000 customers by year-end 2034.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual rate of 1.9 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. In addition, the number of households, incomes, employment, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussions of these assumptions are presented below.

Conservation influences on the load forecast, including Idaho Power energy efficiency demand-side management (DSM) programs, statutory programs, and non-programmatic trends in conservation, are included in the load forecasts of each sector. Idaho Power DSM programs are described in detail in Idaho Power's *Demand-Side Management 2014 Annual Report*, which is incorporated into this IRP document as Appendix B.

During the 20-year forecast horizon, major changes in the electric utility industry (e.g., carbon regulations and subsequent higher electricity prices impacting future electricity demand) could influence the load forecast. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously. The impact of carbon legislation on the load forecast is reflected in the retail electricity price variable for each forecasted customer sector. The alternative sales and load scenarios in *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

Data describing the historical and projected figures for the sales and load forecast are presented in Appendix A1 of this report.

# 2015 IRP SALES AND LOAD FORECAST

## Average Load

The 2015 IRP average annual system load forecast reflects the continued improvement in the service area economy. While economic conditions during the development of the 2013 IRP were positive, they were less optimistic than the actual performance experienced in the interim period leading up to the 2015 IRP. The improved economic and demographic variables driving the 2015 forecast are reflected by a more positive sales outlook throughout the planning period. The stalled recovery in the national and, to a lesser extent, service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic drivers to date. Retail electricity price projections for the 2015 IRP are lower relative to the 2013 IRP, serving to increase the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2015 IRP load forecast include the following:

- The load forecast used for the 2015 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector beginning in 2008 held new construction and customer growth to a near standstill until 2012. However, beginning in 2012, acceleration of in-migration and business investment resulted in renewed growth in the residential and commercial connections along with increased industrial activity. By 2017, customer additions are forecast to approach sustainable growth rates experienced prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflects the impact of additional plant investment and associated variable costs of integrating new resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions. As discussed previously, when compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yields lower future prices. The retail prices are most evident in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. Nonetheless, the expected load forecast reflects only those industrial customers that have made a sufficient and significant binding investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., are treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have taken advantage of higher market prices over the past few years and have put high-lift acreage back into production. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs.

## Peak-Hour Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The 2015 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2015 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the $50^{th}$, $90^{th}$, and $95^{th}$ percentiles of occurrence for each month of the year.

- The all-time system summer peak demand was 3,407 MW (recorded on Tuesday, July 2, 2013, at 4:00 p.m.) and serves as a benchmark for the forecasting model. The previous summer peak demand was 3,245 MW, occurring on Thursday, July 12, 2012, at 4:00 p.m. Historical peak-demand data serve as the basis in the peak-model regressions. Historical new peak loads were reached in July 2007, June 2008, July 2012, and July 2013.

- The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

- Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1984 to 2013 time period (the most recent 30 years).

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# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers are reported as a single forecast category labeled additional firm load. Currently, Idaho Power has no long-term contracts to provide off-system customers with firm energy and demand. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be converted from billed periods to calendar months to synchronize them with the time period in which load is generated. The calendar-month sales are then converted to calendar-month average load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the loss coefficients are lower than those applied to the 2013 IRP generation forecast. This resulted in a permanent reduction of nearly 20 aMW to the load forecast annually.

The peak-load forecast was prepared in conjunction with the 2015 sales forecast. Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive A/C use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis, customer-provided input, and any contractual considerations.

The primary external factors influencing the forecast are economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Construction Monitor, and Federal Reserve Economic Databases.

## Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. In addition to supply-side influences, carbon-reduction legislation creates an upward trend in retail electricity prices throughout the forecast period, resulting in reduced future electricity sales. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2015–2034) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2015 IRP | 1.9% | 0.0% |
| Electricity—2013 IRP | 2.9% | 1.0% |
| Natural Gas | 3.2% | 1.3% |

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1979 to 2014 and over the forecast period 2015 to 2034. Both nominal and real prices are shown. In the 2015 IRP, nominal electricity prices are expected to climb to about 14 cents per kilowatt-hour (kWh) by the end of the forecast period in 2034. Real electricity prices (inflation adjusted) are expected to remain flat over the forecast period at an average rate of 0.0 percent annually. In the 2013 IRP, nominal electricity prices were assumed to climb to about 18 cents per kWh by 2034, and real electricity prices (inflation adjusted) were expected to slowly increase over the forecast period at an average rate of 1.0 percent annually. The impact of the lower real electricity price forecast on the 2015 IRP load forecast serves to positively influence the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yielded lower future prices. The retail prices are more evidently lower in the

second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

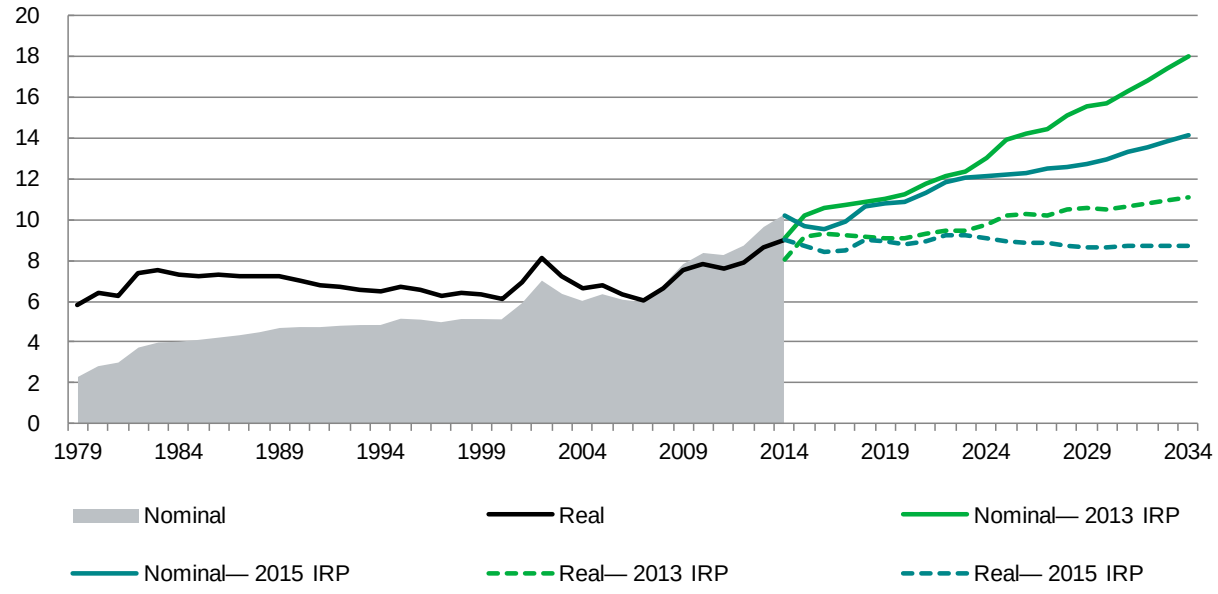


**Figure 1. Forecast residential electricity prices (cents per kWh)**

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1979 to 2013 and forecast prices from 2014 to 2034. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have experienced a steady decline, matching prices from over a decade ago. Nominal natural gas prices are expected to remain flat through 2017, then rise at a steady pace throughout the remainder of the forecast period until nearly doubling by 2034, growing at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

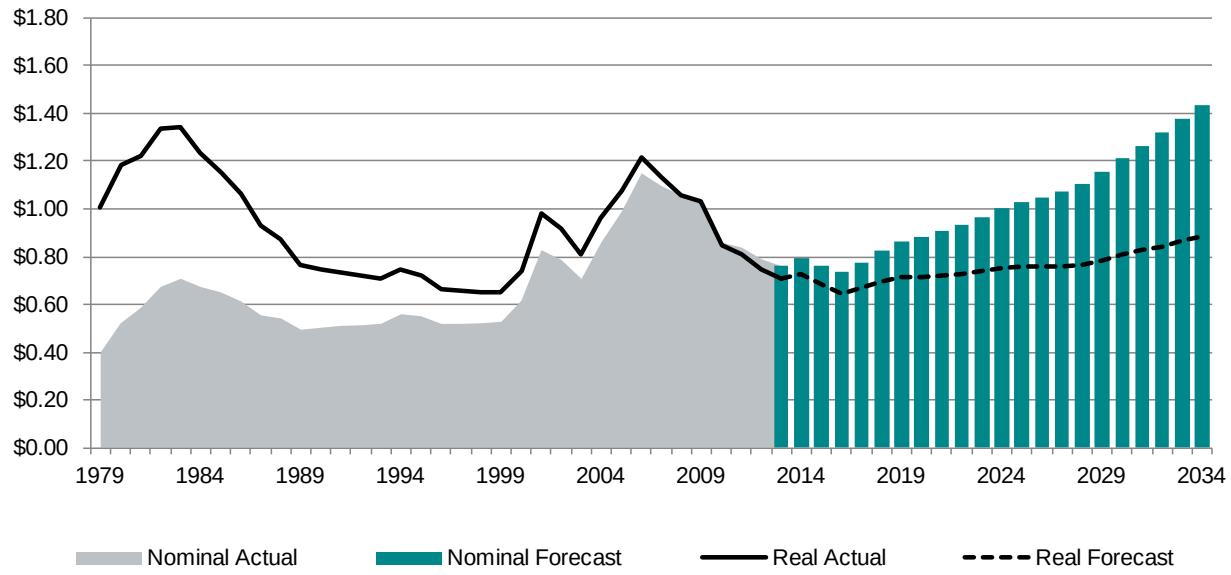


**Figure 2. Forecast residential natural gas prices (dollars per therm)**

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2015 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While PEV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, such limiting attributes of vehicle range and re-fueling time continue to improve the competiveness of these vehicles to non-electric models.

Since the first introduction of the Chevy Volt and Nissan Leaf, the number of PEVs offered in the marketplace has proliferated to over 50 models since 2007. Early in this period, PEVs were sold with unique model names (e.g., VOLT); however, as the market grows, the plug-in technology is increasingly offered as an option to existing models (e.g., Ford Focus).

Initially, the Idaho Power forecast for PEV impact relied on third-party forecasts from the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory due to a lack of service-area vehicle registration data; however, beginning with the 2011 IRP, sufficient service-area data became available via vehicle registration data provided by the Idaho Transportation Department (ITD). This data provides a basis from which to develop service-area adoption rates and support the collection of charging behavior. The methodology continues to integrate the fuel and technology share forecasts of the Department of Energy's (DOE) National Energy Model (NEM). The Idaho Power vehicle share forecast uses these models as well as a Bass consumer adoption model as informed by registration data. Load impacts from the share model output are derived from assumptions of battery-only and hybrid plug-in shares evident from Idaho Power observations and informed by the DOE.

Currently, the registration data collection methodology is being revised to capture vehicles sold with PEV technology as an option (e.g., Ford Focus). The methodology will require the unique string of characters within the vehicle identification number (VIN) to be identified and serve as a key value in the ITD data extraction.

The PEV forecast in this IRP did include registration data for the Toyota Prius PEV but did not capture all models for which PEV technology is sold as an option; however, to capture the impact of these models on future adoption, the forecast used the forecast national share assumptions from the DOE. The net effect was to rely less on the registration data than the 2013 IRP model and more on third-party assumptions, as was the case in earlier forecasts.

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation (i.e., there is a 50-percent chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1984 to 2013 (the most recent 30 years) was 1,039. The 70$^{th}$-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90$^{th}$-percentile HDD is 1,268 and would be exceeded in 1 out of 10 years. The 100$^{th}$-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$-percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70th-percentile or 90th-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th-percentile or 90th-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2015 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

| Scenario | Weather Probability | Probability of Exceeding | Weather Driver |
|---|---|---|---|
| **Forecasts of Average Load** | | | |
| 90th Percentile | 90% | 1 in 10 years | HDD, CDD, GDD, precipitation |
| 70th Percentile | 70% | 3 in 10 years | HDD, CDD, GDD, precipitation |
| Expected Case | 50% | 1 in 2 years | HDD, CDD, GDD, precipitation |
| **Forecasts of Peak Demand** | | | |
| 95th Percentile | 95% | 1 in 20 years | Peak-day temperatures |
| 90th Percentile | 90% | 1 in 10 years | Peak-day temperatures |
| 50th Percentile | 50% | 1 in 2 years | Peak-day temperatures |

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

## *Load Forecasts Based on Economic Uncertainty*

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period.

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared. The forecasts provide a range of possible load growths for the 2015 to 2034 planning period due to high and low economic and demographic conditions. The high and low economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1990–2014).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1990–2014).

Two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrenceare—are reported in Table 3. The probability of exceeding shows the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

| Probability of Exceeding | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 90% | 90% | 90% | 90% |
| Expected Case | 50% | 50% | 50% | 50% |
| High Growth | 10% | 10% | 10% | 10% |
| **Probability of Occurrence** | | | | |
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 26% | 26% | 26% | 26% |
| Expected Case | 48% | 48% | 48% | 48% |
| High Growth | 26% | 26% | 26% | 26% |

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris, Inc.) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Idaho Power system load projections are reported in Table 4 and shown in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects that the system load will increase at an average rate of 0.7 percent per year throughout the forecast period. The high scenario projects a load growth of 1.6 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Low | 1,776 | 1,802 | 1,871 | 2,012 | 0.7% |
| Expected | 1,786 | 1,900 | 2,012 | 2,240 | 1.2% |
| High | 1,864 | 2,009 | 2,181 | 2,500 | 1.6% |

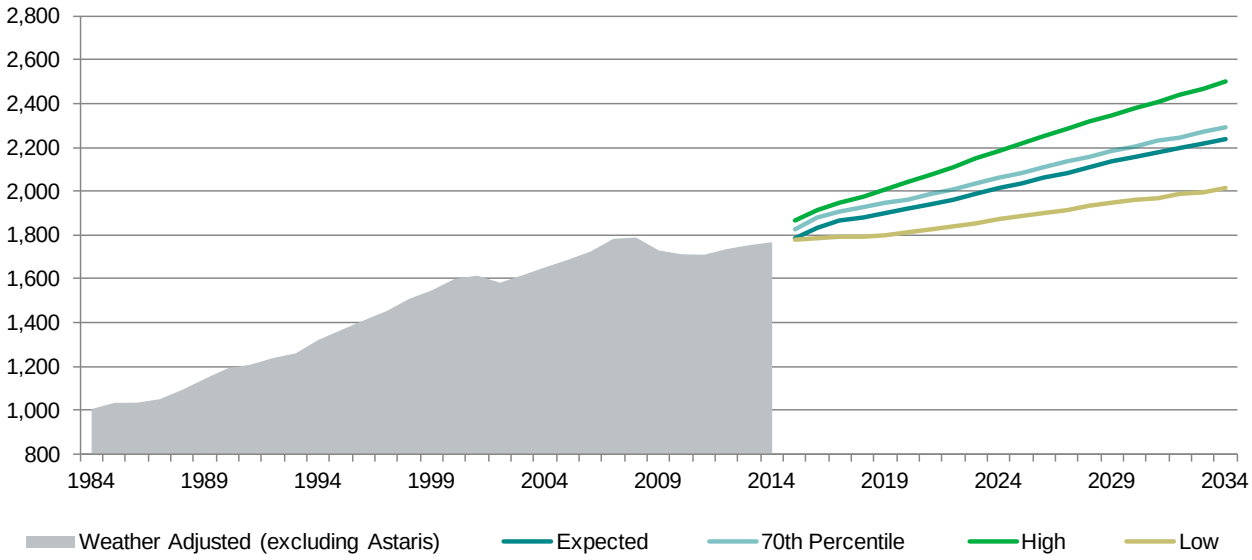


**Figure 3. Forecast system load (aMW)**

# RESIDENTIAL

The expected-case residential load is forecast to increase from 588 aMW in 2015 to 755 aMW in 2034, an average annual compound growth rate of 1.3 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 608 aMW in 2015 to 780 aMW in 2034, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown in Figure 4.

**Table 5. Residential load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90th Percentile | 643 | 689 | 730 | 825 | 1.3% |
| 70th Percentile | 608 | 651 | 689 | 780 | 1.3% |
| Expected Case | 588 | 629 | 666 | 755 | 1.3% |

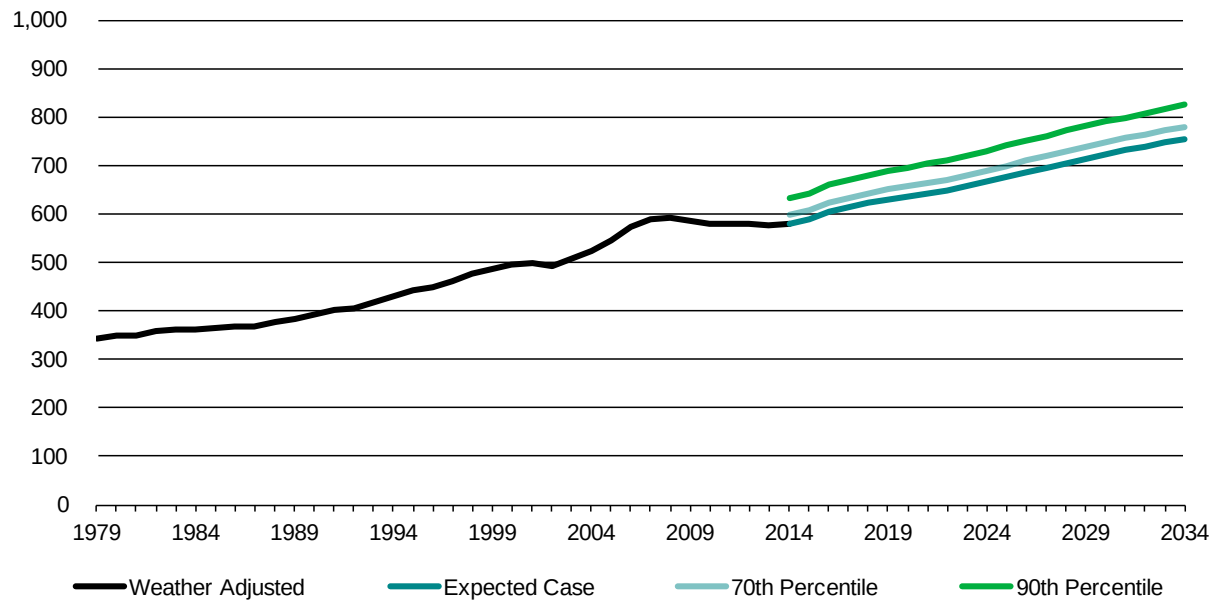


**Figure 4. Forecast residential load (aMW)**

Sales to residential customers made up 32 percent of Idaho Power's system sales in 1984 and 36 percent of system sales in 2014. The residential customer proportion of system sales is forecast to be approximately 37 percent in 2034. The number of residential customers is projected to increase to approximately 591,000 by December 2034.

The average sales per residential customer increased to over 14,800 kWh in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential

use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use, slowed the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2034. Average annual sales per residential customer are shown in Figure 5.

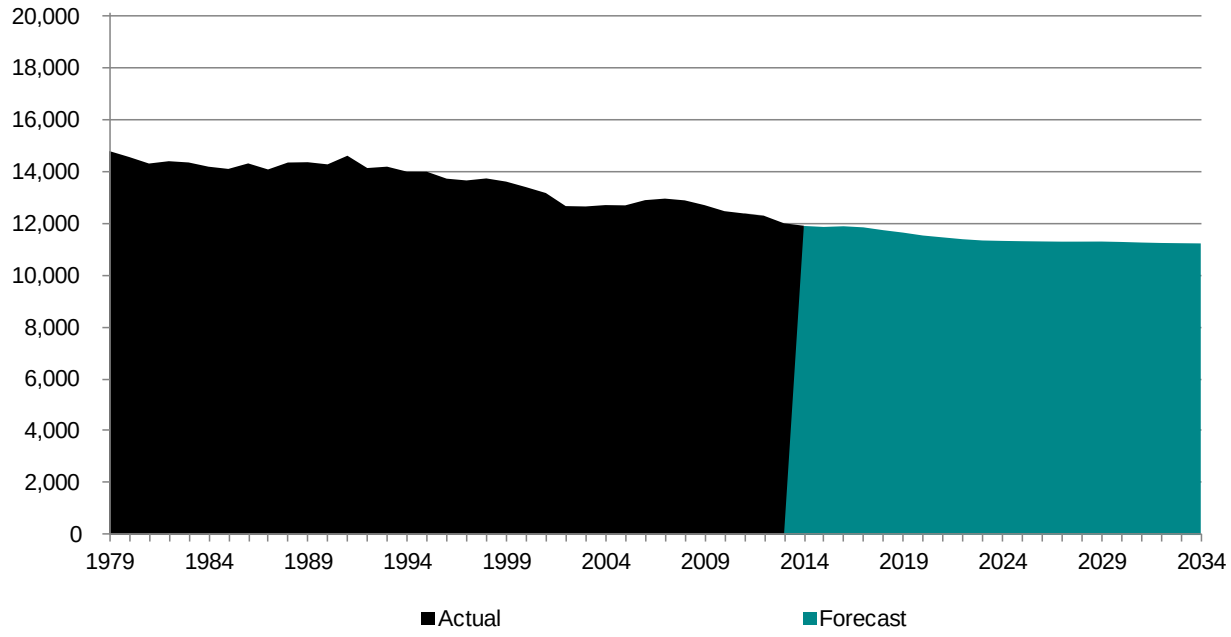


**Figure 5. Forecast residential use per customer (weather-adjusted kWh)**

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics' July 2014 forecast of county housing stock and demographic data. The residential-customer forecast for 2015 to 2034 shows an average annual growth rate of 1.6 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households as derived from Moody's Analytics' forecasts of county housing stock; the real price of electricity; and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other customers associated with this category include unmetered general-service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

In total, within the expected-case scenario, the commercial load is projected to increase from 466 aMW in 2015 to 559 aMW in 2034. The average annual compound-growth rate of the commercial load is 1.0 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th-percentile scenario is projected to increase from 472 aMW in 2015 to 568 aMW in 2034. The commercial load forecasts are illustrated in Figure 6.

**Table 6. Commercial load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90th Percentile | 483 | 504 | 529 | 583 | 1.0% |
| 70th Percentile | 472 | 492 | 516 | 568 | 1.0% |
| Expected Case | 466 | 485 | 509 | 559 | 1.0% |

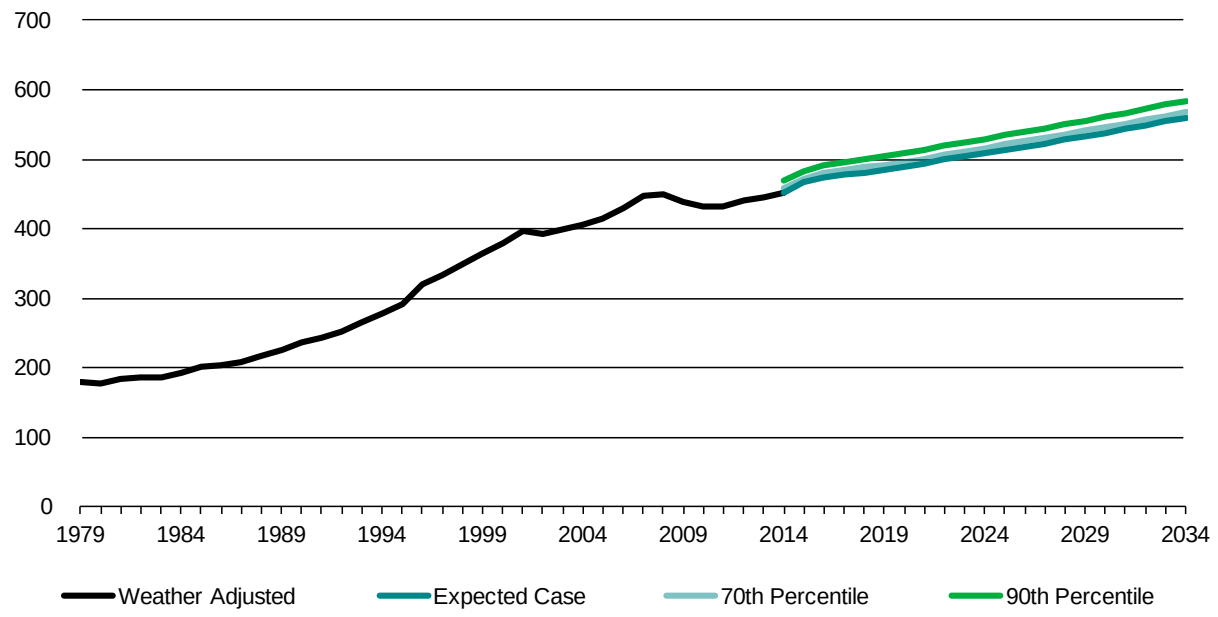


**Figure 6. Forecast commercial load (aMW)**

With a customer base of over 67,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to manufacturing. Due to this diversity, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 7 shows the breakdown of the categories and their relative sizes based on 2014 billed energy sales.

The commercial-customer forecast for 2015 to 2034 shows an average annual growth rate of 1.7 percent.

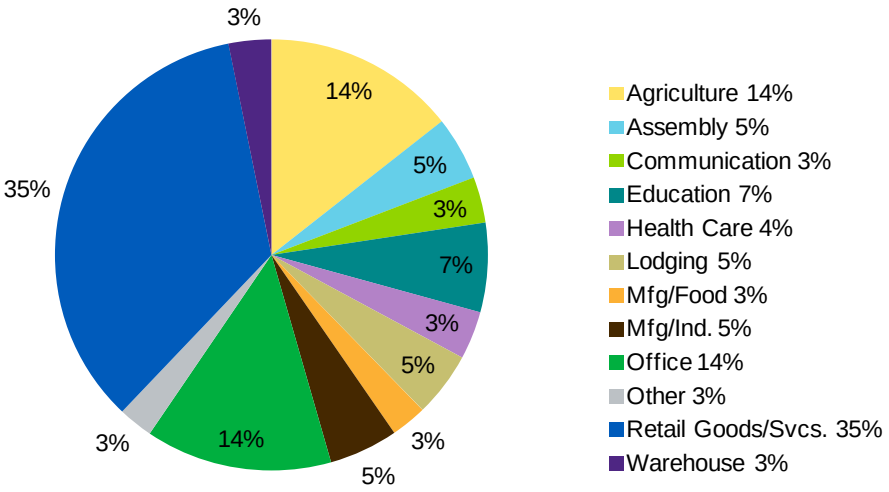


**Figure 7. Commercial building share**

As indicated in Figure 7, retail goods and service providers represent the majority of customers, with 35% of the total in 2014. The number of commercial customers is expected to increase at an average annual rate of 1.7 percent, reaching 94,900 customers by December 2034. Much of the future commercial customer growth is expected to come from retail goods and services. Historically, this category growth is a function of the growth in residential customers. Recent trends indicate continued growth in communications and general manufacturing and small industrial categories.

In 1984, customers in the commercial category consumed approximately 17 percent of Idaho Power system sales, growing to 28 percent by 2014. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 8 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 8 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, but it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,400 kWh and has declined at approximately 0.31 percent compounded annually to 2014. The UPC is forecast to decrease at an annual rate of 0.46 percent over the planning period. For the category as a whole, common elements that drive use down include increases in electricity prices, business-cycle recessions, and the adoption of energy efficiency technology. Within the sub-categories, the UPC varies widely from manufacturing/industrial at 159,500 kWh per customer to communications at 44,250 kWh (2014 basis).

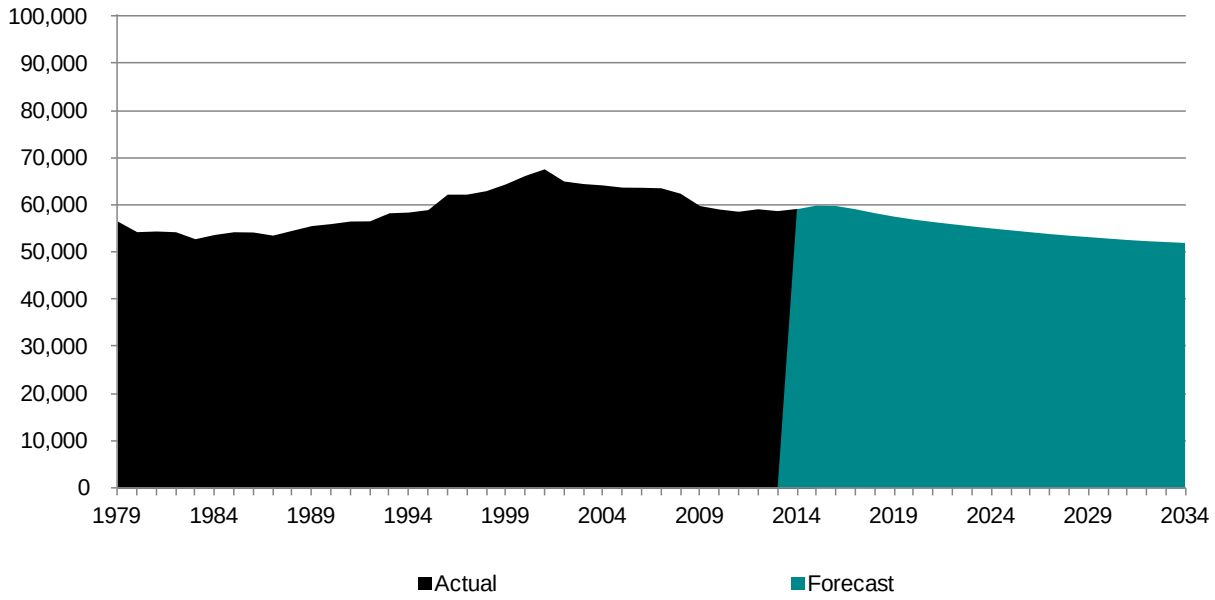


**Figure 8. Forecast commercial use per customer (weather-adjusted kWh)**

Figure 9 shows the diversity in the commercial segments' UPC as well as the trend for these sectors. The figure shows the 2014 UPC for each segment relative to the 2010 UPC. A value of 1.0 indicates the UPC has not changed over this period. The figure supports the general decline of the aggregated trend of Figure 7 but highlights differences in energy and economic dynamics within the commercial category not evident in the residential category.

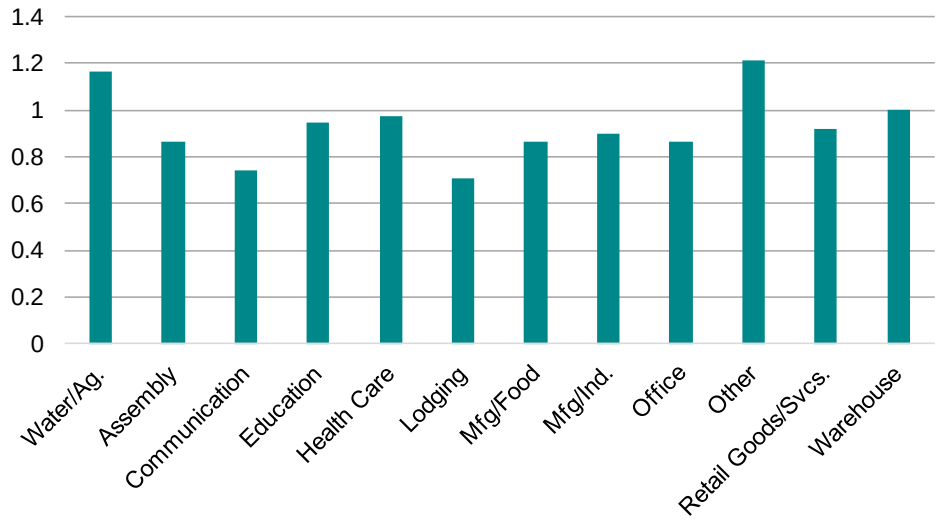


**Figure 9. Commercial categories UPC, 2014 relative to 2010**

Energy efficiency implementation is a large determinant in UPC decline, particularly in high-growth categories, such as retail goods and services, communication, and office, where many structures are new and subject to efficient building code requirements. Increases in the UPC, such as in the water/agriculture (Water/Ag.) category are indicative of an increasing density of pumps and water treatment consolidation. Other influences include a difference in

price sensitivity, sensitivity to business cycles and weather changes, and degree and trends in automation. In addition, aggregate commercial UPC can vary when a customer's use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the sub-category. Typical variables include weather: HDD (wintertime); CDD (summertime); specific industry growth characteristics and outlook; service-area demographics and their derivatives, such as households, employment, and small business conditions; the real price of electricity; and conservation adoption.

# IRRIGATION

The irrigation category is comprised of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

The expected-case irrigation load is forecast to increase slowly from 213 aMW in 2015 to 235 aMW in 2034, an average annual compound growth rate of 0.5 percent. The expected-case, 70$^{th}$-percentile, and 90$^{th}$-percentile scenarios forecast slow growth in irrigation load from 2015 to 2034. In the 70$^{th}$-percentile scenario, irrigation load is projected to be 226 aMW in 2015 and 248 aMW in 2034. The individual irrigation load forecasts (Table 7 and Figure 10) illustrate the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

**Table 7. Irrigation load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 244 | 250 | 254 | 266 | 0.5% |
| 70$^{th}$ Percentile | 226 | 232 | 235 | 248 | 0.5% |
| Expected Case | 213 | 218 | 222 | 235 | 0.5% |

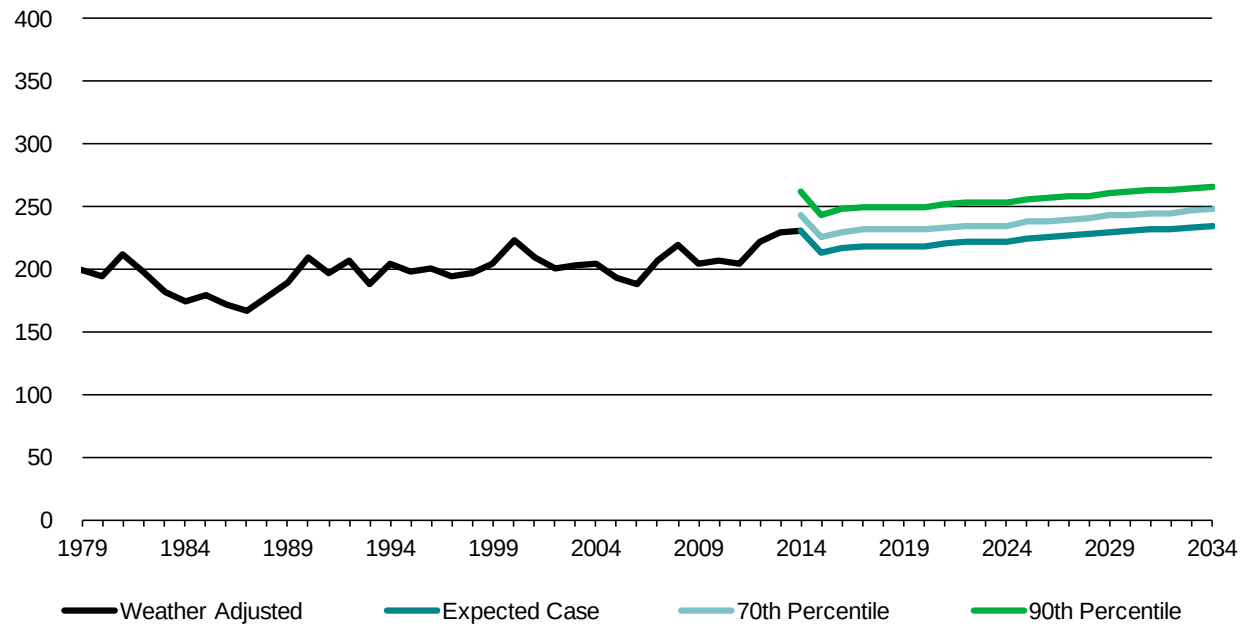


**Figure 10. Forecast irrigation load (aMW)**

The annual average loads in Table 7 and Figure 10 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can reach nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy

consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have taken advantage of higher market prices over the past few years and have put high-lift acreage back into production. Additionally, the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2015 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 2,097,000 MWh in 2013. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 1984, they represented nearly 16 percent of weather-normalized Idaho Power system sales. In 2014, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2034, irrigation customers are projected to consume about 11 percent of Idaho Power system sales. Figure 17 shows the irrigation customer load proportion.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2014, the number of active irrigation accounts had increased to 19,328 and is projected to be nearly 25,000 at the end of the planning period in 2034.

Since 1988, Idaho Power has experienced growth in the number of irrigation customers but very slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

# INDUSTRIAL

The industrial category is comprised of Idaho Power's large power service (Schedule 19) customers requiring monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. The category name "Industrial" is reflective of load requirements and not necessarily indicative of the industrial nature of the customers' business.

In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2014, the number of industrial customers had risen to 118, representing approximately 17 percent of system sales. Given the wide range of customer's energy use in the tariff schedule, customer counts are primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as Special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 277 aMW in 2015 to 401 aMW in 2034, an average annual growth rate of 2.0 percent (Table 8). To a large degree, industrial load variability is not due to weather conditions as is residential, commercial, and irrigation; therefore, the forecasts in the 70$^{th}$- and 90$^{th}$-percentile weather-scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 11.

**Table 8. Industrial load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Expected Case | 277 | 313 | 341 | 401 | 2.0% |

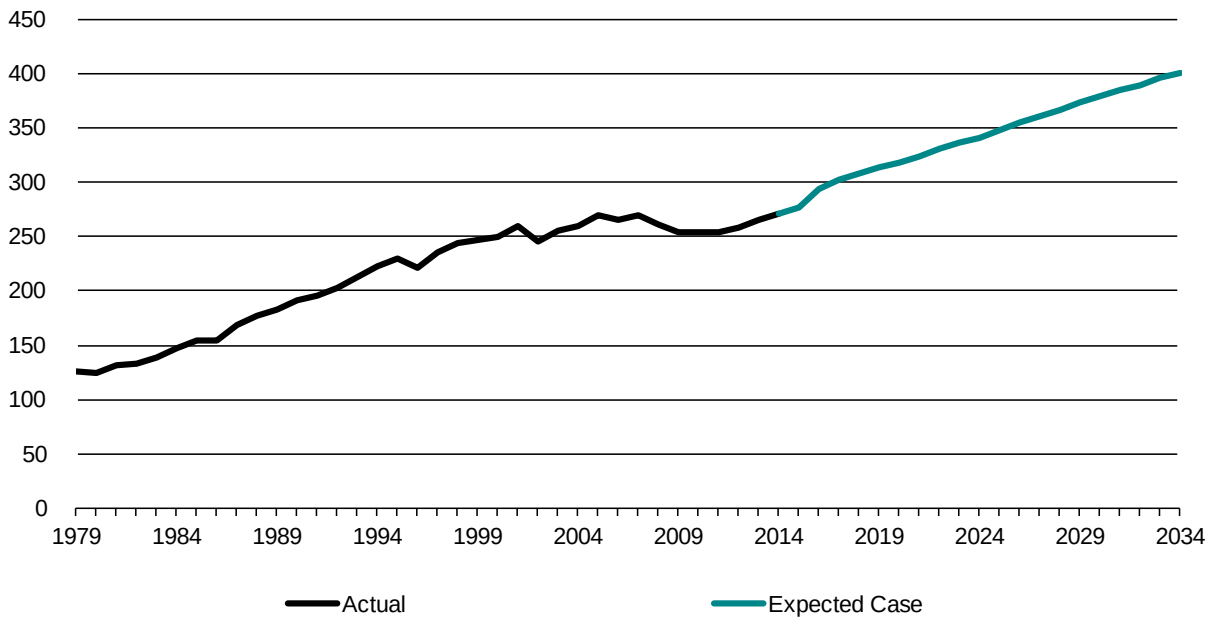


**Figure 11. Forecast industrial load (aMW)**

The industrial category reflects a wide range of business activity ranging from manufacturing to health care. To better specify forecast regression models, the customers are segmented into economic and energy-use profile categories. The industrial energy forecast models integrated the July 2014 national, state, MSA, and county economic time-series from Moody's Analytics and associated derived economic time-series for Idaho Power's service area.

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and historical independent economic, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models that are applied to the appropriate forecasts of independent time series of energy use.

Figure 12 illustrates the 2014 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (38%), followed by dairy (18%) and electronics/technology (Electech) (7%). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, health care). These categorizations provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

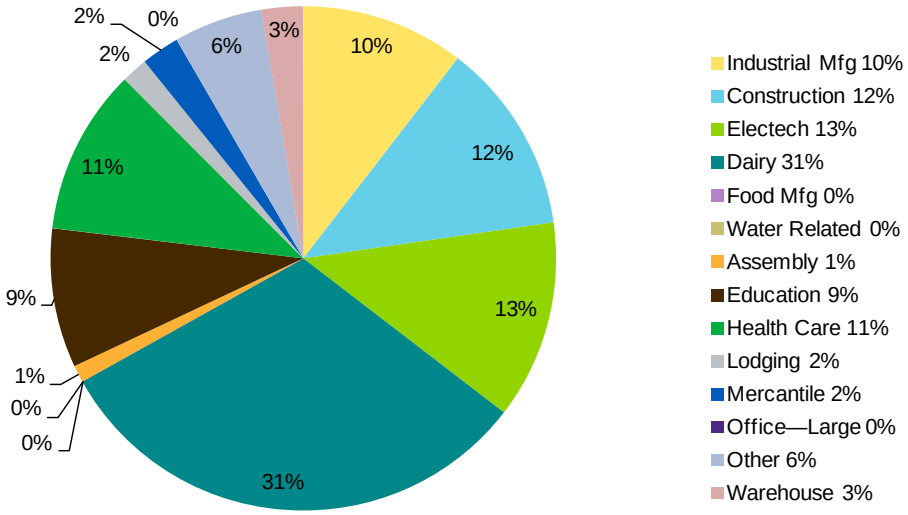


**Figure 12. Industrial electricity consumption by industry group (based on 2014 sales)**

# ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has three special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, and the INL.

In the expected-case forecast, additional firm load is expected to increase from 101 aMW in 2015 to 113 aMW in 2034, an average growth rate of 0.6 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 13.

**Table 9. Additional firm load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Expected Case | 101 | 104 | 115 | 113 | 0.6% |

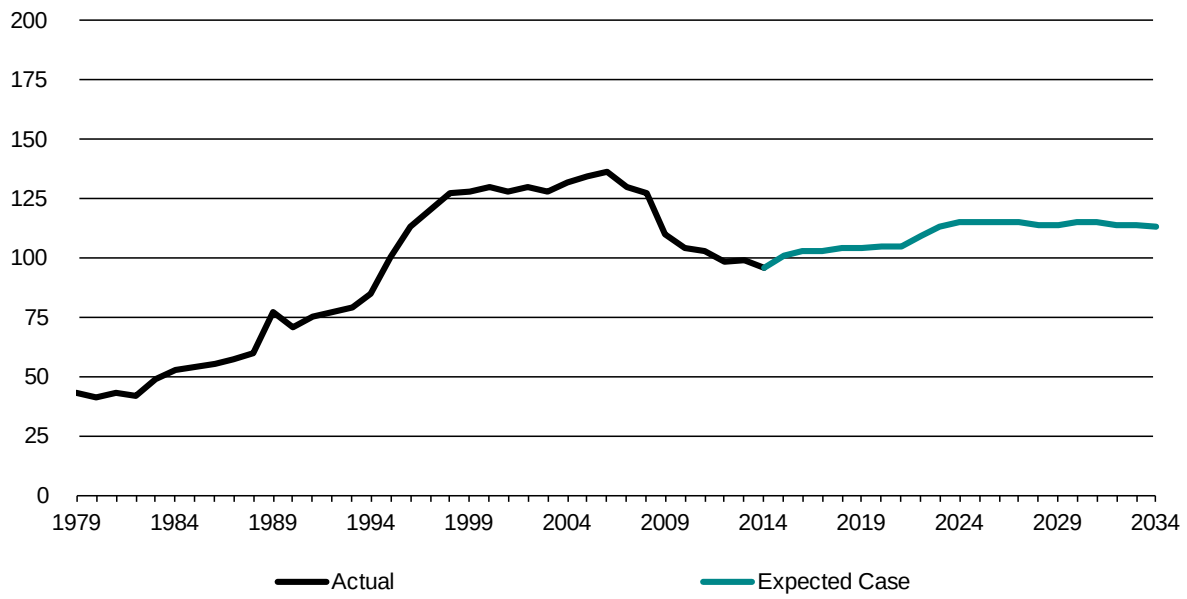


**Figure 13. Forecast additional firm load (aMW)**

## Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate services, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

## Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2034 for the INL. The forecast calls for loads to slowly rise through 2021, rise dramatically through 2024, and stay near that higher level throughout the remainder of the forecast period.

# COMPANY SYSTEM PEAK

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

The all-time system summer peak demand was 3,407 MW, recorded on Tuesday, July 2, 2013, at 4:00 p.m. The previous summer peak demand was 3,245 MW and occurred on Thursday, July 12, 2012, at 4:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,537 MW in 2015 to 4,719 MW in 2034, an average growth rate of 1.5 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,576 MW in 2015 to 4,773 MW in 2034. The three scenarios of projected system summer peak loads are illustrated in Figure 14. Much of the variation in peak load is due to weather conditions. Notably, the 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth (MW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 95th Percentile | 3,576 | 3,847 | 4,151 | 4,773 | 1.5% |
| 90th Percentile | 3,537 | 3,805 | 4,105 | 4,719 | 1.5% |
| 50th Percentile | 3,313 | 3,562 | 3,839 | 4,407 | 1.5% |

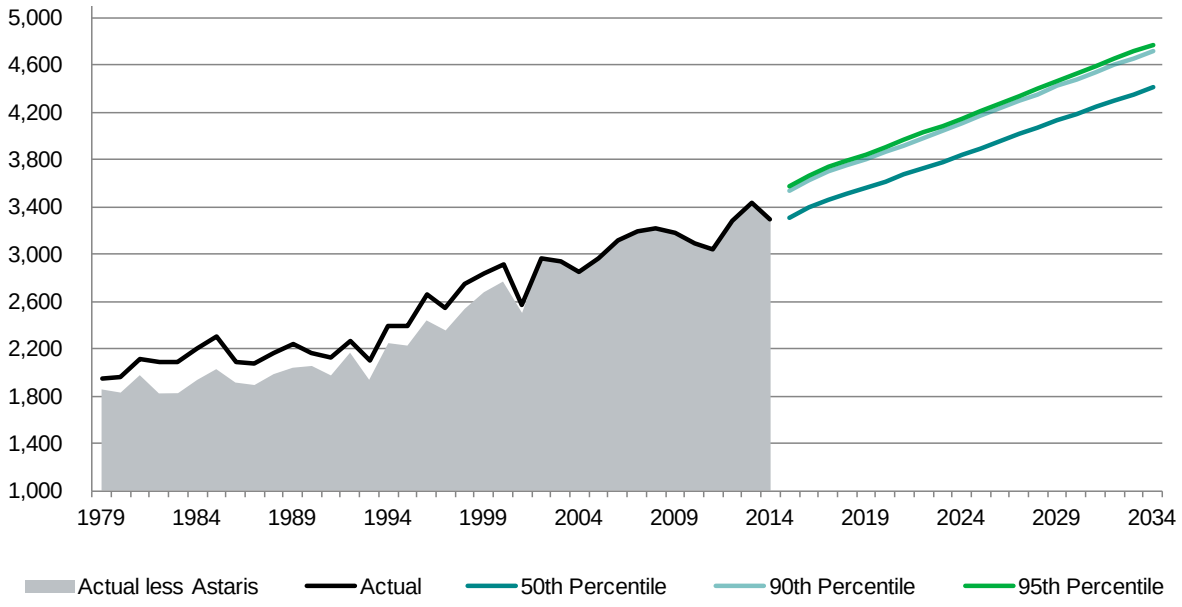


**Figure 14. Forecast system summer peak (MW)**

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 15, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,603 MW in 2015 to 3,077 MW in 2034, an average growth rate of 0.9 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,625 MW in 2015 to 3,100 MW in 2034, an average growth rate of 0.9 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

**Table 11. System winter peak load growth (MW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 95th Percentile | 2,625 | 2,723 | 2,853 | 3,100 | 0.9% |
| 90th Percentile | 2,603 | 2,701 | 2,830 | 3,077 | 0.9% |
| 50th Percentile | 2,330 | 2,428 | 2,557 | 2,805 | 1.0% |

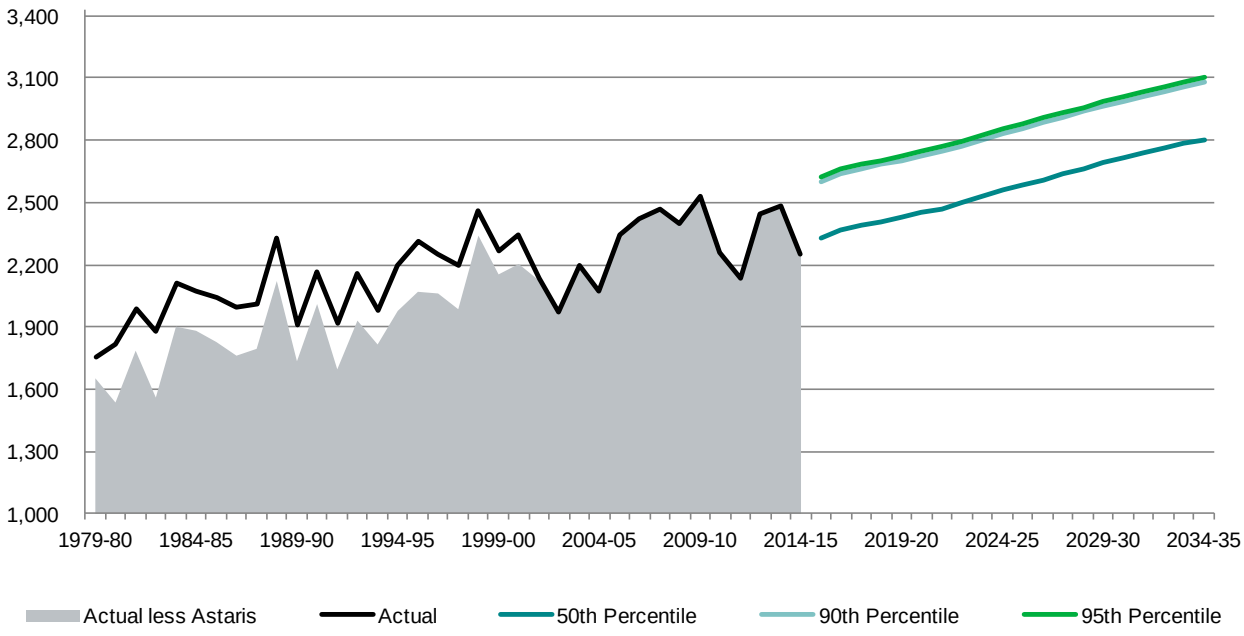


**Figure 15. Forecast system winter peak (MW)**

# COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.2 percent per year from 2015 to 2034. Company system load projections are reported in Table 12 and shown in Figure 16.

In the expected-case forecast, the company system load is expected to increase from 1,786 aMW in 2015 to 2,240 aMW in 2034. In the 70$^{th}$-percentile forecast, the company system load is expected to increase from 1,829 aMW in 2015 to 2,292 aMW by 2034, an average growth rate of 1.2 percent per year over the planning period (Table 12).

**Table 12. System load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,900 | 2,021 | 2,139 | 2,378 | 1.2% |
| 70$^{th}$ Percentile | 1,829 | 1,946 | 2,059 | 2,292 | 1.2% |
| Expected Case | 1,786 | 1,900 | 2,012 | 2,240 | 1.2% |

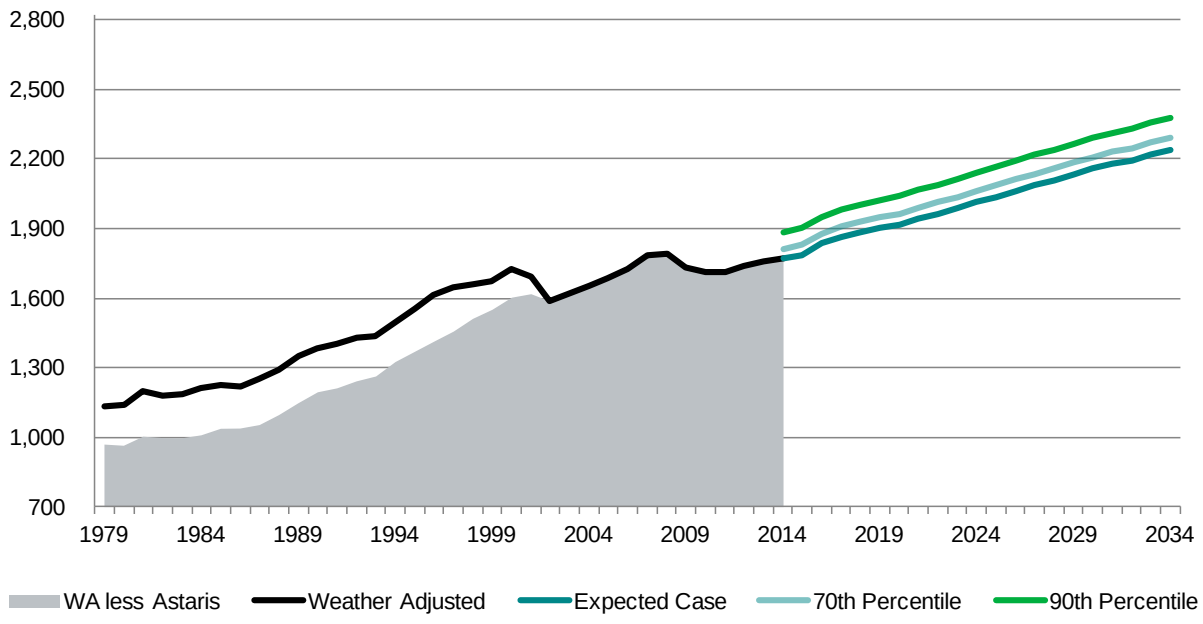


**Figure 16. Forecast system load (aMW)**

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. The system load, excluding Astaris, portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new large-load customer on system load. As noted previously, the forecast excludes any such prospective large-load customers.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term, firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 17. Residential sales are forecast to be nearly 28 percent higher in 2034, gaining 1.5 million MWh over 2015. Commercial sales are also expected to be 20 percent higher, or 0.8 million MWh, than in 2015, followed by industrial (45 percent higher or 1.1 million additional MWh) and irrigation (10 percent higher in 2034 than 2015). Electricity sales to Astaris ended in April 2002.

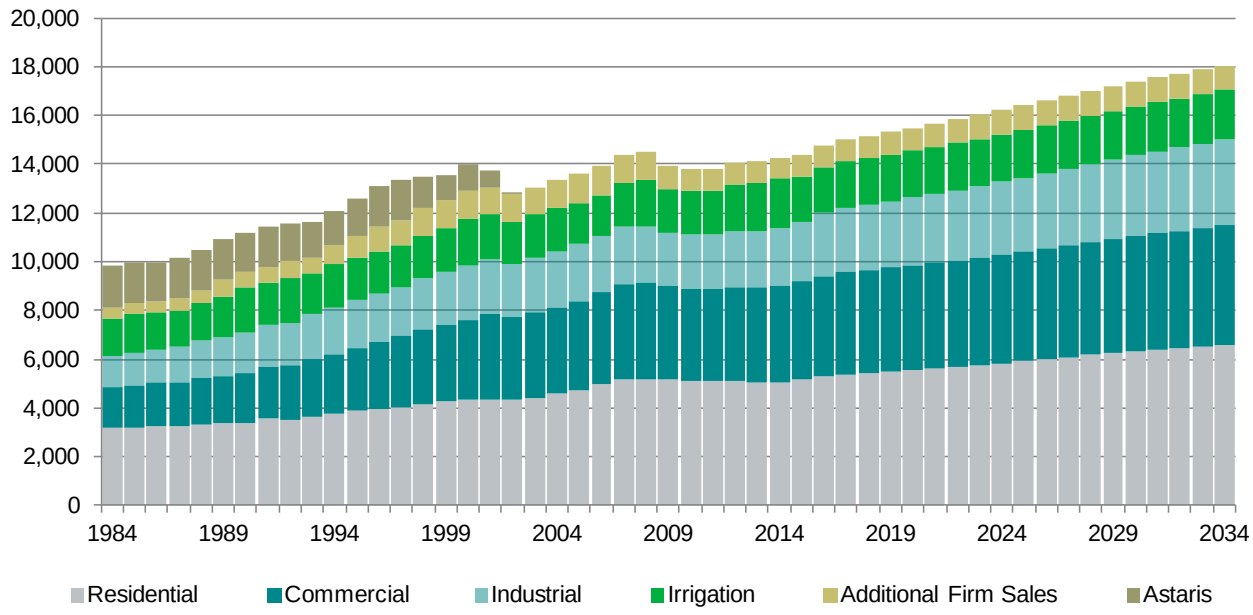


**Figure 17. Composition of system company electricity sales (thousands of MWh)**

The additional firm-load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2015 to 2034.

# CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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# ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions in energy use) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

## Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for irrigation customers and some commercial and industrial customers (i.e., manufacturing related) is not directly surveyed and collected by the DOE; therefore, models for efficiency impacts have been developed using a methodology established in Itron's white paper, *Incorporating DSM into the Load Forecast*.[1] This approach develops statistical methods to recognize efficiency trends from historical energy efficiency utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serve as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to the DOE's population of utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from utility energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by

[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of these new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*.

## Demand Response

Beginning with the 2009 IRP, demand response programs have been effectively treated as supply-side resources and accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries, are detailed in *Appendix C—Technical Appendix*.

As supply-side resources, demand response program impacts are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak-hour load reduction is integrated into the sales and load forecast models. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2014 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

**Residential Load**

**Historical Residential Sales and Load, 1974–2014 (weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 160,151 | – | 12,067 | 1,932 | – | 223 |
| 1975 | 167,622 | 4.7% | 12,956 | 2,172 | 12.4% | 250 |
| 1976 | 175,720 | 4.8% | 13,452 | 2,364 | 8.8% | 272 |
| 1977 | 184,561 | 5.0% | 13,698 | 2,528 | 7.0% | 289 |
| 1978 | 194,650 | 5.5% | 14,234 | 2,771 | 9.6% | 321 |
| 1979 | 202,982 | 4.3% | 14,804 | 3,005 | 8.5% | 342 |
| 1980 | 209,629 | 3.3% | 14,575 | 3,055 | 1.7% | 348 |
| 1981 | 213,579 | 1.9% | 14,323 | 3,059 | 0.1% | 350 |
| 1982 | 216,696 | 1.5% | 14,413 | 3,123 | 2.1% | 357 |
| 1983 | 219,849 | 1.5% | 14,364 | 3,158 | 1.1% | 361 |
| 1984 | 222,695 | 1.3% | 14,201 | 3,163 | 0.1% | 360 |
| 1985 | 225,185 | 1.1% | 14,115 | 3,178 | 0.5% | 365 |
| 1986 | 227,081 | 0.8% | 14,328 | 3,254 | 2.4% | 369 |
| 1987 | 228,868 | 0.8% | 14,094 | 3,226 | -0.9% | 369 |
| 1988 | 230,771 | 0.8% | 14,362 | 3,314 | 2.7% | 378 |
| 1989 | 233,370 | 1.1% | 14,374 | 3,354 | 1.2% | 382 |
| 1990 | 238,117 | 2.0% | 14,291 | 3,403 | 1.4% | 393 |
| 1991 | 243,207 | 2.1% | 14,624 | 3,557 | 4.5% | 403 |
| 1992 | 249,767 | 2.7% | 14,149 | 3,534 | -0.6% | 404 |
| 1993 | 258,271 | 3.4% | 14,202 | 3,668 | 3.8% | 418 |
| 1994 | 267,854 | 3.7% | 14,010 | 3,753 | 2.3% | 430 |
| 1995 | 277,131 | 3.5% | 14,007 | 3,882 | 3.4% | 443 |
| 1996 | 286,227 | 3.3% | 13,739 | 3,933 | 1.3% | 449 |
| 1997 | 294,674 | 3.0% | 13,670 | 4,028 | 2.4% | 461 |
| 1998 | 303,300 | 2.9% | 13,748 | 4,170 | 3.5% | 477 |
| 1999 | 312,901 | 3.2% | 13,625 | 4,263 | 2.2% | 487 |
| 2000 | 322,402 | 3.0% | 13,412 | 4,324 | 1.4% | 494 |
| 2001 | 331,009 | 2.7% | 13,184 | 4,364 | 0.9% | 497 |
| 2002 | 339,764 | 2.6% | 12,680 | 4,308 | -1.3% | 491 |
| 2003 | 349,219 | 2.8% | 12,666 | 4,423 | 2.7% | 507 |
| 2004 | 360,462 | 3.2% | 12,719 | 4,585 | 3.6% | 523 |
| 2005 | 373,602 | 3.6% | 12,708 | 4,748 | 3.6% | 545 |
| 2006 | 387,707 | 3.8% | 12,910 | 5,005 | 5.4% | 573 |
| 2007 | 397,286 | 2.5% | 12,969 | 5,152 | 2.9% | 589 |
| 2008 | 402,520 | 1.3% | 12,901 | 5,193 | 0.8% | 591 |
| 2009 | 405,144 | 0.7% | 12,716 | 5,152 | -0.8% | 587 |
| 2010 | 407,551 | 0.6% | 12,484 | 5,088 | -1.2% | 580 |
| 2011 | 409,786 | 0.5% | 12,394 | 5,079 | -0.2% | 579 |
| 2012 | 413,610 | 0.9% | 12,304 | 5,089 | 0.2% | 580 |
| 2013 | 418,892 | 1.3% | 12,016 | 5,033 | -1.1% | 577 |
| 2014 | 425,036 | 1.5% | 11,922 | 5,067 | 0.7% | 578 |

**Residential Load**

**Projected Residential Sales and Load, 2015–2034**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 432,909 | 1.9% | 11,884 | 5,145 | 1.5% | 588 |
| 2016 | 442,519 | 2.2% | 11,910 | 5,271 | 2.4% | 603 |
| 2017 | 452,660 | 2.3% | 11,868 | 5,372 | 1.9% | 614 |
| 2018 | 462,757 | 2.2% | 11,759 | 5,442 | 1.3% | 622 |
| 2019 | 472,216 | 2.0% | 11,665 | 5,509 | 1.2% | 629 |
| 2020 | 480,984 | 1.9% | 11,553 | 5,557 | 0.9% | 635 |
| 2021 | 489,217 | 1.7% | 11,481 | 5,617 | 1.1% | 642 |
| 2022 | 497,232 | 1.6% | 11,410 | 5,673 | 1.0% | 648 |
| 2023 | 505,314 | 1.6% | 11,361 | 5,741 | 1.2% | 656 |
| 2024 | 513,361 | 1.6% | 11,345 | 5,824 | 1.4% | 666 |
| 2025 | 521,365 | 1.6% | 11,333 | 5,908 | 1.5% | 675 |
| 2026 | 529,313 | 1.5% | 11,324 | 5,994 | 1.4% | 685 |
| 2027 | 537,191 | 1.5% | 11,316 | 6,079 | 1.4% | 695 |
| 2028 | 544,909 | 1.4% | 11,317 | 6,167 | 1.4% | 705 |
| 2029 | 552,467 | 1.4% | 11,320 | 6,254 | 1.4% | 715 |
| 2030 | 559,841 | 1.3% | 11,304 | 6,328 | 1.2% | 723 |
| 2031 | 566,967 | 1.3% | 11,282 | 6,396 | 1.1% | 731 |
| 2032 | 573,885 | 1.2% | 11,265 | 6,465 | 1.1% | 739 |
| 2033 | 580,611 | 1.2% | 11,256 | 6,535 | 1.1% | 747 |
| 2034 | 587,224 | 1.1% | 11,248 | 6,605 | 1.1% | 755 |

## Commercial Load

### Historical Commercial Sales and Load, 1974–2014 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 24,096 | – | 49,028 | 1,181 | – | 136 |
| 1975 | 25,045 | 3.9% | 51,219 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,514 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,416 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,477 | 1,460 | 2.8% | 168 |
| 1979 | 28,087 | 0.9% | 56,391 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,143 | 1,559 | -1.6% | 178 |
| 1981 | 29,567 | 2.7% | 54,285 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,129 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,653 | 1,620 | -0.8% | 185 |
| 1984 | 31,554 | 2.5% | 53,552 | 1,690 | 4.3% | 193 |
| 1985 | 32,418 | 2.7% | 54,128 | 1,755 | 3.8% | 201 |
| 1986 | 33,208 | 2.4% | 54,069 | 1,796 | 2.3% | 204 |
| 1987 | 33,975 | 2.3% | 53,411 | 1,815 | 1.1% | 207 |
| 1988 | 34,723 | 2.2% | 54,425 | 1,890 | 4.1% | 216 |
| 1989 | 35,638 | 2.6% | 55,427 | 1,975 | 4.5% | 226 |
| 1990 | 36,785 | 3.2% | 55,849 | 2,054 | 4.0% | 236 |
| 1991 | 37,922 | 3.1% | 56,390 | 2,138 | 4.1% | 244 |
| 1992 | 39,022 | 2.9% | 56,424 | 2,202 | 3.0% | 252 |
| 1993 | 40,047 | 2.6% | 58,126 | 2,328 | 5.7% | 266 |
| 1994 | 41,629 | 4.0% | 58,283 | 2,426 | 4.2% | 278 |
| 1995 | 43,165 | 3.7% | 58,801 | 2,538 | 4.6% | 291 |
| 1996 | 44,995 | 4.2% | 62,062 | 2,792 | 10.0% | 319 |
| 1997 | 46,819 | 4.1% | 62,067 | 2,906 | 4.1% | 332 |
| 1998 | 48,404 | 3.4% | 62,804 | 3,040 | 4.6% | 348 |
| 1999 | 49,430 | 2.1% | 64,238 | 3,175 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 66,012 | 3,308 | 4.2% | 379 |
| 2001 | 51,501 | 2.8% | 67,409 | 3,472 | 4.9% | 396 |
| 2002 | 52,915 | 2.7% | 64,845 | 3,431 | -1.2% | 392 |
| 2003 | 54,194 | 2.4% | 64,304 | 3,485 | 1.6% | 398 |
| 2004 | 55,577 | 2.6% | 64,013 | 3,558 | 2.1% | 406 |
| 2005 | 57,145 | 2.8% | 63,552 | 3,632 | 2.1% | 415 |
| 2006 | 59,050 | 3.3% | 63,513 | 3,750 | 3.3% | 429 |
| 2007 | 61,640 | 4.4% | 63,412 | 3,909 | 4.2% | 447 |
| 2008 | 63,492 | 3.0% | 62,270 | 3,954 | 1.2% | 449 |
| 2009 | 64,151 | 1.0% | 59,661 | 3,827 | -3.2% | 438 |
| 2010 | 64,421 | 0.4% | 58,927 | 3,796 | -0.8% | 433 |
| 2011 | 64,921 | 0.8% | 58,455 | 3,795 | 0.0% | 433 |
| 2012 | 65,599 | 1.0% | 58,980 | 3,869 | 1.9% | 440 |
| 2013 | 66,357 | 1.2% | 58,588 | 3,888 | 0.5% | 445 |
| 2014 | 67,113 | 1.1% | 59,036 | 3,962 | 1.9% | 452 |

## Commercial Load

### Projected Commercial Sales and Load, 2015–2034

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 68,174 | 1.6% | 59,790 | 4,076 | 2.9% | 466 |
| 2016 | 69,407 | 1.8% | 59,719 | 4,145 | 1.7% | 473 |
| 2017 | 70,839 | 2.1% | 59,044 | 4,183 | 0.9% | 478 |
| 2018 | 72,366 | 2.2% | 58,207 | 4,212 | 0.7% | 481 |
| 2019 | 73,896 | 2.1% | 57,478 | 4,247 | 0.8% | 485 |
| 2020 | 75,384 | 2.0% | 56,853 | 4,286 | 0.9% | 490 |
| 2021 | 76,816 | 1.9% | 56,332 | 4,327 | 1.0% | 494 |
| 2022 | 78,209 | 1.8% | 55,865 | 4,369 | 1.0% | 499 |
| 2023 | 79,591 | 1.8% | 55,409 | 4,410 | 0.9% | 504 |
| 2024 | 80,976 | 1.7% | 54,980 | 4,452 | 1.0% | 509 |
| 2025 | 82,364 | 1.7% | 54,581 | 4,496 | 1.0% | 513 |
| 2026 | 83,749 | 1.7% | 54,189 | 4,538 | 1.0% | 518 |
| 2027 | 85,129 | 1.6% | 53,793 | 4,579 | 0.9% | 523 |
| 2028 | 86,500 | 1.6% | 53,447 | 4,623 | 1.0% | 528 |
| 2029 | 87,856 | 1.6% | 53,150 | 4,670 | 1.0% | 533 |
| 2030 | 89,196 | 1.5% | 52,844 | 4,714 | 0.9% | 538 |
| 2031 | 90,513 | 1.5% | 52,544 | 4,756 | 0.9% | 543 |
| 2032 | 91,806 | 1.4% | 52,293 | 4,801 | 0.9% | 548 |
| 2033 | 93,078 | 1.4% | 52,098 | 4,849 | 1.0% | 554 |
| 2034 | 94,332 | 1.3% | 51,910 | 4,897 | 1.0% | 559 |

## Irrigation Load

### Historical Irrigation Sales and Load, 1974–2014 (weather adjusted)

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 8,971 | – | 147,923 | 1,327 | – | 151 |
| 1975 | 9,480 | 5.7% | 153,993 | 1,460 | 10.0% | 167 |
| 1976 | 9,936 | 4.8% | 156,365 | 1,554 | 6.4% | 177 |
| 1977 | 10,238 | 3.0% | 164,994 | 1,689 | 8.7% | 193 |
| 1978 | 10,476 | 2.3% | 153,762 | 1,611 | -4.6% | 184 |
| 1979 | 10,711 | 2.2% | 163,283 | 1,749 | 8.6% | 199 |
| 1980 | 10,854 | 1.3% | 157,784 | 1,713 | -2.1% | 195 |
| 1981 | 11,248 | 3.6% | 165,251 | 1,859 | 8.5% | 212 |
| 1982 | 11,312 | 0.6% | 153,416 | 1,735 | -6.6% | 198 |
| 1983 | 11,133 | -1.6% | 143,575 | 1,598 | -7.9% | 182 |
| 1984 | 11,375 | 2.2% | 135,263 | 1,539 | -3.7% | 175 |
| 1985 | 11,576 | 1.8% | 135,260 | 1,566 | 1.8% | 179 |
| 1986 | 11,308 | -2.3% | 133,203 | 1,506 | -3.8% | 172 |
| 1987 | 11,254 | -0.5% | 130,082 | 1,464 | -2.8% | 167 |
| 1988 | 11,378 | 1.1% | 137,564 | 1,565 | 6.9% | 178 |
| 1989 | 11,957 | 5.1% | 138,406 | 1,655 | 5.7% | 189 |
| 1990 | 12,340 | 3.2% | 148,368 | 1,831 | 10.6% | 209 |
| 1991 | 12,484 | 1.2% | 138,195 | 1,725 | -5.8% | 197 |
| 1992 | 12,809 | 2.6% | 142,280 | 1,822 | 5.6% | 207 |
| 1993 | 13,078 | 2.1% | 125,883 | 1,646 | -9.7% | 188 |
| 1994 | 13,559 | 3.7% | 131,758 | 1,787 | 8.5% | 204 |
| 1995 | 13,679 | 0.9% | 126,751 | 1,734 | -2.9% | 198 |
| 1996 | 14,074 | 2.9% | 125,559 | 1,767 | 1.9% | 201 |
| 1997 | 14,383 | 2.2% | 118,005 | 1,697 | -4.0% | 194 |
| 1998 | 14,695 | 2.2% | 117,169 | 1,722 | 1.4% | 197 |
| 1999 | 14,912 | 1.5% | 120,036 | 1,790 | 4.0% | 204 |
| 2000 | 15,253 | 2.3% | 128,221 | 1,956 | 9.3% | 223 |
| 2001 | 15,522 | 1.8% | 117,764 | 1,828 | -6.5% | 209 |
| 2002 | 15,840 | 2.0% | 111,181 | 1,761 | -3.7% | 201 |
| 2003 | 16,020 | 1.1% | 111,173 | 1,781 | 1.1% | 203 |
| 2004 | 16,297 | 1.7% | 110,079 | 1,794 | 0.7% | 204 |
| 2005 | 16,936 | 3.9% | 99,646 | 1,688 | -5.9% | 193 |
| 2006 | 17,062 | 0.7% | 96,535 | 1,647 | -2.4% | 188 |
| 2007 | 17,001 | -0.4% | 106,506 | 1,811 | 9.9% | 207 |
| 2008 | 17,428 | 2.5% | 110,770 | 1,930 | 6.6% | 220 |
| 2009 | 17,708 | 1.6% | 100,877 | 1,786 | -7.5% | 204 |
| 2010 | 17,846 | 0.8% | 101,364 | 1,809 | 1.3% | 207 |
| 2011 | 18,292 | 2.5% | 98,400 | 1,800 | -0.5% | 205 |
| 2012 | 18,675 | 2.1% | 104,377 | 1,949 | 8.3% | 222 |
| 2013 | 19,017 | 1.8% | 105,797 | 2,012 | 3.2% | 230 |
| 2014 | 19,328 | 1.6% | 104,512 | 2,020 | 0.4% | 231 |

**Irrigation Load**

**Projected Irrigation Sales and Load, 2015–2034**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 19,566 | 1.2% | 95,218 | 1,863 | -7.8% | 213 |
| 2016 | 19,847 | 1.4% | 95,841 | 1,902 | 2.1% | 217 |
| 2017 | 20,127 | 1.4% | 95,191 | 1,916 | 0.7% | 219 |
| 2018 | 20,408 | 1.4% | 93,999 | 1,918 | 0.1% | 219 |
| 2019 | 20,688 | 1.4% | 92,504 | 1,914 | -0.2% | 218 |
| 2020 | 20,970 | 1.4% | 91,789 | 1,925 | 0.6% | 219 |
| 2021 | 21,250 | 1.3% | 91,179 | 1,938 | 0.7% | 221 |
| 2022 | 21,531 | 1.3% | 90,194 | 1,942 | 0.2% | 222 |
| 2023 | 21,814 | 1.3% | 89,126 | 1,944 | 0.1% | 222 |
| 2024 | 22,092 | 1.3% | 88,442 | 1,954 | 0.5% | 222 |
| 2025 | 22,373 | 1.3% | 87,905 | 1,967 | 0.7% | 225 |
| 2026 | 22,653 | 1.3% | 87,365 | 1,979 | 0.6% | 226 |
| 2027 | 22,933 | 1.2% | 86,784 | 1,990 | 0.6% | 227 |
| 2028 | 23,215 | 1.2% | 86,171 | 2,000 | 0.5% | 228 |
| 2029 | 23,495 | 1.2% | 85,649 | 2,012 | 0.6% | 230 |
| 2030 | 23,777 | 1.2% | 85,060 | 2,022 | 0.5% | 231 |
| 2031 | 24,056 | 1.2% | 84,446 | 2,031 | 0.4% | 232 |
| 2032 | 24,338 | 1.2% | 83,751 | 2,038 | 0.3% | 232 |
| 2033 | 24,617 | 1.1% | 83,159 | 2,047 | 0.4% | 234 |
| 2034 | 24,899 | 1.1% | 82,533 | 2,055 | 0.4% | 235 |

## Industrial Load

### Historical Industrial Sales and Load, 1974–2014 (not weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 65 | – | 11,464,249 | 739 | – | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | -1.1% | 18,597,050 | 2,230 | -0.1% | 254 |
| 2012 | 115 | -4.2% | 19,757,921 | 2,271 | 1.8% | 258 |
| 2013 | 114 | -0.7% | 20,281,837 | 2,314 | 1.9% | 265 |
| 2014 | 113 | -0.7% | 20,863,653 | 2,363 | 2.1% | 271 |

**Industrial Load**

**Projected Industrial Sales and Load, 2015–2034**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 112 | -1.1% | 21,546,339 | 2,413 | 2.1% | 277 |
| 2016 | 113 | 0.9% | 22,776,876 | 2,574 | 6.7% | 294 |
| 2017 | 114 | 0.9% | 23,180,649 | 2,643 | 2.7% | 302 |
| 2018 | 115 | 0.9% | 23,415,713 | 2,693 | 1.9% | 308 |
| 2019 | 115 | 0.0% | 23,815,557 | 2,739 | 1.7% | 313 |
| 2020 | 115 | 0.0% | 24,226,148 | 2,786 | 1.7% | 318 |
| 2021 | 117 | 1.7% | 24,251,880 | 2,837 | 1.8% | 324 |
| 2022 | 117 | 0.0% | 24,697,299 | 2,890 | 1.8% | 330 |
| 2023 | 117 | 0.0% | 25,147,761 | 2,942 | 1.8% | 336 |
| 2024 | 118 | 0.9% | 25,374,712 | 2,994 | 1.8% | 341 |
| 2025 | 120 | 1.7% | 25,397,900 | 3,048 | 1.8% | 348 |
| 2026 | 121 | 0.8% | 25,630,843 | 3,101 | 1.8% | 355 |
| 2027 | 121 | 0.0% | 26,070,612 | 3,155 | 1.7% | 361 |
| 2028 | 121 | 0.0% | 26,512,099 | 3,208 | 1.7% | 366 |
| 2029 | 123 | 1.7% | 26,528,528 | 3,263 | 1.7% | 373 |
| 2030 | 124 | 0.8% | 26,729,282 | 3,314 | 1.6% | 379 |
| 2031 | 125 | 0.8% | 26,914,352 | 3,364 | 1.5% | 385 |
| 2032 | 125 | 0.0% | 27,298,864 | 3,412 | 1.4% | 389 |
| 2033 | 126 | 0.8% | 27,474,833 | 3,462 | 1.4% | 396 |
| 2034 | 127 | 0.8% | 27,632,976 | 3,509 | 1.4% | 401 |

**Additional Firm Sales and Load***

**Historical Additional Firm Sales and Load, 1974–2014**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1974 | 282 | – | 32 |
| 1975 | 314 | 11.2% | 36 |
| 1976 | 289 | -8.1% | 33 |
| 1977 | 311 | 7.8% | 36 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.4% | 43 |
| 1980 | 360 | -3.5% | 41 |
| 1981 | 377 | 4.6% | 43 |
| 1982 | 368 | -2.4% | 42 |
| 1983 | 425 | 15.6% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 482 | 2.3% | 55 |
| 1987 | 503 | 4.2% | 57 |
| 1988 | 531 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | -6.9% | 71 |
| 1991 | 661 | 5.8% | 75 |
| 1992 | 680 | 2.9% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | -2.1% | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | -1.7% | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,141 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |
| 2009 | 965 | -13.4% | 110 |
| 2010 | 907 | -6.0% | 104 |
| 2011 | 906 | 0.0% | 103 |
| 2012 | 862 | -4.8% | 98 |
| 2013 | 867 | 0.5% | 99 |
| 2014 | 841 | -2.9% | 96 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2015–2034**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2015 | 881 | 4.7% | 101 |
| 2016 | 902 | 2.4% | 103 |
| 2017 | 906 | 0.4% | 103 |
| 2018 | 909 | 0.4% | 104 |
| 2019 | 910 | 0.0% | 104 |
| 2020 | 921 | 1.2% | 105 |
| 2021 | 923 | 0.2% | 105 |
| 2022 | 958 | 3.8% | 109 |
| 2023 | 987 | 3.0% | 113 |
| 2024 | 1,007 | 2.0% | 115 |
| 2025 | 1,007 | 0.0% | 115 |
| 2026 | 1,004 | -0.3% | 115 |
| 2027 | 1,004 | 0.0% | 115 |
| 2028 | 999 | -0.5% | 114 |
| 2029 | 999 | 0.0% | 114 |
| 2030 | 1,004 | 0.5% | 115 |
| 2031 | 1,004 | 0.0% | 115 |
| 2032 | 999 | -0.5% | 114 |
| 2033 | 999 | 0.0% | 114 |
| 2034 | 994 | -0.5% | 113 |

*Includes Micron Technology, Simplot Fertilizer, and the INL

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1974–2014 (weather adjusted)**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1974 | 5,463 | – | 682 |
| 1975 | 6,013 | 10.1% | 751 |
| 1976 | 6,431 | 6.9% | 803 |
| 1977 | 6,878 | 7.0% | 855 |
| 1978 | 7,171 | 4.3% | 898 |
| 1979 | 7,798 | 8.7% | 969 |
| 1980 | 7,793 | -0.1% | 964 |
| 1981 | 8,048 | 3.3% | 1,003 |
| 1982 | 8,021 | -0.3% | 997 |
| 1983 | 7,996 | -0.3% | 996 |
| 1984 | 8,140 | 1.8% | 1,009 |
| 1985 | 8,328 | 2.3% | 1,037 |
| 1986 | 8,394 | 0.8% | 1,038 |
| 1987 | 8,481 | 1.0% | 1,053 |
| 1988 | 8,846 | 4.3% | 1,096 |
| 1989 | 9,250 | 4.6% | 1,147 |
| 1990 | 9,575 | 3.5% | 1,194 |
| 1991 | 9,800 | 2.3% | 1,211 |
| 1992 | 10,009 | 2.1% | 1,241 |
| 1993 | 10,185 | 1.8% | 1,262 |
| 1994 | 10,654 | 4.6% | 1,324 |
| 1995 | 11,053 | 3.7% | 1,368 |
| 1996 | 11,415 | 3.3% | 1,412 |
| 1997 | 11,722 | 2.7% | 1,455 |
| 1998 | 12,189 | 4.0% | 1,510 |
| 1999 | 12,510 | 2.6% | 1,549 |
| 2000 | 12,923 | 3.3% | 1,601 |
| 2001 | 13,070 | 1.1% | 1,616 |
| 2002 | 12,796 | -2.1% | 1,584 |
| 2003 | 13,044 | 1.9% | 1,618 |
| 2004 | 13,361 | 2.4% | 1,654 |
| 2005 | 13,593 | 1.7% | 1,688 |
| 2006 | 13,917 | 2.4% | 1,726 |
| 2007 | 14,379 | 3.3% | 1,784 |
| 2008 | 14,500 | 0.8% | 1,790 |
| 2009 | 13,955 | -3.8% | 1,731 |
| 2010 | 13,831 | -0.9% | 1,713 |
| 2011 | 13,810 | -0.2% | 1,711 |
| 2012 | 14,040 | 1.7% | 1,737 |
| 2013 | 14,113 | 0.5% | 1,755 |
| 2014 | 14,253 | 1.0% | 1,768 |

**Company System Load**

**Projected Company System Sales and Load, 2015–2034**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2015 | 14,378 | 0.9% | 1,786 |
| 2016 | 14,793 | 2.9% | 1,835 |
| 2017 | 15,019 | 1.5% | 1,864 |
| 2018 | 15,174 | 1.0% | 1,883 |
| 2019 | 15,318 | 0.9% | 1,900 |
| 2020 | 15,474 | 1.0% | 1,918 |
| 2021 | 15,642 | 1.1% | 1,941 |
| 2022 | 15,832 | 1.2% | 1,964 |
| 2023 | 16,024 | 1.2% | 1,988 |
| 2024 | 16,231 | 1.3% | 2,012 |
| 2025 | 16,425 | 1.2% | 2,037 |
| 2026 | 16,617 | 1.2% | 2,061 |
| 2027 | 16,807 | 1.1% | 2,085 |
| 2028 | 16,997 | 1.1% | 2,107 |
| 2029 | 17,198 | 1.2% | 2,133 |
| 2030 | 17,383 | 1.1% | 2,156 |
| 2031 | 17,552 | 1.0% | 2,177 |
| 2032 | 17,715 | 0.9% | 2,195 |
| 2033 | 17,892 | 1.0% | 2,219 |
| 2034 | 18,060 | 0.9% | 2,240 |

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An IDACORP Company

March 15, 2015

APPENDIX B
DSM Annual Report

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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June 2015

APPENDIX B
DSM Annual Report

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

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# TABLE OF CONTENTS

Table of Contents ..... i
List of Tables ..... iii
List of Figures ..... iii
List of Appendices ..... iv
List of Supplements ..... iv
Glossary of Acronyms ..... v
Executive Summary ..... 1
Introduction ..... 3
DSM Programs Performance ..... 4
Market Transformation ..... 9
Programs and Activities ..... 9
Program Planning Group ..... 9
2014 Regulatory Activities ..... 12
Program Evaluation ..... 12
Customer Satisfaction ..... 13
Cost-Effectiveness ..... 15
Future Plans ..... 18
DSM Expenditures ..... 19
Marketing ..... 21
Energy Efficiency Advisory Group ..... 27
DSM Annual Report Structure ..... 29
Residential Sector Overview ..... 31
Description ..... 31
Programs ..... 31
A/C Cool Credit ..... 35
Ductless Heat Pump Pilot ..... 38
Energy Efficient Lighting ..... 42
Energy House Calls ..... 48
ENERGY STAR® Homes Northwest ..... 53
Heating & Cooling Efficiency Program ..... 59
Home Energy Audit ..... 64
Home Improvement Program ..... 70

Home Products Program ..... 73
Oregon Residential Weatherization ..... 77
Rebate Advantage ..... 79
See ya later, refrigerator® ..... 81
Shade Tree Project ..... 85
Weatherization Assistance for Qualified Customers ..... 90
Weatherization Solutions for Eligible Customers ..... 95
Commercial/Industrial Sector Overview ..... 99
Description ..... 99
Programs ..... 100
Building Efficiency ..... 102
Custom Efficiency ..... 106
Easy Upgrades ..... 116
FlexPeak Management ..... 122
Oregon Commercial Audits ..... 126
Irrigation Sector Overview ..... 129
Description ..... 129
Programs ..... 130
Irrigation Efficiency Rewards ..... 131
Description ..... 131
Irrigation Peak Rewards ..... 136
Market Transformation ..... 141
Northwest Energy Efficiency Alliance ..... 141
Other Programs and Activities ..... 147
Residential Energy Efficiency Education Initiative ..... 147
Student Energy Efficiency Kit Program ..... 150
Easy Savings Program ..... 151
Commercial Education Initiative ..... 152
Regional Technical Forum ..... 153
University of Idaho Integrated Design Lab ..... 154
Local Energy Efficiency Funds ..... 158
Building-Code Improvement Activity ..... 159
Idaho Power's Internal Energy Efficiency Commitment ..... 159
Regulatory Overview ..... 161

Timely Recovery of DSM Program Costs: Energy Efficiency Rider and Prudence Determination of Expenditures ..... 161
Removal of Financial Disincentives: Fixed-Cost Adjustment ..... 163
Promotion of Energy Efficiency through Electricity Rate Design ..... 163
Appendices ..... 165

## LIST OF TABLES

Table 1. 2014 DSM programs by sector, operational type, location, and energy savings/demand reduction ..... 11
Table 2. Program sector summary and energy usage/savings/demand reduction ..... 12
Table 3. Idaho Power's cost-effectiveness ratios for the UC, TRC, and PCT perspectives for its energy efficiency programs, by sector and by portfolio ..... 17
Table 4. 2014 funding source and energy savings ..... 19
Table 5. 2014 DSM program expenditure by category ..... 19
Table 6. 2014 DSM program incentives by segment and sector ..... 20
Table 7. Cumulative results from February and September *Be Energy Smart* and *Use Your Watts Wisely* advertising campaign ..... 24
Table 8. 2014 residential program summary ..... 31
Table 9. Summary of bill communications sent in 2014 ..... 32
Table 10. 2014 weatherization solutions financial breakdown ..... 96
Table 11. 2014 commercial/industrial program ..... 100
Table 12. 2014 Custom Efficiency annual energy savings by primary project measure ..... 107
Table 13. 2014 irrigation program summary ..... 130
Table 14. 2014 program incentives ..... 137

## LIST OF FIGURES

Figure 1. Peak demand-reduction capacity and demand response expenses, 2004–2014 (MW and millions [$]) ..... 5
Figure 2. Annual energy savings and energy efficiency program expenses, 2002–2014 (MWh and millions [$]) ..... 5
Figure 3. DSM expense history, 2002–2014 (millions of dollars) ..... 6
Figure 4. DSM expense history by program type, 2004–2014 (millions of dollars) ..... 6
Figure 5. Annual incremental energy efficiency savings (aMW) compared with IRP targets (2002–2014) ..... 7

Figure 6. Annual cumulative energy efficiency savings (aMW) compared with IRP targets (2002–2014) ..... 7
Figure 7. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts ..... 14
Figure 8. 2014 DSM program expenditures by category ..... 20
Figure 9. 2014 DSM program incentives by segment and sector ..... 20
Figure 10. Summary of participating homes by county ..... 65
Figure 11. Measures installed in participating homes ..... 66
Figure 12. Program participants' benefits experienced ..... 68
Figure 13. How customers heard about program, 2014 ..... 76
Figure 14. See ya later, refrigerator® participation by year June 2009 ..... 82
Figure 15. How customers heard about See ya later, refrigerator® ..... 84
Figure 16. NEEA chart of attendees (in-class seats filled) by attendee sponsor ..... 108
Figure 17. NEEA chart of attendees (webinar-based seats filled) by attendee sponsor ..... 109

## LIST OF APPENDICES

Appendix 1. Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December, 2014) ..... 167
Appendix 2. 2014 DSM expenses by funding source (dollars) ..... 168
Appendix 3. 2014 DSM program activity ..... 169
Appendix 4. Historical DSM expense and performance, 2002–2014 ..... 171
Appendix 5. 2014 DSM program activity by state jurisdiction ..... 186

## LIST OF SUPPLEMENTS

*Supplement 1: Cost-Effectiveness*
*Supplement 2: Evaluation*
NEEA Market Effects Evaluations (included on CD with Supplement 2)

# GLOSSARY OF ACRONYMS

A/C—Air Conditioning/Air Conditioners

ADM—ADM Associates, Inc.

Ads—Advertisement

AHU—Air Handling Unit

AIA—American Institute of Architects

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

AR—Agricultural Representative

ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers

B/C—Benefit/Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BCW—Boise Center West

BML—Building Metrics Labeling

BOC—Boise Operations Center

BOMA—Building Owners and Managers Association

BPA—Bonneville Power Administration

BSUG—Building Simulation Users Group

CAES—Center for Advanced Energy Studies

CAIS—Certified Agricultural Irrigation Specialist

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCOA—CCOA—Aging, Weatherization and Human Services

CEERI—CAE's Energy Efficiency Research Institute

CEL—Cost-Effective Limit

CER—Community Education Representative

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CLEAResult—CLEAResult Consulting, Inc. (acquired Fluid Market Strategies and PECI)

CLRIS—Customer Load and Resource Information System

COP—Coefficient of Performance

CR—Customer Representative (field staff)

CR&EE—Customer Relations and Energy Efficiency Department

CRES—Certified Refrigeration Energy Specialist

CSR—Customer Service Representative (call center)

CTR—Click-Through Rate

CWI—College of Western Idaho

DEAP—Design Excellence Award Program

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

EA5—EA5 Energy Audit Program

EBR—Existing Building Renewal

ECM—Electronically Commutated Motors

EEAG—Energy Efficiency Advisory Group

EER—Energy Efficiency Ratio

EISA—*Energy Independence and Security Act of 2007*

EM&V—Evaluation, Measurement, and Verification

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

EUI—Energy Use Intensity

FCA—Fixed-Cost Adjustment

FFA—Future Farmers of America

FMP—Facility Management Professional

$ft^2$—Square Feet

$ft^3$—Cubic Feet

GIS—Geographic Information System

GMPG—Green Motors Practice Group

GPM—Gallons per Minute

H&CE—Heating & Cooling Efficiency Program

hp—Horsepower

HPWH—Heat Pump Water Heater

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IAC—Industrial Assessment Center

IBCA—Idaho Building Contractors Association

IBOA—International Building Operators Association

IDHW—Idaho Department of Health and Welfare

IDL—Integrated Design Lab (in Boise)

IECC—International Energy Conservation Code

IFMA—International Facility Management Association

INL—Idaho National Laboratory

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

iSTEM—Idaho Science, Technology, Engineering and Mathematics

JACO—JACO Environmental, Inc.

kW—Kilowatt

kWh—Kilowatt-hour

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

M&V—Measurement & Verification

MCR— Major Customer Representative

MDC—MDC Research

MOU—Memorandum of Understanding

MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association

MW—Megawatt

MWh—Megawatt-hour

n/a—Not Applicable

NEB—Non-Energy Benefit

NEEA—Northwest Energy Efficiency Alliance

NEEM—Northwest Energy Efficient Manufactured

NEF—National Energy Foundation

NEMA—National Electrical Manufacturers Association

NWPCC—Northwest Power and Conservation Council

NWRRC—Northwest Regional Retail Collaborative

O&M—Operation and Maintenance

OHCS—Oregon Housing and Community Services

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statute

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PLC—Power-Line Carrier

PSC—Permanent Split Capacitor

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAP—Resource Action Programs

RBSA—Residential Building Stock Assessment

RETA— Refrigerating Engineers and Technicians Association

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure Test

ROCEE—Refrigeration Operator Coaching for Energy Efficiency

ROI—Return on Investment

RPP—Retail Products Platform

RSAT—Regional Sales Allocation Tool

RSE—Runyon Saltzman Einhorn

RTF—Regional Technical Forum

RWLR—Reduced Wattage Lamp Replacement

SCCT—Simple-Cycle Combustion Turbine

SCE—Streamlined Custom Efficiency

SCO—State-Certifying Organization

SEEK—Students for Energy Efficiency Kit

SIR—Savings-to-Investment Ratio

SIS—Scientific Irrigation Scheduling

SKU—Stock Keeping Unit

SOX—*Sarbanes–Oxley Act of 2002*

SRVBCA—Snake River Valley Building Contractors Association

T&D—Transmission and Distribution

TLL—Tool Loan Library

TOD—Time of Day

TRC—Total Resource Cost

TRM—Technical Reference Manual

UC—Utility Cost

UES—Unit Energy Savings

US—United States

USFS—United States Forest Service

VFD—Variable-Frequency Drive

VOC—Volatile Organic Compound

VRF—Variable-Refrigerant Flow

VRI—Variable-Rate Irrigation

VSI—Variable-Speed Irrigation

WAP—Weatherization Assistance Program

WAQC—Weatherization Assistance for Qualified Customers

WRUN—Western Regional Utility Network

WSEEC—Water Supply Energy Efficiency Cohort

WWEEC—Wastewater Energy Efficiency Cohort

# EXECUTIVE SUMMARY

Idaho Power has effectively operated demand-side management (DSM) programs starting with load control programs around 1945 and adding energy efficiency programs beginning in the 1970s. Through the years, the company has maintained a successful DSM portfolio, including both energy efficiency and demand response programs.

Idaho Power's 2014 energy savings exceeded the annual savings target identified in Idaho Power's 2013 *Integrated Resource Plan* (IRP), and the company has exceeded those annual targets 12 out of 13 years. On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002. Additionally in 2014, the Customer Relations and Energy Efficiency (CR&EE) department contributed to the development of the 2015 IRP, including refreshing Idaho Power's *Energy Efficiency Potential Study*.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the total resource cost (TRC) test and the utility cost (UC) test with ratios of 1.89 and 3.49, respectively. Idaho Power's annual energy savings increased by 33 percent in 2014, with the energy efficiency programs saving enough energy to supply electricity to over 9,000 average homes a year. The savings from Idaho Power's energy efficiency programs alone (excluding Northwest Energy Efficiency Alliance [NEEA] savings) increased from 88,938 megawatt-hours (MWh) in 2013 to 118,670 MWh in 2014. Annual energy savings for 2013, including the revised NEEA savings, were 109,506 MWh. In 2014, these savings increased to 138,670 MWh.

Customers' familiarity with Idaho Power's energy efficiency programs meets or exceeds the average of peer utilities according to the J. D. Power and Associates electric utility customer satisfaction studies. Idaho Power has exceeded the average of its peer utilities every year in the last four years with its awareness of business programs, and the company has met or exceeded the average of its peer utilities five out of the last six years with its awareness of residential programs.

In 2014, Idaho Power worked diligently with NEEA and its funders to procure a new plan for regional market transformation. This effort resulted in a 2015 to 2019 NEEA business plan to obtain 145 aMW of energy savings at a cost of about $3 million less over the next five years to Idaho Power customers than the previous five-year business plan.

Idaho Power successfully resumed two of its demand response programs in 2014. The company used all three demand response programs in 2014 for a total demand reduction of 378 megawatts (MW) and an enrolled capacity of 390 MW. The reduced costs of these programs resulted in savings to Idaho Power customers of approximately $6.5 million dollars, with only a slight reduction in capacity of 11 percent from 2012. These strong demand response results are attributable to Idaho Power's collaborative efforts with a multitude of stakeholders.

Idaho Power enhanced its marketing, public relations, and research methods during 2014. These enhancements included the use of public television, new distribution methods for its energy efficiency newspaper inserts, focus groups, and social media. The company will continue with innovative techniques in 2015, including airport signage, broadcast and online radio, television, and feedback from Idaho Power's online customer research panel.

Early in 2014, Idaho Power formed a Program Planning Group to explore new opportunities to expand current energy efficiency programs and offerings. This group ushered new ideas through an assessment

process that will yield new offerings to the DSM program portfolio in 2015. In 2014, Idaho Power also increased the incentive paid under its commercial and industrial programs and made several changes to its commercial/industrial lighting measures based on input from stakeholders.

Energy efficiency program funding comes from the Idaho and Oregon Energy Efficiency Riders (Rider), Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider. Total expenditures from all funding sources on DSM-related activities increased by about 37 percent, from $27 million in 2013 to $37 million in 2014.

Idaho Power takes its responsibility of prudently managing customer funds seriously. The company's actions in 2014, and this report's content, provide evidence supporting the conscientious work Idaho Power employees and leaders have made toward using customers' funds wisely. Some highlights include the demand response settlement, the resulting outcome of restarting the demand response programs, and the establishment of the NEEA contract for the 2015 to 2019 funding cycle. The company believes it is important to provide maximum value to its customers.

This *Demand-Side Management 2014 Annual Report* provides a review of the company's DSM activities and finances throughout 2014 and outlines Idaho Power's plans for DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419, as well as the Memorandum of Understanding (MOU) signed by IPUC staff and Idaho investor-owned utilities in January 2010. Additionally, a courtesy copy of the report will be provided under Oregon Docket UM 1710 to facilitate review of program and measure cost-effectiveness.

# INTRODUCTION

In 2014, Idaho Power continued its long history of pursuing cost-effective energy efficiency. Through the years, the company has maintained a successful demand-side management (DSM) portfolio, including both energy efficiency and demand response programs. This report focuses on the years after 2002 when the Idaho Energy Efficiency Rider (Rider) began.

More specifically, Idaho Power's *Demand-Side Management 2014 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for 2014. In 2014, Idaho Power offered energy efficiency and demand response programs to all customer sectors. The company sponsored numerous activities under its customer education initiatives to improve customers' energy awareness and to educate them about reducing their electricity usage.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. In addition to cost-effectiveness, Idaho Power pays particular attention to ensuring the best value to Idaho Power's customers. Idaho Power strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the total resource cost (TRC) test and the utility cost (UC) test with ratios of 1.89 and 3.49, respectively. The energy savings from Idaho Power's energy efficiency programs in 2014 were 118,670 megawatt-hours (MWh)—enough to power over 9,000 average homes a year. The savings consisted of 21,267 MWh from the residential sector, 28,577 MWh from the commercial sector, 50,363 MWh from the industrial sector, and 18,464 MWh from the irrigation sector. This represents a 33 percent increase from 2013 savings. The industrial Custom Efficiency program contributed 43 percent of the portfolio savings, while residential lighting contributed 61 percent of the residential savings.

Beyond its energy efficiency incentive programs, Idaho Power increased its energy efficiency presence in the community by providing energy efficiency and program information through 116 outreach activities, including events, presentations, trainings, and other outreach activities documented in the company's Outreach Tracking System. In addition to these activities, Idaho Power staff throughout Idaho Power's service area delivered 164 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2014, Idaho Power's Community Education team provided 67 presentations on *The Power to Make a Difference* to 1,756 students. The community education representatives (CER) and other staff also completed 32 senior citizen presentations on energy efficiency programs and shared information about saving energy to 912 seniors in the company's service area. In September 2014, Idaho Power participated in the FitOne Expo in Boise, Idaho. At this event, the booth theme capitalized on light-emitting diode (LED) lighting imagery from the integrated campaign launched in August and previewed the energy-efficient interactive home graphic in the background. Idaho Power staff at the event educated attendees about the benefits of LED lighting technology and distributed 2,500 LED light bulbs to an engaged and receptive audience.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency

programs and education. In 2014, the Commercial Education Initiative worked with and supported various organizations, including the University of Idaho's Integrated Design Lab (IDL) in Boise; Building Owners and Managers Association (BOMA); United States (US) Green Building Council; American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE); International Building Operators Association (IBOA); and the International Facility Management Association (IFMA)—Northern Rockies Chapter to increase customers' energy efficiency knowledge.

Idaho Power's internal commitment to energy efficiency and sustainability increased in 2014. Several Idaho Power properties were enhanced in 2014 with the goal of improving energy efficiency. Numerous corporate headquarters (CHQ) remodel projects were completed in 2014. These remodels included high-efficiency lighting; heating, ventilation, and air conditioning (HVAC); and reflective and better-insulated roofing. The CHQ fourth floor was completely remodeled with new recycled carpet, low volatile organic compound (VOC) paint, and low-partition walls for increased light transmission throughout the floor. At the Boise Operations Center (BOC), Idaho Power installed building-wide Direct Digital Control system controls. At Boise Center West (BCW) the chillers and air handlers were replaced with high-efficiency units. Additionally, Idaho Power's CHQ continued to participate in the FlexPeak Management program, reducing its load when the program was used.

The company was successful in redesigning and reestablishing the Irrigation Peak Rewards and A/C Cool Credit programs in 2014. After a one-season suspension of these programs, participation was only slightly reduced. Each of the demand response programs, including FlexPeak Management, was used three times in the 2014 season for a total demand reduction of 378 MW and an enrolled capacity of 390 megawatts (MW).

Idaho Power uses the same report structure each year to fulfill the objectives of the Memorandum of Understanding (MOU) signed on January 25, 2010, by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities. The report consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows the standard cost-effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category. In 2014, the company continued its commitment to third-party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2014 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. Additionally, the report will be provided under Oregon Docket UM 1710 to facilitate review of program and measure cost-effectiveness.

## DSM Programs Performance

Idaho Power offers energy efficiency and demand response opportunities to all major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either of these sectors.

Idaho Power groups its DSM activities into four major categories: energy efficiency, demand response, market transformation, and other programs and activities. The other programs and activities are generally designed to provide customer outreach and education encouraging the efficient use of electricity. These activities are coordinated to advance Idaho Power's long-term commitment to pursue all prudent cost-effective energy efficiency, demand response, and to enhance customer satisfaction.

Figures 1 and 2 show the demand-reduction capacity and historic energy savings overlaid with the company's DSM expenses.

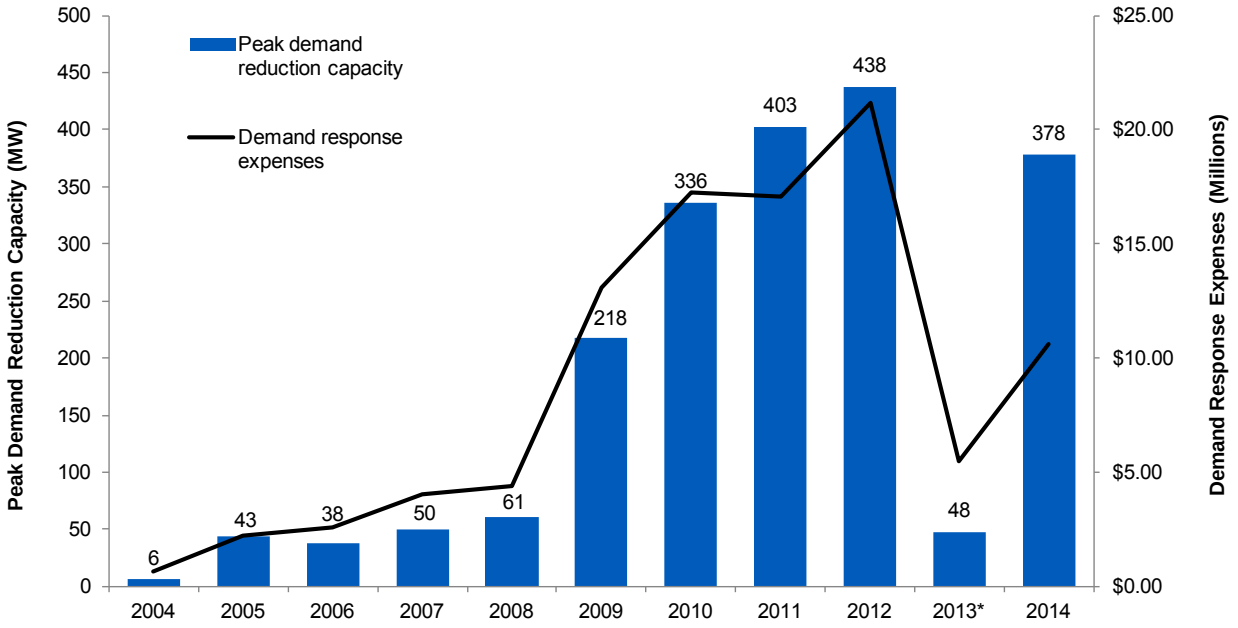


Figure 1. Peak demand-reduction capacity and demand response expenses, 2004–2014 (MW and millions [$])

*In 2013, two of the three demand response programs were temporarily suspended.

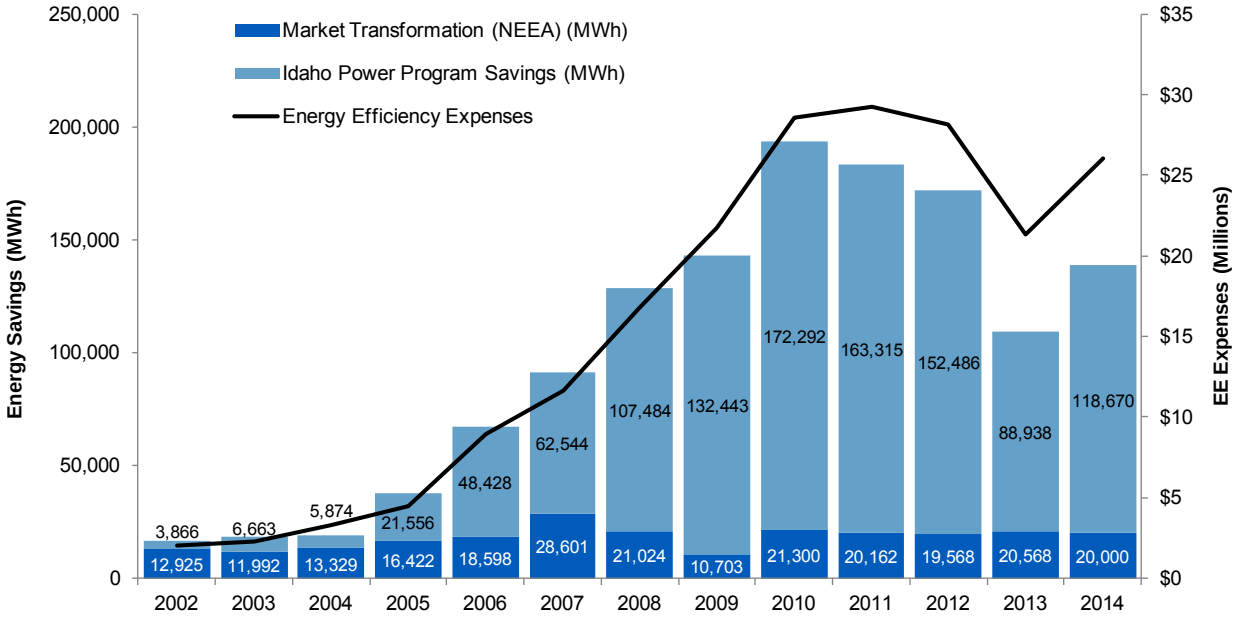


Figure 2. Annual energy savings and energy efficiency program expenses, 2002–2014 (MWh and millions [$])

*In 2013, two of the three demand response programs were temporarily suspended.
Note: 2014 market transformation savings (Northwest Energy Efficiency Alliance [NEEA]) are a preliminary estimate.

Figures 3 and 4 show the company's total DSM expenses for all funding sources, separated between energy efficiency expenses and demand response expenses.

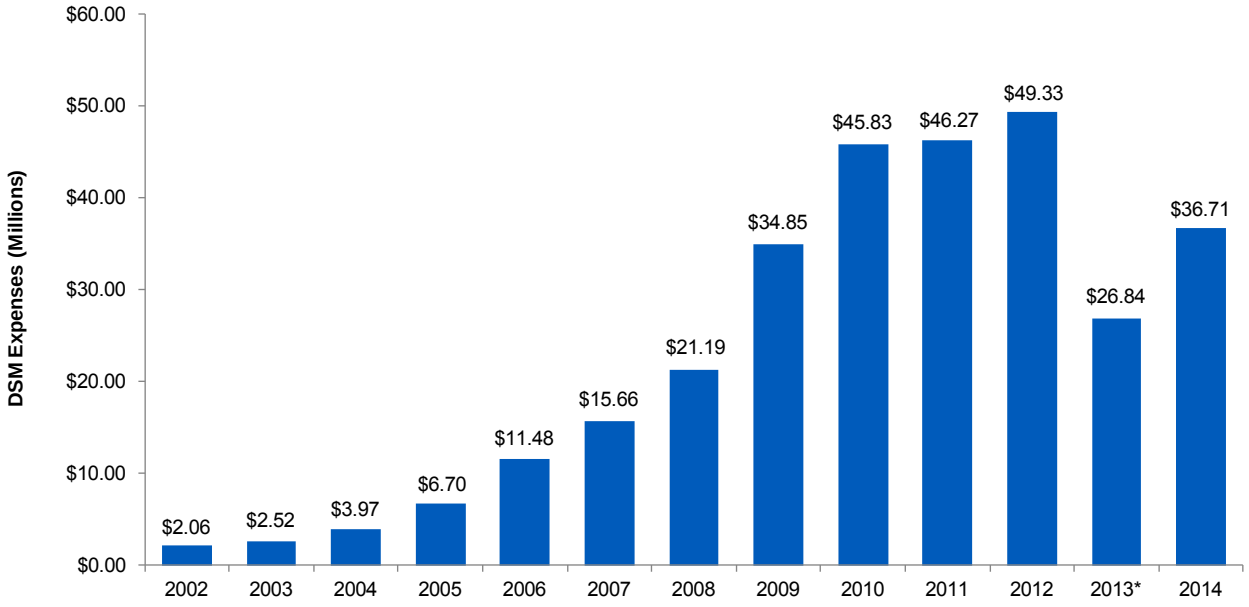


Figure 3. DSM expense history, 2002–2014 (millions of dollars)

*In 2013, two of the three demand response programs were temporarily suspended.

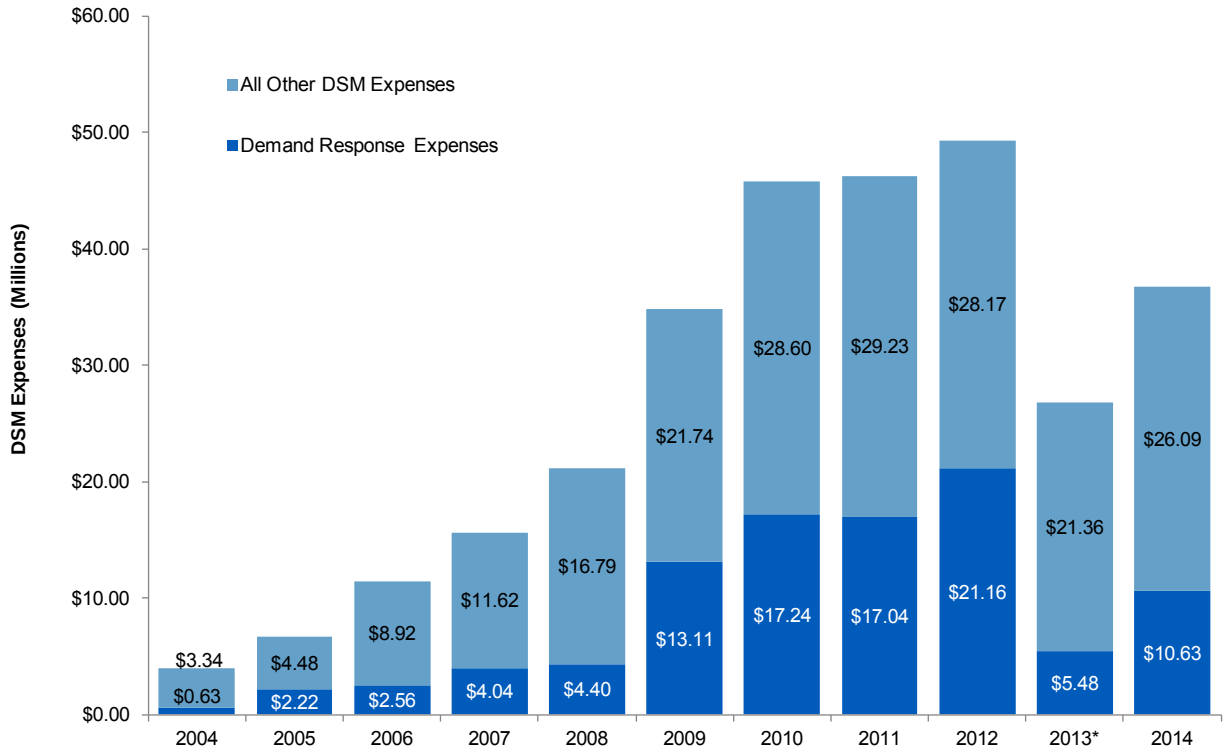


Figure 4. DSM expense history by program type, 2004–2014 (millions of dollars)

*In 2013, two of the three demand response programs were temporarily suspended.

Figure 5 shows Idaho Powers total annual energy efficiency savings in average megawatts (aMW) overlaid with the company's IRP energy-savings targets (aMW).

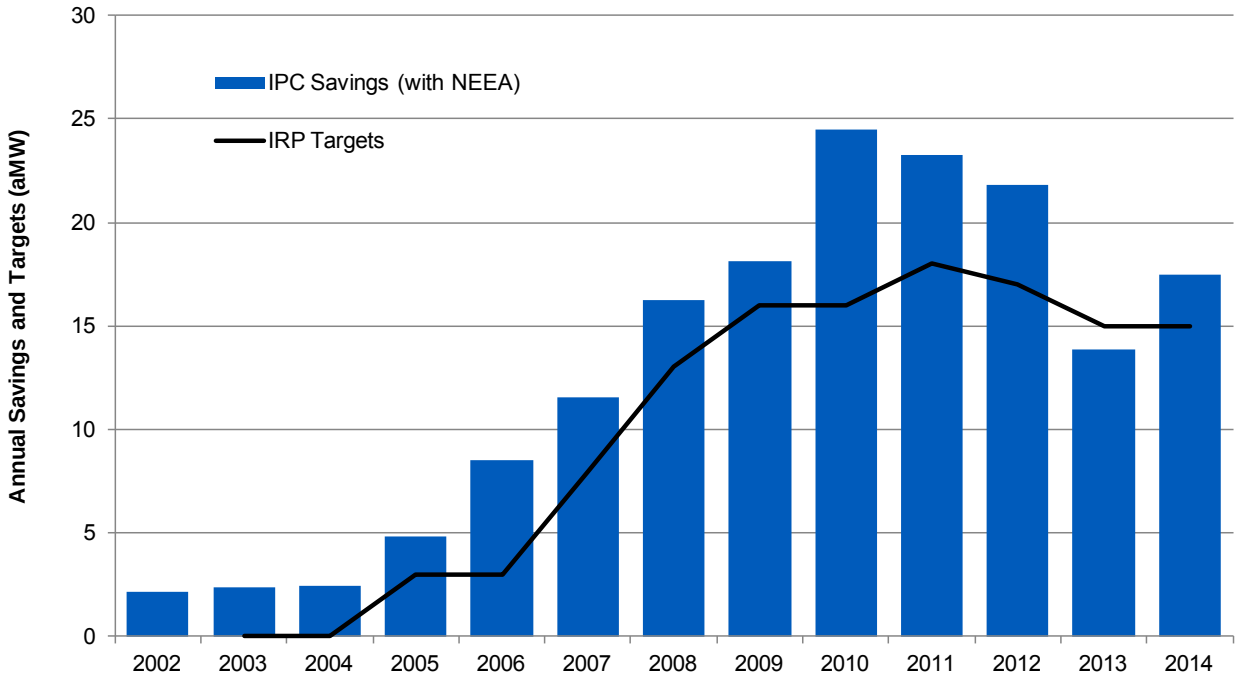


Figure 5. Annual incremental energy efficiency savings (aMW) compared with IRP targets (2002–2014)

Figure 6 shows Idaho Power's total cumulative energy efficiency savings overlaid with the company's cumulative IRP energy-savings targets (aMW).

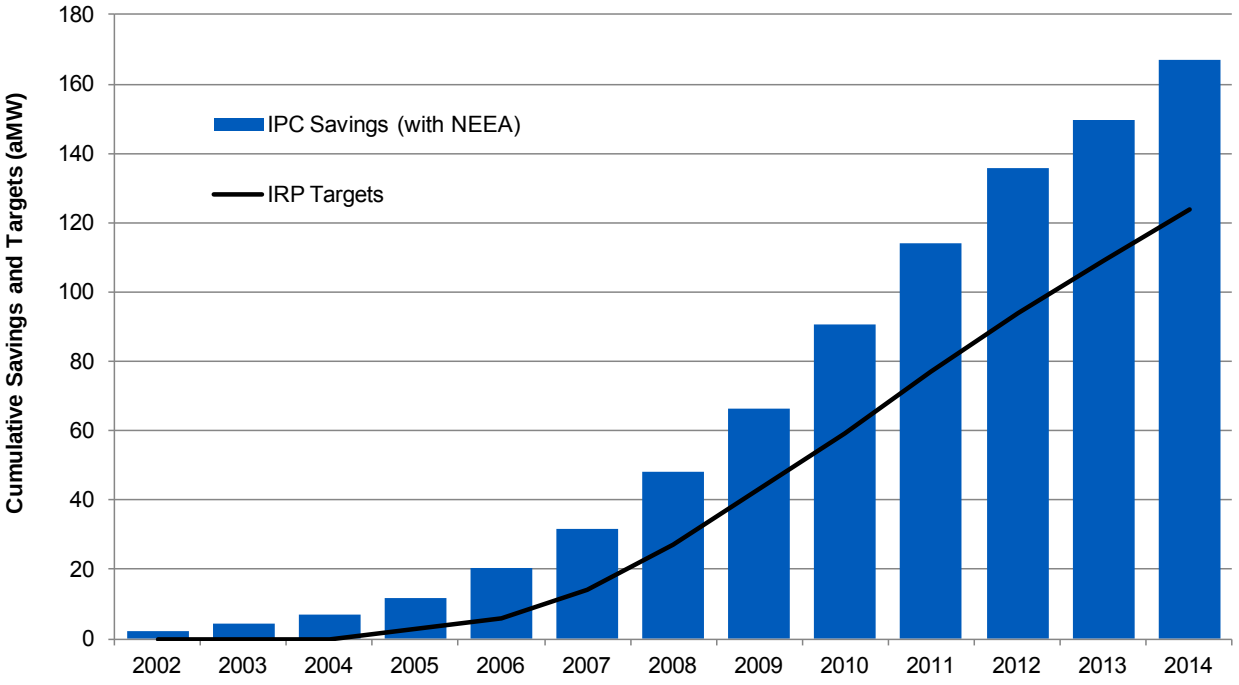


Figure 6. Annual cumulative energy efficiency savings (aMW) compared with IRP targets (2002–2014)

## Demand Response Programs

Idaho Power started its modern demand response programs in 2002 and now has over 10 percent of its all-time peak load available under demand response programs. The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side peaking resources. The company estimates future capacity needs through the IRP planning process and plans resources to mitigate any system peak deficits that exist. Demand response programs are measured by the amount of demand reduction, in MW, available to the company during system peak periods.

Idaho Power's successful demand response portfolio was acknowledged in an article in the March 6, 2015, issue of Clearing Up, a monthly newsletter produced by ENERGY NEWSDATA. Clearing Up is a weekly newsletter update on energy policy, resource development, and energy market news in the Pacific Northwest region and western Canada. The article stated Idaho Power is the regional utility with the most experience in using demand response to reduce peak loads.

In summer 2014, Idaho Power had a combined maximum demand response capacity of 390 MW at the generation level. The amount of capacity available for demand response varies based on weather, the time of year, and how programs are used and managed. The capacity of 390 MW is calculated using total enrolled MW from participants with an expected maximum realization rate on those participants. This maximum realization rate is not always achieved for every program in any given event. This realization rate is expected to be approximately 73 percent of billing demand for Irrigation Peak Rewards, 100 percent of nominated demand from FlexPeak Management, and 1.1 kW per participant for A/C Cool Credit. In 2014, the actual non-coincidental load reduction from all three programs was approximately 378 MW. This number was lower than 390 MW primarily because the Irrigation Peak Rewards did not achieve its maximum realization rate due to equipment maintenance problems that existed with irrigation devices. On Monday, July 14, 2014, the company used all three of its demand response programs together and achieved a coincident load reduction of approximately 356 MW.

The IRP analysis uses extreme load and weather assumptions to identify the need for resources. In 2014, Idaho Power did not experience extreme conditions; however, the company demonstrated successful operation of the programs on the three minimum events for each program. Program participation and readiness for the A/C Cool Credit and the Irrigation Peak Rewards programs were significant considering these two programs were temporarily suspended for a season. Idaho Power temporarily suspended these two demand response programs for summer 2013 under IPUC Case No. IPC-E-12-29 and Tariff Advice No. 13-04 with the OPUC. However, through IPUC Case No. IPC-E-13-14 (Order No. 32923) and OPUC Case No. UM 1653 (Order No. 13-482), Idaho Power and interested parties reached a settlement agreement to continue the company's demand response programs for 2014 and beyond. In 2014, these programs cost $10.6 million; had the programs been used for the maximum number of hours, the cost would have been approximately $13.8 million. These costs represent approximately $6 million dollars in savings compared to 2012 and are significantly less than the value of $16.7 million agreed on in the settlement agreement.

## Energy Efficiency Programs

Idaho Power's energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components for which an energy-efficient design, replacement, or repair can achieve energy savings. Energy efficiency programs sometimes include behavioral components, like in the Residential Energy Efficiency Education Initiative and the Wastewater Energy Efficiency Cohort offering in the Custom Efficiency program. Energy efficiency programs are available to all customer sectors in Idaho Power's service area. Project measures range from entire residential or commercial

building construction to heat pump replacement. Savings from these programs are measured in terms of kilowatt-hour (kWh) or MWh savings. These programs usually supply energy savings throughout the year at different degrees. Idaho Power shapes these savings based on the end-use to estimate energy reduction at specific times of the year and day. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement. Custom programs under the irrigation and industrial sectors offer a wide range of unique opportunities for Idaho Power and its customers to design and execute energy-savings projects.

## Market Transformation

Market transformation achieves energy savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improve their energy efficiency. Idaho Power achieves market transformation savings primarily through its participation in the Northwest Energy Efficiency Alliance (NEEA). Idaho Power has been a funding member of NEEA since its inception in 1997.

The fifth year of NEEA's current, five-year funding cycle ended in 2014. As early as 2009, Idaho Power expressed a desire to see a change in the way NEEA services were offered in the 2015 to 2019 funding cycle that would differentiate "core" services of market transformation activities from optional services. This way, utilities could elect to support projects and activities that matched their interests and needs. During 2014, the company continued to advocate for this model through multiple meetings with NEEA, by actively participating on the NEEA Board of Directors and exploring alternative funding models, and by chairing and serving on the Alternative Funding Model Working Group Committee of the NEEA Board of Directors. This effort resulted in a 2015 to 2019 NEEA business plan, which is forecast to obtain 145 aMW of regional energy savings at a cost savings of about $3 million over the next five years to Idaho Power customers as compared to the previous five-year business plan. The NEEA plan also offered some optional programs and activities to prevent overlap of activities when local utilities have the capability to provide the same services at a lower cost or more effectively. In 2014, Idaho Power executed an agreement to continue its participation in NEEA for the 2015 to 2019 funding cycle and chose not to participate in some of the optional programs and activities where it believes it is providing or can provide the same services at a lower cost or more effectively.

## Programs and Activities

Idaho Power recognizes the value of energy efficiency awareness and education in creating behavioral change that helps customers use energy wisely. The goal of other programs and activities is to promote energy efficiency programs, projects, and behavior to customers. These awareness efforts increase customer demand for, and satisfaction with, Idaho Power's programs and activities. These activities include customer outreach, research, project development, and education programs. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Education Initiative, Local Energy Efficiency Funds (LEEF), and Student Energy Efficiency Kit (SEEK) program.

## Program Planning Group

In early 2014, Idaho Power convened a Program Planning Group (previously referred to as the New Ideas team) to explore new opportunities to expand current DSM programs and offerings. The group consisted of residential program specialists, commercial and industrial engineers, energy efficiency analysts, marketing specialists, energy efficiency program leaders, and the research

and analysis leader. The group has expanded to include a departmental specialist and a research assistant. Throughout 2014, the group met weekly and formalized a process for new ideas to be evaluated. Among other things, the group identified a process for submitting new offering ideas for consideration, determined a consistent screening process for submitted ideas, and provided a mechanism to record and track the status of opportunities considered, including the rationale for decisions made.

In 2014, 18 new ideas were introduced to the team. Three of those ideas have been identified as viable energy efficiency offerings and will be incorporated into the Heating & Cooling Efficiency (H&CE) Program in 2015. They are Single-Family Home Duct Sealing, which is prescriptive duct-sealing for heat pumps and electric resistance heated homes; Residential Electronically Commutated Motor (ECM), which is the more efficient replacement for a failed permanent split capacitor (PSC) motors with ECMs in forced-air systems; and a Residential Whole House Fan Pilot, which is the installation of a whole house fan between a home's attic and the conditioned space that displaces forced air and zonal direct expansion cooling.

Two other offerings have been presented to the Energy Efficiency Advisory Group (EEAG) and have been implemented or are being implemented in 2015. They are Energy Efficiency Kits for High School, which includes age-appropriate curriculum and energy efficiency kit components (such as LEDs and efficient showerheads), and LED bulbs given away at events for promotional and educational and market transformation purposes. Other ideas include distributing clothes drying racks for promotional and educational purposes, smart thermostats, and a small-business offering.

Idaho Power will continue to use the Program Planning Group to receive, evaluate, and deliver new energy efficiency offerings in 2015 and beyond.

Table 1 provides a list of 2014 DSM programs and their respective sectors, operational type, state each was available, and associated energy savings.

Table 1. 2014 DSM programs by sector, operational type, location, and energy savings/demand reduction

| Program by Sector | Operational Type | State | Savings/Demand Reduction |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 44 MW |
| Ductless Heat Pump Pilot | Energy Efficiency | ID/OR | 463 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 12,882 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 579 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 528 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 1,099 MWh |
| Home Energy Audit | Energy Efficiency | ID | 141 MWh |
| Home Improvement Program | Energy Efficiency | ID | 839 MWh |
| Home Products Program | Energy Efficiency | ID/OR | 652 MWh |
| Local Energy Efficiency Funds | Other Programs and Activities | ID/OR | 96 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | 11 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 270 MWh |
| Residential Energy Efficiency Education Initiative | Other Programs and Activities | ID/OR | 1,491 MWh |
| See ya later, refrigerator® | Energy Efficiency | ID/OR | 1,391 MWh |
| Shade Tree Project | Other Programs and Activities | ID | n/a |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 534 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 291 MWh |
| **Commercial/Industrial** | | | |
| Building Efficiency | Energy Efficiency | ID/OR | 9,458 MWh |
| Commercial Education Initiative | Other Programs and Activities | ID/OR | n/a |
| Custom Efficiency | Energy Efficiency | ID/OR | 50,363 MWh |
| Easy Upgrades | Energy Efficiency | ID/OR | 19,118 MWh |
| FlexPeak Management | Demand Response | ID/OR | 40 MW |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| **Irrigation** | | | |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 18,464 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 295 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 20,000 MWh |

Table 2 shows the 2014 annual energy savings, percent of energy usage, number of customers, and aMW savings associated with each of the DSM program categories. The table also provides a comparison of the 2014 contribution of each sector in terms of energy usage and its respective size in the number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

Table 2. Program sector summary and energy usage/savings/demand reduction

| | Energy Efficiency Program Impacts | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (kWh) | Average Energy (aMW) | Peak Load Reduction (MW) | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $ 6,372,640 | 21,171,063 | 2.5 | | 5,034,531 | 35.54% | 428,294 |
| Commercial | 4,409,215 | 28,576,553 | 3.3 | 1.2 | 3,962,785 | 27.97% | 67,522 |
| Industrial | 7,173,054 | 50,363,052 | 5.7 | 5.6 | 3,203,975 | 22.61% | 118 |
| Irrigation | 2,446,507 | 18,463,611 | 2.1 | 4.6 | 1,966,297 | 13.88% | 18,773 |
| Market Transformation | 3,305,917 | 20,000,000 | 2.3 | n/a | | | |
| Demand Response | 10,626,070 | n/a | n/a | 378 | | | |
| Other Programs and Activities | 2,379,929 | 95,834 | 0.0 | n/a | | | |
| **Total Program Expenses** | **$ 36,713,332** | **138,670,112** | **16.0** | **390.0** | **14,167,588** | **100.00%** | **514,707** |

## 2014 Regulatory Activities

On March 14, 2014, Idaho Power filed Case No. IPC-E-14-04 with the IPUC requesting an order finding the company had prudently incurred $25,951,486 in DSM expenses in 2013, including $21,748,331 in Idaho Rider expenses and $4,203,155 in demand response program incentive expenses. In Order No. 33161, dated November 4, 2014, the IPUC deemed $25,951,486 as prudently incurred.

The commission issued an Errata to Order No. 33161, dated November 7, 2014, directing Idaho Power and other parties to do an in-depth review of issues raised by staff and other parties in the company's next IRP process. Idaho Power convened a DSM Working Group that met twice in December 2014 and examined how energy efficiency was treated in the resource planning process, as discussed in the Regulatory Overview section of this report.

## Program Evaluation

Idaho Power considers program evaluation an essential component of its DSM operational activities. In accordance with the 2010 MOU with the IPUC staff, the company contracts with third-party contractors to conduct impact, process, and other evaluations on a scheduled and as-required basis.

Third-party contracts are generally awarded using a competitive bid process managed by Idaho Power's Strategic Sourcing department. In some cases, research and analysis is conducted internally and managed by Idaho Power's Research and Analysis team within the Customer Relations and Energy Efficiency (CR&EE) department. Third-party evaluations are specifically managed by the company's energy efficiency evaluator.

Idaho Power uses industry-standard protocols for its internal and external evaluation efforts, including the *National Action Plan for Energy Efficiency—Model Energy Efficiency Program Impact Evaluation Guide*, the *California Evaluation Framework,* the *International Performance Measurement and Verification Protocol* (IPMVP), the *Database for Energy Efficiency Resources*, and the Regional Technical Forum's (RTF) evaluation protocols.

The company also supports regional and national studies to promote the ongoing cost-effectiveness of programs, the validation of energy savings and demand reduction, and the efficient management of its programs. Idaho Power considers primary and secondary research, cost-effectiveness analyses, potential assessments, impact and process evaluations, and customer surveys as important resources in

providing accurate and transparent program savings estimates. Recommendations and findings from evaluations and research are used to continuously refine Idaho Power's DSM programs.

In 2014, Idaho Power completed five program impact evaluations and three program process evaluations using third-party contractors. Johnson Consulting Group conducted process evaluations of the Home Energy Audit program and Shade Tree Project, Tetra Tech, MA conducted impact evaluations of the residential Energy Efficient Lighting and Northwest ENERGY STAR® Homes programs, CLEAResult Consulting, Inc. (CLEAResult) (acquired Fluid Market Strategies and PECI) conducted impact evaluations of the Irrigation Peak Rewards and A/C Cool Credit program 2014 test events, and Evergreen Economics conducted an impact evaluation on the Custom Efficiency program as well as a process evaluation of the new Streamlined Custom Efficiency (SCE) and Refrigeration Operator Coaching for Energy Efficiency (ROCEE) program offerings. Idaho Power also contracted with Applied Energy Group to update the 2012 energy efficiency potential analysis.

Throughout 2014, Idaho Power administered surveys on several programs to measure program satisfaction. Participant surveys were conducted for A/C Cool Credit, Energy House Calls, Home Energy Audit, Shade Tree Project, Weatherization Assistance for Qualified Customers (WAQC), and Weatherization Solutions for Eligible Customers. In addition to these participant surveys, a non-participant survey was issued for Energy House Calls to gain a better understanding of customers' awareness of the program.

In 2014, Idaho Power received the research results for Custom Efficiency, Building Efficiency, and Easy Upgrades. In 2013, the company selected Market Decisions Corporation to conduct customer research for the Custom Efficiency program and ADM Associates, Inc., to produce a technical reference manual for the Building Efficiency and Easy Upgrades programs.

Final reports from all evaluations, research, and surveys completed in 2014 and an evaluation schedule are provided in *Supplement 2: Evaluation*.

## Customer Satisfaction

In 2014, based on surveys conducted in 2013, Idaho Power ranked sixth out of nine utilities included in the west region midsize segment of the J.D. Power and Associates *2014 Electric Utility Business Customer Satisfaction Study*. Fifty-six percent of the business customer respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than customers who are unaware of the programs. The awareness of Idaho Power's energy efficiency programs not only affects the customer's overall satisfaction with the company but also his/her satisfaction with corporate citizenship.

In 2014, based on surveys conducted in the last six months of 2013 and the first six months of 2014, Idaho Power ranked 8 out of 13 utilities included in the west region midsize segment of the J.D. Power and Associates *2014 Electric Utility Residential Customer Satisfaction Study*. Forty-seven percent of the residential respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than customers who are unaware of the programs. Awareness of Idaho Power's energy efficiency programs improves customers' perceptions regarding price by 13 percent.

Since 1995, Idaho Power has employed Burke, Inc., an independent third-party research vendor, to conduct customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The Burke Customer Relationship survey measures the satisfaction of a number of

aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, it is not the intent of this survey to measure all aspects of energy efficiency programs offered by Idaho Power.

The 2014 results of Idaho Power's quarterly customer relationship survey showed a slight increase in overall satisfaction from the previous year. Customers' perception of Idaho Power's energy efficiency efforts increased from 57 percent at the end of 2013 to 62 percent in late 2014. Figure 7 depicts the quarterly change in the percent of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

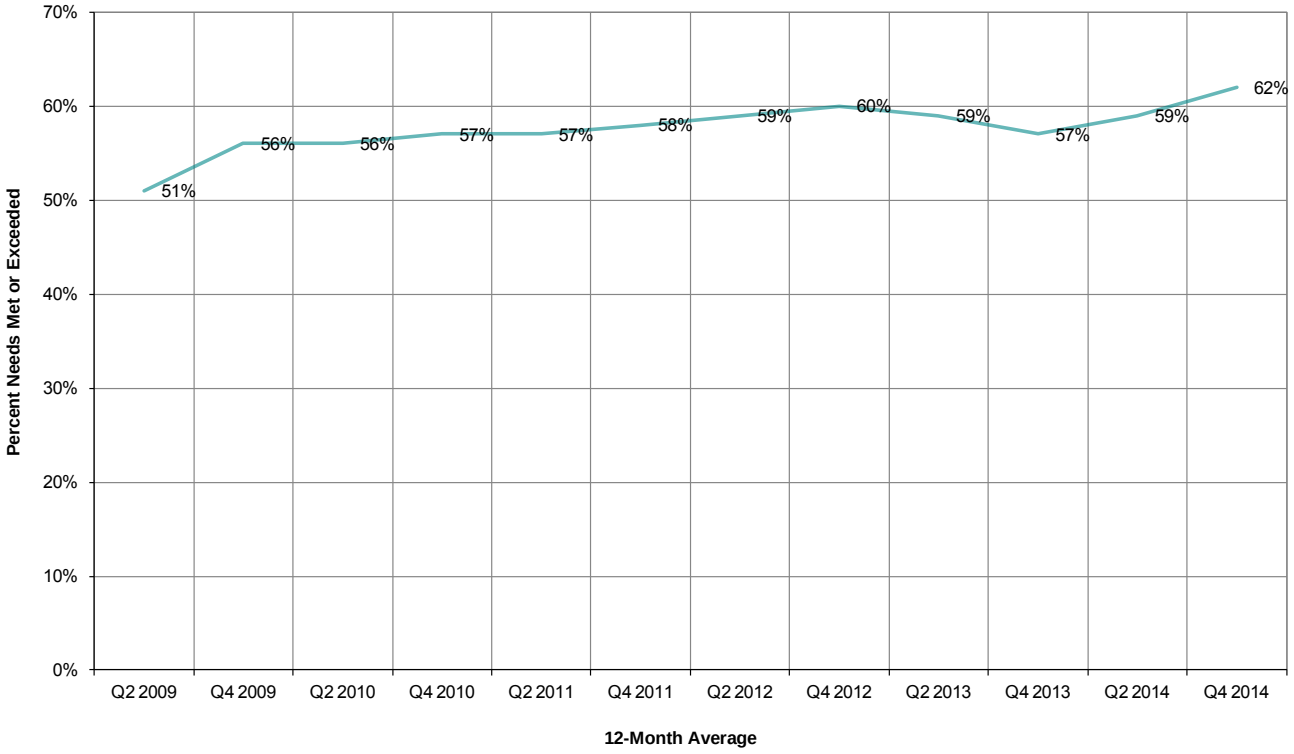


Figure 7. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

Three questions related to energy efficiency programs in the general relationship survey continued in the 2014 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs?, 2) Which energy efficiency program did you participate in?, and 3) Overall, how satisfied are you with the energy efficiency program? In 2014, 37 percent of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program. Of survey respondents who participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program(s).

Due to a concern of over-surveying program participants, and because the measures and specifics of most program designs do not change annually, Idaho Power will not survey most program participants annually. To ensure meaningful research in the future, Idaho Power will conduct program research periodically (every two to three years), unless there have been major program changes.

## Cost-Effectiveness

Cost-effectiveness is of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. Idaho Power's energy efficiency and demand response opportunities are preliminarily identified through the IRP process. Idaho Power uses third-party energy efficiency potential studies to identify achievable cost-effective energy efficiency potential, which is added to the resources included in the IRP. Because of Idaho Power's diverse portfolio of programs, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to programs rather than new programs.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design will be cost-effective from the perspective of Idaho Power and its customers. Incorporated in these models are inputs from sources that use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other utilities in the region or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the TRC test, UC test, and participant cost test (PCT) at the program and measure level where appropriate. If a particular measure or program is pursued even though it will not be cost-effective from each of the three tests, Idaho Power works with EEAG to get input. If the measure or program is indeed offered, the company explains why the measure or program was implemented or continued. The company believes this aligns with the expectations delineated in the MOU under IPUC Case No. IPC-E-09-09 and OPUC Order No. 94-590.

When a new program or measure is considered, Idaho Power launches a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following the implementation of a program, cost-effectiveness analyses are reviewed as new inputs from the actual program activity become available, such as actual program expenses, savings, or participation levels. If measures or programs are determined not to be cost-effective after implementation, the program or measures are re-examined, including using input provided from EEAG.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2014. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. As in 2013, the actual historic savings and expenses are not discounted; only the value of the ongoing savings going forward are discounted to reflect today's dollars. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

In 2014, Idaho Power reviewed its policy to update measure energy savings throughout the year. In the past, when energy savings assumptions were updated during the calendar year by third parties, such as the RTF or an evaluator, Idaho Power immediately applied those assumptions retroactively for the entire year. This caused issues when budgets and goals were set at the beginning of the year using one set of assumptions and those assumptions changed mid-year, making it appear some programs were not meeting their original goals. It has been recommended in previous process evaluations that the company "freeze" savings assumptions at a certain point and update assumptions once a year. After reviewing the practices of other utilities around the region and the impact of these frequent updates to program specialists and field staff, the company established a policy to freeze savings assumptions when the budgets and goals are set for the next calendar year unless code and standards changes or program

updates necessitate an immediate need to use updated savings. As a general rule, the 2014 energy savings reported for most programs will use the assumptions set at the beginning of the year. These assumptions will be discussed in more detail in the cost-effectiveness sections for each program.

The method used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops on Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement was approved in IPUC Order No. 32923 and OPUC Order No. 13-482. Per the settlement agreements, the annual cost of operating the three demand response programs for the maximum allowable 60 hours should be no more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170-MW simple cycle combustion turbine (SCCT) over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million and would have remained cost-effective.

New DSM alternative costs from Idaho Power's 2013 IRP affected the cost-effectiveness of the company's programs and measures in 2014. The 2013 IRP was acknowledged by the IPUC in Order No. 32980 on February 24, 2014, and by the OPUC in Order No. 14-253 on July 8, 2014. The 2013 IRP planning process resulted in a significant drop in the DSM alternative costs used to value energy efficiency compared with previous IRPs. While impacts vary from program to program depending on measure life and the end uses, decreases of program benefits of up to 40 to 50 percent have been seen. Multiple factors led to the reduction of the DSM alternative costs, but two of the primary impacts included a reduced carbon adder used in the 2013 IRP process and decreases in early-year natural gas price forecasts. While these benefit reductions have placed more burden on program cost-effectiveness, some of the impact has been mitigated by the recent addition of quantified non-energy benefits (NEB) in the region.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the TRC test and the UC test with ratios of 1.89 and 3.49, respectively. The company's energy efficiency programs' sector portfolios were also cost-effective from a TRC test and UC test perspective.

In 2014, most of Idaho Power's energy efficiency programs were cost-effective, except the Ductless Heat Pump (DHP) Pilot, ENERGY STAR Homes Northwest, See ya later, refrigerator ®, and the weatherization programs for income-qualified customers.

The DHP Pilot and the ENERGY STAR Homes Northwest program were both cost-effective under the UC test but failed the TRC test with ratios of 0.70 and 0.83, respectively.

In fall 2013, the RTF approved DHP annual savings estimates for customers not screened for supplemental fuel use. In November, the RTF presented its findings and recommendation on the inclusion of health benefits to be part of the cost-effective benefits in the cost-effective analysis of measures and programs, which would increase the NEBs and increase the TRC. The RTF is waiting on the Northwest Power and Conservation Council's (NWPCC) guidance on the issue.

In 2014, 8 of 243 ENERGY STAR Homes Northwest homes were single-family homes and 235 were townhomes. Due to the lower kWh savings for townhomes versus single-family homes and the ratio of townhomes, the program was shown not to be cost-effective from a TRC perspective for 2014. NEEA is planning to transition the Northwest ENERGY STAR Homes program to the national Environmental Protection Agency (EPA) ENERGY STAR Homes program. A second program, NEEA's Next Step

Home program, is still in the pilot stage. Idaho Power will monitor these potential changes to the program for possible implementation in the future.

See ya later, refrigerator® has a UC and TRC of 0.86. The lower cost-effectiveness ratios in 2014 over 2013 are largely due to the updated 2013 IRP DSM alternative costs. In 2014, the RTF updated the energy-savings assumptions for freezer and refrigerator decommissioning and included estimates for NEBs. The updated energy savings and NEB assumptions will be applied in 2015 along with the planned program changes in 2015. The program is expected to be cost-effective in 2015.

WAQC had a TRC of 0.42, and Weatherization Solutions for Eligible Customers had a TRC of 0.50. The cost-effectiveness ratios were impacted by the change in DSM alternative costs and the updated per-home savings. Despite the fact that Idaho Power adopted the IPUC staff's recommendations from Case No. GNR E-12-01 for calculating the programs' cost-effectiveness and the company worked with third-party contractors to improve the audit tool for the Weatherization Solutions for Eligible Customers program, improve savings estimates, and reduce costs, these programs remain not cost-effective. Refer to the specific program sections for more detail.

Thirty nine measures in various programs are shown not to be cost-effective from either the UC or TRC perspective. These measures will be discontinued, analyzed for additional NEBs, modified to increase potential per-unit savings, or monitored to examine their impact on the specific program's overall cost-effectiveness.

Table 3 shows Idaho Power's cost-effectiveness ratios for the UC, TRC, and PCT perspectives for its energy efficiency programs, by sector, and by portfolio.

Table 3. Idaho Power's cost-effectiveness ratios for the UC, TRC, and PCT perspectives for its energy efficiency programs, by sector and by portfolio

| | 2014 B/C Tests | | |
|---|---|---|---|
| **Program/Sector** | **UC** | **TRC** | **PCT** |
| Ductless Heat Pump Pilot | 1.77 | 0.70 | 1.01 |
| Energy Efficient Lighting | 2.98 | 1.99 | 2.67 |
| Energy House Calls | 2.16 | 2.16 | N/A |
| ENERGY STAR Homes Northwest | 1.64 | 0.83 | 1.41 |
| Heating and Cooling Efficiency Program | 3.74 | 1.09 | 1.45 |
| Home Improvement Program | 4.17 | 1.51 | 2.39 |
| Home Products Program | 1.94 | 4.52 | 7.28 |
| Rebate Advantage | 4.39 | 3.23 | 6.21 |
| See ya later, refrigerator® | 0.86 | 0.86 | N/A |
| Students for Energy Efficiency Kit | 2.18 | 3.02 | N/A |
| Weatherization Assistance for Qualified Customers | 0.51 | 0.42 | N/A |
| Weatherization Solutions for Eligible Customers | 0.46 | 0.50 | N/A |
| **Residential Energy Efficiency Sector** | **1.88** | **1.51** | **2.68** |
| Building Efficiency | 5.05 | 2.08 | 2.27 |
| Custom Efficiency | 4.72 | 2.52 | 2.00 |
| Easy Upgrades | 4.08 | 2.35 | 2.85 |
| **Commercial/Industrial Energy Efficiency Sector** | **4.58** | **2.42** | **2.24** |
| Irrigation Efficiency | 5.67 | 1.83 | 1.63 |
| **Irrigation Energy Efficiency Sector** | **5.67** | **1.83** | **1.63** |
| **Energy Efficiency Portfolio** | **3.49** | **1.89** | **2.09** |

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

## Future Plans

Idaho Power will continue to pursue all prudent cost-effective energy efficiency as identified by third-party potential studies and an appropriate amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecast level of energy efficiency and the needed level of demand response are included in Idaho Power's biennial IRP planning process. Idaho Power includes all achievable cost-effective energy savings as identified in its potential studies in each IRP. The IRP is a public document developed in a public process that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency to develop a preferred portfolio of future resources to meet specific energy needs of Idaho Power's customers.

In 2015, Idaho Power plans to increase participation in, and energy savings from, existing energy efficiency programs and initiatives. The company will continue to explore new potential as identified in the company's third-party energy efficiency potential study and through other third-party resources and conferences and will continue to assess and develop new program offerings through its Program Planning Group.

In 2015, Idaho Power will enhance its marketing and outreach efforts as described in the Marketing section and within each program section. Idaho Power will continue to work with NEEA on its market transformation activities during the 2015 to 2019 funding cycle.

The company will complete its research and evaluation, measurement, and verification (EM&V) projects included in the evaluation plan in *Supplement 2: Evaluation* to align with the expectations of the MOU established in IPUC Case N. IPC-E-09-09.

In 2015, Idaho Power will continue with a number of major remodels on the CHQ buildings downtown starting with the remodel of parts of CHQ sixth and seventh floors. The company will begin remodels on the CHQ eighth floor in 2016. Remodels will incorporate energy efficiency items, such as lower partitions, lighting retrofits, and lighting controls.

# DSM EXPENDITURES

Funding for DSM programs in 2014 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. For 2014, the Idaho Rider was 4 percent of base-rate revenues. The 2014 Oregon Rider was 3 percent of base-rate revenues. Additionally, Idaho-related demand response program incentives were paid through base rates and the annual power cost adjustment (PCA) mechanism. Energy efficiency and demand response-related expenses not funded through the Rider are included as part of Idaho Power's ongoing operation and maintenance (O&M) costs.

Total DSM expenses funded from all sources were $36.7 million in 2014. At the beginning of 2014, the Idaho Rider balance was approximately $6.7 million, and by December 31, 2014, the balance was negative $0.8 million. At the beginning of the year, the Oregon Rider negative balance was approximately $3.7 million, and by year-end, the negative balance was $3.9 million.

Table 4 shows the total expenditures funded by the Idaho Rider, $25,556,089; the Oregon Rider, $1,325,865; and non-rider funding, $9,831,379, resulting in Idaho Power's total DSM expenditures of $36,713,333. The non-rider funding category includes Idaho Power demand response incentives, WAQC expenses, and O&M costs.

Table 4. 2014 funding source and energy savings

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider | $ 25,556,089 | $ 131,383 |
| Oregon Rider | 1,325,865 | 6,753 |
| Non-Rider Funding | 9,831,379 | 534 |
| **Total** | **$ 36,713,333** | **138,670** |

Table 5 and Figure 8 indicate 2014 DSM program expenditures by category. The expenses in the Other Expense category include marketing ($671,408), program evaluation ($350,135), and program training ($318,357). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs: EnerNOC, Inc., for Irrigation Peak Rewards; JACO Environmental, Inc. (JACO), for See ya later, refrigerator®; Honeywell for A/C Cool Credit; Cascade Energy, Inc., for Custom Efficiency; Evergreen Consulting and RM Energy Consulting for Easy Upgrades; and contractors for WAQC and Weatherization Solutions for Eligible Customers.

Table 5. 2014 DSM program expenditure by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $ 21,169,645 | 58% |
| Labor/Administrative Expense | 3,139,448 | 9% |
| Materials & Equipment | 52,473 | 0% |
| Other Expense | 1,610,466 | 4% |
| Purchased Services | 10,741,301 | 29% |
| **Total 2014 Rider Expenditures, by Category** | **$ 36,713,333** | **100%** |

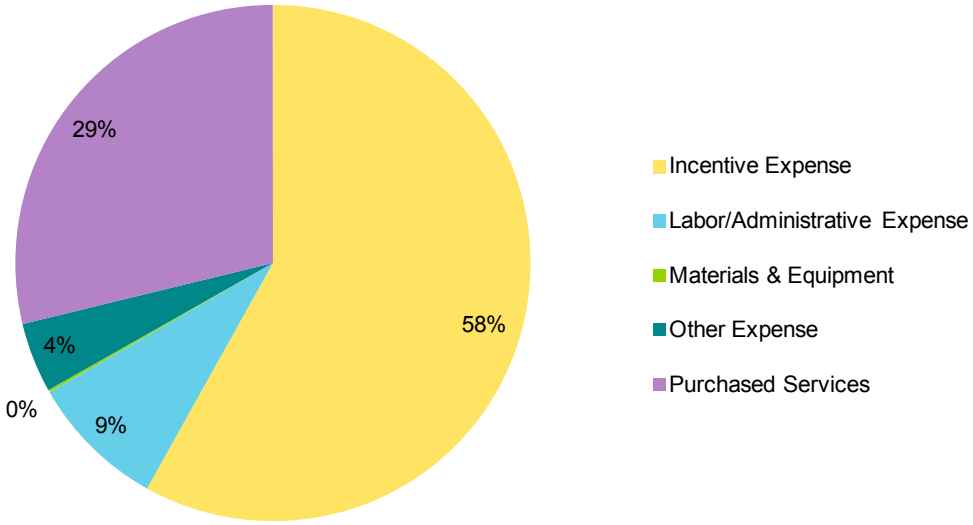


Figure 8. 2014 DSM program expenditures by category

Table 6 and Figure 9 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments—demand response and energy efficiency—and three sectors—residential, commercial/industrial, and irrigation. The incentives are funded by the Idaho and Oregon Rider, Idaho PCA mechanism, and Idaho Power base rates. Market transformation-related payments made to NEEA and payments made to third-party community action partners under the WAQC and Weatherization Solutions for Eligible Customers programs are not included in the incentive amounts.

Table 6. 2014 DSM program incentives by segment and sector

| | Sector Total | % of Total |
|---|---|---|
| DR[a]—Residential | $ 445,046 | 2% |
| DR—Commercial/Industrial | 1,502,163 | 7% |
| DR—Irrigation | 6,107,828 | 29% |
| EE[b]—Irrigation | 2,170,220 | 10% |
| EE—Residential | 2,333,594 | 11% |
| EE—Commercial/Industrial | 8,610,794 | 41% |
| **Total Incentive Expense** | **$ 21,169,645** | **100%** |

[a] DR = demand response
[b] EE = energy efficiency

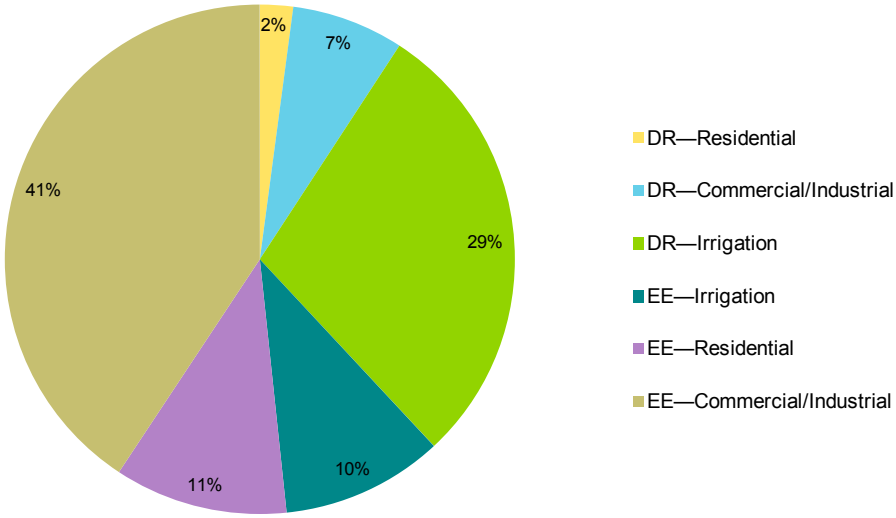


Figure 9. 2014 DSM program incentives by segment and sector

# MARKETING

Idaho Power used a variety of marketing, public relations, and research methods during 2014. The company will continue with innovative techniques in 2015. The following describes a selection of the methods, approaches, and tactics.

In spring 2014, Idaho Power contracted with MDC Research (MDC) to conduct four focus groups in Boise, Caldwell, Pocatello, and Twin Falls. The research objective was to gather customer feedback on current and future communication efforts. Each focus group had 9 or 10 participants. Key findings showed that 1) when prompted, recall of bill inserts and the *Connections* monthly newsletter was very high; 2) customers were most interested in topics related to rate changes, energy efficiency, and how to reduce their bills; 3) there was little differentiation between advertising and other types of communication; 4) many participants did not recall specific advertisements (ad), but the more engaged customers were able to recall specific ads, particularly those dealing with safety and program offerings.

To conduct the focus groups, Idaho Power converted space in the CHQ to administer focus groups. A one-way mirror, chairs, and video/audio equipment were installed.

In the second half of the year, Idaho Power hired a contractor to set up and manage an online panel. The purpose of the panel is to solicit customer feedback on a number of company-wide topics, including energy efficiency. Members of the panel may be sent surveys, print ads, videos, and questions to provide feedback on areas, such as program design, messaging, and graphics.

Idaho Power named the online panel the em**powered** community. The online panel will consist of Idaho Power residential customers who agree to participate in monthly online research on a variety of topics. The panel will incorporate customer opinions, values, and motivators into company planning and strategies at a lower cost and with less lead-time than contracting with different marketing research firms. Monthly surveys/queries of the community are anticipated throughout the year. More details regarding the spring 2015 launch are provided in the 2015 marketing plans section below.

To keep abreast of current trends, Idaho Power attended an International Direct Marketing Association Conference in San Diego, a Community-Based Social Marketing Workshop in Seattle, a live online course on the psychology of marketing, and a live online course on integrated marketing.

In fall 2014, the company took advantage of an earned media opportunity by participating in monthly energy efficiency segments on the KTVB-TV afternoon news program with Idaho Power's customer relations and energy efficiency manager. The segments, which began in October, focused on energy efficiency tips for residential customers, including weatherizing a home, the benefits of LED lighting, and how to receive an Idaho Power energy efficiency guide.

In regard to employee energy efficiency education, in previous years Idaho Power conducted an internal campaign to educate employees about the company's energy efficiency programs. After talking to field employees and regional managers, Idaho Power decided the most effective way to capture employee attention was through a video they could watch on their own time. The company created a humorous educational script mimicking Saturday Night Live's *Weekend Update* sketch. Professional actors, an Idaho Power manager, and an Idaho Power executive played characters in the sketch. The company emailed the video to all employees in fall 2014, and it received positive reviews. As of December 31, 2014, 1,057 employees—over half of the company's employees— viewed the video, thereby enhancing awareness of the programs.

Two guides were designed to educate and motivate customers to participate in energy efficiency programs and take energy efficiency actions at home. Through the customer focus groups conducted in 2014, the company researched the importance of energy efficiency communications and evaluated the readership and effectiveness of energy efficiency guides. One of the findings was that most of the customers in the focus group found the information valuable yet many had not seen the publication.

Historically, Idaho Power used public relations to help make customers aware of the seasonal energy efficiency guides. For the first time in fall 2014, Idaho Power used several marketing tactics to test demand for and explore other distribution channels for the *Fall Energy Efficiency Guide* and the 96-page booklet *30 Simple Things You Can Do to Save Energy*. Marketing tactics used to drive demand for the guide included an ad in the November issue of *Connections* sent to 415,000 customers, over 40,000 bill inserts in residential customer bills in November, and a digital ad campaign from October 25 to November 23 that garnered 514,744 impressions. When referring to online advertising, the term "impressions" indicates the number of times an ad is shown.

The company created a webpage for customers to request printed copies via mail, view past issues, or download a PDF or printable version of these publications. All advertising drove customers to this webpage. A toll-free number was set up for customers who saw the *Connections* ad or received a bill insert and preferred to order via phone. The bill inserts had a form that customers could mail in to request the guide.

Results of the October 31 to November 23, 2014, digital campaign yielded 514,744 total impressions and a 0.19 percent campaign click-through rate (CTR). Overall performance was above average. Audience targeting performed satisfactorily, but re-messaging drove the best results, with an outstanding CTR. Re-messaging means ads are delivered back to consumers that have visited Idaho Power's website and/or specific program pages within idahopower.com, as directed by Idaho Power program managers (maximum 3 to 4 ads per day to individual internet addresses). Total re-messaging impressions were 103,526, and the re-messages CTR was 0.68 percent. Generally, the digital advertising industry average for CTR is 0.07 to 0.10 percent.

Idaho Power tracked visits to the website. A sample of the results gathered from the web tracking from October 24 to November 30 included 1,931 visitors to the home page, 495 clicks on the promo pod—a promotional icon or small image used to draw viewers attention to information on the company's website that the company wishes to promote—on the home page, and 268 visitors to the printable version of the *Fall Energy Efficiency Guide*, all located at idahopower.com/EnergyEfficiency/Residential/Programs/eeClasses/default.cfm.

Because customer testimonials are credible, unbiased recommendations, the company conducted ad hoc interviews to procure customer testimonials at the September 2014 FitOne Expo in Boise. Clips were to be used to create a short video of customer testimonials regarding Idaho Power's energy efficiency programs for viewing on Idaho Power's website. Using the ad hoc interview technique, the company learned customers do not recall program details and were inaccurate regarding the programs. In the future, should Idaho Power decide to revisit customer testimonials, Idaho Power will record interviews in a formal studio, film retakes as needed, and provide customers with time to prepare and recall program information.

The company employed a number of new communication/advertising opportunities in 2014. The company reached out to professional associations to determine how they communicate with members and if there are advertising opportunities in newsletters, webpages, and/or resource guides. Idaho Power met with the lobbyist for the Idaho Retailers Association, Idaho State Pharmacy

Association, and Idaho Lodging & Restaurant Association. This meeting resulted in ongoing communication with Idaho Power providing energy efficiency information for inclusion in a newsletter to association members.

Idaho Power placed a half-page ad in the November and December issues of the Building Contractors Association of Southwestern Idaho (BCASWI) monthly newsletter to promote the company's ENERGY STAR® Homes Northwest program and the builder incentive. The newsletters went to members in Ada, Boise, Camas, Elmore, Gem, and Canyon counties. A full-page insert was placed in the Idaho Chamber of Commerce publication to promote Idaho Power's commercial energy efficiency programs to building owners, managers, tenants, and contractors.

One of the target segments for Idaho Power's Weatherization Solutions for Eligible Customers program is senior citizens. To focus on this segment, Idaho Power sent program information to a number of resources used by senior citizens.

In 2014, 10 digital ad campaigns ran for one to three months each. These included ads on the Yahoo! network and targeted behavioral ads. Specific customer segments were shown Idaho Power ads based on customers' past behavior on the Internet. For example, if a customer within Idaho Power's specific geographic area visited a site about heat pumps or home improvement, an Idaho Power ad for DHPs would appear on subsequent webpages. The site was programmed to follow that user. Audience targeting puts Idaho Power marketing messages in front of the people the company wants to reach when they are most receptive. This was the first time the company advertised ENERGY STAR Homes Northwest on sites such as zillow.com.

During 2014, Idaho Power purchased over 42 unique print ads in newspapers, event program guides, and chamber of commerce inserts. These print ads were placed in trade publications, association newsletters, association event program brochures, *Horizon Air Magazine*, and weekly and daily newspapers. Advertised programs included Building Efficiency, Easy Upgrades, Custom Efficiency, ENERGY STAR Homes Northwest, Irrigation Efficiency, Home Improvement, Home Energy Audit, H&CE Program, and DHP Pilot. Additional ads encompassed all of the energy efficiency residential programs.

In February and September 2014, Idaho Power ran the *Be Energy Smart* and *Use Your Watts Wisely* integrated advertising campaigns to increase awareness of the company's energy efficiency programs as a whole rather than individually. This multi-channel campaign included 15-second spots on Idaho Public Television, newspaper print ads throughout Idaho Power's service area, online ads, Facebook ads, and an editorial focus in the company's monthly *Connections* newsletter. This integrated campaign will continue in 2015.

Cumulative results from the *Be Energy Smart* and *Use Your Watts Wisely* integrated advertising campaigns are indicated in Table 7.

Table 7. Cumulative results from February and September *Be Energy Smart* and *Use Your Watts Wisely* advertising campaign

| Marketing Tactic | February 2014 | | September 2014 | |
|---|---|---|---|---|
| Idaho Public Television | 509,350 | impressions | 335,960 | impressions |
| Print advertising | 628,812 | impressions | 886,220 | impressions |
| Online advertising | 515,199 | impressions | 514,135 | impressions |
| Click-through rate | 0.06% | | 0.18% | |
| Number of clicks | 331 | clicks | 915 | clicks |
| *Connections* | 405,000 | printed | 405,000 | printed |
| Facebook ads | N/A | | 54,407 | customers reached |
| Number of page views on the web | | | | |
| idahopower.com/energyefficiency | 554 | views | 4,277 | views |
| idahopower.com/save | 54 | views | 209 | views |

For television, impressions refers to the sum of audiences, in terms of people or households viewing, where there is exposure to the same commercial or program on multiple occasions. Two gross impressions could mean the same person was in the audience on two occasions or that two different people had been exposed only once. Impressions for print advertising means the circulation of the publication on the days the ad ran multiplied by the number of times the ad ran. September print impressions were higher than February for the same cost because rates were lower at *The Idaho Statesman*; the ad was smaller, so Idaho Power could run more ads for the same cost; Idaho Power had an extra ad on Sunday, which resulted in higher numbers, and Idaho Power added *Idaho Senior News* to the print buy. Idaho Public Television impressions were less in September compared to February because people watch more television in northern climates in February. In addition, Nielsen does not rate public television in September, so the numbers for September from Idaho Public Television are approximated using November Nielsen ratings. Nielsen is a leading global provider of information and insights into what consumers watch and buy.

To make advertising easier for Idaho Power's trade allies, the company launched a contractor portal in 2014. The portal allows trade allies access to a specific area of Idaho Power's website where they can customize pre-approved marketing pieces. New marketing pieces will be added as needed.

In 2014, all Idaho Power commercial energy efficiency programs were revised with updated marketing materials and web content to reflect programmatic changes. Various direct-mail pieces went to customers. A letter was mailed to commercial customers regarding changes to the Easy Upgrades program and resulted in a number of inquiries to the company's customer representatives (CR). A similar mailing highlighting program changes to the Building Efficiency program went to architects and engineers in Idaho Power's service area. Idaho Power also developed a letter for the company's major customer representatives (MCR) to distribute to their customers highlighting changes to the commercial and industrial programs. Idaho Power placed a promo pod on Idaho Power's commercial landing page alerting customers about upcoming commercial program revisions and suggesting customers check back regularly to learn about changes. The company's *ENERGY@WORK* newsletter—mailed to the company's small/medium-size business customers—contained an article informing customers about the changes to the commercial programs and advised them to go to Idaho Power's website for details. A targeted mailing went to hotels and motels at the end of the year. The mailing included the *Energy Efficiency Tips for Hotels* brochure and a flyer inserted in the brochure outlining hotel and motel incentives. A customized cover letter included the name and phone number of the CR for the customer to call with any questions. Idaho Power asked CRs to call their specific hotel and motel

customers the week after the mailing to ascertain if the customer received the mailing, if they felt it was helpful, and if the representative could help them initiate an energy efficiency project.

Similar mailings will continue in 2015, highlighting industries including convenience stores, health care, health care facilities, restaurants, grocery stores, and office buildings. These brochures are online at idahopower.com/EnergyEfficiency/Business/Tips/eeBusinessSpecificTips.cfm.

Historically, Idaho Power used bill inserts to exclusively promote residential programs. Energy efficiency bill inserts were included in every month except December. However, in 2014, Idaho Power expanded the use of bill inserts to include intermittent commercial bill inserts that outline Idaho Power's suite of commercial/industrial programs.

In 2014, 11 new commercial success stories were posted on the company's website. The success stories showcased commercial customers, including Riverstone School, ON Semiconductor, Technichem, Riverside Hotel, North Star Charter School, and CSHQA. The stories are written by a third-party contractor, approved by Idaho Power, placed in a template, sent to the customer for final approval, and posted on the Idaho Power website at idahopower.com/EnergyEfficiency/Business/SuccessStories/default.cfm.

The company created the *Energy Efficiency Solutions* video highlighting three commercial customers in various geographic locations and posted it at idahopower.com/business.

In December 2014, Idaho Power marketing staff met with NEEA marketing personnel in Portland. For the past three years, marketing staff from NEEA and Idaho Power have met in-person annually. Moving forward, Idaho Power and NEEA plan to coordinate marketing activities on initiatives Idaho Power didn't opt out of through monthly conference calls and ongoing work groups.

In 2013, third-party contractor TRC Energy Services was contracted to provide a process evaluation of the H&CE Program and ENERGY STAR Homes Northwest program. In their 2014 report, TRC Energy Services recommended Idaho Power develop a portfolio-level brand for Idaho Power's energy efficiency programs to increase customer awareness of its DSM programs. Idaho Power considered this recommendation and determined Idaho Power's energy efficiency programs are consistently branded to align with the overall company brand. The Idaho Power brand is aligned with the company's vision and mission. To build a strong brand, all of the company's materials need to be consistent and recognizable.

In 2015, the company plans to initiate new marketing tactics in addition to ongoing marketing activities. New approaches include an online panel, airport signage, public radio broadcasts, and additional ad sources. When programs have new measures added or removed, Idaho Power ensures the updates are included in web content and in hard copy materials.

The em**powered** community online panel launches in spring 2015. Starting March 2015, Idaho Power will send at least one survey or other online research request each month to community members. The em**powered** community will provide a readily accessible and reliable group of customers that can respond quickly to online questionnaires and other online research requests. Using an online community allows for a quicker turnaround on focused topics or research. It is also a lower-cost option for ad hoc or quick-turnaround studies. Recruitment is being conducted primarily through bill inserts included in all February residential bills. Postcards are being direct-mailed to customers that currently receive a paperless bill from Idaho Power. Additionally, a promo pod will be placed on idahopower.com. The initial recruitment period for the em**powered** community is February 2 through March 31. Customers who register to become a member of the em**powered** community during this recruitment

period will be eligible to win one of four $250 prizes. Ongoing community members who participate in monthly surveys will be eligible to win one of two $100 prizes per month. Idaho Power employees and their immediate family members are not eligible to participate.

Another new marketing tactic in 2015 is signage at the Boise Airport. Idaho Power will advertise its commercial programs for a year with a large sign above a baggage claim and a large LED backlit sign on the B Concourse. The Boise Airport serves 2.8 million passengers annually, and 42 percent of the passengers are business travelers.

During the focus groups planned for 2015, Idaho Power will test messaging that may motivate customer participation in energy efficiency programs. While secondary research informed messaging in the past, the results from the qualitative study of Idaho Power customers will be considered when writing advertising copy and content for marketing materials.

In the first quarter of 2015, Idaho Power will expand its energy efficiency radio ads throughout the service area by adding public radio to the 2015 marketing mix. Boise State Public Radio broadcasts on over 20 stations to more than 100,000 listeners throughout southern and central Idaho's metropolitan and rural areas. Idaho Power will also use KISU-FM public radio to cover eastern Idaho.

Marketing in 2015 will use new publications dedicated to senior citizens. *Senior Goldmine* is a monthly publication delivered to 10 senior citizen centers and over 100 locations in the Treasure Valley. It is also hand-delivered to over 700 Meals-on-Wheels recipients. The company is researching advertizing in the *Senior Blue Book*, a semi-annual resource directory mailed to over 28,000 seniors and healthcare professionals. Senior publications with distribution outside of the Treasure Valley— such as the *Idaho Senior News*—will also be used.

Commercial marketing for the upcoming year will include advertorials and print ads in *The Idaho Business Review* and *The Business Insider*. New success stories will be produced, and association event sponsorships will remain. Industry-specific mailings will continue, and Facebook ads will be launched to appeal to commercial/industrial customers.

In January 2015, Idaho Power marketing and advertising personnel met with sales representatives from Pandora Internet Radio to initiate and plan an audio-mobile ad and an audio web ad for March 2015. Pandora offers advertising opportunities in the form of banner ads, video ads, and audio ads, with 71,697 monthly unique visitors ages 25 to 54 in Ada county and 27,988 monthly unique visitors in the same age group in Canyon county.

In 2015, Idaho Power will refresh its energy efficiency web pages. This effort started in 2014 and will continue in 2015. The redesign is intended to make navigation and web content more intuitive and easily accessible to users.

# ENERGY EFFICIENCY ADVISORY GROUP

Formed in 2002, the EEAG provides input on formulating and implementing energy efficiency and demand-reduction programs. Currently, EEAG consists of 14 members from Idaho Power's service area and the Pacific Northwest. Members represent a cross section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power. Idaho Power appreciates the input from EEAG and acknowledges the commitment of time and resources of individual members to participate in EEAG meetings and activities. In 2014, Idaho Power would especially like to thank those EEAG members that participated in the IRP energy efficiency workshops.

EEAG met four times in 2014: February 6, May 20, August 19, and November 12. Additionally, a conference call was held on March 17 and April 24. During these meetings, Idaho Power discussed and requested recommendations on new program and new measure proposals, marketing methods, and specific measure details; provided a status of the Idaho and Oregon Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues and important issues occurring in the region. Idaho Power relies on input from EEAG to provide a customer and public-interest review of energy efficiency and demand response programs and expenses. The minutes from the 2014 EEAG meetings are included in *Supplement 2: Evaluation*.

During the February 6 EEAG meeting, the results of a process evaluation done for both of Idaho Power's weatherization programs was presented by Johnson Consulting. The impact evaluation for the Irrigation Efficiency program was presented by ADM.

On March 17, members of EEAG participated in a conference call to discuss potential modifications to the Building Efficiency and Easy Upgrades programs. This conference call also contained a confidential discussion about the company's proposal to transfer $20 million of Idaho Rider funds to customers through the 2014/2015 PCA.

A conference call was held on April 24, 2014, to review NEEA's proposed business plan for the 2015 to 2019 funding cycle. The proposed business plan focuses on four strategic markets with a draft budget between $145 and $169 million. Also included in the proposed business plan are a few optional initiatives for funders.

At the May 20 EEAG meeting, Idaho Power's *Energy Efficiency Potential Study* conducted by EnerNOC, Inc., was a main topic of discussion. A subset of EEAG members met on May 19 to review the potential study and discuss ideas that could close the gap between the economic and achievable potential as indentified in the study.

At the August 19 EEAG meeting, there was a demand response update highlighting the success of all three programs—Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management—for the 2014 season. Idaho Power had approximately 390 MWs of demand response capacity enrolled in the three programs.

During the November 12 EEAG meeting, four new program ideas were highlighted during the New Program Ideas Update. Idaho Power's *Demand Response as Operating Reserves Report* was also presented. This report was filed with the IPUC in September 2014 and the OPUC in October 2014, as a requirement from the *Demand Response Programs Settlement Agreement*.

In addition to EEAG, Idaho Power solicits further customer input by meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

# DSM ANNUAL REPORT STRUCTURE

The structure of Idaho Power's *Demand-Side Management 2014 Annual Report* remains mostly unchanged from the 2013 report. It aligns with the reporting requirements included in the MOU with the IPUC staff and Idaho's other investor-owned utilities.

This main *Demand-Side Management 2014 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a chart containing 2014 and 2013 program metrics in tabular format, followed by a general description, 2014 activities, cost-effectiveness, customer satisfaction/evaluation, and 2015 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. Appendices 1 through 5 follow the written sections and contain tabular information on 2014 expenses and savings and historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions: 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams, Valley, and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot, and Salmon areas.

Idaho Power currently divides its service area into three geographic regions: 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the five historical regions are referred to throughout this report.

Appendices 1 through 5 remain generally unchanged in form and contain financial, energy savings, demand reduction, levelized costs, and program-life B/C ratios from the UC and TRC perspectives. Appendix 5 contains detailed financial and energy savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Included again this year are two supplements and an attached CD. *Supplement 1: Cost Effectiveness* contains detailed annual cost-effectiveness information by program and energy-saving measures, as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, ratepayer impact measure test (RIM), and PCT perspectives. As of 2014, Idaho Power is using the DSM alternate costs and other financial inputs from Idaho Power's 2013 IRP.

*Supplement 2: Evaluation* contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) and other reports provided by NEEA is attached to Supplement 2.

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# RESIDENTIAL SECTOR OVERVIEW

## Description

Idaho Power serves a little over one million people in southern Idaho and eastern Oregon. At the end of 2014, the company was serving 428,294 residential customers in its service area. During 2014, Idaho Power added 6,106 residential customers. This was almost identical growth to 2013 when the company added 6,168 new residential customers. The regional economy continues to improve, and the company is seeing a steady increase of new, residential customers and more housing starts. In 2014, the residential segment represented 36 percent of Idaho Power's total electricity usage.

In 2014, residential customers used 5.6 percent less energy than in 2013. This lower usage can be attributed to a variety of reasons, including, but not limited to, energy efficiency program activities, customer education, and milder temperatures. Idaho Power also continued its education and promotion of energy efficiency programs/information to all residential customers through a variety of marketing channels during the year. Idaho Power's marketing efforts are described in the Marketing and individual program sections of this report.

Table 8 shows a summary of 2014 participants, costs, and savings from the residential energy efficiency programs.

## Programs

Table 8. 2014 residential program summary

| | | | Total Cost | | Savings | |
|---|---|---|---|---|---|---|
| **Program** | **Participants** | | **Utility** | **Resource** | **Annual Energy (kWh)** | **Peak Demand (MW)** |
| **Demand Response** | | | | | | |
| A/C Cool Credit | 29,642 | participants | $1,465,646 | $ 1,465,646 | | 44 |
| **Total** | | | **$1,465,646** | **$ 1,465,646** | | **44** |
| **Energy Efficiency** | | | | | | |
| Ductless Heat Pump Pilot | 179 | homes | 251,446 | 884,211 | 462,747 | |
| Energy Efficient Lighting | 1,161,553 | bulbs | 1,909,823 | 7,148,427 | 12,882,151 | |
| Energy House Calls | 297 | homes | 197,987 | 197,987 | 579,126 | |
| ENERGY STAR® Homes Northwest | 243 | homes | 343,277 | 689,021 | 332,682 | |
| ENERGY STAR® Homes Northwest (gas fuel) | 282 | homes | | | 195,372 | |
| Heating & Cooling Efficiency Program | 230 | projects | 362,014 | 1,247,560 | 1,099,464 | |
| Home Energy Audit (direct install savings) | 354 | homes | | | 141,077 | |
| Home Improvement Program | 555 | homes | 324,717 | 896,246 | 838,929 | |
| Home Products Program | 10,061 | appliances/ showerheads | 227,176 | 302,289 | 652,129 | |
| Oregon Residential Weatherization | 13 | homes | 5,462 | 9,723 | 11,032 | |
| Rebate Advantage | 44 | homes | 63,231 | 89,699 | 269,643 | |
| See ya later, refrigerator® | 3,194 | refrigerators/freezers | 576,051 | 576,051 | 1,390,760 | |
| Student Energy Efficiency Kits* | 6,312 | | | | 1,491,225 | |
| Weatherization Assistance for Qualified Customers | 255 | homes/non-profits | 1,320,112 | 1,997,108 | 533,800 | |
| Weatherization Solutions for Eligible Customers | 118 | homes | 791,344 | 791,344 | 290,926 | |
| **Total** | | | **$6,372,640** | **$14,829,666** | **21,171,063** | |

**Notes:**
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.
*Student Energy Efficiency kits are offered through the Residential Energy Efficiency Education Initiative.

Programs available to residential customers in 2014 included 13 energy efficiency programs, the Residential Energy Efficiency Educational Initiative, the Easy Savings Program, and the Shade Tree Project. Residential efficiency programs included Energy House Calls; Rebate Advantage; ENERGY STAR® Homes Northwest; Home Products Program; Home Improvement Program; Energy Efficient Lighting; WAQC; Weatherization Solutions for Eligible Customers; DHP Pilot; Oregon Residential Weatherization; H&CE Program; See ya later, refrigerator®, and the new Home Energy Audit program.

Idaho Power markets its residential energy efficiency programs to its customers through online advertising, print ads, radio and television commercials, media and public relations, billboards, retail events, customer visits, meetings with trade allies and contractors, participation in home and garden shows, remodeling events, and county fairs.

Bill communication included monthly bill inserts and messages; energy efficiency guides; and articles in the *Connections* customer newsletter, including two issues (February and September) devoted entirely to energy efficiency topics and programs. *Connections* is mailed in bills monthly to approximately 415,000 customers and available online for those who request paperless billing. Energy efficiency guides included the *Spring/Summer Energy Efficiency Guide* (April) and the *Fall/Winter Energy Efficiency Guide* (October). Table 9 shows a summary of bill inserts by month, program, topic, and number of inserts sent.

Table 9. Summary of bill communications sent in 2014

| Month | Program/Topic | Total Inserts |
|---|---|---|
| January | Energy efficiency summary | 383,424 |
| | See ya later, refrigerator® | 20,069 |
| February | See ya later, refrigerator® | 41,091 |
| March | See ya later, refrigerator® | 142,707 |
| April | Home Improvement Program | 350,177 |
| | See ya later, refrigerator® | 219,595 |
| May | Ductless heating | 363,225 |
| | ENERGY STAR Homes Northwest | 363,258 |
| June | Home Improvement Program | 352,566 |
| | See ya later, refrigerator® | 364,240 |
| July | See ya later, refrigerator® | 164,236 |
| | Commercial energy efficiency | 40,147 |
| | Home Products Program | 364,235 |
| August | See ya later, refrigerator®—Dog | 178,786 |
| | See ya later, refrigerator®—Man | 190,402 |
| September | Weatherization | 353,813 |
| | Energy House Calls | 365,491 |
| October | See ya later, refrigerator® | 364,587 |
| | Commercial energy efficiency | 40,142 |
| November | *Fall/Winter Energy Efficiency Guide* | 40,650 |

Throughout the year, public relations and media opportunities were identified to create awareness of energy efficiency programs and encourage the wise use of energy. From the weekly *News Briefs* email sent to all media in Idaho Power's service area to targeted media alerts and releases (also posted online), content was provided for news stories to inform and educate Idaho Power customers. The company

successfully pitched the concept of a monthly energy efficiency segment on the KTVB-TV afternoon news program with Idaho Power's CR&EE manager. The segments, which began in October, focused on energy efficiency tips for residential customers, including weatherizing your home, the benefits of LED lighting and how to receive an Idaho Power energy efficiency guide. Broadcasting both in the Boise and Twin Falls markets, the show reached 20,000 to 30,000 viewers each time.

In October, Idaho Power celebrated national Energy Awareness Month with the annual student art contest, which featured a category, "Ways to Save Energy." Idaho Power promoted the event in *News Briefs* and issued news releases in support of local award presentations for students and their winning artwork, which was displayed at local events and recognized in the media.

Social media in 2014 continued to be an effective method of informing and educating stakeholders on the company's energy efficiency programs, incentives, and events. Idaho Power Facebook fans climbed to over 11,100, up from 7,600 in 2013. Twitter followers also grew from 1,900 in 2013 to over 3,000 in 2014. On YouTube, the most popular video continued to be the educational clip on DHPs. The video has been viewed over 20,000 times for an estimated 41,531 minutes watched. Ensuring quality content is a team effort, with the social-media specialist working with program specialists and marketing staff to ensure messaging alignment for key campaigns and energy efficiency events throughout the year.

In 2014, the online myAccount tool was the focus of a comprehensive communications campaign, from advertising to public relations. One important message of the campaign was "Understand Your Use." Customers were encouraged to learn how they use energy by completing a Home Profile and to use Idaho Power's tips, advice, and programs to save energy. An entire issue of *Connections* (May) featured myAccount and ways customers can save on their energy bill. The same messaging appeared in myAccount bill inserts (June and October), the KTVB segments, online promotional links, advertising, and a new display panel designed for the company's special events exhibit. In August, an *eNews* internal video was produced about myAccount with the same messaging about ways to save, and the video was posted externally on YouTube. By the end of the year, Idaho Power offered a new mobile version of its website with myAccount functionality available.

Presentations to community groups and businesses continued to be a major emphasis during 2014. Idaho Power CRs and CERs made hundreds of presentations in communities served by the company.

The Home Energy Audit program launched in early 2014. The program was based on insights gained from the Boise City Home Audit project conducted in 2011 and 2012. For details regarding the Boise City Home Audit project, view the *Demand-Side Management 2012 Annual Report*, pages 125 to 127, and the *Demand-Side Management 2013 Annual Report*, page 25.

In 2014, Idaho Power distributed 2,041 shade trees to residential customers through the expanded Shade Tree Project. Using results from a state-sponsored urban tree-canopy study and online tools developed by the Arbor Day Foundation, the Shade Tree Project encouraged the strategic planting of trees to reduce summertime residential energy use.

Idaho Power conducts the Burke Customer Relationship survey each year. In 2014, 59 percent of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-one percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. While 43 percent of Idaho Power residential customers surveyed in 2014 indicated Idaho Power is meeting or exceeding their needs in offering

energy efficiency programs, 28 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 81 percent are "very" or "somewhat" satisfied with the program.

# A/C Cool Credit

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants) | 29,642 | n/a |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 44 | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $962,286 | $537,163 |
| Oregon Energy Efficiency Rider | $56,988 | $29,731 |
| Idaho Power Funds | $446,372 | $96,964 |
| Total Program Costs—All Sources | $1,465,646 | $663,858 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners (A/C) or heat pumps off and on via a direct-load control device installed on the A/C unit. This program enables Idaho Power to reduce system capacity needs peaking requirements during times when summer peak load is high.

In alignment with the settlement agreement reached in Case No. IPC-E-13-14, changes were made to the program in 2014. To create consistency among Idaho Power's demand response programs, the cycling season was reduced from June 1 through August 31 to June 15 through August 15. The maximum number of cycling hours available per season was reduced from 120 hours to 60 hours. A minimum of three cycling events per season was set, and the incentive was reduced from $21 per season to $15 per season. The incentive is paid as a bill credit of $5 on the July, August, and September bills. The program continued to be available to reduce energy demand during critical summer peak periods. As before, the program is not available on weekends or holidays, and the maximum length of an event remains at four hours.

Customers' A/C units are controlled using switches that communicate by power-line carrier (PLC). A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C unit during a cycling event.

## 2014 Program and Marketing Activities

In early winter, the company sent letters to program participants regarding the new program details and the implications for customers. As agreed to in the settlement agreement, Idaho Power did not actively market the A/C Cool Credit program in 2014; however, customer communication and retention was active. Idaho Power attempted to recruit customers who had moved into a home that already had a load-control device installed and recruit previous participants who changed residences to a location that did not have a load-control device. Idaho Power also completed the replacement of any remaining radio-paging switches on current participants' residences with advanced metering infrastructure (AMI)-compatible devices in 2014.

Before the cycling season began, participants were sent a postcard reminding them of the program specifics. Also, in the company's June 9 *News Briefs* weekly email to all media throughout Idaho Power's service area, the company included a reminder to customers participating in the program that A/C season had arrived and the program was in effect. Three cycling events occurred in 2014 on July 14, July 31, and August 11. At the end of the summer, a thank you card was sent to program participants. The company followed up with a *News Briefs* item on September 3 crediting the demand response programs for effectively helping offset energy use during periods of high electrical demand that summer.

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must not be more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective.

The A/C Cool Credit program was dispatched for 9 event hours and achieved a maximum demand reduction of 44 MW. The total expense for 2014 was $1,465,646 and would have remained the same if the program was fully used for 60 hours because there is no variable incentive paid for events beyond the three required events.

## Customer Satisfaction and Evaluations

In fall 2014, a customer satisfaction survey, along with a postage-paid envelope, was mailed to 5,000 current A/C Cool Credit participants. The response rate was over 36 percent, with 1,810 responses.

Survey participants were asked "What was the main reason you participated in the A/C Cool Credit program?" Over 38 percent of respondents indicated it seemed like the right thing to do. Approximately 30 percent of respondents indicated to earn the bill credit. Over 28 percent indicated to reduce overall electrical usage on hot summer days. The remaining respondents selected "other" as their main reason.

When asked how many days participants would estimate Idaho Power cycled their A/C unit during the past summer, nearly 65 percent stated they didn't know. Over 17 percent of respondents estimated there were 1 to 5 events. Just over 8 percent thought there were over 10 events.

The survey respondents were satisfied with the program, with over 89 percent indicating they were "very" or "somewhat" satisfied with the program. Participants were asked how significantly they were impacted by the program this past summer, and nearly 82 percent of respondents indicated "very little" or "not at all." Eighty-eight percent indicated they receive the right amount of information about the program. Results of the survey are in *Supplement 2: Evaluation*.

Idaho Power contracted with CLEAResult (acquired PECI), to complete an impact evaluation of the 2014 A/C Cool Credit program. The goal of the impact evaluation was to calculate the estimated demand reduction achieved by three A/C Cool Credit curtailment test events and update the program's existing predictive model to account for the 2014 curtailment event results.

PECI completed analyses of curtailment events held on July 14, July 31, and August 11, 2014, each with a three-hour duration. Results of the analyses showed maximum single-hour demand reductions of 1.33 kilowatts (kW), 0.91 kW, and 1.07 kW per participant, respectively, for the three events. The average hourly demand reduction was 1.25 kW, 0.86 kW, and 1.00 kW per participant, respectively. Due to the distinct weather patterns between the Boise and Pocatello/Twin Falls regions, each curtailment event analysis includes region-specific results.

The impact evaluation demonstrated that Idaho Power's A/C Cool Credit program functions as intended, and, if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid.

## 2015 Program and Marketing Strategies

Per the terms of the settlement agreement, Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing but will accept new participants who request to participate, regardless of whether they were previous participants in the program. Attempts will be made to recruit previous participants who have moved, as well as new customers moving into homes that already have a load-control device installed.

Idaho Power will maintain the existing A/C Cool Credit program, equipment, and participation by providing an opportunity for all current program participants to continue to participate if they choose. This strategy aligns with the settlement agreement reached in Case No. IPC-E-13-14. The company will be able to continue using the investment that Idaho Power's customers have made in the existing equipment in the field.

# Ductless Heat Pump Pilot

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 179 | 215 |
| Energy Savings (kWh) | 462,747 | 589,142 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $235,099 | $230,761 |
| Oregon Energy Efficiency Rider | $9,614 | $6,814 |
| Idaho Power Funds | $6,733 | $0 |
| Total Program Costs—All Sources | $251,446 | $237,575 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.042 | $0.032 |
| Total Resource Levelized Cost ($/kWh) | $0.148 | $0.132 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.77 | |
| Total Resource Benefit/Cost Ratio | 0.70 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area. The company extended the project as an Idaho Power DHP Pilot through 2014. A primary goal of the Northwest DHP Pilot project is to promote DHP technology as an energy-saving alternative for customers who primarily heat their homes with electricity. In 2014, Idaho Power offered customers a $750 incentive payment to have a qualified DHP installed.

The program targets existing homes heated with electric zonal systems. Typically, these homes do not have air ducting and therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboards, ceiling cables, and wall-mounted units. Homes heated with fossil fuel forced-air systems or electric forced-air systems do not qualify. Qualifications include having one DHP indoor unit installed in the main living area of the home, since this is where most occupants spend most of their time.

Other Northwest DHP Pilot goals are to identify how much energy this technology saves to determine an RTF deemed-savings amount and to obtain customer satisfaction and behavioral patterns regarding the units.

Field monitoring of selected homes throughout the Pacific Northwest, an analysis of billing data, and other evaluations occurred from 2009 through 2014. In 2014, NEEA published a final summary report and a third market progress evaluation report. Detailed information about the regional DHP effort is located at goingductless.com and neea.org.

## 2014 Program and Marketing Activities

The DHP Pilot had a decrease of 37 applications in 2014 compared to the prior year. This was primarily due to a one-time 40-installation project that was received in 2013 and not repeated in 2014. The 2013 project involved converting baseboard heat to DHPs in 40 living units that were in 10 fourplex properties. Marketing expenses for the DHP Pilot increased by $36,065 in 2014 when compared to the prior year. This increase caused total annual expenses to exceed 2013 expenses even though fewer incentives were processed in 2014.

Knowing contractors are a vital marketing asset, contractor visits were made throughout 2014 to better understand how Idaho Power can support participating contractors in promoting the DHP Pilot. As a result, Idaho Power developed a contractor portal housed on Idaho Power's website. The portal was launched August 2014. It allowed authorized contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address and phone number. Two fliers were offered for use by participating contractors in the DHP Pilot. The offering was part of a combined portal launch with the H&CE Program and Home Improvement Program.

Expanding the network of participating contractors remained a key growth strategy for the DHP Pilot. The goal was to support contractors currently in the DHP Pilot while adding new contractors. To accelerate the expansion of the participating contractor network, Idaho Power provided three DHP Pilot orientation training sessions to participating and prospective contractors. Expansion strategies resulted in the addition of three companies to the list of participating contractors (4 percent increase). Three training sessions were offered in 2014 as compared to 11 in 2013. The decrease in the number of new companies was a result of successful trainings and contractor additions completed in 2012 and 2013. About a dozen companies have contacted Idaho Power and are pending addition to the program. Future meetings with potential contractors could yield additional participants.

To hasten the residential adoption of the DHP technology in the Idaho Power service area, a key strategy was to communicate with other tiers of the supply chain. In the Idaho Power service area, there are numerous wholesalers supplying DHPs to the contractors. Idaho Power met with several of these wholesalers in Idaho Power's service area to share helpful information and to encourage them to promote DHPs to their contracting customers.

Marketing tactics for Idaho Power's DHP Pilot varied. Approximately 3,000 radio ads ran on over 20 radio stations for six weeks throughout Idaho Power's service area. During spring 2014, a digital behavioral ad campaign was launched. The DHP Pilot had 781,461 ads viewed by people browsing the internet over the course of two months from this ad campaign.

A direct-mail campaign was conducted in April 2014. Over 27,000 letters were sent to homeowners of electrically heated homes. In addition, information about the DHP Pilot was included in a postcard sent to people who purchased a home within the previous six months. Bill inserts and newspaper ads rounded out the ongoing marketing and promotion of the DHP Pilot.

In May, the company issued a press release in southeast Idaho recognizing NEEA's *Northwest DHP 2014 Idaho Installer of the Year* that provides services to Idaho Power's customers in that area. In addition, a *Heat Pumps: Cozy and Cool* article appeared in the September energy efficiency issue.

The *Demand-Side Management 2013 Annual Report* mentioned possible changes to the DHP webpages. Changes to the DHP webpages were not made in 2014 because on a separate project, the company began

working on a website redesign to improve navigation on the energy efficiency website. The decision was made to wait until that work was completed before any changes were made to DHP webpages. The *Demand-Side Management 2013 Annual Report* also stated contractors would be asked to comment on the portal during 2014. Comments were not pursued due to the portal launching in the third quarter of the year, which limited contractors' time to try the portal in 2014.

## Cost-Effectiveness

The 2014 savings estimates and reported deemed savings values were unchanged from the 2013 values. During 2014, the RTF reviewed the savings models for DHP with updates occurring in May, June, and December around the calibration of savings models, screening for supplemental fuel use, and the assumptions around other efficiency measures occurring in DHP homes. The RTF's decisions and resulting changes in savings will be applied in 2015. Idaho Power calculated the participant costs for the TRC by averaging one-unit installations that occurred in Idaho Power's service area over the two-year period 2013 to 2014. The average installation cost over the time period was $4,285.

In 2014, Idaho Power included RTF-approved NEBs, accounting for annual avoided supplemental fuel costs and avoided capital expenses of A/C purchases that would have occurred in the absence of the installation of a DHP system. A current sub-committee was formed in 2014 to address the possible inclusion of NEBs for decreased health impacts from reduced wood-burning emissions. In November, the RTF presented its findings and recommendation on the inclusion of health benefits to be part of the cost-effective benefits in the cost-effective analysis of measures and programs. The RTF is waiting the council's guidance on the issue.

After including the RTF-approved NEBs, the DHP measure is not cost-effective from a TRC perspective. However, Idaho Power determined DHPs meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power originally filed UM-1710 to request cost-effectiveness exceptions with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For cost-effective details, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the DHP Pilot, Idaho Power's third-party contractor conducted on-site verification (OSV) on at least 10 percent of the completed installations in Idaho Power's service area in 2014 to ensure installations complied with program requirements. The OSVs were beneficial for customers and the contractors. The inspector provided customers with information about how to maximize the benefits of their new DHP. The contractors received feedback from the inspector and reviewed the installation requirements of the DHP Pilot.

In 2014, NEEA provided two reports updating the DHP Pilot. The following are highlights from the reports.

### NEEA Report E14-274, released February 2014

NEEA published a summary report addressing five key components of the DHP Pilot. The report includes market progress, laboratory testing, field monitoring, billing analysis, and cost analysis/NEBs. Each component is described individually in the report with detailed summaries. Several NEEA reports were published since the beginning of the DHP Pilot in 2009 addressing the five components. The February report recapped prior information and discussed DHP products, potential energy savings,

and potential sustainability of DHPs in the Northwest region. A copy of the NEEA Report E14-274 is included on the CD accompanying *Supplement 2: Evaluation*.

### NEEA Report E14-278, released April 2014

This report was the third MPER for NEEA's Northwest DHP Initiative (the Initiative). The report presents the findings of surveys and interviews conducted with a mix of homeowners who owned or did not own DHPs. Feedback collected from installing contractors, utilities, wholesalers, and manufacturers is presented in the report. The report details the effectiveness and progress of the Initiative's ability to transform the target market. A copy of the NEEA Report E14-278 is included on the CD accompanying *Supplement 2: Evaluation*.

## *2015 Program and Marketing Strategies*

Idaho Power will sponsor and provide training sessions and orientations to the DHP Pilot program for new and existing contractors to assist them in meeting program requirements and further their product knowledge.

Expanding the network of participating contractors remains a key strategy for the DHP Pilot. The goal is to support contractors currently in the DHP Pilot while adding new contractors. Performance of the DHP Pilot is substantially dependent on the contractor's ability to promote and leverage the DHP Pilot. Frequent individual contractor meetings will be held in 2015.

The strategy to promote the residential adoption of the DHP technology in Idaho Power's service area includes communicating with the complete supply chain. To accelerate the wholesaler's ability to increase contractor awareness of DHPs and the DHP Pilot, Idaho Power will meet with the wholesalers and share information.

The 2015 marketing strategy will include proven tactics previously used and new methods. Since homeowners make more improvements to their home during the first two years of ownership, the company plans to continue to target new customers in their first six months of new-home ownership. Postcards will be mailed to these new customers, raising awareness of the incentives available to them. The strategy will include many marketing tactics, such as bill inserts, print ads in newspapers, and direct-mail letters. Social media, such as Facebook, will be used. A DHP display will be used at several residential home and garden and home improvement trade shows.

New marketing pieces will be added to the contractor portal over time as needed.

# Energy Efficient Lighting

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 1,161,553 | 1,083,906 |
| Energy Savings (kWh) | 12,882,151 | 9,995,753 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,860,046 | $1,331,113 |
| Oregon Energy Efficiency Rider | $45,959 | $25,812 |
| Idaho Power Funds | $3,818 | $0 |
| Total Program Costs—All Sources | $1,909,823 | $1,356,926 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.018 | $0.016 |
| Total Resource Levelized Cost ($/kWh) | $0.066 | $0.058 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.98 | |
| Total Resource Benefit/Cost Ratio | 1.99 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy Efficient Lighting program strives for residential energy savings through the replacement of less-efficient lighting with more efficient technology. The most recent studies indicate consumer usage patterns. According to the *NEEA 2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study, the average Idaho home has 63 bulb sockets. The *2010 Idaho Power Residential End-Use Survey* shows 88 percent of customers have less than 20 compact fluorescent light (CFL) bulbs installed, indicating there is still potential to install more energy-efficient bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR® qualified energy-saving bulbs, including CFLs and LEDs, are a more efficient alternative to standard incandescent and halogen incandescent light bulbs. Bulbs come in a variety of wattages, colors, and styles, including bulbs for three-way lights and dimmable fixtures. ENERGY STAR bulbs use 70 to 90 percent less energy and last 10 to 25 times longer than traditional incandescent bulbs.

The Energy Efficiency Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers, with savings passed on to the customer at the point of purchase. The benefits of this model are low administration costs, better availability of products to the customer, and the ability to provide an incentive for specific products.

## 2014 Program and Marketing Activities

In 2014, the Energy Efficient Lighting program provided almost 61 percent of all energy savings derived from residential energy efficiency customer programs.

Idaho Power continued to participate in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings™ promotion focusing on ENERGY STAR CFL and LED bulbs and LED light fixtures. CLEAResult managed the promotion. CLEAResult is responsible for retailer and manufacturer contracts, marketing materials at the point of purchase, and providing support and training to retailers.

In 2014, Idaho Power continued to respond to recommendations made in the 2013 process evaluation conducted by TRC Energy Services. TRC Energy Services found that the program is generally successful. Since the inception of this program in 2010, the program has consistently exceeded kWh savings goals. The recommendations and Idaho Power's actions and considerations in 2014 are described below.

One recommendation was to continue to investigate options to bring LED products into the program while maintaining cost-effectiveness. In February 2014, Idaho Power added LED bulbs into the promotion in Oregon and Idaho service areas. LED bulbs comprised 13 to 29 percent of light bulb sales each month. LED fixtures were introduced in the Idaho service area March 2014 and comprised less than 1 percent of lighting sales each month through the rest of the year.

TRC Energy Services recommended increasing coordination with retailers to find mutually beneficial in-store advertising solutions and to speak with corporate representatives from a few large retailers to understand the restrictions on advertising, then work with retailers to overcome these barriers. Through its contractor, Idaho Power reached out to corporate representatives to find mutually beneficial advertising solutions. In 2014, all but two of the retailers in the Simple Steps, Smart Savings promotion allowed for some form of in-store advertising. All but five allowed for utility logos. Those that did not allow for utility logos allowed for wording such as "brought to you by your local utility." Retailers cited shopper consistency across the nation and protecting their brand as reasons to set advertising guidelines.

In addition, in 2014, Idaho Power continued to work with the region to address utility programs within the retail sector through participation in the Northwest Regional Retail Collaborative (NWRRC) facilitated by NEEA and by following promotions initiated by the Western Regional Utility Network (WRUN). Both the NWRRC and WRUN sought to develop collaborative approaches to working with manufactures and retailers to increase uptake of energy-efficient products in the retail market.

Through CLEAResult, several special promotions were conducted at the retail stores through Simple Steps, Smart Savings. These promotions generally involved special product placement and signs. For example, in March and September, Fred Meyer stores had special endcap displays with promotional products. Costco used pallet displays in February. Home Depot held a truckload event in September. These types of promotions and special product placement help increase the visibility and sales of promotional products. CLEAResult staff also conducted 1,017 store visits in 2014 to check on stock, point-of-purchase signs, and displays.

TRC Energy Services recommended Idaho Power further investigate opportunities to bring more grocery chains and small retailers into the program or to work with participating retailers of these types to overcome participation barriers and increase program sales. In 2014, Idaho Power worked with 18 participating retailers, representing 144 individual store locations throughout Idaho Power's service area. The majority—63 percent of retailers in the program—are smaller grocery, drug, and small hardware stores.

Regionally, the *2012–2013 Northwest Residential Lighting Market Tracking Study* shows the majority of customers purchase light bulbs at do-it-yourself, mass merchants, and wholesale club stores. Smaller stores have lost market share for lighting products. Regionally, lighting sales at smaller stores have decreased from 28 percent in 2006 to 14 percent in 2012, the most recent year data is available. Larger stores tend to have a larger product selection and more competitive pricing.

Instead of focusing on increasing sales at smaller stores, Idaho Power evaluated its distribution of retail stores to ensure customers had access to promotional products. Idaho Power studied the geographic distribution of participating retailers and confirmed there were participating stores located throughout Idaho Power's service area with the exception of the Salmon area.

In addition, to help facilitate customer access to the promotion under Simple Steps, Smart Savings, Idaho Power launched its first online offering with Costco. With this offering, Idaho Power customers who purchased bulbs online through Costco could access Idaho Power incentives. For the Costco promotion, after selecting the shipping zip code, the customer was prompted to pick their utility service area, thereby emphasizing the tie between Idaho Power and the discounted price.

TRC Energy Services recommended Idaho Power consider adopting changes in RTF metrics for future cycles (not retroactively). In early 2015, Idaho Power established a policy that as a general rule, beginning for 2014 reporting of energy savings from energy efficiency programs, Idaho Power will freeze the savings metrics annually. This means that all savings for a given year will not be changed mid-year. This policy conforms to recommendations from third-party evaluators and seems consistent with other energy efficiency providers in the region.

Another recommendation from TRC Energy Services was to consider assigning the task of reviewing the invoices to junior or administrative staff so the program specialist would have more time to follow other recommendations provided. Idaho Power reviewed this recommendation and believes it is important that the staff with the most expertise review invoices to ensure customer funds are prudently spent; therefore, the program specialist continued to perform the invoice review in 2014. Furthermore, the specific process referenced by TRC Energy Services is a control that is necessary to meet the financial reporting requirements of the *Sarbanes–Oxley Act of 2002* (SOX). Idaho Power has fiduciary responsibility and must ensure all of its legal and regulatory requirements are met.

TRC Energy Services recommended Idaho Power ensure consistent language and terminology for product type categories through drop-down menus or similar strategies and provide future contractors with a data dictionary or other description of database terms. Idaho Power's program database is standardized to the promotion. The database covers program participation from 2009 onward and reflects several different promotions and promotion implementers. As a result, the data classifications tie directly to the original classifications used by the implementer at the time of sale. This allows Idaho Power to differentiate between different promotions and timeframes and tie data directly back to the original source files. A data dictionary will be developed in 2015.

Additional activities in 2014 included education and marketing. Idaho Power and CLEAResult conducted four education events at Costco stores in Pocatello, Twin Falls, Nampa, and Boise. At each event, Idaho Power and CLEAResult personnel talked with customers and staffed a table with literature, promotional items, and a lighting display.

Additional marketing and customer education by Idaho Power included the company's website, a redesigned program brochure, and discussions with customers at community events. The program brochure, which focused on how to shop for an energy-efficient bulb, was redesigned to include LEDs

and the Federal Trade Commission-required *Lighting Facts Label*. This label makes it easier for consumers to choose between different light bulbs by displaying common metrics (energy used, lumens, and color temperature.)

The September issue of Idaho Power's *Connections* customer newsletter and the *Fall/Winter Energy Efficiency Guide* featured lighting. Topics in both publications included understanding how to shop for the right bulb, lighting design basics, LEDs, and lighting controls. In the November *Connections*, the back page promoted the guide with the image of a large LED light bulb. The weekly media *News Briefs* email included stories on energy-efficient lighting on October 28 (guide focuses on lighting), December 1 (tips for safe holiday lighting), and December 8 (LED holiday lights use less energy). In addition, monthly energy efficiency segments on the afternoon KTVB-TV news program (broadcast in Boise and Twin Falls) mentioned energy-efficient lighting on October 27, November 13, and December 9—reaching from 20,000 to 30,000 viewers per program.

Additional 2014 program activities included customer education through distribution of bulbs to customers. Through Idaho Power's local events, bulbs were given directly to customers at a range of venues. Venues included energy efficiency presentations at senior centers and environmental and health fairs. In 2014, 1,524 CFL bulbs and 3,234 LED bulbs were distributed through this route. This included 2,500 LED bulbs distributed along with educational materials at the FitOne Expo in Boise.

## Cost-Effectiveness

Throughout 2013, the RTF analyzed the savings for residential LED bulbs. Savings were finalized in October 2013. Idaho Power reviewed the savings and cost assumptions and determined residential LEDs are cost-effective. LEDs were added to the program in early 2014.

In 2014, the RTF updated and revisited the assumptions for both CFLs and LEDs to standardize and reduce the number of measures. The number of lamp types was reduced from 10 to 5 categories. The lumen categories within each bulb type were merged and reduced from six groups of lumen ranges to three groups. All other assumptions regarding baseline bulb, hours of use, lamp life, lamp cost, room type, and space conditioning remained the same. In grouping these measures, the RTF used a weighted average from the Residential Building Stock Assessment (RBSA).

Several lamp types were included in the program that had no corresponding savings or cost assumptions available from the RTF. These non-RTF lamp types include high-lumen CFL bulbs and LED reflector fixtures. In Tetra Tech's evaluation of the 2013 program activities, the evaluators recalculated the energy savings Idaho Power associated with the high-lumen bulbs. After the evaluation, Idaho Power requested that Tetra Tech review the non-RTF bulbs included in the program. Tetra Tech recommended that the RTF savings and cost assumptions for either the "general purpose and dimmable" bulbs or the "reflector and outdoor" bulbs be assigned to the LED reflector fixtures. After reviewing the hours of use for reflector bulbs and discussing the potential uses of reflector fixtures, Idaho Power decided to assign the "reflector and outdoor" LED bulb savings to these fixtures.

As discussed in the Introduction, Idaho Power reviewed its policy of updating savings and cost assumptions and decided to freeze savings at the beginning of each year. However, this decision was made after efforts had been made to re-map the bulbs sold in 2014 to the new RTF categories. As a result, the savings for this measure reflect the changes approved by the RTF in mid-2014. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2014, Idaho Power administered an impact evaluation of 2013 ex-ante energy savings using third-party Tetra Tech to validate ex-post results. Overall, Tetra Tech found the program has well-established design and delivery processes, supported by the program tracking systems, program documentation, and savings tools and that processes are operating efficiently and with careful attention to detail.

The impact evaluation indicated ex-post verified savings were 10,047,811 kWh compared to 9,995,753 kWh ex-ante claimed savings, resulting in a gross realization rate of over 100 percent. The driver of the difference in the overall kWh realization rate from 100 percent was an adjustment made to non-RTF high-wattage lamps.

To facilitate more accurate, transparent, and consistent program reporting, Tetra Tech identified the recommendations below for program improvement.

Tetra Tech recommended working with the administration contractor to track allocation methods and negotiations that relate to allocations. While the administration contractor included the allocation used for each monthly report for each retailer and product model number, Tetra Tech stated Idaho Power should receive and retain a full accounting of Idaho Power's and the administration contractor's understandings of allocation and resolve any variances as part of monthly quality assurance (QA) checks.

Idaho Power reviewed this recommendation and found no action was necessary. Idaho Power already receives the full Regional Sales Allocation Tool (RSAT) used by CLEAResult, which includes a full accounting of the assumptions used to assign allocations. The tool is commissioned by the BPA and is updated approximately once per year. Idaho Power receives newly released versions and reviews the allocations for its retailers. Idaho Power has the opportunity to work with the tool developer to address any concerns. Idaho Power has always and will continue to verify allocations applied to sales as part of its monthly verification check.

Another recommendation by Tetra Tech was to consider updates to the Energy Efficient Lighting program tracking system. Tetra Tech stated that with the recent shift in RTF deemed savings amounts for lighting from wattage to lumen based, Idaho Power should consider adding lumens to the tracking database for each stock keeping unit (SKU) and work to identify future RTF changes in collaboration with the administration contractor. Idaho Power added lumens to the program database in January 2014.

Additionally, Tetra Tech recommended Idaho Power continue to comprehensively track retailer reports and RTF savings but consider a shared system that aligns all specifications that lead to reported energy savings. Tetra Tech also said to consider a database or similar system that the administration contractor and Idaho Power could share to enable additions of SKUs and available technical data to drive consistency between administration contractor reporting and Idaho Power tracking data for all factors.

Idaho Power reviewed this recommendation and found that new reports developed by CLEAResult in 2014 address this concern. Starting in 2014, Idaho Power began to receive a monthly current products list of all potential models in the promotion. Data includes lumens, model numbers, and bulb/fixture descriptions. Since the promotion began, Idaho Power has received detailed sales data directly from the contractor database each month with its invoice. The monthly invoice detail will continue to be compared against the raw sales data as reported by the retailer or manufacturer as part of the invoice reconciliation process.

Tetra Tech suggested Idaho Power consider alternative reviews of unique non-RTF lamps and characterizations. They stated that when identifying lamps that are not identified by the RTF, Idaho Power should take care when lamps are substantially different from an RTF category and verify lamp efficacy against manufacturer specifications and general performance. Idaho Power reviewed this recommendation and found quality concerns are covered by the program requirement that all lamps in the promotion be ENERGY STAR certified. Those without a deemed savings tend to be styles with specialty applications, such as high wattage. Due to lack of data, the RTF set the savings to not applicable (N/A) for some product categories. However, bulbs without deemed RTF savings values, "non-RTF lamps," have passed the ENERGY STAR qualifications for certification. These qualifications include testing procedures, general performance requirements, and minimum efficiency standards.

For non-RTF lamps, Tetra Tech recommended Idaho Power consider directly calculating energy savings using standard industry approaches or working with others to develop region-wide savings values. They stated that for lamps that fall well beyond the RTF categories or *Energy Independence and Security Act of 2007* (EISA) affected baseline lamps, Idaho Power should consider several options, including 1) working with NEEA and/or the RTF to develop lamp adjustment factors and baseline assumptions based on regional market knowledge; 2) conducting independent market research to understand the use of these lamps; and/or 3) using energy savings calculations based on general engineering principles and underlying RTF market adjustment and performance factors. In response to this recommendation, Idaho Power contracted with Tetra Tech to evaluate savings for non-RTF lamps using general engineering principles and the underlying RTF market adjustment and performance factors. Results will be available in early 2015.

A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Idaho Power will continue to participate in Simple Steps, Smart Savings in 2015. CLEAResult was awarded the BPA implementation contract for 2015. Idaho Power will enter into a new promotion contract with CLEAResult beginning April 1, 2015. No disruption in services will occur.

Idaho Power will continue to monitor the number of participating retailers and geographic spread of these retailers. The company will reach out to stores in the Salmon area and invite them to participate in the promotion. Idaho Power will also work regionally to develop online promotions that allow customers to access promotional pricing regardless of location.

In 2015, Idaho Power will participate in the NWRRC and follow the work of WRUN. Involvement in the NWRRC and WRUN will help facilitate research into transitioning the Energy Efficient Lighting program to a more comprehensive retailer markdown program with additional product categories and will help Idaho Power test online retail platforms.

Marketing and education tactics in 2015 will focus on helping customers purchase the right bulb for their need. CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, special product placement, and displays.

# Energy House Calls

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 297 | 411 |
| Energy Savings (kWh) | 579,126 | 837,261 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $186,732 | $164,173 |
| Oregon Energy Efficiency Rider | $8,174 | $35,822 |
| Idaho Power Funds | $3,080 | $0 |
| Total Program Costs—All Sources | $197,987 | $199,995 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.024 | $0.017 |
| Total Resource Levelized Cost ($/kWh) | $0.024 | $0.017 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.16 | |
| Total Resource Benefit/Cost Ratio | 2.16 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program gives homeowners of electrically-heated manufactured homes an opportunity to reduce electricity use by improving the home's efficiency. Specifically, this program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump. Participation is limited to one time per premise.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installation of a CFL bulb; two replacement furnace filters with installation instructions; testing water heater temperatures for the proper setting; and energy efficiency educational materials appropriate for manufactured-home occupants. The value of the service to the customer is dependent on the complexity of the repair. Although participation in the program is free, a typical cost for a similar service call would be $400 to $600. Idaho Power provides the customer with the contractor contact information via the Idaho Power website and marketing material. The customer then schedules an appointment directly with one of the recognized, certified sub-contractors specifically trained to provide these services in their region. The contractor verifies the customer's eligibility by initially testing the home to determine if it qualifies for duct-sealing. The actual energy savings and benefits realized by each customer depend on the measures installed and the repairs and/or adjustments made.

## 2014 Program and Marketing Activities

Energy House Calls serviced 297 manufactured homes during 2014, resulting in 579,126 kWh savings. An additional 33 homes were serviced with a test only. Of the homes served, 44 percent were located in the Treasure Valley and 56 percent were outside the Treasure Valley, with 34 percent east of Ada County and 22 percent west of Canyon County. Idaho Power marketed the program, coordinated sub-contractors' performance of local duct-sealing and energy efficiency services for this program, processed sub-contractor paperwork, and paid sub-contractors directly for work performed.

Participation declined in 2014 relative to 2013, with 297 and 411 homes completed, respectively. During the 11 years the program has been active, 10,779 homes have been serviced. Although it is difficult to pinpoint market saturation, there is a concern the program may be in its declining years. Concern over declining numbers prompted specific action in 2014, including an increase of marketing activities planned for the upcoming year and a review of new measures that may provide an increase in savings and encourage reluctant customers.

A variety of marketing tactics were employed to cultivate and capture the interest of a declining target audience. In the first quarter of 2014, 1,225 flyers were sent to churches, senior centers, and mobile home parks to enlist their aid in recruiting participants through their networks.

In spring 2014, Idaho Power tested advertising on Facebook based on results from a Foremost Insurance study that reported 79 percent of residents living in manufactured homes use Facebook and 42 percent visit social media multiple times per day. The results were positive, with 146,663 impressions and 515 click-throughs to the program landing page. The CTR was 0.029 compared to a good industry average of 0.02 to 0.024. Due to the CTR, the ads were rescheduled for November 1 through December 31.

In August, the non-participant survey was distributed to 4,000 potential participants with marketing and contact information in the packet. Contractors reported an uptick in scheduled appointments shortly after the survey was fielded. Collateral was redesigned to emphasize that program participation is free—a concern brought forward by respondents of the non-participant survey.

A September bill insert was sent to all residential customers in Idaho and Oregon. In November, 10,592 postcards were sent directly to all residents of electrically-heated manufactured homes that have not yet participated in the program. Postcards were delivered in either English or Spanish, as appropriate.

As in the past, door hangers continued to be delivered by the contractors to homes in areas where they were completing Energy House Calls visits. Idaho Power delivered postcards from the marketing campaign to Community Action Partnership (CAP) agencies for distribution to customers who need assistance but do not meet the qualifications to receive weatherization assistance through those agencies. In addition, Idaho Power CRs and customer service representatives (CSR) knowledgeable about the program continued to offer the program to qualified customers.

Although Idaho Power considered Spanish radio opportunities in Canyon County, the company decided to focus efforts on establishing monthly television segments to reach a larger audience. Television interviews began in October and are scheduled to continue into 2015. All direct-mail postcards and the participant and non-participant surveys were available in Spanish and delivered directly to homes identified in Idaho Power's database as Spanish-speaking customers.

## Cost-Effectiveness

In 2014, Idaho Power used the same RTF-deemed savings for manufactured-home PTCS duct-sealing as was used in 2013. However, the average savings per home are slightly reduced in 2014 from 2013 due to the size and location of the manufactured homes serviced. Savings are greater in colder heating zones and for double and triple-wide homes than they are for single-wide homes. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Comments received in Case No. IPC-E-14-04 suggested Idaho Power should increase its incentive for this program due to the continued strength of its TRC ratio. Although the incentive for a free program cannot be increased, Idaho Power looked into incorporating additional measures to enhance the value for future program participants. The inclusion of these additional measures will be implemented in 2015.

## Customer Satisfaction and Evaluations

To monitor QA in 2014, third-party verifications were conducted by Momentum, LLC on approximately 6 percent of the 297 participant homes, resulting in 18 home inspections. Homes were selected at random. The QA reports indicate customers were pleased with the work sub-contractors completed in their homes. Each home inspection included an on-site visual confirmation that the reported work had been completed. Weather permitting, blower door and duct blaster tests were also conducted to verify the results submitted by the sub-contractor.

In August, a program satisfaction survey was mailed to 367 customers that had participated in the program from July 2013 through July 2014. The survey and letter were printed in both English and Spanish. The letters included a link giving the participants an option to complete the survey online. One hundred forty-three participants provided feedback, resulting in a response rate of nearly 39 percent. Key findings included the following:

- Nearly 93 percent of the respondents indicated they were either “very satisfied” or “somewhat satisfied” with their overall program experience, and nearly 88 percent were “very likely” to recommend the program to friends or family.
- When asked to select their reasons for participating in the program, just over 92 percent of respondents indicated that reducing energy costs was a motivating factor.
- Nearly 86 percent of respondents indicated it was “very easy” to participate in the program.
- Following their Energy House Calls participation, just over 57 percent of respondents had noticed a change in comfort in their home. Of those that noticed a change, nearly 98 percent reported that the comfort in their home was either “much better” or “somewhat better” following their participation in the program.
- Finally, respondents “strongly agreed” nearly 75 to 82 percent of the time that the service specialists that completed work on their home were punctual, courteous, professional, and thorough.

In August, a non-participant survey was mailed to 4,000 customers that had not participated in the Energy House Calls program. The survey and letter were printed in both English and Spanish, and the letter included a link giving customers an option to complete the survey online. The non-participant

survey had a response rate of nearly 14 percent, with 542 customers completing the survey. Key findings identified included the following:

- Just over 82 percent of respondents lived in homes built prior to 1999, 66 percent lived on private land, and just over 87 percent owned their homes.
- Approximately 12 percent of respondents indicated they had primary heating systems other than central furnaces with ducts or heat pumps. These customers are ineligible for the program.
- Nearly 84 percent of respondents indicated that based on what they knew of the program, they were "very likely" or "somewhat likely" to participate in the program.
- Nearly 82 percent of respondents indicated lowering energy costs would be a "very motivating" factor for participation. Over 77 percent indicated no/low cost to participate would also be a "very motivating" factor for participation.
- When customers were asked to identify their preferences for how Idaho Power should communicate with them about programs and issues impacting their bills, about 48 percent of respondents said they preferred "promotional material in their Idaho Power bill" and nearly 61 percent indicated a preference for a letter or postcard in the mail.
- Over 63 percent of respondents were unaware of the program prior to receiving the survey.
- For those that were aware of the program, they were asked to select all of the reasons for not participating in the program. Over 26 percent indicated they didn't know the program was free, nearly 25 percent did not fully understand the program, and almost 12 percent did not see the benefits of participating.

## 2015 Program and Marketing Strategies

During the 11 years Energy House Calls has been in operation, 10,779 electrically-heated manufactured homes have been serviced through the program. Each year, Idaho Power prepares its direct-mail marketing list by analyzing kWh use of homes designated as manufactured or mobile in Idaho Power's customer information system to find those that appear to be electrically heated. After removing those homes that had already participated in the program, the 2014 direct-mail list contained 10,808 customers, indicating that approximately 50 percent of eligible homes had already been served by the program. An additional percentage of these homes may have had their ducts sealed through Idaho Power's low-income programs, as a few respondents from the non-participant survey indicated they had already participated in a duct-sealing program. Idaho Power will continue to monitor these numbers, but as response rates continue to decline across the service area, there is concern the market may be reaching saturation.

In 2015, more products and services will be offered to program participants during each scheduled visit. Specifically, contractors will install LEDs in main living areas. When water is heated with electricity, contractors will be able to wrap the inlet/discharge pipes from the water heater tank and install high-efficiency showerheads and faucet aerators.

Marketing tactics will continue to include potential participants' most-preferred methods for receiving information—promotional materials in the Idaho Power bill or a letter/postcard in the mail. However, to boost participation in a market that is moving toward saturation, marketing efforts will

double and emphasis will be placed on the variety of services offered. Two bill inserts will advertise program benefit and expected savings, and free participation will be highlighted. A targeted mail campaign direct to residents of manufactured homes that have not yet participated in the program will be conducted in spring and fall. Contractors and CRs will continue to distribute door hangers in mobile home parks and will take every opportunity to distribute program literature at appropriate events and presentations. Additionally, flyers and posters will be mailed to organizations with constituents that may benefit from the program.

Throughout the year, the program will explore new ways to reach customers and continue to look for additional cost-effective measures that can add value to the program.

# ENERGY STAR® Homes Northwest

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 243 | 267 |
| Energy Savings (kWh) | 528,054* | 365,370 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $330,523 | $344,217 |
| Oregon Energy Efficiency Rider | $7,612 | $4,664 |
| Idaho Power Funds | $5,141 | $4,000 |
| Total Program Costs—All Sources | $343,277 | $352,882 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.055 | $0.053 |
| Total Resource Levelized Cost ($/kWh) | $0.111 | $0.104 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.64 | |
| Total Resource Benefit/Cost Ratio | 0.83 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

* Includes savings from 282 certified gas-heated ENERGY STAR homes in 2014.

## *Description*

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA's Northwest ENERGY STAR Homes to improve and promote the construction of energy-efficient homes using guidelines set forth by the EPA. This program targets the lost-opportunity energy savings and summer-demand reduction that results by increasing the efficiency of the residential-building envelope and air-delivery system above current building codes and building practices. An ENERGY STAR certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR rater/home performance specialist (HPS) to meet the stringent ENERGY STAR requirements. This third-party rater is hired by the builder to perform these duties.

The ENERGY STAR Homes Northwest residential construction program promotes homes that use electric heat pump technology and are at least 15 percent more energy efficient than those built to standard Idaho and Oregon code. The program specifications for ENERGY STAR Homes Northwest are verified by the HPS and are certified by the Washington State University Extension Energy Program and Building Energy, Inc., organizations that conduct the certification inspections throughout Idaho and Oregon for the EPA. ENERGY STAR homes are more efficient, comfortable, and durable than homes constructed to standard Idaho building codes.

Homes that earn the ENERGY STAR label include six required specifications: 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

To encourage builders to construct ENERGY STAR homes, builders participating in ENERGY STAR Homes Northwest in 2014 received a $1,000 incentive per home built to the Northwest ENERGY STAR Single and Multi-Family Homes Requirements with heat pump technology. Builders who entered their homes in a Parade of Homes received the standard $1,000 incentive plus an additional $500 marketing incentive to cover their expenses for ENERGY STAR signage and brochures. Another benefit to the builders is the right from ENERGY STAR Homes Northwest to use the logo and the ENERGY STAR name to promote themselves as an ENERGY STAR qualified builder.

The Idaho Power program collaborates with many local entities for program promotion, including ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2014 was to provide marketing materials and support for the building contractors associations (BCA) throughout the Idaho Power service area.

## 2014 Program and Marketing Activities

A majority of the homes certified in 2014 were townhomes. This trend toward ENERGY STAR townhome certifications is a regional trend. In 2014, 5 of the 240 ENERGY STAR home certifications in Idaho were single-family homes. The decrease in the number of participating homes in 2014 as compared to 2013 is due to fewer ENERGY STAR Homes, employing heat pump technology, being certified in Idaho Power's service area. The trend the past couple of years has been toward an increase in multi-family construction Idaho Power's service area. In 2013, seven multi-family ENERGY STAR developments were constructed. In 2014, five multi-family ENERGY STAR developments were constructed, resulting in 61 fewer homes being certified in 2014.

The company maintained a strong presence in the building industry by supporting the Idaho Building Contractors Association (IBCA) and several of its local affiliates throughout Idaho Power's service area in 2014. The company presented the Energy Efficient Design and Construction Awards to builders who integrated energy efficiency features in their parade homes at the BCASWI Parade of Homes awards banquet. In addition, the company participated in the BCASWI builder's expo, and the Snake River Valley Building Contractors Association (SRVBCA) builder's expo. The company also supported Parade of Homes events with full-page ENERGY STAR ads in the Parade of Homes magazines of the following BCAs: The Magic Valley Builders Association Parade of Homes (MVBA), the BCASWI Parade of Homes, SRVBCA Parade of Homes, and the Building Contractors Association of Southeast Idaho (BCASEI) Parade of Homes. Bill messages were added to residential customer's billing statements informing them of Parade of Homes events in their area. In addition, the company sponsored the IBCA annual winter and summer meetings. A half-page ad was placed in the BCASWI monthly November and December newsletters to promote the program and the builder incentive.

In fall 2014, a bill insert was sent to all residential customers in the Idaho Power service area promoting the ENERGY STAR Homes Northwest program. The company ran print ads for four weeks in real estate sections of daily newspapers in Boise; Pocatello; Canyon County; and Ontario, Oregon. During this same timeframe, a digital behavioral ad campaign ran for two months across Idaho Power's service area, totaling 2,683,717 impressions/ads served and including such real estate sites as zillow.com. A letter to residential builders was mailed in spring 2014 reminding builders of the benefits of building ENERGY STAR homes and of the available builder incentive.

Idaho Power administered a process evaluation of the ENERGY STAR Homes Northwest program in 2013. This evaluation was performed by third-party contractor TRC Energy Services. In general, TRC Energy Services found the ENERGY STAR Homes Northwest program was successfully meeting goals and delivering energy savings. TRC Energy Services noted this was particularly impressive given

the challenges of the recent market downturn and the exclusion of customers with natural gas heat from the program. Based on the results of this evaluation, TRC Energy Services provided several recommendations for program improvement. The recommendations and Idaho Power's responses are described below.

TRC Energy Services recommended continued support from the company for the multi-family and townhome market, identification of other markets that could be building electrically heated homes, and targeting marketing efforts toward these sectors. In 2014, the company continued to support the multi-family ENERGY STAR homes market through certification of 235 multi-family homes and through its continued support of local BCAs.

The evaluators recommended Idaho Power develop an argument for the value of the ENERGY STAR label and verification and provide this (through talking points or a one-page flyer) to CRs, HPSs, and builders and to work with other entities to develop these talking points. Idaho Power determined the marketing materials, and the talking points developed by Idaho Power and Northwest ENERGY STAR Homes, currently available to CRs, HPSs, and builders appropriately addressed the argument for the value of the ENERGY STAR homes certification.

TRC Energy Services recommended Idaho Power provide continued support for the HPSs, meet with them one-on-one to understand their barriers to participation, and work with them to overcome these barriers. In particular, revisit the QA procedure for the program. In 2014, Idaho Power continued to maintain good relationships with the active HPSs and communicated multiple times throughout the year through email, phone calls, and face-to face visits. NEEA manages the QA function of the Northwest ENERGY STAR Homes program. While Idaho Power uses the QA results for its program compliance within the company's service area, the procedures used are dictated by NEEA. The company will encourage NEEA to communicate with the raters concerning QA procedural issues.

The evaluators recommended Idaho Power update the contractor list so it contains only builders that provide accurate information about the program, and to periodically update this list (e.g., biannually) by reaching out to contractors. In response to this recommendation, the builder list on the company ENERGY STAR Homes Northwest website is now a link to the Northwest ENERGY STAR Homes builder listing, which is current and updated frequently.

Another recommendation was to test the hypothesis reported by Idaho Power staff that multi-family builders are the primary group building homes with heat pumps by analyzing the residential nonparticipant survey results and through interviews with BCA staff. Idaho Power concluded multi-family homes with heat pumps versus single-family homes with heat pumps being submitted for ENERGY STAR Homes certification via the Northwest ENERGY STAR Homes database strongly indicated a current regional trend that multi-family builders are the primary group building heat pump homes.

The evaluators recommended using the regional program database to identify builders that are building electrically heated homes in Idaho Power's service area but do not qualify for the Idaho Power program. Idaho Power ascertained that all homes built using heat pump technology and meeting all Northwest ENERGY STAR Homes criteria currently qualify for the Idaho Power program.

TRC Energy Services recommended Idaho Power develop new relationships between the CRs, program specialist staff, key homebuilders, heat pump contractors, and heat pump suppliers and to reconnect with previously participating builders. In 2014, the program specialist and the CRs continued to establish and maintain new and existing relationships primarily through BCA builder events and industry-related meetings. The primary relationship within the ENERGY STAR Homes Northwest

program and company staff was with builders. CRs also formed relationships with heat pump contractors through the Idaho Power heating and cooling program. The company sent out a letter to all current and past ENERGY STAR Homes Northwest builder participants in April 2014 to update them on the program and the incentives offered.

Another recommendation was to provide additional builder training addressing the benefits of heat pump technology, electric heat pump home design, and design strategies to reduce electricity use in homes. While there was no on-site, heat pump specific training done in Idaho Power's service area in 2014, Northwest ENERGY STAR offered a DHP webinar in November 2014. All Northwest ENERGY STAR builder and HVAC contractor partners were encouraged to attend this event.

Last, the evaluators recommended Idaho Power provide CRs with goals for marketing the program, such as contacting a certain number of builders or presenting at a BCA meeting about the program; have CRs use the heat-pump flyer as a talking point with builders; and have CRs attend program trainings or heat-pump presentations with builders to learn about the program and develop relationships with local builders. Of note, Idaho Power CRs don't have specific goals that require them to contact a certain number of builders, but they are asked to be involved in their local BCA chapter where the opportunity to meet and establish relationships with builders is high. The CRs have been and continue to be active in the local BCA chapters where they come into direct contact with a majority of builders in their area. When program trainings are held, CRs are invited and encouraged by Idaho Power to attend.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness savings assumptions from the RTF for ENERGY STAR Homes Northwest for 2014 as were used in 2013. While savings assumptions remained the same for 2014, the RTF-calculated NEBs were added to the cost-effectiveness calculations to account for water and avoided maintenance savings over the lives of these efficient homes. The inclusion of NEBs helped improve cost-effectiveness for the different building packages and climate combinations from a TRC perspective, but the townhome/multi-family homes in the Bose–Nampa–Caldwell climate zone, which is the primary home submitted since 2012, is still not cost-effective from a TRC perspective.

Idaho Power has participated in ENERGY STAR Homes Northwest, a regionally coordinated initiative, supported by a partnership between Idaho Power and NEEA, since 2004. The company has been a continued proponent and driver of the increased awareness of the ENERGY STAR Homes Northwest brand. The majority of electrically heated ENERGY STAR Homes Northwest certifications are from several large multi-family builders exclusively building homes to ENERGY STAR specifications employing electric heat pump technology.

Because of Idaho Power's support of NEEA and the ENERGY STAR Homes Northwest brand, Idaho Power is claiming savings for 282 natural gas-heated, ENERGY STAR certified homes certified in Idaho Power's Idaho service area in 2014. These savings account for 195,372 kWh of annual savings from efficient cooling equipment, insulation, windows, doors, water heating, ventilation, appliances, and lighting. NEEA does not claim these savings, and they will be included in the program savings totals in appendices 3 and 4.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

The HPS works with builders to ensure the ENERGY STAR homes are compliant with the Northwest ENERGY STAR Homes specification. Along with verifying the installation of building components and

equipment through on-site inspections, prior to being certified, the HPS ensures the home passes a blower door test, an air-duct leakage test, and combustion back-draft tests.

The state-certifying organizations (SCO) perform QA inspections. The Washington State University Energy Extension Program is under contract with NEEA to perform QA and technical assistance duties within Idaho. For QA purposes, 5 percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed by the Washington State University Energy Extension Program. This is a technical verification of the homes. All of the homes randomly chosen for QA in Idaho Power's service area passed the QA inspection process in 2014.

In 2014, the Customer Research and Analysis team administered an impact evaluation using Tetra Tech to provide third-party analysis. The findings from this evaluation found that the ENERGY STAR Homes Northwest program has well-established program design and delivery processes that are supported by the program tracking systems, program documentation, and savings tools. The impact evaluation approach emphasized compliance with the RTF energy savings as the basis for verification of savings.

Results of the impact evaluation indicated that 2013 ex-post verified savings were 353,828 kWh compared to 365,370 kWh ex-ante claimed savings, resulting in a gross realization rate of 96.8 percent. The driver of the difference in the overall kWh realization rate was adjustments made to seven townhomes removed from the program savings.

Tetra Tech also identified several recommendations for the ENERGY STAR Homes Northwest program as a result of the impact evaluation. The evaluator recommended continuing to use the program tracking system for savings assignments and noted that in 2014, Idaho Power made recent improvements to their energy efficiency programs database to assist in automating savings assignments and prevent the need to develop savings assignments outside the database. Tetra Tech also noted that improving the database usability and allowing for the automation of look-up functions to occur within the database will also assist in reducing potential error, enhance the quality review process, and help facilitate reviews. This will also ensure other parameters are entered correctly by allowing for data checks across fields. The evaluator stated that an additional result would be avoiding misalignment between participating homes and the assigned savings values. In response, in 2014 Idaho Power enhanced database functionality and will continue to automate database tracking systems as needed.

Tetra Tech recommended the continued use of RTF categories and continued use of the RTF proven measure savings, but recommended Idaho Power develop savings assignments and calculations with a clear alignment with the RTF savings values for single-family and multi-family homes. Tetra Tech stated that a unified participant tracking and savings workbook could contain such information and provide an efficient and standardized approach that can address potential future program regional complexity. Idaho Power uses the RTF proven measure savings, and the independent values for single-family and multi-family savings are assigned in the DSM Customer Load and Resource Information System (CLRIS) application based on housing type.

Another recommendation was to investigate methods for obtaining project-level documentation. Tetra Tech stated the program and a future evaluation effort may benefit by having greater access to project-level details covering project eligibility and greater technical details. For the benefit of the program and evaluators, Tetra Tech recommended Idaho Power work with NEEA and their contractors to improve the level of detail captured for each project and made available to Idaho Power for the Builder Option Package inspection results for each home. In response, Idaho Power considered this recommendation and determined the documentation provided for each certified ENERGY STAR home, via the Northwest ENERGY STAR Homes database, provides the necessary detail for Idaho Power to pay incentives to builders. This documentation, the *Northwest ENERGY STAR Homes Program Report*,

denotes that all testing and inspection on the home meets or exceeds all minimum values of ENERGY STAR Home certification. This report also denotes the certified status of the home, states that each program checklist was completed successfully, and provides the performance testing results.

Last, the evaluators recommended working to increase QA inspections within the company's service area and working with NEEA and their contractors to better understand the protocols and information obtained and documented during QA inspections in Idaho Power's service area. This recommendation is to ensure appropriate home parameters are captured for the current and future needs of Idaho Power evaluations and that a minimum number of Idaho Power ENERGY STAR certified homes are QA inspected each year. The evaluator recommended that, absent the ability of Idaho Power to ensure a minimum level of service for QA, Idaho Power should consider conducting and documenting its own QA process using the same protocols as the NEEA initiative. In response to the recommendation, in 2014 Idaho Power began discussions with NEEA to ensure a representative number of QA inspections of heat pump homes in Idaho Power's service area that qualify for the Idaho Power incentive. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Builders involved in ENERGY STAR Homes Northwest during 2015 in Idaho Power's service area will receive a $1,000 incentive per home built to the Northwest ENERGY STAR Homes specifications using heat pump technology standards. Builders showcasing their electric heat pump home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive.

Idaho Power plans to continue marketing efforts to help promote ENERGY STAR homes to home builders and new homebuyers. These marketing efforts include Parade of Homes ads in parade magazines for the BCASWI, SRVBCA, MVBA, and the BCASEI. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Marketing materials will be available for use by builders. Bill inserts will be sent to all residential customers in May. Bill messaging is planned in June, July, and August to support the various BCA Parade of Homes events throughout Idaho Power's service area.

A direct-mail letter to builders is planned for 2015. This direct-mail piece will highlight the requirements and the Idaho Power builder incentive for building to Northwest ENERGY STAR Homes specifications. In addition, the program will be promoted in the *Idaho Business Review* in issues targeting residential contractors and builders.

NEEA is planning a 2015 transition of the Northwest ENERGY STAR Homes program to the national EPA ENERGY STAR Homes program and to local market partners/stakeholders. NEEA will continue to provide program and technical oversight of ENERGY STAR Home Northwest through 2015 with plans to then transfer oversight to the national program. The program will be available for builders if they so choose to continue building ENERGY STAR certified homes under the national program.

A second program, NEEA's Next Step Home program, is still in the pilot stage. At the end of 2014, NEEA began developing the Phase III recruitment plan to continue building participation and awareness in the Next Step Home pilot. Homes built during Phase III will incorporate Next Step Home minimum requirements, guidelines, and best practices learned from Phase I and II. Despite NEEA recruiting efforts, there are no builders who have, as of yet, signed on to build a Next Step Home in Idaho Power's service area.

# Heating & Cooling Efficiency Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 230 | 210 |
| Energy Savings (kWh) | 1,099,464 | 1,003,730 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $340,551 | $317,973 |
| Oregon Energy Efficiency Rider | $14,627 | $11,700 |
| Idaho Power Funds | $6,836 | $0 |
| Total Program Costs—All Sources | $362,014 | $329,674 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.022 |
| Total Resource Levelized Cost ($/kWh) | $0.075 | $0.050 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.74 | |
| Total Resource Benefit/Cost Ratio | 1.09 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The H&CE Program provides incentives to residential customers for the purchase and proper installation of qualified heating and cooling equipment.

The objective of the program is to acquire energy savings by providing customers with energy-efficient alternatives for electric space heating. Incentive payments are provided to both residential customers and HVAC participating contractors who install eligible equipment. The eligible measures in 2014 include air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Heating and A/C companies authorized by Idaho Power as participating contractors for the program are required to perform all installations, with the exception of evaporative coolers, which can be self-installed.

The H&CE Program's list of measures and incentives includes the following:

- Customer incentive for replacing an existing air-source heat pump with a new air-source heat pump is $250 for a minimum efficiency 8.5 heating seasonal performance factor (HSPF).
- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump is $400 for a minimum efficiency 8.5 HSPF. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.

- Incentive for customers or builders of new construction installing an air-source heat pump in a new home is $400 for a minimum efficiency 8.5 HSPF.

- Customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump is $500 for a minimum efficiency 3.5 coefficient of performance (COP).

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump is $1,000 for a minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.

- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home is $1,000 for a minimum efficiency 3.5 COP.

- The evaporative-cooler customer incentive is $150.

## 2014 Program and Marketing Activities

The expansion of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal was to support contractors currently in the program while adding new contractors. The company held meetings with several prospective contractors to support this strategy. Idaho Power added eight companies to the list of participating contractors in 2014.

Idaho Power held nine training sessions for contractors in 2014. For a company to be eligible to join the program as a participating contractor, they must have participated in this required training that provides general instructions on heat pumps and program guidelines. These training sessions remain an important part of the program because they create opportunities to invite additional contractors into the program.

To increase contractor participation in the program, stronger relationships with the equipment wholesalers was necessary. In Idaho Power's service area, there are numerous wholesalers supplying heat pumps to the contractors. Idaho Power met with several of these wholesalers in Idaho Power's service area to share helpful information and to encourage them to promote the program to their contracting customers.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review the incentive applications and perform OSVs. This contractor provides direct support to participating contractors and the residential program participants. Honeywell offers local assistance through representative visits to contractors at their businesses as needed. Using a program database via a portal developed by Idaho Power, Honeywell reviews and submits incentive applications for Idaho Power payment. This allows Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor.

Multiple marketing tactics were used for Idaho Power's HC&E Program. Approximately 3,000 radio ads ran on over 20 radio stations for six weeks throughout Idaho Power's service area. In spring 2014, a digital behavioral ad campaign was launched and resulted in 771,211 ads displayed on pages viewed by people browsing the internet over two months.

A contractor portal was launched in 2014. The portal allowed authorized contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address, and phone number. Two door hangers were offered for insulation

contractors, two door hangers for window contractors, and two fliers for participating contractors in the HC&E Program. The *Demand-Side Management 2013 Annual Report* stated the contractors would be asked to comment on the portal during 2014. Comments were not pursued due to the portal launching the third quarter of the year, which limited contractors' time to try the portal in 2014.

The *Demand-Side Management 2013 Annual Report* mentioned possible changes to the HC&E webpages. Changes to the HC&E webpages were not made in 2014 because on a separate project, the company began working on a website redesign to improve navigation on the Energy Efficiency website. The decision was made to wait until that work was completed before any changes were made to HC&E webpages. The website navigation changes did not result in any changes being made to the Energy Efficiency website during 2014.

A direct-mail campaign was conducted in April 2014. Over 27,000 letters were sent to homeowners of electrically heated homes. In addition, information about the heat pump program was included in a postcard sent to people who purchased a home within the previous six months. Bill inserts and newspaper ads rounded out the ongoing marketing and promotion of the HC&E Program.

Idaho Power administered a process evaluation of the H&CE Program in 2013, performed by third-party contractor TRC Energy Services. Based on the evaluation results received in 2014, TRC Energy Services identified program trends, successes, and barriers, then developed recommendations to address the barriers.

It was recommended Idaho Power gain a better understanding of the eligible market, such as customers with electric, oil, or propane heat and their barriers for program participation, to better target marketing efforts. In response to this recommendation, Idaho Power participated in seven local trade shows and benefited from one-on-one discussions with residential homeowner attendees.

The evaluators recommended Idaho Power provide contractors with co-branded marketing materials, case studies, or cost calculation examples to assist them with their marketing efforts. A new online contractor portal was already in development and was launched on the Idaho Power website late summer 2014. This password-protected portal provided participating contractors with pre-designed colored marketing fliers printable by the contractor for distribution. Fliers could be personalized with the contractor's business name, address, logo, and phone number.

TRC Energy Services recommended Idaho Power consider requiring contractors to attend refresher training and/or deliver a minimum number of projects per year to continue to be listed on the program website. In 2014, the H&CE Program incorporated this recommendation by providing nine refresher training sessions and requiring each participating contractor to submit a minimum of one application per year beginning in 2015 to avoid being placed on inactive status.

Another recommendation was that program requirements be described clearly and prominently in marketing collateral and on the website. In response to this recommendation, all marketing collateral and web content were reviewed. Improvements were made to ensure the reader realized incentive requirements apply.

It was recommended that Idaho Power CRs be engaged in the contractor training sessions routinely provided by Idaho Power. Idaho Power invited the CRs to sessions in 2014, and several CRs attended the sessions.

TRC Energy Services recommended Idaho Power annually contact the participating contractors to ensure there is at least one installing technician trained by the program. This recommendation was made due to employee turnover experienced with some participating contractors. Idaho Power provided training where there was a lack of a trained technician.

The evaluators recommended surveys be initiated to gather various types of program feedback from participating contractors. This has not been implemented because Idaho Power decided face-to-face meetings between participating contractors, the CRs, and the program specialist gathered program feedback promptly and effectively.

It was recommended a cash-based incentive be offered to participating contractors in an attempt to drive additional and more specific types of participation. Idaho Power has not implemented this recommendation because research data was unavailable in the Idaho Power service area that identifies what the common reason is for variability in contractor participation and what the key motivation tactics should be. Going forward, Idaho Power will investigate if a contractor incentive is needed to increase participation in its programs.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness unit energy saving (UES) assumptions for the H&CE Program during 2014 as were used in 2013. For 2014, Idaho Power calculated participant-cost averages used for the cost-effectiveness analysis based on Idaho Power-specific project data over two years (2013–2014) to estimate typical project costs instead of relying on regional averages.

Due to the lower alternative costs from the 2013 IRP, water-source heat pumps and heat pump conversions to 8.50 HSPF became non cost-effective. However, Idaho Power determined that heat pumps meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power filed UM-1710 to request a cost-effectiveness exception with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Honeywell performed random OSVs on 10 percent of the completed installations in the Idaho Power service area. These OSVs verified the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with respect to the contractors' quality of work. The program specialist continues to work with contractors to help them understand the importance of accurate documentation.

## 2015 Program and Marketing Strategies

Idaho Power will sponsor and provide training to new and existing contractors in the program to assist them in meeting program requirements and further their product knowledge. Sessions will be held on-site at contractor businesses and at Idaho Power facilities.

Expanding the network of participating contractors remains a key strategy for the program because the performance of the program is substantially dependent on the contractors' abilities to promote and leverage the measures offered. Idaho Power's goal is to support contractors currently in the program while continuing to add new contractors. To meet this objective, the program specialist, along with

Idaho Power CRs, will arrange frequent individual meetings to discuss the program with contractors in 2015.

To increase participation in the program in the Idaho Power service area, the program specialist will work to strengthen relationships with equipment wholesalers. To accelerate the wholesalers' abilities to increase contractor awareness of the program, the program specialist will meet with the wholesalers and share information.

The 2015 marketing strategy will include proven tactics previously used and new methods. Since homeowners make more improvements to their home during the first two years of ownership, the company plans to continue to target new customers in the first six months of new-home ownership. Postcards will be mailed to these new customers, raising awareness of the incentives available to them. The strategy will include many marketing tactics, such as bill inserts, print ads in newspapers, and direct-mail letters. Social media, such as Facebook, will also be used.

New marketing pieces will be added to the contractor portal over time as needed. In 2015, it has not yet been determined if/when portal feedback would be formally solicited from the contractors.

# Home Energy Audit

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 354 | n/a |
| Energy Savings (kWh) | 141,077 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $164,579 | n/a |
| Oregon Energy Efficiency Rider* | −$248 | n/a |
| Idaho Power Funds | $6,318 | n/a |
| Total Program Costs—All Sources | $170,648 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2014 | |

* Reversal of a 2013 charge to the Oregon Rider.

## *Description*

The Home Energy Audit is an in-home energy evaluation by a certified, third-party HPS. It is used to identify areas of concern and provide specific recommendations to improve the efficiency, comfort, and health of the home. An audit includes a visual inspection of the crawl space and attic, a health and safety inspection, and a blower door test to identify and locate air leaks. In addition to the energy evaluation, some energy-saving improvements are installed at no additional cost to the customer if appropriate. After the audit is complete, the customer is supplied with a written report of the HPS's findings and recommendations. Available improvements include installation of the following:

- Up to 20 CFLs
- One high-efficiency showerhead
- Pipe insulation from the water heater to the home wall (approximately 3 feet)

The current Home Energy Audit program is based on the insights gained from the Boise City Home Audit project conducted in 2011 and 2012, as described in the *Demand-Side Management 2012 Annual Report*. To qualify for the Home Energy Audit program, participants must live in Idaho and be an Idaho Power customer of record for the home. The home must be an existing all-electric, site-built home. Renters may participate with prior written landlord permission. Single-family homes, duplexes, triplexes, and fourplexes qualify. Manufactured homes, new construction, or buildings with more than four units do not qualify. Multi-family homes heated by a central heating unit or that aren't separately metered are not eligible.

Participating customers pay $99 for the audit and installation of measures, with the remaining cost covered by the Home Energy Audit program. Energy audits of this type normally cost $300 or more, not including the select energy-saving measures, materials, and labor. The cost of the materials potentially installed at each home is approximately $84.

## 2014 Program and Marketing Activities

In January 2014, the program launched in Blackfoot with an open house at the Bingham County Senior Center. The public was invited by direct-mail letters, newspaper ads, an article in the Blackfoot Chamber of Commerce newsletter, and posters located in the Bingham County Senior Center. The open house was later written up in the *Morning News* in Blackfoot. Three additional open houses were held in Homedale, Gooding, and Salmon. In addition to letters, newspaper ads, and posters, radio spots were used in Salmon, as well as a press release sent to local media.

Participants for the program were recruited through small batches of 1,000 to 2,000 direct-mail letters. Customers interested in participating were directed to a website for additional information and the online application. Those who did not have internet access or were uncomfortable using the application online were able to call Idaho Power and apply via phone.

Seven energy audit companies were selected to serve the program. Audits were randomly assigned to the HPSs serving each area, grouping locations for each HPS to save on travel time and expense.

In 2014, 354 audits were completed, surpassing the 2014 goal of completing 300 energy audits. The average age of participating homes was 36 years old. The homes were built between 1900 and 2013. Home sizes ranged from 700 square feet ($ft^2$) to 7,920 $ft^2$, with 2,463 $ft^2$ being the average home size. Figure 10 shows the number of participating homes located in various counties, demonstrating considerable program expansion from a Boise-based audit project to a program reaching the edges of the Idaho Power service area.

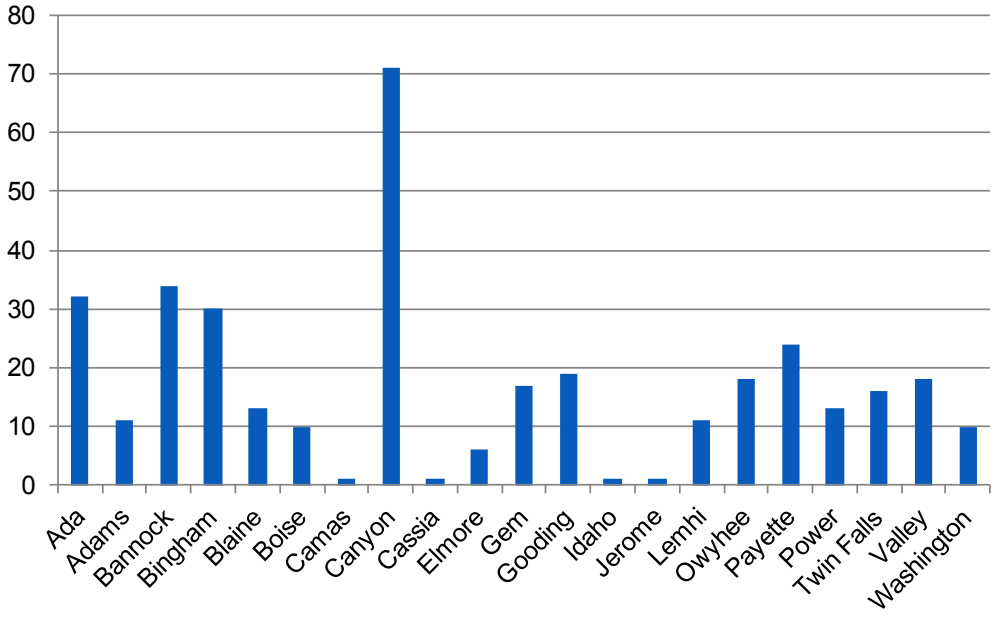


Figure 10. Summary of participating homes by county

The program was designed for all-electric homes only. All written communication sent to customers and the website included that the program was limited to all-electric homes. If the application was taken over

the phone, the customer was asked if their home had electric heat and water heating, and non-electric sources were turned down. In addition, when the HPS contacted the customer to schedule the appointment, the customer was asked if the home had electric heat and water heating. Non-electric sources were turned down. The electrically heated homes used a variety of heating styles, with heat pumps being the most common (153), then furnaces (99) and wall heaters (96). Eight of the 354 participating homes audited were not electrically heated homes, despite numerous efforts to ensure participants had all-electric homes.

Each HPS collected data on appliances and lighting in each home. The average number of incandescent lights per home was 24, and the average number of fluorescent lights was 12. When performing an audit, the HPS determined which available measures were appropriate for the home, and if the homeowner approved, those measures were installed. Figure 11 indicates the total quantity of items installed by measure.

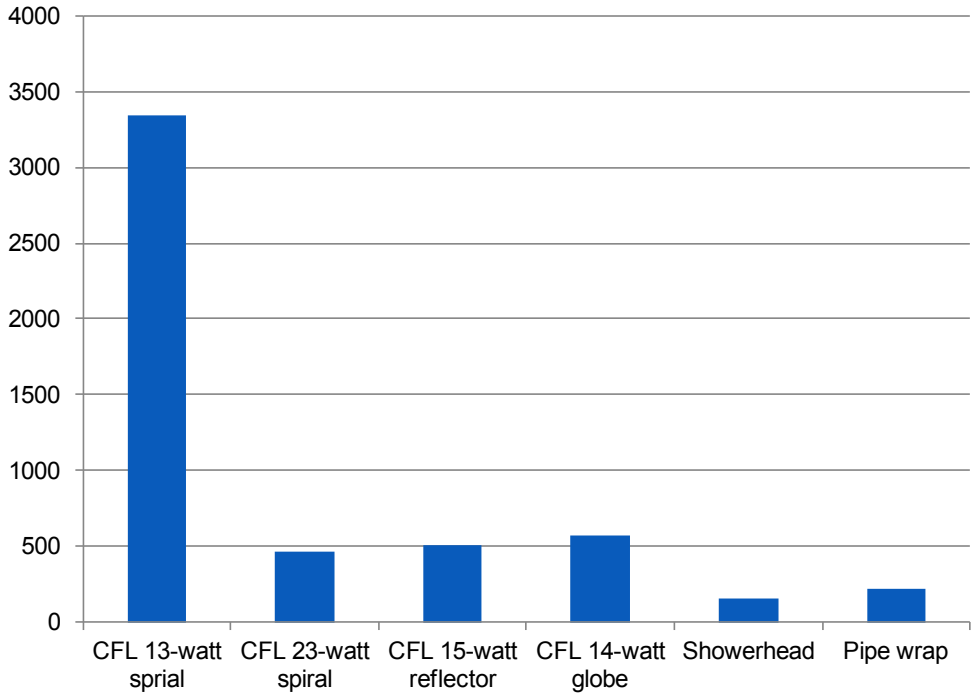


Figure 11. Measures installed in participating homes

The QA goal for the program was inspection of 10 percent of all audits, translating into approximately 35 audits in 2014. Twenty-seven QAs were completed in 2014, with all audits passing inspection. The 10 percent audit goal was unmet in 2014 because it was challenging to find participants willing to allow the auditor into their home for a 1- to 2-hour audit, especially if the participant worked outside the home.

## Cost-Effectiveness

In IPUC Order No. 32667, the commission encouraged "the Company to take other opportunities to improve customer's energy I.Q. and to educate them about the Company's energy efficiency programs." One of the goals of the Home Energy Audit program is to increase participants' understanding of how their home uses energy, and if eligible, encourage their participation in Idaho Power's energy efficiency programs. As an educational and marketing program, the traditional cost-effectiveness tests have not been applied to the program.

For the items installed directly in the homes, Idaho Power used the RTF savings for direct-install bulbs, which range 17 to 29 kWh per year. The RTF savings for 2.0 gallons-per-minute (GPM) showerheads directly installed in a home are 139 kWh per year. In Idaho Power's *Energy Efficiency Potential Study*, Applied Energy Group (AEG) estimates that pipe wraps save 150 kWh per year.

## Customer Satisfaction and Evaluations

A survey designed to assess customers' experience with program enrollment, scheduling, the auditor, the report value, and information learned was sent in July and November to a total of 225 program participants. Ninety-five participants responded to the survey, resulting in a response rate just over 42 percent. Program strengths and areas for improvement were also assessed. Participants that supplied an email address were sent the survey online. Those without an email address were sent a hardcopy of the survey with a postage-paid envelope. Results were reviewed for the program as a whole and for responses related to individual HPSs.

When asked a series of questions about their experience with the program, just under 94 percent of respondents "strongly agreed" or "somewhat agreed" they would recommend the program to a friend or relative, and just under 94 percent of respondents "strongly agreed" or "somewhat agreed" they were satisfied with their overall experience with the program.

Almost 97 percent of the respondents indicated it was "very easy" or "somewhat easy" to apply for the program. Individual program audit report results were available online, and a hard copy of the report was mailed to participants who did not supply an email address. Of the 95 survey respondents, 55 customers rated the difficulty of accessing the report online. Of those 55 customers, just under 77 percent of customers indicated that accessing the report online was "very easy" or "somewhat easy."

HPSs were rated on a number of attributes, including courteousness, professionalism, explanation of work/measurement to be performed, explanation of audit recommendations, and overall experience with the HPS. Respondents rated their HPSs as "good" or "excellent" 96 to 100 percent of the time.

When asked how strongly they agree or disagree with statements around what they learned during the audit process, just over 95 percent of respondents "strongly agreed" or "somewhat agreed" they were more informed about the energy use in their home. Almost 88 percent indicated they "strongly agreed" or "somewhat agreed" they were more informed about energy efficiency programs available through Idaho Power. Just under 87 percent indicated they "strongly agreed" or "somewhat agreed" they learned what no- to low-cost actions they could take.

After the audit, just over 51 percent of respondents indicated they visited the Idaho Power website, approximately 61 percent unplugged appliances when not in use, 42 percent signed up for myAccount, and almost 75 percent shared their experience with relatives and/or friends. Sixty-five percent of the respondents indicated they replaced additional incandescent light bulbs with CFLs or LEDs. Nearly forty-one percent indicated they serviced their heating equipment, and 38 percent serviced cooling equipment. Additional information on the actions that respondents indicated they already completed or planned to do within the next year are shown in the survey results included in *Supplement 2: Evaluation*.

Survey participants were asked to identify all of the benefits they experienced from participating in the program. Almost seventy-six percent of respondents indicated the biggest benefit they found in the audit was personal satisfaction, with nearly 71 percent citing raised awareness of energy use, just over 58 percent citing cost savings, 57 percent citing home improvement, approximately 42 percent citing

comfort, and just over 39 percent citing benefit to the environment. When survey participants were asked to identify all of the barriers they encounter when making energy-saving changes in their home, nearly 74 percent of respondents indicated the biggest barrier was cost. Figure 12 below shows benefits experienced by category and percent.

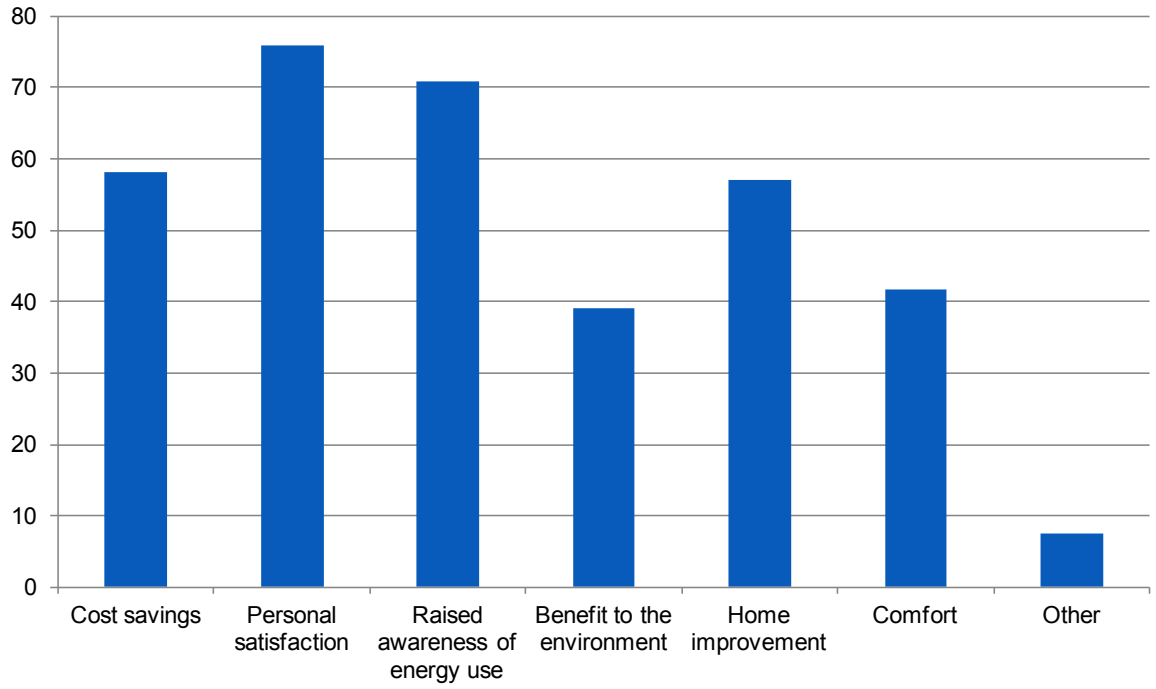


Figure 12. Program participants' benefits experienced

In 2014, Idaho Power administered a process evaluation of the Home Energy Audit program. The analysis was performed by Johnson Consulting Group. The overall conclusion of the evaluation was that the Home Energy Audit program is well designed and well run. The evaluation stated a key finding was the program had a successful launch because the design leveraged the "lessons learned" from the Boise City Audit Project. An additional finding from the evaluation was that the Home Energy Audit program incorporated most of the marketing best practices shown to be effective in promoting successful weatherization, energy audits, and "whole house" program approaches. Johnson Consulting Group also found customer and contractor feedback to be positive based on in-depth interviews. The final key finding of the evaluation was that the program participation process was quick and easy. Johnson Consulting Group's evaluation offered several recommendations for consideration. The first recommendation was to change the program name to *not* include the word audit. However, after careful review of the terms customers repeatedly used when asking for this type of service when calling or writing, Idaho Power learned that the word "audit" was the most-used term by customers. Thus, "audit" is included in the program's name.

The rest of the recommendations were around direct-install measures, customer surveys, follow up, and HPS work. For the direct-install measures, it was recommended to review the mix of measures available to ensure they are still cost-effective, appropriate, and correct for the homes. Pipe wrap had already been identified not fitting all pipes, and a larger size was made available. LEDs were also identified as a potential direct-install measure, and a cost analysis was reviewed.

Johnson Consulting Group's evaluation recommended considering a formal customer survey to assess satisfaction levels and to identify barriers preventing customer follow-through on auditor

recommendations. Idaho Power decided it wouldn't be prudent to spend additional funds for another survey because the current participant survey conducted in-house is sufficient to assess these items. Another recommendation was to develop a protocol or procedure for reaching out to customers and encouraging them to follow up on the energy efficiency recommendations. A procedure was developed to address customer follow-up and incorporated into the new HPS contracts for 2015.

The final recommendations were around additional training and guidance for the HPS. Two of the recommendations were around controlling what the HPS included in the customer's report. While guidelines are provided, such as to educate and encourage participation in energy efficiency programs, the HPSs are independent contractors and therefore have some leeway in what the contractors include in an audit. The basic parts of the audit are consistent for all auditors so all participants have a consistent experience. However, each home is different, plus the auditor is on-site inspecting the home and talking to the customer. Based on what the auditor observes and conversations with the customer, auditors need the latitude to personalize the recommendations as much as possible. Additional training on the audit software and its capabilities occurred in 2014. Although it was covered in the Statement of Work, one auditor was still unaware he was allowed to market his services to customers post-audit. That information has been directly reiterated with all auditors. The 2015 program changes resulting from a review of the process evaluation recommendations are described in detail below. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

With the cost of LEDs decreasing and customer interest in this technology increasing, two LEDs and 18 CFLs will be available for each participating home starting January 1, 2015. This change was made due to customer and HPS feedback and a recommendation from the process evaluation to review the mix of measures available.

Starting January 1, a new procedure for reaching out to customers to follow up on the audit recommendations as recommended by the process evaluation requires the HPS to perform a follow-up call to participants approximately 10 to 14 days after their audit. This change is expected to provide several benefits. First, the HPS will be able to verify the customers received reports. Second, the call provides a prompt and an opportunity for participants to ask their HPS additional questions. Third, the call allows the HPS to verify customers' understanding of the specific recommendations for their homes and what actions they can take next.

To account for the additional time the follow-up calls will take—and to make the fees more in-line with industry standards—the fee to the auditor will be increased in 2015 from $101 to $201. The customer fee will remain at $99.

While the HPSs were provided a program handbook to study, the program process evaluation showed it would be beneficial to provide the information verbally to each HPS. In early 2015, each HPS will take part in a live training session. The training will focus on ensuring a deep understanding of the program, including goals, standards, the timeline, and program flow. It will include information on other energy efficiency programs to promote and the use of myAccount. It will also include feedback from the surveys and areas for improvement.

A trade show booth backdrop and interactive webpages have been created using a cutaway house design to promote the Home Energy Audit program as well as demonstrate energy-saving tips for customers. These new tools will be used and promoted in 2015.

# Home Improvement Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 555 | 365 |
| Energy Savings (kWh) | 838,929 | 616,044 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $315,616 | $299,032 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $9,101 | $465 |
| Total Program Costs—All Sources | $324,717 | $299,497 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.020 | $0.025 |
| Total Resource Levelized Cost ($/kWh) | $0.055 | $0.090 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.17 | |
| Total Resource Benefit/Cost Ratio | 1.51 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Home Improvement Program offers incentives to homeowners for upgrading insulation and windows in electrically heated homes. To qualify for an incentive under this program, the home must be a single-family home, a multi-family structure three stories or under, or a manufactured home in Idaho Power's service area in Idaho. The home must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system. Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor.

Participating insulation contractors must successfully complete a two-day contractor training course delivered by CLEAResult and Idaho Power. Customers must use a participating contractor to qualify for the Idaho Power incentive, processed by Idaho Power.

The program details include the following:

- Customer incentives for attic insulation, wall insulation, and under-floor insulation require prescriptive air- and duct-sealing.
- Customer incentives to Idaho residential customers in the Idaho Power service area for additional insulation professionally installed are 15 cents per $ft^2$ for attic insulation, 50 cents per $ft^2$ for wall and under-floor insulation, and 30 cents per linear foot for air- and duct-sealing.

- Existing attic insulation must be an R-20 or less to qualify, and the final R-Value must meet the local energy code. Idaho Power's service area consists of climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-Value must be R-19.
- The existing insulation level under floors must be R-5 or less, and the final R-Value must be R-30.
- Customer incentives are $2.50 per $ft^2$ of window area to Idaho residential customers for installing energy-efficient windows and/or sliding glass doors with a U-Factor of 0.30 or lower.
- Pre-existing windows/sliding glass doors must be single- or double-pane aluminum or single-pane wood.

## 2014 Program and Marketing Activities

At the beginning of the year, webpages for the Home Improvement Program were updated and improved to make customer navigation easier. A contractor portal was launched in 2014. The portal allowed contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address, and phone number. Currently offered on the portal for use are two door hangers for insulation contractors, two door hangers for window contractors, and two fliers for HVAC contractors. New marketing pieces will be added over time as needed. A video was produced at the beginning of the year to highlight program measures and to provide customers with a visual of how the upgrades are performed. This video can be viewed at idahopower.com/homeimprovement. A Facebook ad campaign ran from June to September, reaching approximately 310,563 customers. A series of newspaper ads ran multiple times during 2014. Newspaper ads were placed in publications that serve rural areas where there is a higher concentration of electrically heated homes (a program eligibility requirement). Digital behavioral ads ran during mid-March to the end of May. The number of impressions/ads served totaled 771,024. Two information bill inserts were sent out, one in February and one in June, and a targeted direct-mail letter was sent in fall 2014. In addition, window clings and retail signage were created and used in retail locations in eastern Idaho.

## Cost-Effectiveness

In 2014, Idaho Power used the same savings and cost-effectiveness assumptions as were used in 2013. For all measures, deemed-savings values specific to Idaho Power's heating and cooling climate zones the company used published by the RTF, including cooling savings based on the RTF's deemed-savings specifications for single-family home weatherization UES values. Incremental costs for the calculation of TRCs were estimated from customer project data for insulation projects, while regional RTF cost averages were used for efficient windows. Idaho Power did not have adequate window costs for baseline efficiency windows. For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

For QA purposes, third-party contractors performed random reviews of 5 percent of all installations completed in the Home Improvement Program. QA contractors verified the correct installation of

measures. In addition, the QA contractor assisted and educated the contractors on program requirements. Of the 37 QA inspections completed in 2014, no issues were reported.

The program incentive application form included an optional question asking customers how they heard about the program. Of the 555 applications, 506 customers answered the marketing question. The results are as follows:

- 219 respondents (43%) heard about the program from a program contractor.
- 148 respondents (29%) heard about the program from an Idaho Power bill insert.
- 58 respondents (11%) heard about the program from the Idaho Power website.
- 44 respondents (9%) received a referral from a friend or acquaintance.
- 9 respondents (2%) heard about the program from a home improvement show or fair.
- 6 respondents (1%) heard about the program from a newspaper or online ad.
- 22 respondents (4%) heard about the program from a direct mailer.

## *2015 Program and Marketing Strategies*

Numerous marketing activities are planned for 2015. Two informational bill inserts are planned. A targeted direct-mail letter is scheduled for February. Online ads will include both Facebook and behavioral network ads. Print ads will be placed in rural publications to target customers with electrically heated homes. The contractor portal will be populated with additional marketing pieces. Marketing materials will be updated as needed.

# Home Products Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances/showerheads) | 10,061 | 13,792 |
| Energy Savings (kWh) | 652,129 | 885,980 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $212,787 | $391,348 |
| Oregon Energy Efficiency Rider | $9,250 | $14,117 |
| Idaho Power Funds | $5,139 | $50 |
| Total Program Costs—All Sources | $227,176 | $405,515 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.031 | $0.041 |
| Total Resource Levelized Cost ($/kWh) | $0.041 | $0.071 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.94 | |
| Total Resource Benefit/Cost Ratio | 4.52 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances. ENERGY STAR qualified appliances and products must meet higher, stricter efficiency criteria than federal standards. In 2014, the measures and related incentives included ENERGY STAR qualified refrigerators ($30) and freezers ($20).

Participants have two options to submit their application. They may complete a mail-in incentive application and submit it to Idaho Power with an itemized copy of the sales receipt or submit an online application and scanned copy of their receipt via email. If the purchase qualifies, the customer receives an incentive check by mail.

The Home Products Program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point of purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products at the retail level. One measure offered through the retailer markdown model is low-flow showerheads. Low-flow showerheads are part of the Simple Steps, Smart Savings™ markdown promotion administered by the BPA. Simple Steps, Smart Savings is coordinated by CLEAResult.

Idaho Power works in collaboration with NEEA on the Retail Products Platform (RPP). This initiative launched in 2014 and provides a direct incentive to retailers for selling the most energy-efficient products.

## 2014 Program and Marketing Activities

Through the Home Products Program, Idaho Power paid 3,292 appliance incentives during 2014, resulting in 77,574 kWh annual savings. Ninety percent of incentives were for refrigerators, and 10 percent were for freezers. Additionally, Idaho Power paid incentives on 6,769 showerheads sold under the regional BPA Simple Steps, Smart Savings promotion, resulting in 574,555 annual kWh savings. This promotion uses the same retailer markdown model used in the Energy Efficiency Lighting program.

In 2014, Home Products Program participation decreased by 27 percent compared to 2013 participation. This is due primarily to the inclusion of clothes washers in the program through the first quarter 2013. In 2013, 20 percent of participation was due to incentives paid on 2,624 clothes washers. Idaho Power also found that purchases came from fewer stores in 2014. Some retailers, such as the Pocatello Sears, closed. However, retailers may have become less engaged when clothes washers were removed from the program.

In 2014, incentive processing was brought in-house. This decision was due in part to the removal of clothes washers from the promotion in 2013, resulting in fewer applications.

An option on the application allowed customers to donate their entire incentive to Project Share, an energy assistance partnership between Idaho Power and the Salvation Army. In 2014, Home Products Program participants donated $1,340 to this cause. The Home Products Program sent a Project Share donation thank-you card to customers who donated their incentive.

Idaho Power promoted the program to residential customers via retail store salespeople, a bill insert in July, and the Idaho Power *Connections* newsletter. Idaho Power staff promoted the program directly to customers through community events and other outreach activities. Historically, bill inserts account for about 4 to 5 percent of program enrollments. One bill insert detailing the program was mailed to all residential customers in July 2014. However, a bill insert was also sent in November 2013, which also impacted participation in 2014. As a result, 14 percent of program participants reported hearing about the program from bill inserts in 2014.

Home Products Program marketing efforts included online display ads and visual ads that pop up based on specific search behaviors, such as previous visits to Idaho Power's website or appliance-related searches. The campaign ran from September 25, 2013, through January 7, 2014, and could have influenced 2014 program participation. The campaign resulted in 771,884 impressions and 3,029 clicks for a CTR of 0.39 percent. The industry average for this type of online advertising is 0.07 to 0.10 percent.

In 2014, Idaho Power participated in the NWRRC, facilitated by NEEA, and followed the work by the WRUN. The NWRRC identifies and pursues opportunities that can best be achieved by working collaboratively in the region. WRUN is a network of western utilities, primarily serving California. Both the NWRRC and WRUN seek to develop collaborative approaches to working with manufacturers and retailers to increase the uptake of energy-efficient products in the retail market.

With WRUN, Idaho Power participated in its first upstream appliance promotion with Sears and Samsung, offering an incentive on select Samsung clothes washers. The promotion was coordinated by WRUN. Utilities such as Idaho Power were allowed to opt-in. Under the promotion, Sears and Idaho Power each offered a $50 incentive, giving the customer a $100 discount taken at the point of purchase. Sears provided utility-branded tent cards to display on qualifying units. The promotion ran from

September 12 to 26 at three Idaho Sears stores located in Boise, Twin Falls, and Pocatello. However, the Pocatello Sears store was in the process of closing during the promotion and had no sample stock available on the floor. In total, four qualifying models were sold during the promotion. While this may represent a small number of total units, the promotion allowed Idaho Power to gain valuable experience in upstream appliance promotions, including establishing contracts with a national retailer, managing in-store point-of-purchase materials, and training retail staff.

In 2014, NEEA launched the RPP. The RPP is based on the Consumer Electronics Energy Forward Initiative, which ended in 2013. The RPP uses mid-stream incentives to influence retail stocking practices, ultimately driving manufacturing and standards for a portfolio of energy-efficient products sold through the retail channel. For more information on the initiative, view the *NEEA Residential Activities in Idaho* section of this *Demand-Side Management 2014 Annual Report*.

In 2014, new federal appliance standards for refrigerators and freezers went into effect. As a result, Idaho Power began to explore new cost-effective program delivery options. Two models were explored. The first continued a mail-in incentive program, providing incentives based on a qualified products list using the Consortium for Energy Efficiency product tiers. Idaho Power also proposed an upstream model similar to the Simple Steps, Smart Savings lighting promotion. Upstream promotions can often be delivered at lower administrative costs than mail-in rebate programs.

Both program designs were presented at the EEAG August 19 meeting. After the new efficiency standards were enacted, the RTF published new deemed savings values for refrigerators and freezers. Idaho Power determined the qualified products list approach would not meet its cost-effectiveness thresholds. Idaho Power again met with EEAG November 12 and propose retiring the current measures and moving toward upstream promotions in 2015.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness UES assumptions as were used in 2013 for the refrigerators, freezers, and showerheads.

In September 2014, the federal standards for refrigerators and freezers increased 20 to 30 percent depending on the product class. The RTF discussed the impact of these federal standard changes, which raised the baseline used to calculate the electric energy savings estimates. As a result of these higher standards, the annual gross energy savings for refrigerators dropped from 29 to 21 kWh per year, and freezers dropped from 40 to 23 kWh per year. The lower alternate costs from the 2013 IRP as well as the lower savings estimates from the RTF resulted in the measures no longer being cost-effective under the mail-in incentive model. Idaho Power will continue to evaluate the cost-effectiveness of these measures under other program delivery methods that may be less expensive than the mail-in incentive model.

For detailed information for all measures within the Home Products program, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Due to program changes in 2014, a planned customer satisfaction survey was re-evaluated. As mentioned above, with the updated savings assumptions for freezers and refrigerators from the RTF and the new 2013 DSM alternative costs from the IRP, freezers and refrigerators were determined not to be cost-effective. The measures will no longer be available to customers beginning January 2015,

and the program will transition away from a mail-in incentive request format. As a result of these changes, a program satisfaction survey was not administered.

Information collected from a question on the incentive application form indicated salespeople are a proven marketing channel. Sixty-three percent of program participants that submitted an incentive application reported hearing about the program from a retail sales person. To support this channel, Idaho Power CRs visited participating retailers multiple times in 2014 to distribute program applications and discuss program requirements. Figure 13 indicates how customers heard about the program in 2014.

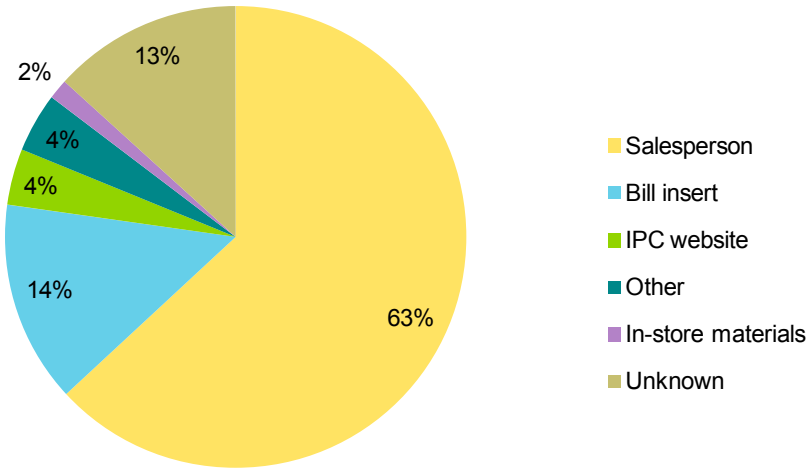


Figure 13. How customers heard about program, 2014

## 2015 Program and Marketing Strategies

Beginning January 1, 2015, Idaho Power will no longer offer incentives on refrigerators and freezers to its Idaho customers. Incentives will be paid on qualifying appliances purchased on or before Dec. 31, 2014. Beginning January 14, 2015, Idaho Power will no longer offer incentives on refrigerators and freezers to its Oregon customers. Incentives will be paid on qualifying appliances purchased on or before January 13, 2015. Applications must be received within 120 days of purchase.

In December 2014, the BPA announced changes to its Simple Steps, Smart Savings program. The program will continue to be administered by CLEAResult. BPA anticipates that clothes washers, refrigerators, and freezers will be brought into the Simple Steps, Smart Savings program beginning June 2015. Idaho Power expects to have the details of the appliance promotion at the end of first quarter of 2015 and will run the appropriate cost-effectiveness tests. If cost-effective, Idaho Power plans to opt in to the regional appliance promotion.

In 2015, Idaho Power will continue to participate in the NWRRC, follow the work by WRUN, and serve on NEEA's work group.

# Oregon Residential Weatherization

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits/projects) | 13 | 14 |
| Energy Savings (kWh) | 11,032 | 14,907 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $5,234 | $8,248 |
| Idaho Power Funds | $228 | $768 |
| Total Program Costs—All Sources | $5,462 | $9,017 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.028 | $0.035 |
| Total Resource Levelized Cost ($/kWh) | $0.050 | $0.055 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1980 | |

## *Description*

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program as required by Oregon Revised Statute (ORS) 469.633 offered under Oregon Schedule 78. Upon a customer's request, an Idaho Power CR visits the home to analyze it for energy efficiency opportunities. An estimate of costs and savings for specific measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

## *2014 Program and Marketing Activities*

During May, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. Thirteen Oregon customers responded. Each customer returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Thirteen audits and responses to customer inquiries to the program were completed, with five incentives paid.

Idaho Power issued five incentives totaling $1,614.61 for 11,032 kWh savings. Three incentives and related savings were for ceiling insulation measures. One incentive was for floor insulation, and one incentive was paid for a combination of wall and floor insulation. There were no loans made through this program during 2014.

## Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program described in Oregon Schedule 78. The cost-effectiveness of this program is defined within this schedule. Pages 3 and 4 of the schedule list the measures determined to be cost-effective and the specified measure-life cycles for specific measures. This schedule also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years.

Thirteen audits were conducted with five savings projects completed. Projects consisted of increasing attic, floor, and wall insulation. The projects combined for an annual energy savings of 11,032 kWh at a levelized TRC per kWh of 4.9 cents over the 30-year attic-insulation measure life as defined by Oregon Schedule 78.

The CEL for insulation (30-year measure life) is $1.30 per annual kWh saved. Since the actual levelized cost of energy savings for the 2014 projects was 4.9 cents from the TRC perspective, these projects are considered cost-effective.

## 2015 Program and Marketing Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective incentive and loan applications.

# Rebate Advantage

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 44 | 42 |
| Energy Savings (kWh) | 269,643 | 269,891 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $57,155 | $58,674 |
| Oregon Energy Efficiency Rider | $5,324 | $2,097 |
| Idaho Power Funds | $753 | $0 |
| Total Program Costs—All Sources | $63,231 | $60,770 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.014 | $0.014 |
| Total Resource Levelized Cost ($/kWh) | $0.020 | $0.021 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.39 | |
| Total Resource Benefit/Cost Ratio | 3.23 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

The Rebate Advantage program helps Idaho Power customers with the initial costs associated with purchasing a new, energy-efficient, ENERGY STAR® qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. The program also provides an incentive to the sales consultants to encourage more sales of ENERGY STAR qualified homes and more discussion of energy efficiency with their customers during the sales process.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured (NEEM) housing program establishes quality-control (QC) and energy efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

Idaho Power residential customers who purchased a new, all-electric, ENERGY STAR qualified manufactured home in 2014 and sited it in Idaho Power's service area were eligible for $1,000 through the Rebate Advantage program. Salespersons received $200 for each qualified home they sold.

## *2014 Program and Marketing Activities*

During 2014, Idaho Power paid 44 incentives on new manufactured homes, which accounted for 269,643 annual kWh savings. In 2014, all Rebate Advantage collateral was updated, including table-top

posters, brochures, call-out cards for inside model homes, and outdoor vinyl banners. A bill insert, shared with Energy House Calls, was sent to all Idaho and Oregon Customers in September 2014. Idaho Power tested a digital advertising campaign with this target market because according to the *2014 Manufactured Home Market Facts Report* by Foremost®, 79 percent of manufactured home residents use Facebook and 42 percent visit social media multiple times per day. A digital advertising campaign was run from December 15, 2014, to January 15, 2015. Total impressions were 541,400 with 846 clicks for a CTR of 0.16 percent. Generally, in the digital advertising industry, the average CTR is 0.07 percent to 0.10 percent.

Idaho Power continued to support dealerships in 2014 by providing them with Rebate Advantage brochures and applications as needed. CRs visited these dealerships to distribute material, promote the program, and answer salespersons' questions.

## Cost-Effectiveness

In 2014, Idaho Power used the same savings and assumptions as were used in 2013. All cost-effectiveness analyses were based on the January 2011 approval decision by the RTF. The measures remained cost-effective for 2014. The measure is currently under review, and the RTF extended the sunset date for the measure until March 2015. For details, see *Supplement 1: Cost-Effectiveness*.

## 2015 Program and Marketing Strategies

Customers who purchase a new, all-electric, ENERGY STAR qualified manufactured home in 2015 and site it in Idaho Power's service area will continue to be eligible for $1,000. Salespersons will continue to receive a $200 incentive for each qualified home they sell.

In 2015, Idaho Power intends to continue the digital advertising due to a very solid response in 2014. Two informational bill inserts are planned for 2015. The first one will be distributed in February, and the second distributed in the fall. An informational direct-mail letter will be sent to manufactured home dealerships in August. In addition, targeted direct online ads will be placed. Program collateral will be updated throughout 2015 as needed.

# See ya later, refrigerator®

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (refrigerators/freezers) | 3,194 | 3,307 |
| Energy Savings (kWh) | 1,390,760 | 1,442,344 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $562,002 | $571,304 |
| Oregon Energy Efficiency Rider | $12,410 | $17,750 |
| Idaho Power Funds | $1,639 | $0 |
| Total Program Costs—All Sources | $576,051 | $589,054 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.062 | $0.061 |
| Total Resource Levelized Cost ($/kWh) | $0.062 | $0.061 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.86 | |
| Total Resource Benefit/Cost Ratio | 0.86 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

The See ya later, refrigerator® program acquires energy savings through the removal of qualified refrigerators and stand-alone freezers in residential homes throughout Idaho Power's service area.

Idaho Power contracts with JACO to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Marketing assistance is provided by JACO through Runyon Saltzman Einhorn (RSE). RSE is a marketing company that assists utility appliance recycling programs throughout the country. Idaho Power provides participant confirmation, additional marketing, and internal program administration.

Applicants enroll online or by phone. Idaho Power screens each applicant to confirm eligibility. JACO screens each applicant to confirm the refrigerator or freezer unit under consideration meets all program eligibility requirements, including being residential-grade, a minimum of 10 cubic feet ($ft^3$) as measured using inside dimensions, no larger than 30 $ft^3$, and in working condition. Customers receive a $30 incentive check mailed after the removal of the unit. The program targets older, extra units for maximum savings.

## *2014 Program and Marketing Activities*

The program reclaimed or recycled up to 95 percent of the components of each unit collected. In 2014, this amounted to more than 435,000 pounds of materials. Reclaimed materials may include oils or refrigerants that can be distilled and reused. See ya later, refrigerator® program participation declined by

3 percent between 2013 and 2014. This represents the natural ebb and flow of programs, demonstrated in Figure 14.

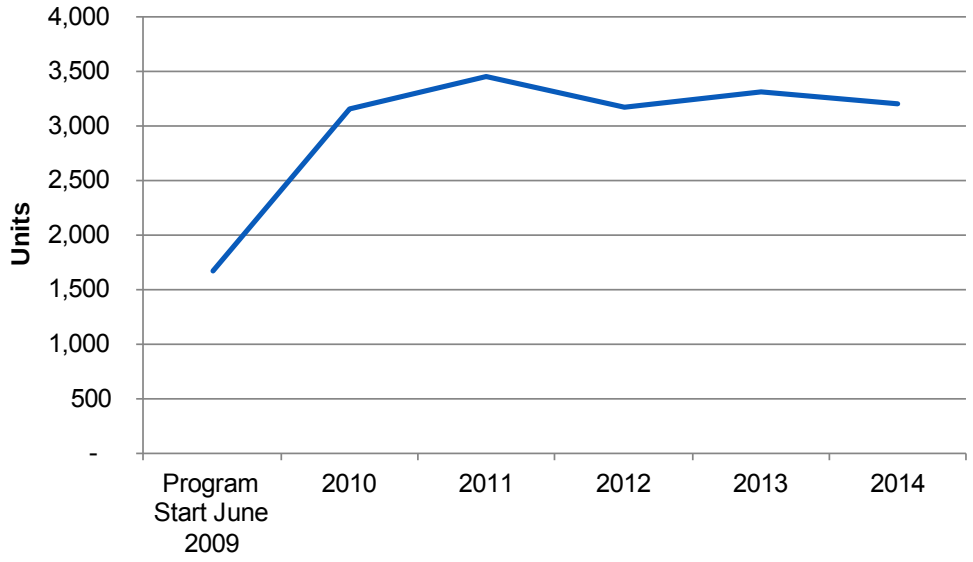


Figure 14. See ya later, refrigerator® participation by year June 2009

Idaho Power continued to offer See ya later, refrigerator® participants the option to receive their $30 incentive or donate it to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army that helps customers who need help paying for energy services, including fuel bills and furnace repairs. In 2014, over 4 percent of Idaho Power's See ya later, refrigerator® participants chose this option, raising $4,230 for Project Share.

Idaho Power used an integrated, layered approach to market the program in 2014. All marketing tactics in 2014 used like imagery and messaging to build awareness and recognition. The messaging focused on convenience. Survey data showed 52 percent of participants reported they received the most value from the convenience of the program. Idaho Power and RSE used bill inserts, newspaper advertising, radio, direct mail, and earned media through two television spots to promote the program.

Bill inserts were sent during February, March, April, June, July, August, and October. In late May, a direct-mail postcard was sent to a highly targeted audience. The target audience for the program has been identified as older, empty-nesters who own their home. The mailing was sent to higher energy users and longer-term customers of Idaho Power that were likely to represent the target audience. The direct-mail had a response rate of approximately 1 percent. Program cards were included in energy-kits given to low-income customers.

Awareness tactics, such as radio and newspaper ads, ran from April through August. Handheld fans with program information were distributed at summer events, including several county fairs. In July, Idaho Power representatives and JACO staff appeared in live television broadcasts in the Twin Falls and Pocatello/Idaho Falls markets promoting the program and demonstrating how materials from refrigerators can be recycled and reused.

RSE managed a nine-month online Google AdWords™ campaign. Google AdWords™ brings up an ad based on specific combinations of search terms. The campaign resulted in 8,497 impressions and a CTR of nearly 6 percent.

## Cost-Effectiveness

Idaho Power used the same savings and other cost-effective assumptions for the 2014 reporting year as were used in 2013. However, with the implementation of acknowledged 2013 IRP avoided costs, the program measures for both decommissioning freezers and refrigerators became not cost-effective in 2014 from the UC and TRC perspectives. For details and program assumptions, see *Supplement 1: Cost-Effectiveness*.

Looking forward, the company evaluated different program options to increase the program's cost-effectiveness for 2015. Two options explored included restricting the ages of qualifying units and changing incentive levels. At the August 19 and November 12, 2014, EEAG meetings, Idaho Power discussed proposed program changes for 2015.

For cost-effective details and assumptions, see *Supplement 1: Cost-Effectiveness.*

## Customer Satisfaction and Evaluations

No formal evaluations were conducted in 2014 for this program. However, JACO tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2014 unit data showed that 21 percent of units the program picked up were stand-alone freezers, and 79 percent of the units were refrigerators. Fifty-eight percent of the units were secondary, 29 percent were primary, and 13 percent were unknown. In 2014, 50 percent of the units collected were manufactured from 1965 to 1990, which generally represents the least efficient years of refrigerator manufacturing. By comparison, in 2013, 55 percent of the units were of this vintage.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 49 percent of customers learned of the program through bill inserts. Nineteen percent of customers learned of the program through a friend or neighbor. Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because the program focuses on the removal of secondary units rather than replacing existing units. Retailers sell new units to replace older units. In addition, a retailer selling a new unit will usually pick up and recycle the old one.

Seventy percent of customers who enrolled used the toll-free telephone number, and 30 percent used the online enrollment form. Idaho Power uses the customer information JACO collects and the surveys from Idaho Power evaluations to target future marketing efforts and increase the effectiveness of marketing.

Figure 15 indicates ways customers heard about the program. The Other category includes sources, such as community events, repeat customers, the truck wrap ad, and unknown sources.

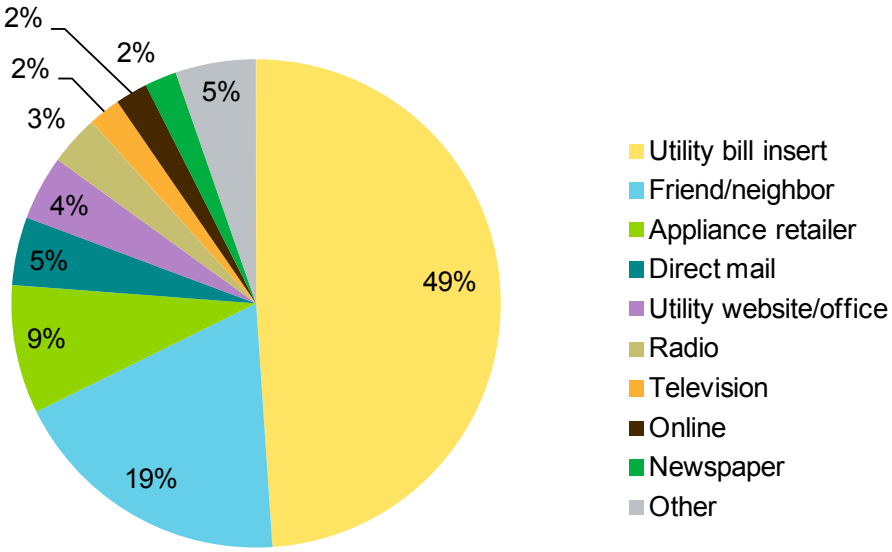


Figure 15. How customers heard about See ya later, refrigerator®

## 2015 Program and Marketing Strategies

Idaho Power will contract with JACO to provide services in 2015. To increase program cost-effectiveness, starting February 1, Idaho Power will no longer offer participants a $30 incentive for participating.

Marketing tactics in 2015 will include six bill inserts. The truck that picks up the refrigerators will continue to display a truck wrap—a large Idaho Power See ya later, refrigerator® ad—on its side. The truck wrap will be redesigned in January. This low-cost marketing tactic is expected to account for about 1 percent of program participation. Program information will continue to be included in over 2,000 energy kits distributed to low-income customers. The program will be promoted at community events and by Idaho Power's CRs. Idaho Power will also focus on online marketing tactics, including promotional advertising on Idaho Power's website, Facebook postings, and Google AdWords.

# Shade Tree Project

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 2,041 | 220 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $143,750 | n/a |
| Oregon Energy Efficiency Rider | $66 | n/a |
| Idaho Power Funds | $3,474 | n/a |
| Total Program Costs—All Sources | $147,290 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2013 | |

## *Description*

The Shade Tree Project began as a pilot in 2013. According to the US Department of Energy (DOE), a well-placed shade tree can reduce energy used for summer cooling by 15 percent or more. Utility programs throughout the country report high customer satisfaction with shade-tree programs and an enhanced public image for the utility related to sustainability and environmental stewardship. Other utilities report energy savings between 40 kWh per year (coastal climate San Diego) and over 200 kWh per year (Phoenix) per tree planted.

To be successful, trees should be planted to maximize energy savings and ensure survivability. Two developments in urban forestry—the state-sponsored Treasure Valley Urban Tree Canopy Assessment and the Arbor Day Foundation's Energy Saving Trees tool—provided Idaho Power with the tools to develop a shade tree project.

The Shade Tree Project was launched in Ada and Canyon counties, offering free shade trees to residential customers. Participants enroll using the online Energy Saving Trees Tool and pick up their tree at specific events. In the fall 2013 pilot, 220 trees were distributed to residential customers.

In 2014, the Shade Tree Project expanded. Idaho Power distributed 2,041 shade trees to residential customers.

## *2014 Program and Marketing Activities*

The best time to plant shade trees is in the spring and fall. Therefore, Idaho Power held two offerings in 2014. The spring shade tree offering was held in April 2014 and resulted in 1,058 trees distributed. The fall offering was held in October, and 983 trees were distributed.

Trees were purchased from regional growers in advance of each event. Species offered depended on availability at time of purchase. Idaho Power worked with its own arborists, along with city and state arborists, to select a range of tall growing, deciduous trees that should work well with the climate and soils of the two counties.

Idaho Power used direct mail to market this program in 2014 and used the state-sponsored Treasure Valley Urban Tree Canopy Assessment to develop a mailing list. The assessment is a geographic information system (GIS)-based study that mapped land use throughout the Treasure Valley including existing trees and vegetation, buildings, roads, waterways, and parking lots. The study identified areas where a tree can be planted and if that tree can be a large-growing shade tree. Idaho Power used the study to identify potential planting sites on residential properties situated to the west of the home. The mailing list was created from the results.

To enroll, customers accessed an online Energy Saving Trees Tool developed by the Arbor Day Foundation. Using this tool, participants mapped their home, selected from a list of available trees, and evaluated the potential energy savings associated with planting in different locations. During enrollment, participants learned how trees planted to the west and east save more energy over time than trees planted to the south and north. In 2014, customers could reserve up to two trees.

Participants picked up their tree at prescheduled events held throughout the Treasure Valley. Four pickup events were held in the spring and three in the fall, conducted on different days at different locations. By offering several pickup days, locations, and times, about 90 percent of participants enrolled and picked up their tree.

Ensuring the tree is planted properly helps it grow to provide maximum energy savings. At the tree pickup events, participants received additional education on where to plant trees for maximum energy savings and other tree care guidance from experts. Local specialists included city arborists from Boise, Kuna, Nampa, and Meridian; Idaho Power utility arborists; Canyon County master gardeners; and College of Western Idaho (CWI) horticulture students.

## *Customer Satisfaction and Evaluations*

In early 2014, a survey was emailed to 205 customers that participated in the first Shade Tree Project offering in fall 2013. The response rate was just over 63 percent with 130 respondents. Survey participants were asked, “How likely would you be to recommend Idaho Power’s Shade Tree Project to a friend or relative?” Just over 89 percent indicated they “definitely would” and just over 10 percent indicated they “probably would.” After reviewing these survey results, the survey was revised to remove questions with little value and to capture additional information from participants. The revised survey was sent in summer 2014 to 577 customers that participated in the spring 2014 offering. The response rate was nearly 61 percent with 351 respondents. When asked how much they would agree or disagree with statements about the Shade Tree Project, just over 95 percent of respondents “strongly agreed” and just over 4 percent “somewhat agreed” they would recommend the project to a friend or family. Nearly 93 percent indicated they “strongly agreed” and just over 6 percent “somewhat agreed” they were satisfied with their overall experience with the Shade Tree Project.

In 2014, the Customer Research and Analysis team administered a process evaluation contracting with Johnson Consulting Group for analysis. The findings from the process evaluation were, overall, the Shade Tree Project is well designed and well managed. Key findings and recommendations from the evaluation, along with Idaho Power’s responses, are described below.

The evaluators found Idaho Power successfully leveraged industry best practices to design and develop the Shade Tree Project. Program design was developed by combining internal resources from a diverse group of Idaho Power staff with input from critical external stakeholders involved in urban forestry projects throughout the region.

Evaluators indicated Idaho Power staff are responsive and flexible and have adapted this project based on both experience and customer feedback. The staff continues to refine the program delivery model, increasing the number of trees offered to customers and improving the program marketing and educational materials. In addition, the Shade Tree Project delivery strategy is consistent with the industry best practices for shade tree programs.

Johnson Consulting Group determined the online program enrollment was quick and easy. Citing Idaho Power's survey of program participants, nearly two-thirds, 60 percent, of the survey respondents were able to enroll in the program in ten minutes or less. Nearly three quarters, 72 percent, of survey respondents found the online enrollment tool very easy to use. Overall, the participants reported high satisfaction rates for the Shade Tree Project and were very satisfied with both the planting care and education they received at the distribution events.

Johnson Consulting Group noted a few respondents were dissatisfied with the quality of the trees provided. Upon further review, Idaho Power found that the comments around quality of tree related to the size of the tree. Trees came in 3- to 5-gallon containers and ranged in size from approximately 4 to 10 feet. The trees were sized so participants could safely transport and plant the trees. To address this concern, information on tree size was added to the direct-mail letter and main program landing webpage to help set participant expectations.

Based on the process evaluation findings, the Johnson Consulting Group evaluation team developed the following recommendations to improve program operations.

They recommended Idaho Power staff should standardize the current program evaluation questionnaires to allow for consistent feedback and tracking across all program events. This includes asking questions to all customers to assess satisfaction, determining the actual planting locations for all trees provided, and exploring more fully the reasons for participation.

Idaho Power agrees with this recommendation and plans to use a consistent survey starting in 2015. The company ran a small Shade Tree pilot in 2013 and issued a survey to all participants. After that survey, some small modifications were made to the survey questions with the intent of clarifying questions to obtain better data and seeking new information that would be relevant to a larger program design. Idaho Power will issue a third survey in early 2015 to capture participant feedback from the fall 2014 offering and will again refine a few questions based on specific feedback from Johnson Consulting Group. Specifically, the survey was designed in 2013 around one tree per participant. In 2014, the program was expanded to allow two trees per participant. Survey questions were adjusted for this program change. The company does not anticipate any future survey modifications but will maintain the flexibility to ensure the survey captures the data needed to manage and improve the program.

Johnson Consulting Group recommended Idaho Power staff develop a pre-screening tool to maximize energy savings potential at the initial application stage. The evaluator stated given both the survey responses and the experience with other shade tree programs, Idaho Power staff should try to maximize energy savings at the initial screening by incorporating the strategies used by other shade tree programs, such as pre-screening for customers who do not intend to plant trees with western, northwestern,

or southwestern orientation. The evaluator suggested Idaho Power staff should also assess actual free ridership rates through customer surveys in future program evaluations.

While Idaho Power agrees it is important to maximize energy savings and has taken several steps throughout the program design to do so, the company looked at other shade tree programs and has not yet found a pre-screening solution that would result in west planting locations that does not increase the cost of the project. Programs that require specific planting locations conduct one or more site visits to each participant's home and/or plant the tree for customers. For example, the Sacramento Municipal Utility District's program conducts up to three site visits—one to determine proper placement; one to deliver trees; and, for some customers, a third visit to verify planting.

Idaho Power also has concerns that a screening question at the time of enrollment alone may not lead to the desired results. Without site verification at the time of tree delivery and planting, it would be difficult to verify customers would answer a screening question truthfully.

Idaho Power uses many methods to encourage customers to plant in the most optimum location for energy efficiency. First, the program is marketed to those customers identified using the urban tree canopy assessment as having a western planting location. Messaging throughout the program includes the phrase *West is Best*. The enrollment tool uses community-based social marketing techniques, including interactive feedback, commitments, and prompts to promote western planting locations.

Second, although western planting locations result in maximum energy savings, significant savings can occur to the east and some, albeit less, savings can be achieved planting to the south and north. Idaho Power will continue to look for opportunities to maximize energy savings and promote plantings to the west of the home. The company will continue to monitor other shade tree programs and delivery models for best practices to minimize free ridership and maximize energy savings.

Johnson Consulting Group recommended Idaho Power staff should implement a QA/QC process to provide ongoing tracking of the distributed trees and that this QA/QC process should include follow up with all program participants via a customer survey and a sample of on-site visits to verify planting orientation and tree health. The evaluator noted the QA/QC process can also help to provide more accurate estimates of actual tree planting locations and therefore provide a more accurate estimate of overall program effectiveness.

Idaho Power agrees with this recommendation and currently has QA/QC procedures in place. The company follows up with all participants through an online survey after the each offering. In 2015, Idaho Power plans to conduct site visits to a subset of participant homes to measure tree planting location, planting quality, and tree health.

Two of the evaluators' recommendations regarded data collection. First, according to Johnson Consulting Group, the Shade Tree Project should develop a standard database that consistently tracks the disposition of trees and key program metrics in a standard manner. The evaluator stated that as this program evolves from a pilot to a full-scale program, it is critical to develop a standardized program tracking tool that tracks key program milestones, customer feedback, and electric and non-electric savings and allows easy comparison between offerings.

Second, Johnson Consulting Group also recommended Idaho Power staff should try to quantify the non-electric benefits associated with this program as a way to enhance its overall cost-effectiveness. The evaluator noted the technical assessments included detailed models demonstrating the significant non-electric benefits that shade tree programs provide and Idaho Power staff should leverage this

information and include the quantification of program non-electric benefits attributed to this project, including reductions in carbon emissions, carbon sequestration, and other benefits quantified in the US Forest Service (USFS) i-Tree™ model.

In regard to these two recommendations, Idaho Power continues to build upon prior work to move toward the evaluators' recommendation around data in the following manner. Idaho Power has captured program metrics for each offering, including customer data, tree type, tree planting location, marketing tactics, event pickup location, and enrollment date, as well as 20-year energy benefits (as determined by the model). In 2014, Idaho Power worked with the Arbor Day Foundation to create additional reports for each offering to track energy savings and environmental benefits. The Arbor Day tool is based on the i-Tree model, in which benefits for each tree distributed are calculated based on species and planting location. Benefits are forecasted for years 5, 10, 15, and 20. Environmental benefits include carbon benefits per pound, storm water runoff mitigated per gallon, and air pollutants per pound. Once these reports were finalized in fall 2014, Idaho Power merged the data with the other program metrics to create a central tracking system. In 2015, Idaho Power will create a data dictionary—describing each term and field used—for this database and will continue to add results from each offering going forward.

## 2015 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2015, using the Arbor Day enrollment tool and events to distribute the trees. Idaho Power will continue to market the program by direct mail and focus on customers identified using the urban tree-canopy assessment. In addition, Idaho Power maintains a waiting list of customers that either heard about the program through a friend or relative or did not enroll in the fall offering before it subscribed. Idaho Power will reach out to these customers through direct mail or email. Should enrollment response rates not be as successful as past years, Idaho Power will consider targeted advertising on Facebook.

This project relies on strong partnerships with the cities, counties, CWI, and others. These groups provide guidance on tree selection and donate volunteer hours. Together, Idaho Power, local arborists and others interested in green infrastructure have formed the Treasure Valley Canopy Network (Network) to enhance the region's urban forest. The Network, through the Southwest Resource Conservation and Development and Idaho State Department of Lands, received a Western Competitive States Grant through the USFS. The grant proposal was the top ranked proposal submitted. Grant funds will be used to support urban tree planting for energy savings, develop local resources for tree procurement and storage, and develop additional educational materials. In 2015, the grant funds will offset some Idaho Power costs and allow Idaho Power to explore ways to procure trees locally at a lower cost. It will also be used to sustain the partnerships needed for this project.

Idaho Power will continue to collect metrics to evaluate program success and effectiveness. A survey will be sent in early 2015 to the fall 2014 participants. A survey will be sent to participants in the spring and fall 2015 offerings. In summer 2015, Idaho Power will conduct site visits to a statistically valid sample of past participant homes to confirm planting location and evaluate tree planting quality and tree health. This data will help inform assumptions used to evaluate energy savings from this program. Idaho Power is collecting data to evaluate energy savings from this project. With the available costs and savings assumptions, shade trees were added as a measure in the 2014 potential study that was prepared for the 2015 IRP. Based on currently planned tree distributions, it was estimated that just over 5 million kWh could be saved over 20 years.

# Weatherization Assistance for Qualified Customers

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 255 | 254 |
| Energy Savings (kWh) | 533,800 | 681,736 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,320,112 | $1,391,677 |
| Total Program Costs—All Sources | $1,320,112 | $1,391,677 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.149 | $0.125 |
| Total Resource Levelized Cost ($/kWh) | $0.225 | $0.184 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.51 | |
| Total Resource Benefit/Cost Ratio | 0.42 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

## *Description*

The WAQC program provides funding to install weatherization measures in qualified, owner-occupied and rental homes that are electrically heated. In 2014, qualified households included those with incomes up to 200 percent of the federal poverty-level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house non-profit organizations who serve special-needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the CAP agencies to administer the WAQC program in its service area.

WAQC is modeled after the DOE weatherization program. The DOE program is managed through the Idaho Department of Health and Welfare (IDHW) in Idaho and by the Oregon Housing and Community Services (OHCS) in Oregon. Federal funds are allocated to the IDHW and OHCS, then to CAP agencies based on US Census data of population and poverty levels within each CAP agency's geographic area. The CAP agencies serve as the administrators of the state Weatherization Assistance Program (WAP) and oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. The WAQC funding provided by Idaho Power allows these state agencies to leverage their federal weatherization dollars and serve more Idaho Power customers who heat their homes with electricity by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, and pipes;

furnace tune-ups, modification, and replacement; and the installation of CFL bulbs. The Idaho WAP calculates savings with the EA5 energy audit program (EA5). Consistent with the Idaho WAP, WAQC offers several measures that have costs but do not save energy or for which savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a household's existing indoor air quality. Other non-energy-saving measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, and pipes; furnace tune-ups, modification, and replacement; and the installation of CFL bulbs. Non-profit building measures that have costs but do not save energy or for which savings cannot be measured are health and safety, vents, furnace repair, and energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2013 Annual Report*, dated April 1, 2014, located in *Supplement 2: Evaluation*. The new *Weatherization Assistance for Qualified Customers 2014 Annual Report* will be filed on April 1, 2015.

## 2014 Program and Marketing Activities

During 2014, CAP agencies weatherized 239 electrically heated homes in Idaho and 11 in Oregon, totaling 250 weatherized homes. Five Idaho buildings housing non-profit organizations that serve special-needs populations were also weatherized in 2014.

Idaho Power continued the focus on addressing recommendations from a 2012 impact evaluation conducted by D&R International and a 2013 process evaluation conducted by Johnson Consulting. A contract was signed with Kearns ENTerprises™ to develop a Home Audit tool to be used in Idaho Power's Weatherization Solutions for Eligible Customers program starting in 2015. The updated tool was designed to capture key data and more details regarding measures installed for health and safety. Updated calculations for estimates of energy savings and measure information to more accurately report program effectiveness were built into the program. The new WxSol Home Audit Tool (HAT 14.1) was distributed in January 2015 to contractors participating in the Weatherization Solutions for Eligible Customers program and will be tested throughout 2015 in that program. The WAQC program will use the tool if the state adopts it.

In January 2014, in Oregon, Idaho Power moved funds from the non-profit pooled fund to the fund used to weatherize homes of electrically-heated qualified customers. This funding shift allowed additional funds to be spent on home efficiency improvements of qualified customers in Oregon.

Idaho Power marketed WAQC throughout 2014 at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions to reach customers who may benefit from the program. Marketing for this program was conducted in cooperation with weatherization managers. Working with the CCOA—Aging, Weatherization and Human Services (CCOA), a Weiser project was identified to be featured in an internal *eNews* video. Once produced, it was released on YouTube and promoted through social media in October.

## Cost-Effectiveness

The WAQC program has been proven to provide real and substantial per-home savings, but due to the costs of comprehensive whole-house weatherization, the program remains not cost-effective from either a UC or TRC perspective. In 2014, additional billing analysis was conducted on 2012 participants' billing data. This analysis was based on a recommendation from the 2012 impact evaluation conducted by D&R International. The evaluation recommended using a control group to account for non-weather related changes in energy use not attributable to the program's weatherization measures. The 2012 impact evaluation performed a billing analysis on 2011 projects. The average realized annual savings in all housing types was 2,684 kWh per home. For the update billing analysis, Idaho Power wanted to know if savings could be further differentiated between housing stock (single family versus manufactured home), occupant size, heating footprint of the home, and the number of occupants in the home. All billing analysis and data preparation was done in accordance with the *Whole-building Retrofit with Consumption Data Analysis Evaluation Protocol* document published in April 2013 by the DOE (energy.gov/eere/about-us/ump-protocols).

Analysis results showed that manufactured home savings per home were similar to the previous 2012 evaluation results at 2,568 kWh per year. Single-family homes, when analyzed independently from manufactured homes, revealed fewer savings than the 2012 evaluation results at 1,551 kWh per year per home. The effects of further segregating savings analyses by the heating footprint of the home, number of occupants, and climate was shown not to be statistically significant. Idaho Power plans to continue to monitor savings from this program through further billing analyses. Additionally, the RTF contract staff is analyzing manufactured home audit data from 2011 to 2012 that will provide useful insights into how to potentially incorporate the measure-level audit data into future billing analyses.

To analyze program cost-effectiveness, the recommendations from IPUC staff's report and IPUC Order No. 32788 are used for cost-effectiveness analysis for 2014. For further details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power used two independent, third-party verification companies to randomly check approximately 10 percent of weatherization jobs submitted for payment by the program. These verifiers discussed the program with participating customers and confirmed installed measures in their homes. Home verifiers visited 43 homes for feedback about the program. When customers were asked how much they learned about saving electricity, 32, or over 74 percent, answered they learned "a lot" or "some." When asked about how many ways they tried to save electricity, 34, or approximately 79 percent, responded "a lot" or "some."

As recommended by Johnson Consulting Group in a 2013 process evaluation, a new customer survey was developed to assess major indicators of customer satisfaction and program operations consistently throughout the service area. The 2014 Weatherization Programs Customer Survey was provided to all WAQC participants in all regions upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely. Demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 237 of the 250 households weatherized by the program in 2014. Of the 237 surveys received back from customers, 228 were from Idaho customers and 9 were from Oregon customers. Some key highlights include the following:

- Over 47 percent of respondents learned of the program from a friend or relative, and another almost 15 percent learned of the program from an agency flyer. Nearly 6 percent learned about the weatherization program by receiving a letter in the mail.

- Almost 90 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, and over 45 percent wanted to improve the comfort of their home.

- Almost 74 percent reported they learned how air leaks affect energy usage, and just over 65 percent indicated they learned how insulation affects energy usage during the weatherization process. Another almost 57 percent of respondents said they learned how to use energy wisely.

- Over 79 percent reported they were very likely to change habits to save energy, and almost 80 percent reported they have shared all the information about energy use with members of their household.

- Over 86 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 94 percent said they were very satisfied with the program.

- Over 86 percent of the respondents reported that the habit they were most likely to change was turning off lights when not in use, and over 61 percent said that washing full loads of clothes was a habit they were likely to change to save energy. Turning the thermostat up in the summer was reported by nearly 51 percent, and turning the thermostat down in the winter was reported by almost 58 percent as a habit they and members of the household were most likely to change to save energy.

A summary of the report is included in *Supplement 2: Evaluation*.

Idaho Power participates in the Idaho state monitoring process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and IDHW reviewing homes weatherized by each of the CAP agencies. Results of the state monitoring review show all CAP-agency weatherization departments are weatherizing in accordance with federal guidelines.

Additionally, the DOE audits state agencies each year. The DOE audits include field work, paperwork, and billing audits, which show that the Idaho WAP and therefore, WAQC, is in compliance with DOE standards.

## 2015 Program and Marketing Strategies

WAQC will continue using DOE guidelines and leveraging each weatherization job with state WAP funding on each job. The budget and projected number of jobs for 2015 will remain the same as 2014.

Idaho Power will continue working in partnership with the IDHW, OHCS, CAPAI, and individual CAP agency personnel to maintain the targets and guidelines and improve the cost-effectiveness of the WAQC program.

Idaho Power will continue involvement with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho.

The company plans to continue to selectively market WAQC throughout 2015. The program will be promoted at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions to reach customers who may benefit from the program. Marketing for this program will be conducted in cooperation with weatherization managers.

# Weatherization Solutions for Eligible Customers

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 118 | 166 |
| Energy Savings (kWh) | 290,926 | 303,116 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $757,748 | $1,239,132 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $33,596 | $28,659 |
| Total Program Costs—All Sources | $791,344 | $1,267,791 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.163 | $0.256 |
| Total Resource Levelized Cost ($/kWh) | $0.163 | $0.256 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.46 | |
| Total Resource Benefit/Cost Ratio | 0.50 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are below poverty level, at poverty level, or slightly above poverty level. The program is designed to mirror WAQC. Potential participants are interviewed by the contractor to determine household eligibility as well as ensure the home is electrically heated. If the home is eligible, an auditor inspects the home to determine what energy-saving upgrades will save energy, improve indoor air quality, and increase comfort for the residents. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a savings-to-investment ratio (SIR) of 1.0 or higher. The amount spent on each home is limited to an annual average of Idaho Power's portion of the cost per home. Homes considered for this program are electrically heated and either owned or rented. If rented, the landlord's permission is needed to perform the upgrades, along with an agreement to maintain the unit's current rent for a minimum of one year.

Idaho customers eligible for this program have earned incomes between 175 percent and 250 percent of the federal poverty level. These customers typically do not have expendable income to participate in other residential energy efficiency programs, and they live in similar housing as WAQC customers.

## *2014 Program and Marketing Activities*

The program served customers in Idaho Power's service area in Idaho, including Canyon, Southern, and Capital regions, as well as most of the Eastern region. In 2014, the program participation decreased from 166 in 2013 to 118 in 2014. This was due to some challenges in finding income-eligible customers in portions of Idaho Power's service area. Income guidelines overlap between the Weatherization Solutions

for Eligible Customers program and WAQC, therefore some of those eligible customers were served by WAQC. Additionally, reliance on word-of-mouth communication between prior customers and potential customers, which was a helpful method in the past, was less effective in 2014. Future marketing activities will be increased by Idaho Power and weatherization managers to locate more customers eligible to participate in the Weatherization Solutions for Eligible Customers program.

Table 10 shows the number of jobs and costs associated with measures installed in homes (production costs). Also shown are job average costs and total payments to contractors for the year.

Table 10. 2014 weatherization solutions financial breakdown

| Contractor | Number of Jobs | Production Costs | Average Job Cost | Administrative Payment to Contractor | Total Payment |
|---|---|---|---|---|---|
| Energy Zone | 55 | $ 317,757 | $ 5,777 | $ 31,776 | $ 349,533 |
| Home Energy Management | 35 | 185,276 | 5,294 | 18,528 | 203,803 |
| Power Savers | 23 | 130,176 | 5,660 | 13,018 | 143,194 |
| Savings Around Power | 5 | 28,994 | 5,799 | 2,899 | 31,894 |
| **Total** | **118** | **$ 662,204** | **$ 5,612** | **$ 66,220** | **$ 728,424** |

**Note:** Average Job Cost calculations based on the direct cost of installed measures without the administrative payment.

In response to the 2012 impact evaluation and the 2013 process evaluation, Idaho Power contracted with an outside programmer to complete a new home audit tool for use in the program. Throughout 2014, Idaho Power staff worked with Kearns ENTerprises™ to incorporate the evaluation recommendations into an audit tool for use in 2015. In January 2015, the new tool, WxSol Home Audit Tool (HAT 14.1), was distributed to the four program contractors for use in 2015.

Updates in the audit tool include more specific housing types, the most current measure life of individual measures, and an updated chart of heating degree days. LED lighting was added to the CFL measure to incorporate new bulbs and associated savings. A health and safety menu was included to better capture non-energy saving upgrades necessary to the weatherization process and to further research and quantify NEBs of the program. A percentage limit was programmed for contractor support costs on each measure, and a 10-percent funding participation mandate was added for landlords when a home is not owner occupied. The refrigerator replacement measure was updated to reflect more accurate savings.

In 2014, Idaho Power contracted with the University of Idaho IDL to develop a Weatherization HVAC Replacement Savings Calculator that is interactive with each measure upgraded in a home that receives a new HVAC system. This tool is expected to be completed in early 2015, and Idaho Power will use it to compare savings reported by the new WxSol Home Audit Tool (HAT 14.1) in anticipation of improving the accuracy of savings being reported by the program.

Marketing approaches in 2014 included a newsletter, bill inserts, and ads. For example, an energy efficiency edition of the *Connections* customer newsletter was in the February bill; a bill insert was added in April and September mailings, an ad ran in *Idaho Senior News*, and a three-day ad ran in the *Idaho State Journal*.

Contractor personnel left flyers with previous participants to spread information about the program to families and friends who might be eligible. Word-of-mouth continued to be a helpful marketing tool for the program in 2014. Several articles about the program were featured in various local publications. The program was promoted at Idaho Power and CAP agency outreach booths and resource fairs.

One of the target customer groups for Idaho Power's Weatherization Solutions program is seniors. To more directly focus on this customer group, information about the program was emailed to a number of resources used by seniors. This resulted in an assisted living provider with facilities throughout southern Idaho supplying program information in their monthly newsletter to residents, families, business partners, and healthcare providers. A health/hospice program included Idaho Power program information in their newsletter emailed to professionals/resources that work with senior citizens. Idaho Power placed print ads in the *Idaho State Journal* in October to promote program participation in eastern Idaho.

## Cost-Effectiveness

The billing analysis conducted in 2014 by Idaho Power on 2012 projects showed higher savings over the results published in the 2012 impact evaluation conducted by D&R International. However, due to the costs of comprehensive whole-house weatherization, the program remains not cost-effective from either a UC or TRC perspective. In 2014, Idaho Power conducted an additional billing analysis on 2012 participants. The company applied the recommendation from the 2012 impact evaluation by using a control group to account for non-weather related changes in energy use not attributable to the program's weatherization measures. The 2012 impact evaluation performed a billing analysis on 2011 projects. The average realized annual savings in all housing types was 1,826 kWh per home. For the update billing analysis, Idaho Power wanted to know if savings could be further differentiated between housing stock (single family versus manufactured home), occupant size, heating footprint of the home, and the number of occupants in the home. All billing analysis and data preparation was done in accordance with the *Whole-building Retrofit with Consumption Data Analysis Evaluation Protocol* document published in April 2013 by the DOE (energy.gov/eere/about-us/ump-protocols).

Analysis results showed that manufactured homes savings per home exceeded the previous 2012 evaluation results at 3,426 kWh per year. Single-family homes, when analyzed independently from manufactured homes, revealed higher savings than the 2012 evaluation results at 2,108 kWh per year per home. The effects of further segregating savings analyses by heating footprint of the home, number of occupants, and climate was shown not to be statistically significant.

To analyze program cost-effectiveness, the recommendations from IPUC staff's report and IPUC Order No. 32788 are used for cost-effectiveness analyses for 2014. For further details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Two independent companies continued to perform random verifications of weatherized homes and visit with customers about the program. In 2014, 28 homes were verified, and 21, or 75 percent, of those customers reported they learned "a lot" or "some" about using energy wisely in their home. Twenty-six, or 93 percent, reported they had tried "a lot" or "some" ways to save energy in their home.

As recommended by Johnson Consulting Group in the 2013 process evaluation, a new customer survey was developed to consistently assess major indicators of customers' satisfaction and program operations throughout the service area. The 2014 Weatherization Programs Customer Survey was provided to all program participants in all regions on completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely. Demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 115 of the 118 households weatherized by the program in 2014. Some key highlights include the following:

- Almost 34 percent of respondents learned of the program through a letter in the mail and another almost 26 percent learned of the program from a friend or relative.
- Over 84 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills.
- Just over 70 percent indicated they learned how insulation affects energy usage during the weatherization process, and 68 percent reported they learned how air leaks affect energy usage. Another almost 61 percent of respondents said they learned how to use energy wisely.
- Over 68 percent reported they were very likely to change habits to save energy, and almost 65 percent reported they have shared all of the information about energy use with members of their household.
- Almost 89 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 96 percent said they were very satisfied with the program.

A summary of the report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Contractors will use the new WxSol Home Audit Tool (HAT 14.1) throughout 2015.
The Weatherization HVAC Replacement Savings Calculator developed by the IDL will be used to compare energy savings of the WxSol Home Audit Tool (HAT 14.1) when an HVAC system is upgraded in a home. As recommended in former program evaluations, the new calculator will provide more accurate savings estimates for the program.

In 2015, marketing plans include emails, ads, bill inserts, and distribution of the program brochures. Targeting various customer segments with bill insert and direct mailings has been helpful in the past in increasing program participation and will be used in 2015. A printed bill message is scheduled for May, and bill inserts will go out in February and again in the fall. Webpages for the Weatherization Solutions for Eligible Customers program will be refreshed during the coming year.

Idaho Power will create a program brochure and provide it to contractors for use in their individual regional marketing campaigns. Idaho Power will mail a letter to customers in April, July, and September whose energy consumption indicates electrically heated homes. The program will be promoted at senior centers and resource and energy fairs throughout the year, and a redesign of the energy efficiency pages of the Idaho Power website is scheduled.

Publications dedicated and directed to senior readers that have not been used in the past will be used in 2015. *Senior Goldmine* is a monthly publication delivered to 10 senior centers and over 100 other locations in the Treasure Valley. It is also hand-delivered to over 700 Meals-on-Wheels recipients. The company will also advertise in the *Senior Blue Book*, a semi-annual resource directory mailed to over 28,000 seniors and healthcare professionals. In 2015, February, May, August, and November ads in the *Idaho Senior News* are scheduled. This publication focuses on a demographic of senior readers ages 50 and older with a readership of over 80,000 statewide.

# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

Idaho Power's commercial sector consists of over 67,522 customers. In 2014, the commercial sector's number of customers increased by 788, an increase of a little over 1 percent from 2013. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 30 percent of Idaho Power's total electricity usage in 2014.

The industrial and Special Contracts customers are Idaho Power's largest individual energy consumers. There are approximately 116 industrial customers. These customers can use millions of kWh a month and account for 17.9 percent of Idaho Power's total electricity usage in 2014.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical retrofit measures with prescriptive incentive amounts for lighting, HVAC, building shells, variable-speed/frequency drives (VFD), plug loads, and food-service equipment. These energy-saving measures give customers the option of choosing the best selections for incorporating energy efficiency into their business. The Custom Efficiency program offers financial incentives for large commercial and industrial energy users undertaking more complex projects to improve the efficiency of their electrical systems or processes. Incentive levels are 70 percent of the project cost or 18 cents per kWh for first-year savings, whichever is less. During 2014, Idaho Power combined how the Easy Upgrades and Custom Efficiency programs treat lighting projects so they are processed together and the incentives and criteria are the same. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost-opportunity savings and encourage business owners to incorporate energy efficiency measures that are more efficient than current commercial building codes require. This program continues to be successful, incorporating qualified energy-saving improvements for lighting, cooling, building shells, and energy-management control options.

Idaho Power continues to offer the statutory Oregon Commercial Audits program to medium and small commercial customers. The program identifies opportunities for commercial building owners to achieve energy savings.

In 2014, FlexPeak Management, a demand response program, was offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracted directly with Idaho Power's commercial and industrial customers to achieve demand reduction. For 2015, Idaho Power has proposed to internally run and manage the program.

The Custom Efficiency program continued to represent the highest total energy savings among commercial and industrial programs in 2014, with a total savings of 50,363 MWh. The Easy Upgrades program continued to lead the sector in projects completed with 1,095 projects. Combined, all programs completed 1,295 projects that achieved 78,940 MWh of energy savings. Table 11 shows a summary of savings and expenses from the three commercial and industrial energy efficiency programs that produce direct savings and one demand response program.

# Programs

Table 11. 2014 commercial/industrial program

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Energy (kWh) | Demand (MW) |
| **Demand Response** | | | | | |
| FlexPeak Management | 93 sites | $ 1,563,211 | $ 1,563,211 | n/a | 40 |
| **Total** | | **$ 1,563,211** | **$ 1,563,211** | | **40** |
| **Energy Efficiency** | | | | | |
| Building Efficiency | 69 projects | 1,258,273 | 3,972,822 | 9,458,059 | 1.2 |
| Easy Upgrades | 1,095 projects | 3,150,942 | 5,453,380 | 19,118,494 | |
| Custom Efficiency | 131 projects | 7,173,054 | 13,409,922 | 50,363,052 | 5.6 |
| **Total** | | **$ 11,582,269** | **$ 22,836,124** | **78,939,605** | **6.8** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

Although 2014 was a good year for Idaho Power's commercial and industrial energy efficiency programs, Idaho Power program managers recognized early in 2014 that some changes needed made to the programs. The company took action by increasing incentives to most measures in all three programs, removing non-cost effective measures, modifying how lighting retrofit projects were processed, adding trade ally outreach for lighting, and offering a cohort to wastewater treatment plants.
The commercial and industrial programs continued to develop and strengthen Idaho Power's strategic partnerships. These partnerships include the IDL, engineering and architectural firms, a vast network of trade allies, the Northern Rockies Chapter of International Facilities Managers Association, the IBOA, and most importantly, Idaho Power customers. Training and education continued to be an important aspect of the company's programs in 2014. Trade ally meetings included training on lighting design and lighting controls. These training classes qualified for continuing education credits for eligible, licensed trade allies. Building Efficiency sponsored a number of outreach training sessions conducted by the IDL. Last, Custom Efficiency continued to offer a host of industrial training sessions that were well attended.

The Green Rewind offering is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 29 Green Rewind motors achieved a total annual savings of 91,582 kWh in 2014, with 14 commercial/industrial sector motors contributing 56,499 kWh per year and 15 irrigation sector motors contributing 35,083 kWh per year.

Twenty-one service centers in Idaho Power's service area have the necessary equipment and training to participate in the Green Rewind offering. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, four service centers have signed on as Green Motors Practice Group (GMPG) members in Idaho Power's service area. The GMPG will also expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2 per horsepower (hp) by the GMPG for each National Electrical Manufacturers Association (NEMA) Standard hp-rated motor up to 5,000 hp for industrial and agricultural uses that receive a verified Green Rewind. Customers are paid $1 per hp from the service center that completed their rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with a quality check and QA.

Idaho Power continued research on the potential to expand incentives in the Building Efficiency program in 2014 for multi-family dwellings in new construction and major remodel projects. In 2013, it was determined that most multifamily construction uses natural gas as a heat source, resulting in minimal electricity savings based on cooling measures alone. Because of this, multi-family projects do not pass Idaho Power's cost-effectiveness tests.

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. Sixty percent of Idaho Power's large commercial and industrial customers surveyed in 2014 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-six percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Seventy-three percent of respondents indicated Idaho Power was meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 77 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated 52 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 22 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 82 percent are "very" or "somewhat" satisfied with the program.

Customers' familiarity with Idaho Power's business energy efficiency programs meets or exceeds the average of its peer utilities according to the J. D. Power and Associates Electric Utility Business Customer Satisfaction Study. Idaho Power has exceeded the average of its peer utilities every year in the last four years with its awareness of business programs.

# Building Efficiency

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 69 | 59 |
| Energy Savings (kWh) | 9,458,059 | 10,988,934 |
| Demand Reduction (MW) | 1.2 | 1.1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,212,907 | $1,489,195 |
| Oregon Energy Efficiency Rider | $31,052 | $17,839 |
| Idaho Power Funds | $14,315 | $0 |
| Total Program Costs—All Sources | $1,258,273 | $1,507,035 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.012 |
| Total Resource Levelized Cost ($/kWh) | $0.037 | $0.032 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.05 | |
| Total Resource Benefit/Cost Ratio | 2.08 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies in new commercial or industrial construction, expansion, or major remodeling projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, controls, appliances, and refrigeration-efficiency options. These measures may otherwise be lost opportunities for savings on customers' projects. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or Special Contracts customers are eligible to participate. Program marketing is targeted toward architects, engineers, and other design professionals.

Twenty prescriptive measures are offered through this program. The measures are interior-light load reduction, exterior-light load reduction, daylight photo controls, occupancy sensors, high-efficiency exit signs, efficient AC and heat pump units, efficient variable refrigerant flow (VRF) units, efficient chillers, air-side economizers, direct evaporative coolers, reflective roof treatment, energy-management control systems, guest room energy management systems, HVAC VFDs, efficient laundry machines, ENERGY STAR® under-counter dishwashers, ENERGY STAR commercial dishwashers, refrigeration head pressure controls, refrigeration floating suction controls, and efficient condensers.

The IDL has been a useful resource for the Building Efficiency program. Idaho Power is a primary sponsor of the IDL, which provides technical assistance and training seminars focused on energy efficiency to local architects, engineers, and designers through Lunch & Learn sessions and the

Idaho Building Simulations Users Group (BSUG). Sessions are outlined in the IDL section of *Supplement 2: Evaluation*.

## 2014 Program and Marketing Activities

The Building Efficiency program completed 69 projects, resulting in 9,458,059 kWh in annual energy savings in Idaho and Oregon. Although the program showed a slight decrease in total kWh savings from 2013, the program increased the total number of projects by 17 percent from 59 projects in 2013. New construction and major renovation project design and construction life is much longer than small retrofits and often encompasses multiple calendar years.

The Building Efficiency program was modified in 2014, adding six new incentive measures. Idaho Power contracted with ADM to provide a technical reference manual (TRM) to address recommendations provided in the ADM impact evaluation in 2012. The TRM was completed in 2014 and provided updated savings for existing measures and savings for new measures that were added to the program.

Research conducted at the end of 2012 revealed that one barrier to participation is the amount of uncompensated time it took to fill out and submit supporting project documentation. Idaho Power addressed this barrier in 2014 by adding a "Professional Assistance Incentive" equal to 10 percent of the participant's total incentive, up to a maximum amount of $2,500, to improve participants' satisfaction with the incentive process. Modifications to the program were posted on Idaho Power's website, in the fall edition of the *ENERGY@WORK* commercial newsletter, and in a letter mailed directly to engineers and architects throughout Idaho Power's service area. Idaho Power worked with the American Institute of Architects—Idaho Chapter to have the program revisions posted to their website at aiaidaho.com/.

Idaho Power marketing and program staff participated in bi-monthly conference calls in support of the Kilowatt Crackdown™ competition. A video highlighting positive participant experiences was produced by the company and shown at the 2014 BOMA Symposium. In addition to the video, Idaho Power was a symposium sponsor and as such, had a full-page ad in the program magazine. The Kilowatt Crackdown™ Awards luncheon held April 16 recognized the top three highest-performing buildings, the top three most improved buildings, and two special recognition rewards. Idaho Power issued a news release that day to recognize the winners and encourage additional coverage of the competition. Idaho Power scheduled two additional training sessions with BOMA members in 2014.

Building Efficiency was marketed as a single program and as part of Idaho Power's suite of commercial energy efficiency programs. Ads that include all of Idaho Power commercial programs appeared in association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, the *Business Insider*, the *Idaho Business Review*, and bill inserts.

Additional commercial/industrial sector success stories were added to the Idaho Power website in 2014, with one specific to a Building Efficiency program new construction project titled *CSHQA architects and engineers design sustainability into their own offices*. Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

In 2014, Idaho Power created a new commercial video showing how energy efficiency can be incorporated into new construction or as a retrofit. The Hailey Interpretive Center, a Building Efficiency program participant, was one of three projects featured on the video. The IDL was also featured in the video.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Twenty technical training lunches were completed in 2014, with 281 attendees, including architects, engineers, interior designers, and project managers. Technical training sessions were held in Boise, Pocatello, and Ketchum. The Building Efficiency program, in conjunction with the Custom Efficiency program, sponsored the Idaho BSUG through the IDL. Topics and sessions are outlined in the IDL section of *Supplement 2: Evaluation*.

The Building Efficiency program supports a number of associations and events, including placing ads in the American Institute of Architects (AIA) directory and sponsoring the AIA Honor awards, Grow Smart awards, BOMA symposium, and ASHRAE Technical Conference.

## Cost-Effectiveness

To calculate energy savings for the Building Efficiency program, Idaho Power verifies the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters, including the efficiency of the installed measure compared to code efficiency. Another method for calculating savings is based on industry-standard assumptions when precise measurements are unavailable. Since Building Efficiency is a prescriptive program and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry-standard assumptions from the International Energy Conservation Code (IECC) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kilowatt reduction.

In 2014, under contract with Idaho Power, ADM completed a TRM for Building Efficiency, which provides savings and costs related to existing and new measures for the Building Efficiency program. The TRM was evaluated in 2014, and cost-effectiveness analyses were performed on all measures addressed through the TRM. The analyses resulted in modifications to several existing measures, the removal of one measure, and the addition of six measures to the updated 2014 Building Efficiency program.

Several measures that are not cost-effective remain in the program. These measures include daylight photo controls, high-efficiency A/C units, and high-efficiency heat pump units. After reviewing these measures, Idaho Power determined these measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These modification and cost-effectiveness exceptions were approved by the OPUC in Advice No. 14-10 for 2014 and went into effect in Idaho in July 2014 and in Oregon in November 2014. Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Building Efficiency continued random installation verification on 10 percent of projects in 2014. The purpose of the verifications is to confirm program guidelines and requirements are adequate and ensure participants are able to provide accurate and precise information with regard to energy efficiency

measure installations. The IDL completed on-site field verifications on 7 of the 69 projects, which encompass approximately 10 percent of the total completed projects in the program. Out of the seven projects verified, six projects were installed with only minor or no discrepancies compared to how they were declared on the final application. The minor discrepancies resulted in a total increase of energy-efficient measures for six of the seven projects. Only one project was installed with less energy-efficient measures than declared. The project involved the installation of additional lighting fixtures and did not meet the program guidelines. Random project installation verification will continue in 2015.

## 2015 Program and Marketing Strategies

The following strategies are planned for 2015:

- Continue to perform random post-project verifications on a minimum of 10 percent of completed projects.
- Continue to sponsor technical training through the IDL to address the energy efficiency education needs of design professionals throughout the Idaho Power service area.
- Continue to support Kilowatt Crackdown participants through continued coaching and technical support to further energy efficiency projects.
- Support organizations focused on promoting energy efficiency in commercial construction.
- Place print ads in the *Idaho Business Review* when the editorial content is dedicated to commercial property developers and engineers/architects.
- Actively support the 2015 Idaho Energy and Green Building Conference as a member of the conference planning committee. Participate in planning the conference agenda and energy efficiency sessions.
- Continue to sponsor the BOMA symposium and offer energy efficiency training and support to the real estate market.

# Custom Efficiency

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 131 | 73 |
| Energy Savings (kWh)* | 50,363,052 | 21,370,350 |
| Demand Reduction (MW) | 5.6 | 2.4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $6,705,219 | $2,402,903 |
| Oregon Energy Efficiency Rider | $418,537 | $60,245 |
| Idaho Power Funds | $49,299 | $3,077 |
| Total Program Costs—All Sources | $7,173,054 | $2,466,225 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.013 | $0.010 |
| Total Resource Levelized Cost ($/kWh) | $0.024 | $0.024 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.72 | |
| Total Resource Benefit/Cost Ratio | 2.52 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

* Includes 56,499 kWh from Green Motors projects.

## *Description*

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy efficiency projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education regarding energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit pre-applications to Idaho Power for potential projects that have been identified by the customer, Idaho Power, or by a third-party consultant. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves a pre-approval application finalizing the terms and conditions of the applicant's and Idaho Power's obligations. A payment application is later submitted when the project is installed and operating. In some cases, large, complex projects may take as long as two years to complete. Every project is verified post-completion by Idaho Power staff or an Idaho Power contractor. Lighting projects are typically pre- and post-inspected by an Idaho Power contractor or an Idaho Power representative. Incentive levels for the Custom Efficiency program were increased from 12 cents per kWh per year saved to 18 cents per kWh per year saved in July 2014; however, the 70-percent project cost cap remained in place. The lighting incentives for Custom Efficiency changed in July 2014. All standard lighting measures are now paid at

the stated prescriptive amount, which were revised in July 2014. All non-standard measures for interior lighting are now paid at the rate of 18 cents per kWh for first-year savings, up to 70 percent of the cost. All non-standard measures for exterior lighting are paid at the rate of 12 cents per kWh for the first-year savings, up to 70 percent of the cost.

## 2014 Program and Marketing Activities

Custom Efficiency had a very successful year in 2014. A total of 131 projects, including nine Oregon projects, were completed by 95 customers. Program energy savings increased in 2014 by 135 percent over 2013, from 21,370 MWh to 50,306 MWh.

Savings for the Custom Efficiency program can vary greatly based simply on the timing of projects as evidenced by the drastic difference in program savings year to year. In 2014, 145 new applications were submitted, totaling 64,729 MWh. There were 150 submitted projects in the pipeline for Custom Efficiency at the end of 2014, representing almost 67,665 MWh of potential future savings.

The Custom Efficiency program may also have reached some level of saturation through program maturity, as over 95 percent of the large-power service customers have engaged in the program. With the high percentage of industrial customers that have completed projects in the program, deeper energy savings will be challenging to achieve.

Table 12 indicates the program's 2014 annual energy savings by primary project measures.

Table 12. 2014 Custom Efficiency annual energy savings by primary project measure

| Program Summary by Measure | Number of Projects | kWh Saved |
|---|---|---|
| Lighting | 53 | 11,107,700 |
| Refrigeration | 19 | 24,158,395 |
| HVAC | 4 | 1,247,404 |
| Compressed air | 12 | 3,446,633 |
| Fan | 10 | 3,326,987 |
| Controls | 2 | 1,850,541 |
| Pump | 3 | 1,629,045 |
| VFD | 27 | 2,733,098 |
| Other | 1 | 806,750 |
| Total[a] | 131 | 50,306,553 |

[a] Does not include Green Rewind project counts and savings.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. The 2014 activities in the key components are described below.

### Facility Energy Auditing

In 2014, five scoping audits and seven detailed audits were completed on behalf of Idaho Power customers. These audits identified over 24,000 MWh per year of savings potential, and most of the customers engaging in these audits have used the information to move forward with projects or have expressed interest in moving forward in the near future. A Scoping Audit and an Energy Management Assessment was provided to 11 facilities as part of the Wastewater Energy Efficiency Cohort (WWEEC) offering.

### Customer technical training and education services

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. The training is coordinated by the NEEA Industrial Training Project, and Idaho Power is a co-sponsor. Idaho Power provides funds for extra NEEA trainings in the Idaho Power service area. Additionally, Idaho Power pays customers' attendance fee in the classroom-based training sessions. Seven technical classroom-based training sessions were completed in 2014. Two of these classes were two-day classes, and the rest were one-day classes. Topics included compressed air, air-cooled refrigeration systems, pump systems, and fan system efficiency. A schedule of training events is posted on Idaho Power's website.

The level of attendance in 2014 remained high, with 115 Idaho Power-sponsored seats for customers and various Idaho Power staff, consultants, and trade allies out of the 119 total attendees. Customer feedback indicated average overall satisfaction levels of 99 percent.

Additionally, 2014 encompassed Phase IV of the webinar pilot plan coordinated by NEEA. Three webinars were presented free to all attendees. Topics included VFDs, efficient industrial lighting, and energy auditing and troubleshooting. There were 24 Idaho Power end-use customers, multiple Idaho Power personnel, and various consultants attending the webinar recordings. Idaho Power posted the webinar recordings and PDFs on the commercial and industrial training page on the Idaho Power website.

Figure 16 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the 2014 in-class NEEA industrial trainings. This figure uses data from ECOVA™'s summary of the trainings provided in the *NEEA Regional Industrial Training Update, December 2014* included in *Supplement 2: Evaluation*.

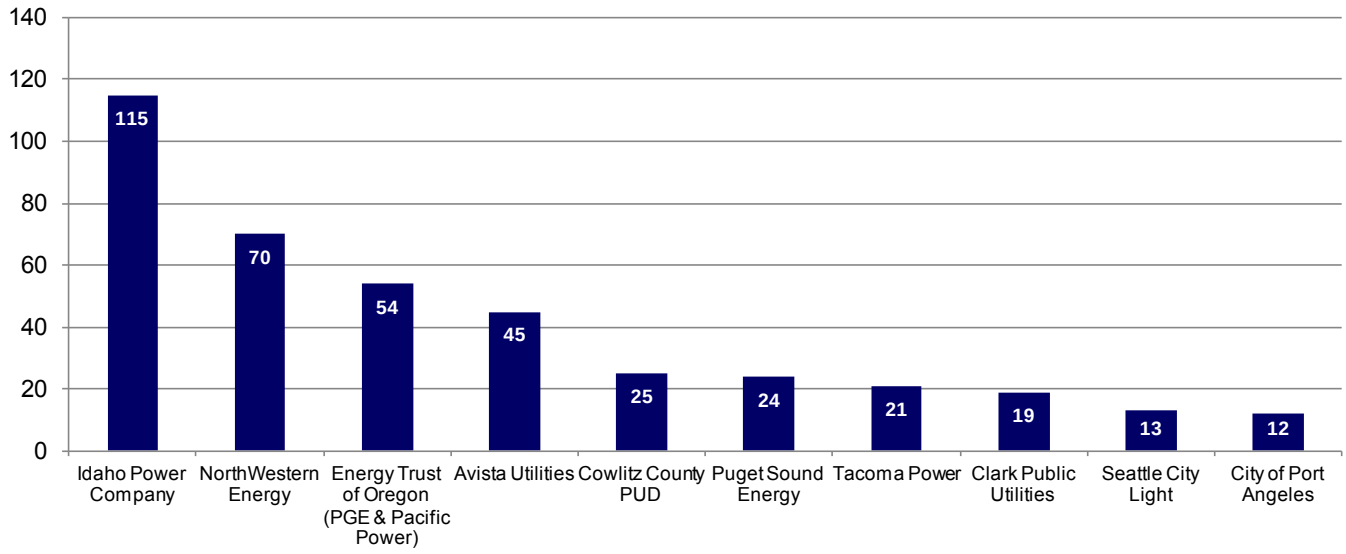


Figure 16. NEEA chart of attendees (in-class seats filled) by attendee sponsor[1]

[1] Data source: NEEA Regional Industrial Training Update, December 2014

Figure 17 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the three 2014 webinar-based NEEA industrial trainings. This figure uses data from ECOVA's summary of the trainings provided in the NEEA Regional Industrial Training Update, December 2014, included in *Supplement 2: Evaluation*.

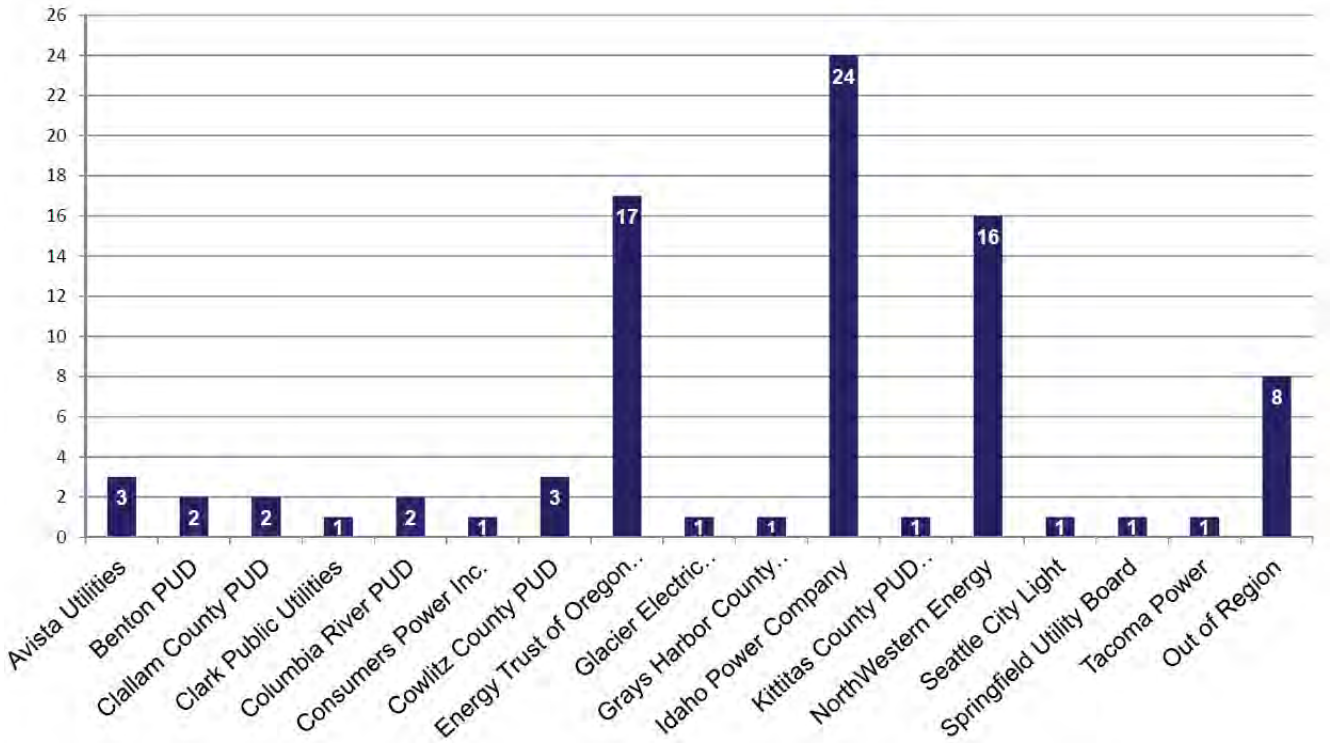


Figure 17. NEEA chart of attendees (webinar-based seats filled) by attendee sponsor[2]

In 2014, Idaho Power sponsored a Refrigeration training at the CWI during the September Treasure Valley Refrigerating Engineers and Technicians Association (RETA) chapter meeting.

In November in Boise, Idaho Power also co-sponsored a two-day RETA Certified Refrigeration Energy Specialist (CRES) review class training with NEEA with 13 customers in attendance. The purpose of the training was to review refrigeration energy efficiency concepts and to prepare the attendees for the RETA CRES exam. The requirement for signing up for the free training was for the students to apply for the CRES exam.

Custom Efficiency program engineers and the MCRs set up numerous target visits with the large commercial and industrial customers in 2014. The visits ranged from commercial/industrial efficiency program training to a comprehensive targeted technical training session for a larger audience on potential energy-savings opportunities for different measure types, such as refrigeration, pumps and fans, compressed air, HVAC, lighting, etc. Because of WWEEC, Custom Efficiency program engineers also set up multiple program marketing meetings with the area civil engineering firms specializing in water and wastewater designs to educate them on the efficiency programs, audit process, energy efficiency opportunities, and tools and resources available to them.

[2] Data source: NEEA Regional Industrial Training Update, December 2014

Under the IDL, Idaho Power participated in the BSUG. The goal was to facilitate the Idaho BSUG, which was designed to improve the energy efficiency-related simulation skills of local design and engineering professionals. In 2014, 11 sessions were hosted by the IDL. For one session, the IDL hosted the remote viewing of sessions taught by the Building Energy Simulation Forum in Portland. The sessions were made available remotely and were attended by 179 professionals in-person and 318 professionals remotely. Details regarding BSUG topics and additional details are located in the Other Programs and Activities section of the report and in *Supplement 2: Evaluation*.

The IDL provided a Tool Loan Library (TLL). The goal was to operate and maintain a measurement equipment tool loan library, including a web-based equipment tool loan tracking system, and provide technical training on how each tool is intended to be used. There were a total of 286 tools loaned in 2014 as part of 37 total loans. Fourteen new tools were purchased or acquired in 2014. Details regarding the types and number of loans, types of tools, and additional IDL activities are located in the Other Programs and Activities section of the report and in *Supplement 2: Evaluation*.

As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency by ensuring certain standards and methods in the motor rewind process. There were 14 Green Rewind motors in the commercial/industrial sector in 2014, contributing 56,499 kWh in annual savings.

In 2013, Custom Efficiency launched two new offerings to increase the total program savings in 2014 and beyond. Early in 2013, the ROCEE offering was rolled out to Idaho Power's larger customers with complex refrigeration systems in the western half of Idaho Power's service area. This was a two-year engagement with the eight participating customers. ROCEE provided a series of technical training workshops with a cohort cluster training approach. Workshops included visits to participants' refrigeration engine rooms to gain hands-on experience viewing and discussing energy efficiency concepts. The goal of the training was to equip refrigeration operators with the skills necessary to identify and implement energy efficiency opportunities on their own and to ensure these energy and cost savings are maintained long term. Sessions included technical training, hands-on learning exercises to demonstrate simple low- and no-cost actions to diagnose problems and save energy, and peer-to-peer sharing of lessons learned as the classes progressed.

ROCEE provided energy audits of the participants' facilities in conjunction with a qualified refrigeration system expert. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as processing set-point changes. Participants had technician and engineering support between each workshop, facilitated by an expert team of energy engineers. Energy savings were tracked via an energy model that was constructed for each participating facility using third-party energy management software that Idaho Power provided as part of the cohort. In some cases, bottom-up calculations or sub-system data logging captured the savings. The incentives and the energy savings for year one of the offering totaled $13,886 and 3,678,985 kWh per year. In all cases, the incentive was capped on 70 percent of the eligible costs. Year two incentives and savings will be processed in 2015. Additionally, some ROCEE participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These projects' savings are captured in the main Custom Efficiency program savings.

The second program offering rolled out in 2013 was SCE. This offering targets projects that may have typically been too small to participate in the Custom Efficiency program due to the resources required to adequately determine measure savings. Idaho Power has contracted SCE out to a company to manage the data collection and analysis for each project. SCE provides custom incentives for small compressed air system improvements, fast-acting doors in cold-storage spaces, refrigeration controllers for walk-in

coolers, and process-related VFDs. In 2014, the SCE offering processed 46 projects, totaling 4,698,478 kWh per year of savings and $540,375 in incentives paid.

In January 2014, Custom Efficiency launched the WWEEC program offering to increase the total program savings. Similar to ROCEE, WWEEC is a cohort training approach to low-cost or no-cost energy improvements. WWEEC is a two-year engagement with 11 Idaho Power service area municipalities. WWEEC provided a series of five technical training workshops with a cohort training approach. In addition, WWEEC provided energy audits in conjunction with a qualified wastewater system expert and an Energy Management Assessment conducted by a Strategic Energy Management professional for each participating facility. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as turning off equipment or adjusting control points for systems. They also implemented many energy management principles, including forming an energy team, setting energy goals, and establishing energy policies in their organization for persistence of savings. Energy savings were tracked via Idaho Power provided third-party software and an individual energy model for each facility. WWEEC contributed several capital projects to Idaho Power incentive programs from some of the WWEEC participants. Additionally, pre-planning meetings were held with consultants and municipalities for upcoming new wastewater construction projects.

2014 was the third year the Idaho Power CR&EE department filled a summer internship position with a university mechanical engineering student. A Custom Efficiency engineer served as the intern mentor. The intern was involved with many aspects of the day to-day program operation, including, but not limited to, measurement and verification of energy efficiency aspects related to Custom Efficiency program lighting projects; attendance at customer meetings related to energy efficiency; familiarization with, and communication for, all three commercial incentive programs; calculation and review of energy-saving projects; exposure to program marketing and planning activities; and administrative work related to the Custom Efficiency program.

The Custom Efficiency program has achieved a high service-area penetration rate. As stated previously, through 2014, over 95 percent of the large-power service customers have submitted applications for a project. Idaho Power staff met with all of the Special Contracts customers to discuss energy efficiency programs and opportunities. Specifically, only 2 of the 107 large-power service customers have not submitted an energy efficiency project, and all three Special Contracts customers have submitted projects. The company staff are actively working to support these customers in new ways.

Idaho Power's Custom Efficiency program is unique from the company's other energy efficiency programs by providing individualized energy efficiency solutions to a somewhat limited number of customers. Idaho Power's MCRs often act as the company's sales force. Marketing supports the MCRs by providing collateral to help them inform customers of the measures and benefits available to them.

The Custom Efficiency program was updated in July 2014, increasing incentive rates to 18 cents per kWh for first-year savings from 12 cents per kWh for first-year savings. As a result, marketing materials and web content were updated to reflect programmatic changes. A letter was sent to MCRs to distribute to their customers to increase awareness of changes to the commercial/industrial programs. Also, a PowerPoint presentation was created for the engineers and MCRs to use as part of their target visits with customers to highlight ongoing program activities and program changes.

In 2014, two new pieces of collateral were created for the Custom Efficiency program: 1) a flyer describing the types of incentives available under the Streamlined Custom Efficiency offering, and 2) a general overview brochure described the Custom Efficiency program. The flyer detailed the

types of improvements that fit under the Streamlined Custom Efficiency program offering, eligibility, and the application process. A new Custom Efficiency brochure was created to easily provide an overview of the program without reading through pages of text. Both of these documents were designed with the same look and feel. MCRs took flyers and brochures with them on customer visits. Both documents are available at idahopower.com/EnergyEfficiency/Business/Programs/CustomEfficiency/default.cfm.

As incentives were received, some commercial customers wanted to publicize the work they have done to become more energy efficient. Upon request, Idaho Power created large-format checks that are used for media events and or board meetings. Idaho Power also worked with customers on coordinating media events.

In early January, Idaho Power reached out to administration offices of cities in the company's service area participating in the Custom Efficiency WWEEC in Boise to encourage media opportunities in their communities. An alert was sent to all press outlets on January 27, the first day of the workshop, in the form of a media advisory, to inform the media of a public relations opportunity, with contact information for each city's public information officer and/or mayor's office representative. At the workshop, Idaho Power interviewed participants for testimonials to be included in an internal *eNews* video that was posted on YouTube in April and the link shared with workshop participants and promoted on social media. The video is titled *Partnering for Efficiency—Wastewater Plants* and is posted at youtube.com/watch?v=ES46PET3B70. In September, a press release was sent to all media on the day of the last of the five workshops held in Boise providing more information about the work being done by Idaho Power partnering with participants to improve energy efficiency throughout the service area. The press release included a link to the YouTube video. Local media was invited to join a tour of one of the local wastewater treatment plants; video footage was taken during the tour and a link to the footage was provided to any media that did not attend. In October, Idaho Power helped create a press release template for the participants to report out their results to local media.

Custom Efficiency has been marketed as a single program and also as part of Idaho Power's suite of commercial energy efficiency programs. Ads that include all Idaho Power commercial programs have appeared in association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, the *Business Insider*, the *Idaho Business Review*, and bill inserts. Also, industry-specific energy efficiency brochures were developed in 2014 for several industries, including grocery stores, convenience stores, offices, hotels, restaurants, and healthcare facilities. These brochures are being distributed by CRs and MCRs and are available on the company's website here: idahopower.com/EnergyEfficiency/Business/Tips/eeBusinessSpecificTips.cfm.

## Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires that all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculate the energy savings. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, especially the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or MCRs solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to allow posting the customers' success stories on the Idaho Power website. In 2014, seven new success stories described energy efficiency projects submitted by Custom Efficiency program participants. An example of a success story posted in 2014, *A chilling story of ON Semiconductor and Idaho Power incentives*, refers to a project ON Semiconductor completed. Idaho Power provided $53,255 in incentives for energy efficiency measures that reduced costs. The facility expects to save over $25,000 in annual utility bills. Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

Qualitative research for the Custom Efficiency program began in late 2013. MDC was selected through a competitive request for proposal (RFP) process. The research served to provide a deeper understanding of customers' awareness and knowledge of the program offering and benefits as well as gauge customer satisfaction with the program and equipment installed. Customer feedback was collected on the program processes and preferred method of communication. The research involved one-on-one interviews with program participants based on the nature of the equipment installed and the industry. MDC interviewed 26 large commercial and industrial program participants in several industries, such as manufacturing, services, and retail trade. In addition, MDC conducted one-on-one interviews with 10 eligible commercial and industrial customers that have not yet participated in the Custom Efficiency program.

As a qualitative study, the following key findings only reflect the general thoughts of those that participated in the interviews and are not representative of the entire program. Overall, the 26 participants were "highly satisfied" with the Custom Efficiency program processes. Some participants cited their own internal processes as more difficult than the program's steps. The "vast majority" that worked directly with an Idaho Power representative were "highly satisfied." The consensus was that when an Idaho Power representative is involved, they tend to "fully drive the process." For both participants and non-participants, the return on investment (ROI) is the primary factor considered before participating. The 10 non-participants interviewed believed they would be "somewhat likely" to participate in the program in the future. They need more guidance around the qualified equipment, probable ROI, and probable upfront costs to help make that decision. Respondents were mixed on an "ideal" outreach strategy; however, most would pay attention to an in-person visit from Idaho Power.

Comprehensive results of all findings related to the Custom Efficiency program research were delivered in early 2014, and a copy of the report is provided in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Additional program offerings are currently under consideration for implementation in 2015. These efforts will be targeted at maintaining a high level of customer participation as well as achieving year- over-year program goals.

Items currently under consideration include the following: additional contractors for energy studies and measurement and verification (M&V) efforts; retro-commissioning offering; and new cohorts including ROCEE II (target Southern Region), Compressed Air (could be a stand-alone offering), Data Centers (could be a stand-alone offering), and Water Supply Energy Efficiency Cohort (WSEEC).

The second year of energy savings for the ROCEE offering will be reported and incentives paid in 2015. The first year of energy savings for the WWEEC offering will be reported and incentives paid around mid-year 2015.

The SCE offering will continue to be offered in 2015, and new measures, processes, and other improvements will be evaluated to continuously improve the effectiveness of this offering.

In addition, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities and continued development of strategic partnerships. These activities will include direct marketing of the Custom Efficiency program by Idaho Power MCRs to further educate customers on Idaho Power energy efficiency programs, including identification of potential ways the customer can reduce energy costs and drive program participation. A target visit brochure will be developed for the MCRs to use with their customers. The brochure will allow the customer to customize the visit by letting Idaho Power know the type of training and energy information they would like to know more about.

Idaho Power will continue to provide site visits by Custom Efficiency engineers and energy scoping audits for project identification and energy-savings opportunities; M&V of larger complex projects; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored Strategic Energy Management improvement practices to customers.

In 2015, additional industry-specific energy efficiency tip brochures will be revised and mailed to targeted customers, along with an insert highlighting possible incentives.

In 2015, an article on the WWEEC offering will be created to discuss the cohort approach on energy efficiency and energy management training with the municipal wastewater segment. A brochure outlining energy efficiency tips and benefits for the wastewater sector will be produced and posted to a new Idaho Power webpage. Hard copies will be printed and distributed at events and through CRs and MCRs as needed.

Each year, the company designs and pays for a “Top 10” ad that appears in the *Idaho Business Review*. This ad publicly congratulates companies that had the most energy savings throughout the year. The company will continue this tradition in 2015. Success stories will continue to be written and produced throughout 2015. These stories focus on businesses that took advantage of Idaho Power’s Custom Efficiency program and the resulting benefits. Success stories are posted on Idaho Power’s website so the highlighted businesses can print and use them to publicize their energy-efficient projects. Idaho Power will continue to assist customers with public relations opportunities by creating certificates for display within the building and having an Idaho Power representative speak at press events if requested.

The Custom Efficiency team will be mentoring another engineering intern in 2015. These internships are important mechanisms that help drive work-force development in the energy efficiency profession.

Idaho Power will continue to support the IDL in 2015. In addition to the specific tasks outlined in the IDL description in the Other Program and Activities section of the main report and in *Supplement 2: Evaluation*, the IDL provides foundational services to customers in the Idaho Power service area. The IDL will provide energy modeling assistance for large, new-construction projects. The energy modeling is used by the Custom Efficiency team to support the claimed energy savings that are not covered by the existing measures through the Building Efficiency program.

The Custom Efficiency team will continue to support the Center for Advanced Energy Studies (CAES) Industrial Assessment Center (IAC) by marketing their IAC services during both customer site visits and at technical training workshops. The IAC is part of the CAES's Energy Efficiency Research Institute (CEERI), which is a collaboration between Idaho's three state research universities where students provide energy audits and general recommendations to improve operations for mid-sized, local, manufacturing companies.

# Easy Upgrades

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,095 | 1,392 |
| Energy Savings (kWh) | 19,118,494 | 21,061,946 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $3,020,323 | $3,258,427 |
| Oregon Energy Efficiency Rider | $112,623 | $101,363 |
| Idaho Power Funds | $17,996 | $0 |
| Total Program Costs—All Sources | $3,150,942 | $3,359,790 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.015 | $0.014 |
| Total Resource Levelized Cost ($/kWh) | $0.025 | $0.029 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.08 | |
| Total Resource Benefit/Cost Ratio | 2.35 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

Easy Upgrades is Idaho Power's prescriptive measure program for the commercial and industrial retrofit market. Customers can also apply for incentives for non-standard lighting incentives. The program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering specific incentives on a defined list of measures, except for the non-standard lighting. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, VFDs, food-service equipment, and other commercial measures. A complete list of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial and industrial customers and Special Contracts customers are eligible. For projects with expected incentive payments of $1,000 or more, or Complete Lighting Upgrade projects, applicants must submit a pre-approval application prior to installing the project. For projects not requiring pre-approval, customers may elect to skip the pre-approval application process and submit the payment application and accompanying documentation. Customers may assign their incentive payment to a third party (e.g., their contractor or supplier), as approved by Idaho Power.

## *2014 Program and Marketing Activities*

To increase customer and trade ally participation in the Easy Upgrades program, several changes were made to the program in 2014. Idaho Power increased incentives for numerous measures, added new measures, adjusted processes to enhance project submission and review, and added more trade ally outreach support.

The following are highlights of the modifications to lighting measures:

- For purposes of encouraging/rewarding more robust energy savings per project, and after considering how to adopt a form of a comprehensive lighting incentive in the program, Idaho Power added the Complete Lighting Upgrade bonus incentive. This new incentive applied to projects where all the interior inefficient lighting was retrofitted with more cost-effective, efficient technologies, including the incorporation of controls, where applicable. The Complete Lighting Upgrade was a bonus incentive given in addition to the calculated incentive on the lighting tool.

- To increase trade ally and customer participation, the program reviewed all lighting measures to determine if incentive increases could be made. The review resulted in increased incentives on several standard incentive measures and an increase to the non-standard incentive for interior lighting retrofits.

- The program segmented lighting incentives based on an interior or exterior application installation.

- To expedite project submission and reduce trade ally wait time to begin a project, the program eliminated the requirement for projects less than the $1,000 incentive with non-standard measures to be submitted for pre-approval. This change was heartedly received by participating trade allies and has resulted in quicker turnaround of project implementation.

In 2013, Idaho Power contracted with ADM to review the non-lighting Easy Upgrades measures and compile a TRM for these measures. Based on information provided by ADM and the RTF measure list, changes were made to several non-lighting measures. Highlights of the modifications to the non-lighting measures are described below.

New measures were added to the program, such as non-process chillers, electric combination and convection ovens, fryers, steamers, energy-free stock tanks, efficient electric water heaters, and commercial showerheads.

Some measures were removed from the program due to no longer meeting cost-effective criteria. Discontinued measures include refrigeration cases, refrigerators, door gasket repair, roof insulation, standard windows, and window shade screens.

Several measures were modified to reflect the updated TRM data and subsequent cost-effectiveness analysis. Idaho Power increased incentives for refrigeration line insulation, auto-closers, and floating head/suction pressure controls. The company moved VFDs installed on process applications to the Custom Efficiency program due to the highly variable nature of those applications. Idaho Power revised the eligibility and incentive level for qualifying efficient air conditioners, heat pumps, and HVAC controls.

The primary reason the project count decreased in 2014 compared to 2013 can be attributed to the delay in rolling out the 2014 program changes. Idaho Power announced the proposed program changes to participating lighting trade allies beginning in March. At that time, the expected effective date for the changes was the end of May; however, due to various delays, including the filing of OPUC Advice No. 14-06, and the company's desire to have uniform programs in both Idaho and Oregon jurisdictions, the program changes did not become effective until the end of July. Most trade allies and customers

delayed implementing lighting retrofit projects until the program changes became effective because of the increased incentive offered.

In addition to the reduction in lighting project submissions, the program experienced reduction in HVAC and food-service applications. The reason for the decline in these areas is attributed to the program changes in these categories (e.g., the removal of several measures for cost-effectiveness and/or adjustment to incentive or requirements). In 2013, the program had 140 food-service projects. In 2014, the program had 55 (the gasket seal measure went away). In 2013, there were 86 HVAC projects, and in 2014 there were 47.

Following the success from the *It's So Easy Lighting Campaign* targeted-town approach offered to the Pocatello area in fall 2013, the Easy Upgrades program expanded this offer to the Payette/Ontario and Twin Falls areas in spring 2014. In preparation for each week-long event, Idaho Power CRs and interested local trade allies in the two areas identified customers who would benefit from a lighting retrofit. The customers were offered a free facility lighting audit, a lighting consultation, or an expedited inspection of a proposed energy efficiency project. The local lighting trade allies were informed of the event and asked to participate.

The *It's So Easy Lighting Campaign* resulted in many positive outcomes for the program. Ninety-one visits were made to customer facilities in the participating two areas. Customers were appreciative of the offer made to them by Idaho Power. Customers gained tangible project information for decision-making with regard to undertaking a lighting retrofit. Trade allies appreciated the dedicated support the program gave them during the events.

The Easy Upgrades program facilitated 17 program workshops and technical classes across the Idaho Power service area targeting lighting trade allies, electrical contractors, and large customers. Offerings included six program workshops, one lighting 101 class, two lighting controls classes, and eight power quality classes. The program received feedback from trade allies requesting power quality education. The trade allies involved with energy efficiency projects involving VFDs were required to comply with power quality requirements. Idaho Power's power quality engineers developed a class to address this need, and the program facilitated delivery of the classes in 2014. The technical lighting and power quality classes qualified for continuing education credits for licensed electrician and electrical contractor trade allies. These classes and workshops resulted in 470 attendees receiving valuable industry-related training.

In addition to the formal training classes held, Idaho Power staff contacted over 110 trade allies in the field, via telephone, at the trade ally's business, or at a customer location to further educate them on program criteria and to respond to their inquiries. Contacts were made to strengthen relationships, encourage program participation, increase knowledge of the Easy Upgrades program, and to receive trade ally feedback about the market, the program, and trade allies' experiences. This targeted outreach was to electrical contractors, electrical distributors, and HVAC contractors.

Idaho Power also partnered with the IDL by sponsoring Daylight Harvesting Controls System classes. These classes provided education and training for electrical contractors and the design community on the concepts of daylight-harvesting control systems. IDL details are located in a description in the Other Programs and Activities section of the *Demand-Side Management 2014 Annual Report* and in *Supplement 2: Evaluation*.

Idaho Power continued to contract with Evergreen Consulting Group, LLC to provide ongoing lighting specialist expertise, project support, and trade ally training. In fall 2014, Idaho Power expanded its

contract with Evergreen Consulting Group to locate personnel in Idaho Power's service area to perform ongoing trade ally outreach to lighting trade allies. The trade ally outreach position enabled Idaho Power to increase support to its largest trade ally group—those working on lighting retrofit projects. Idaho Power continued to contract with Honeywell, Inc., to perform non-lighting project reviews and pre- and post-non-lighting project inspections. Idaho Power continued to contract with RM Energy Consulting to support lighting project review, lighting inspections, and audits for the targeted-town events.

Some inspections matched the information in the submitted paperwork, while other inspections showed discrepancies in submitted paperwork. To ensure projects in the program met program specifications and to verify conditions in the field were as stated on the program application, the Easy Upgrades program conducted 297 pre-inspections and 419 post-inspections, representing 552 unique customers in 2014. The program adjusted the incentive and kWh savings on projects with discrepancies to reflect actual field findings. Idaho Power took various steps to increase the accuracy and thoroughness of incoming paperwork to the program. Program personnel communicated the importance of being accurate on project submittals with trade allies at its annual program update workshops, as well as during communications with trade allies throughout the year. Program staff commended trade allies on submitting accurate and thorough paperwork as well as provided feedback and encouragement to trade allies whose paperwork would benefit from increased accuracy. The new trade ally support person began meeting with trade allies on a more frequent basis to provide ongoing education on program processes, paperwork submittal, and program requirements. In addition, the new outreach support person met with contractors who were new to the program to help them gain a thorough understanding of the program and requirements.

Several marketing tactics were used to promote and create awareness of the Easy Upgrades program in 2014. These included traditional approaches, such as running print ads in the *Business Insider* and *The Idaho Statesman* business section, a cover story in the fall edition of Idaho Power's commercial newsletter *ENERGY@WORK*, and marketing Easy Upgrades in combination with Idaho Power's other commercial/industrial energy efficiency programs. In fall 2014, a full-page Easy Upgrades ad appeared on the back cover of the *Small Business Administration's Resource Guide*. Ads that included all Idaho Power commercial/industrial programs appeared in various association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, *Business Insider*, *Idaho Business Review*, and bill inserts.

The program implemented targeted direct mailing as a new strategy in 2014. A direct-mail letter was sent to 22,000 business customers announcing the 2014 program changes. This direct-mail strategy proved most successful in terms of getting customers to act. The letter briefly notified customers of the recently implemented program changes, included several customer testimonials, and specifically listed the Idaho Power CR and the CR's phone number for that particular recipient. Customers were encouraged to call their CR and find out more information about the Easy Upgrades program. Because the direct-mail letter was targeted and specific, customers did not need to look up anything—they were able to make a phone call and find out information right away.

In fourth quarter 2014, a targeted mailing was sent to hotel and motel businesses. The mailing included the brochure *Energy Efficiency Tips for Hotels*. A flyer was inserted in the middle of the brochure that outlined specific Easy Upgrades incentives relevant to the lodging industry market segment.

As part of its Commercial Lighting work group, NEEA continued work on its Reduced Wattage Lamp Replacement (RWLR) Pilot Initiative and development of the Top Tier Trade Ally Initiative Program.

An Idaho Power employee was on this working group, and the company is updated on progress at periodic conference calls and meetings. Details are provided later in the NEEA section of this report.

Idaho Power contracted in 2013 with Opinion Dynamics to conduct an Easy Upgrades process evaluation. Based on the results, the following recommendations were addressed in 2014.

Opinion Dynamics recommended Idaho Power consider adding or shifting staff resources (or subcontractors) to contractor-related outreach. The program contracted with Evergreen Consulting Group for local trade ally outreach support.

The evaluators recommended increasing the Easy Upgrades marketing and outreach budget. Opinion Dynamics stated that "A prudent use of additional marketing funds would be to boost contractor outreach." This recommendation was implemented in 2014 by securing dedicated trade ally outreach support and by increasing the Easy Upgrades marketing budget for 2015.

Opinion Dynamics recommended Idaho Power consider workflow and customer relationship management tools to help staff administer the program to increase efficiencies. Opinion Dynamics recommended it would be ideal to have all program management functions take place within one system. Opinion Dynamics recommended Idaho Power investigate what types of enhancements could be made to CLRIS so the management functions could happen with the existing system or, alternately, they noted there are a number of software packages available with workflow and customer relationship management capabilities. Idaho Power believes it is more reasonable and economical to enhance its existing system, which is tied into Idaho Power's customer billing system, than to invest in a third-party developed system. The company is constantly making enhancements to CLRIS and continues to explore further development.

## Cost-Effectiveness

In 2014, Idaho Power reviewed and modified most of the measures offered in the Easy Upgrades program. Idaho Power contracted with Evergreen Consulting Group to review the assumptions within the lighting tool for all the current and proposed standard lighting measure offerings. For the lighting measures, Idaho Power segmented the lighting incentives based on an interior or exterior application installation. Based on the difference in hours of use and end-use load shapes, the benefits associated with the energy savings with interior lighting measures are greater than comparable exterior lighting applications. The incentives for many interior lighting measures were increased to reflect the higher value of these lighting applications. The incentives for exterior lighting measures remained the same. The initial analysis of the standard lighting measures within the tool showed the measures to be cost-effective based on the average input watts and hours of operation. The actual savings for each lighting project are calculated based on the input watts of existing light fixtures, the replacement light fixture, and the actual hours of operation. As a result of these changes, there are over 100 lighting combinations under Easy Upgrades' Standard Lighting Incentives worksheet. In *Supplement 1: Cost-Effectiveness*, these lighting measures have been grouped under 26 similar categories.

In 2014, ADM completed a TRM for Easy Upgrades that provides savings and costs related to existing and new non-lighting measures for the Easy Upgrades program. The TRM was evaluated in 2014, and cost-effectiveness analyses were performed on all measures addressed through the TRM. Additionally, Idaho Power reviewed the list of commercial measures with deemed savings from the RTF that were not currently offered in the program. The analyses resulted in modifications to several existing measures, the removal of non cost-effective measures, and the addition of several measures as listed under the 2014 Program and Marketing Activities section.

Several lighting and non-lighting measures that are not cost-effective remain in the program. These measures include several lighting combinations with mostly exterior applications, high-efficiency A/C units, high-efficiency heat pump units, and wall insulation. After reviewing these measures, Idaho Power determined the measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These modifications and cost-effectiveness exceptions were approved by the OPUC in Advice No-14-06 for 2014 and went into effect in Idaho in July and in Oregon in August 2014.

Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Although the program did not solicit formal customer satisfaction surveys in 2014, the program received unsolicited customer and trade ally comments throughout the year indicating their satisfaction with the program. In addition, CRs and program staff asked customers about their experience with the program, their contractor, and their retrofit project during inspection visits and phone conversations.

In 2014, three new success stories describing energy efficiency projects were developed and posted to the company's website. The first 2014 success story, titled *Industrial detergent manufacturer cleans up with Idaho Power Easy Upgrades incentive*, references the lighting retrofit project completed at detergent formulator, Technichem Corporation. Company president, Brian Rencher, said, "I would recommend the Easy Upgrades program to anyone who has been hesitant about it, or has an old building. Or even a not-so-old building."

The second success story, titled *Using less energy to create better lighting is a win/win for Riverstone International School*, speaks of another lighting upgrade project. Todd Predovich, Riverstone International School's facilities manager, said, "When I got the proposal and I saw what Idaho Power's incentive was going to be, it felt like a win/win kind of deal." He said they took out half the bulbs and still got brighter classrooms. Todd described that the first day of class after they installed the new lights, the middle school art teacher asked what was done to her classroom. She noticed the difference in the quality of the light, which, in the case of new lighting technologies, can resemble daylight.

The third success story posted in 2014, titled *North Star Charter School graduates to a better lighting system*, refers to the lighting upgrade in North Star Charter School's gymnasium. Dan Conti, the school's athletic director, noted the gym is used for varied and wide purposes—from chess tournaments, quilt shows, and weddings to sports. Dan said, "We got our [incentive check] less than two weeks after the project was completed, so we could use the money to pay the contractor. It worked out nice." Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Idaho Power will evaluate the viability to implement new program offerings and strategies and will look at ways to increase penetration in hard-to-reach small businesses. A customer satisfaction survey is planned to be implemented in 2015.

Marketing strategies for 2015 may include some or all of the following: trade ally trade show, direct mail to small and medium businesses, focus on trade ally outreach, program update workshops, print ads in the *Idaho Business Review* and/or major regional newspapers highlighting customer success stories and trade ally thank you ads, and Idaho Power monthly newsletter and bill inserts.

# FlexPeak Management

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (sites) | 93 | 100 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 40 | 48 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $50,964 | $108,842 |
| Oregon Energy Efficiency Rider | $78,131 | $137,184 |
| Idaho Power Funds | $1,434,116 | $2,497,589 |
| Total Program Costs—All Sources | $1,563,211 | $2,743,615 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

FlexPeak Management is a demand response program administered by Idaho Power through a third-party aggregator. It is a voluntary program available in Idaho and Oregon service areas designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak load days. The program objective is to reduce the demand on Idaho Power's system during periods of extreme peak electricity use. The program is active June 15 to August 15 between 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand-reduction event two hours prior to the start of the event, and events last between two and four hours. Reduction events may be called a maximum of 60 hours per season.

In November 2008, EnerNOC, Inc. was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805. In June 2010, the program was approved by the OPUC in Order No. 10-206.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours with minimal impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring

equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week during the active season, EnerNOC commits a demand-reduction amount in MW to Idaho Power that EnerNOC is obligated to meet during a demand-reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand-reduction event in aggregate. Customers can also continuously monitor their demand-reduction performance using their individual, near real-time energy-usage data through EnerNOC's proprietary software. This metering data and software are available to participating customers throughout the year.

## 2014 Program and Marketing Activities

In 2014, Idaho Power worked with EnerNOC to implement changes that would better align the program with the Settlement Agreement approved by the IPUC in Case No. IPC-E-13-14. The changes included extending the contract termination date through the end of 2014, reducing payments to EnerNOC, amending the payment structure, removing the lower bound of EnerNOC's committed load reduction, modifying the program availability dates to June 15 through August 15, and allowing notification of dispatch of a demand response event to occur through a web portal.

During the first week of the program, EnerNOC committed to provide a meter-level reduction of 29.6 MW. This weekly commitment, or nomination, was comprised of 92 facility sites, of which 90 participated in the program in 2013, and two were added in 2014. The weekly nomination at the end of the season was 25.7 MW and was comprised of 93 facility sites.

EnerNOC was contractually obligated to commit to provide a maximum meter-level reduction of 35 MW for each week in 2014. Their weekly commitments ranged from 25.6 MW to 30 MW. Their commitment peaked the first week in July at 30 MW.

Idaho Power called three demand response events for the FlexPeak Management program in 2014. The first two events occurred in July, and the third event occurred in August. EnerNOC exceeded the committed MW reduction in two of the three events. For the third event, EnerNOC did not reach their committed MW reduction; performance was 96 percent of the committed level. The highest hourly reduction achieved was 39.6 MW, calculated using 9.7-percent line losses (36.1 MW at the meter).

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must be no more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective because there is no variable incentive paid for events beyond the three required events.

The FlexPeak Management program was dispatched for 12 event hours and achieved a maximum demand reduction of 40 MW. The total expense for 2014 was $1,563,211.

## Customer Satisfaction and Evaluations

EnerNOC sent a post-season survey via email to 93 participants representing all the sites enrolled in the program for 2014. Thirteen participants responded for a 14-percent response rate. All of these responses were slightly down from the previous year:

- When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was 9.2.
- When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8.7.
- When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8.2.
- When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.8.

A summary of the results is in *Supplement 2: Evaluation*. Also included in the supplement is the *FlexPeak Management Annual Report*.

## 2015 Program and Marketing Strategies

Idaho Power has proposed to internally run and manage the FlexPeak Management program, changing the name to the Flex Peak program starting in 2015. As of December 31, 2014, Idaho Power's contractual obligation agreement with EnerNOC ended. Idaho Power reviewed and received feedback from EEAG on the idea of running the program internally during a conference call on January 9, 2015. Idaho Power filed an application with the IPUC on February 4, 2015 (IPUC Case No. IPC-E-15-03), and filed an advice with the OPUC on March 10, 2015. Prior to this decision in fall 2014, the company conducted an informal inquiry with 25 of the largest participants in the FlexPeak Management program. The company asked them how they might respond to a change in the way the program was designed and managed. The responses generally indicated they would likely participate even if the program changed and they were not provided with the same monitoring and coaching services EnerNOC had provided. The feedback supported Idaho Power's proposal to internally run the Flex Peak Program. Current Flex Peak Program customers were notified on February 11, 2015, that EnerNOC would no longer be managing the program and that the company had filed an application with the IPUC to internally manage the Flex Peak Program.

There are several benefits to a company-managed program. First, the company has identified significant annual cost savings. These cost savings directly impact customer-provided funds. Second, the company-offered program would require each participating customer to adhere to the terms and conditions, and receive payments, as available under the Idaho and Oregon tariff schedules publically available. Last, the company welcomes any opportunity to cross-market energy efficiency programs and strengthen the communication and relationship with its customers directly.

Pending IPUC and OPUC approval, the Flex Peak Program will be available from June 15 through August 15, Monday through Friday, from 2:00 p.m. to 8:00 p.m., excluding holidays. Each dispatch

event will last up to four hours per participant within the available program hours. Dispatch events will not occur more than 60 hours per season. In the event of a system emergency, demand response capacity from the Flex Peak Program will be available. Idaho Power will conduct a minimum of three dispatch events per season. There will be two hours of advance notice to participants.

As per the settlement agreement, Idaho Power has proposed to maintain the current capacity of 35 MW during the 2015 program season. The company believes it can retain current participants and enroll new customers to meet this 35 MW amount. In 2015, Idaho Power will market the Flex Peak Program as needed to acquire enough participation to meet the 35 MW target. The marketing strategies will include a variety of channels, including field interaction by CRs and MCRs, and direct mailers.

# Oregon Commercial Audits

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 16 | 18 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $9,464 | $5,090 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $9,464 | $5,090 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program as required by ORS 469.865 offered under Oregon Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2014 Program and Marketing Activities*

Idaho Power sent out its annual mailing to 1,574 Oregon commercial customers in late September 2014. Customers were notified of the availability of no-cost energy audits and were provided with the Idaho Power publication *Saving Energy Dollars*. Sixteen customers requested an audit, and five customers requested only the brochure. Of the 16 audits, 12 audits were completed by Idaho Power, and 4 were completed by a third-party contractor. The costs were up in 2014 over 2013 because an ongoing invoice for audits performed late in 2013 was not paid for until early 2014.

Idaho Power contracts with EnerTech Services to perform a portion of the requested audits. Energy audits include a review of the customer's past billing data and an inspection of the building shell, HVAC equipment, operating schedules if available, and lighting systems. Additionally, specific business operating practices that can be incorporated to improve energy use are discussed. During the audits, customers receive Idaho Power energy efficiency program information.

## Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82. Since the required parameters of the Commercial Energy Audit Program are specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost-effective. Idaho Power claims no energy savings from this program.

## Customer Satisfaction and Evaluations

Audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Both activities can lead to energy efficiency projects being undertaken. Customers are generally pleased with the audit process. This is especially true when the business owner is fully engaged in the audit. Business owners can make the decisions to change operating practices or make capital improvements designed to use energy wisely. Additionally, the audits help identify energy-saving opportunities that may not be obvious to the business owner.

## 2015 Program and Marketing Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities. The audits help pinpoint favorable energy-saving actions that customers may pursue through customer behavioral changes or potential capital projects, such as replacing inefficient lighting. Additionally, the audit process will be used to introduce customers to Idaho Power's energy efficiency incentive programs. The program will be marketed through the annual customer notification.

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# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is composed of agricultural customers operating water-pumping or water-delivery systems to irrigate agricultural crops or pasturage. End-use equipment primarily consists of agricultural irrigation pumps and center pivots. The irrigation sector does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2014, the active and inactive irrigation service locations totaled 18,773 system-wide. This was an increase of 1.5 percent compared to 2013, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow-irrigated to sprinkler irrigation systems. Irrigation customers accounted for 1,966,297 MWh of energy usage in 2014, which was a decrease from 2013 by over 6 percent due to a cooler, wetter summer. This sector represented nearly 14 percent of Idaho Power's total electricity usage and about 25 percent of the summer coincident peak demand. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to provide a system peak resource and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind offering in which motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor up to 5,000 hp for agricultural uses that receives a verified Green Rewind. Participation in Green Rewind ensures the motor's original efficiency is maintained if it is rewound at an approved service center.

In 2014, the Irrigation Peak Rewards program was back in full operation after temporarily being suspended for the 2013 season to address need and cost in light of the company's load and resource balance from the *2013 IRP* showing the company had adequate resources in the near-term. In spring 2014, Idaho Power successfully marketed to the majority of prior participants to continue their participation in the programs, with only an approximated 9-percent drop in potential load reduction from 2013 even though incentives to participate were reduced.

The Irrigation Efficiency Rewards program, in operation since 2003, experienced annual savings that were nearly the same, with 18,511 MWh in 2013 and 18,464 MWh in 2014. During 2014, the Irrigation Efficiency Rewards program contributed 18,428 MWh, while the 15 motors in Green Rewind contributed 35,083 kWh per year of energy savings.

Table 13 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

# Programs

Table 13. 2014 irrigation program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| Irrigation Peak Rewards | 2,225 service points | $ 7,597,213 | $ 7,597,213 | n/a | 295 |
| **Total** | | **$ 7,597,213** | **$ 7,597,213** | **n/a** | **295** |
| **Energy Efficiency** | | | | | |
| Irrigation Efficiency Rewards | 1,128 projects | $ 2,446,507 | $18,459,781 | 18,463,611 | 4.6 |
| **Total** | | **$ 2,446,507** | **$18,459,781** | **18,463,611** | **4.6** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 52 percent of Idaho Power irrigation customers surveyed in 2014 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 40 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 92 percent are “very” or “somewhat” satisfied with the program.

In response to a 2013 phone survey conducted by Hansa GCR regarding non-participants of Idaho Power irrigation energy efficiency program options, in 2014 Idaho Power identified irrigation customers that had not participated in either irrigation program. The company’s agricultural representatives (ARs) contacted a few potential customers in each region to ensure awareness of the Idaho Power offerings. To provide information in detail to Idaho Power irrigation customers, in 2014 the company created two irrigation-specific newsletters. Newsletters included energy efficiency information and other important information of interest to irrigation customers.

In 2015, Idaho Power ARs will continue contacting non-participants potentially eligible for program participation and will continue providing a newsletter at least twice a year.

# Irrigation Efficiency Rewards

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,128 | 995 |
| Energy Savings (kWh)[a] | 18,463,611 | 18,511,221 |
| Demand Reduction (MW) | 4.6 | 3.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,256,235 | $2,277,059 |
| Oregon Energy Efficiency Rider | $144,392 | $134,789 |
| Idaho Power Funds | $45,880 | $29,539 |
| Total Program Costs—All Sources | $2,446,507 | $2,441,386 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.016 |
| Total Resource Levelized Cost ($/kWh) | $0.119 | $0.098 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.67 | |
| Total Resource Benefit/Cost Ratio | 1.83 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind projects.

# Description

The Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help customers recover a portion of the costs of installing a new, more efficient irrigation system or energy-efficient improvements to existing systems.

Two options help meet the needs for major or minor changes to new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per the first year of kWh saved above standard installation methods, not to exceed 10 percent of the new system's cost. For existing system upgrades, the incentive is 25 cents per the first year of kWh saved, or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh usage of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in many situations, post-usage demand data are available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems where

small maintenance upgrades provide energy savings from 11 separate measures. These measures are as follows:

- New flow-control type nozzles
- New nozzles for impact, rotating, or fixed-head sprinklers
- New or rebuilt impact or rotating type sprinklers
- New or rebuilt wheel-line levelers
- New complete low-pressure pivot package
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand-lines, wheel-lines, and portable mainlines
- New wheel-line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on pre-determined average kWh savings per component.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power ARs sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits conducted by Idaho Power ARs evaluate prospective customers' potential savings. ARs from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing their knowledge of energy efficient designs and awareness of the program and promoting the program through the irrigation equipment distribution channels. Marketing efforts include direct mailings, ads in agricultural publications, and participation in agricultural workshops and conferences.

Because the irrigation sector is a load comprised primarily of motors, Idaho Power participates in Green Rewinds. It is an opportunity that enables customers to maintain the motor's original efficiency by ensuring proper rewind of the electric motor. Motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor 15 hp to 5,000 hp that receives a verified Green Rewind. The RTF approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings for industrial and agricultural applications. In 2013, the RTF updated the deemed-savings values.

## 2014 Program and Marketing Activities

In 2012, the RTF approved a plan to re-evaluate the deemed savings for each measure under the Menu Incentive Option. Idaho Power met with the RTF in early 2013 and evaluated the research done by the University of Idaho to study the savings impacts of the measures provided in the Menu Incentive Option. In April 2013, the RTF approved the updated savings under the RTF Small Saver category. The 2013 RTF-deemed savings have a slightly different component itemization for some measures.

For example, nozzle replacements, sprinklers, and replacement regulators were combined under one sprinkler package, and gasket and drain replacements were separated into two measures. ADM conducted an impact evaluation in 2013. In this evaluation, it was recommended Idaho Power align measures to be consistent with how the RTF has deemed savings. Idaho Power presented the RTF updated savings values and proposed program changes at the EEAG meeting February 6, 2014. After the EEAG presentation, the program was filed with the OPUC as Advice No. 14-04 and was approved effective May 16, 2014. The 2014 energy savings values reflect the new RTF values for 2014.

Of the 1,128 irrigation efficiency projects completed in 2014, 1,000 were associated with the Menu Incentive Option, providing an estimated 14,051 MWh of energy savings and 2.75 MW of demand reduction. The Custom Incentive Option had 128 projects, of which 70 were new irrigation systems and 58 were on existing systems. This option provided 4,377 MWh of energy savings and 1.83 MW of demand reduction for the year. Also during 2014, irrigation customers contributed 35,083 kWh of energy savings from 15 motors participating in the Green Rewind opportunity.

Idaho Power ARs, the program specialist, and the agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2014, Idaho Power provided seven workshops promoting the Irrigation Efficiency Rewards program throughout the service area. Approximately 250 customers attended workshops in Blackfoot, Aberdeen, Eden, Twin Falls, Mountain Home, Nampa, and Ontario. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Shoshone, Hailey, Ontario, and Burley. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. In addition, ARs made target visits or communicated with a selected number of non-program participants to increase customer education. A database of irrigation dealers and vendors was maintained for direct-mail purposes. Irrigation dealers and vendors are a key component to the successful marketing of the program; therefore, direct mailings containing the most up-to-date program information, brochures, and dealer-specific meetings ensured correct program promotion.

The Irrigation Efficiency Rewards brochure was updated in spring 2014 and distributed to all irrigation rate schedule customers using direct mail. Idaho Power ARs also distributed large quantities to irrigation dealers and vendors in the service area.

In 2014, the newsletter *Irrigation News* was created to improve customer satisfaction with all irrigation customers in Idaho and Oregon. The newsletter shares valuable information specifically for irrigation customers to help clarify processes, help customers better understand their bill, provide information on energy efficiency and energy efficiency programs, clarify rates, and provide information on safety. The newsletter stimulated numerous opportunities to communicate and dialogue with irrigation customers on the variety of topics to help improve customer relations and promote the Irrigation Efficiency Rewards program. Media outreach included an Irrigation Efficiency Rewards success story provided to Capital Press about a project in Richfield, Idaho, that upgraded a farm’s irrigation system.

The total number of print publications that marketed the Irrigation Efficiency Rewards program consisted of 10 print ads in five agricultural print publications. Idaho Power also used two opportunities

in radio advertising during Agri-Action and the Future Farmers of America (now FFA) National FFA Week. New creative advertising material was launched in fall 2014 to promote Idaho Power's Irrigation Efficiency Rewards program. Four ads were created that targeted Idaho-specific crops, including potatoes, sugar beets, hay, and corn. Digital ads using the new creative material are being tested with the target audience to determine if they respond well to digital information sources. Digital ads are running in *The Capital Press* from December 19, 2014, to January 16, 2015, with a guaranteed 60,000 impressions during the cycle.

At the end of 2014, a postcard was mailed to all irrigation dealers and vendors thanking them for the integral role they play in the success of this program.

In 2013, Idaho Power conducted an impact evaluation of the Irrigation Efficiency Rewards program. This evaluation was performed by third-party contractor ADM. Data for the study was collected through a review of program materials and interviews with participating agricultural customers, agricultural trade allies, and Idaho Power staff. Based on the results of this evaluation, ADM provided recommendations for program improvement. Their recommendations and Idaho Power's 2014 responses are described below.

The evaluators suggested Idaho Power consider including NEBs as part of a comprehensive cost-effectiveness test for the program and that currently, there is no known previously published research conducted on NEBs for irrigation systems. ADM indicated the RTF provides values for societal costs and benefits for menu components. However, Idaho Power has identified the RTF benefits being referred to are already considered as part of the power system benefits and costs and are not considered NEBs. Idaho Power converted its previous NEB assumptions to a per-kWh basis as recommended by ADM and is currently collecting customer-calculated NEBs to more accurately account for these benefits. A new brochure and application providing an opportunity for customers to identify NEBs, such as yield, labor, and other benefits, was direct-mailed to all irrigation customers in May 2014.

ADM recommended that Idaho Power update the menu component incentives and expected savings to match the RTF. ADM noted that the 2013 version of the RTF combined the existing nozzle measure, low-pressure regulator measure, and sprinkler-head measures into a new "sprinkler package" measure. The application for the 2014 irrigation program should be revised to match the measures covered under the RTF. To comply with this ADM recommendation, changes to the Irrigation Efficiency Rewards program aligning the measures and expected savings to the RTF recommendations were presented to EEAG at the February 6, 2014, EEAG meeting. These changes were filed with the OPUC and approved in Advice No. 14-04, effective May 16, 2014, and are reflected in the new program brochure.

## Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements under the Custom Incentive Option and the Menu Incentive Option of Irrigation Efficiency Rewards.

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. On existing system upgrades, Idaho Power estimates the effectiveness of a project using a service point's previous five years of electricity usage history on a case-by-case basis depending on the applicant's history. On new system installations, the company uses standard practices as the baseline and determines the efficiency of the applicant's proposed project. Based on the specific equipment to be installed, the company calculates the estimated post-installation energy consumption of the system. The company verifies the completion of the system design through aerial photographs, maps, and field

visits by Idaho Power ARs to ensure the irrigation system is installed and used in the manner the applicant's documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure deemed savings are appropriate and reasonable. Payments are calculated on a prescribed basis by measure. In some cases, the energy-savings estimates in the Menu Incentive Option are adjusted downward from deemed RTF savings to better reflect known information in how the components are actually being used. For example, a half-circle center pivot may use half as much energy as a full-circle center pivot, or acres irrigated using spring water for a portion of the season reduces seasonal pumping kWh usage. All deemed savings are based on seasonal operating hour assumptions by region. If a system's usage history indicates it has lower operating hours than the assumptions, like the examples above, the deemed savings are adjusted.

Based on the deemed savings from the RTF, all the measures offered under the Menu Incentive Option are cost-effective with the exception of rebuilt or new brass impact sprinklers. Idaho Power determined these brass sprinklers meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power filed UM-1710 to request a cost-effectiveness exception with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

## 2015 Program and Marketing Strategies

Marketing plans for 2015 include conducting 7 to 10 customer-based irrigation workshops. Additionally, Idaho Power will continue to participate in five regional agricultural trade shows. These workshops and trade shows enable discussions between Idaho Power representatives, the company's customers, irrigation dealers, and trade allies while continually educating them about irrigation best practices, the program, and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power will work closely with customers who have participated in the Irrigation Efficiency Rewards program to create success stories by highlighting efficient irrigation system designs for program promotion.

The Idaho Power *Irrigation News* newsletter will continue to provide a direct line of communication on valuable information that will clarify processes, help customers better understand their bill, provide information on energy efficiency and energy efficiency programs, clarify rates, and provide information on safety, specifically for irrigation customers.

Idaho Power will continue to work with the Scientific Irrigation Scheduling (SIS) sub-committee consisting of RTF members, utility representatives, and professional experts to determine the potential for SIS programs.

A 2015 media plan was created aimed at increasing the impact of advertising on this program. Idaho Power will continue to promote the program in print ads in agricultural-focused editions of Idaho newspapers and agriculture magazines. The effectiveness of online ads will be evaluated with this target audience.

In early 2015, Idaho Power will test the effectiveness of translating various agriculture workshops and presentations into Spanish. The company will look at how this is received and make appropriate decisions moving forward.

# Irrigation Peak Rewards

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 2,225 | n/a |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 295 | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,374,724 | $407,496 |
| Oregon Energy Efficiency Rider | $104,995 | $30,117 |
| Idaho Power Funds | $6,117,494 | $1,634,494 |
| Total Program Costs—All Sources | $7,597,213 | $2,072,107 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

Idaho Power's 2014 Irrigation Peak Rewards program is a voluntary program available to Idaho and Oregon agricultural irrigation customers with service locations that had participated in the past. The purpose of the program is to minimize or delay the need to build new supply-side resources. By reducing demand on the most extreme load days in the most extreme summer conditions, the Irrigation Peak Rewards program can reduce the amount of generation and transmission resources Idaho Power needs to build. The program pays irrigation customers a financial incentive for the ability to turn off specified irrigation pumps with the use of one or more load control devices during the program season of June 15 through August 15. The Irrigation Peak Rewards program provides approximately 300 MW of load reduction, which is a capacity near 9 percent of Idaho Power's all-time system peak. This program, along with Idaho Power's other demand response program, has eliminated or delayed the need to build supply-side resources.

In 2013, Idaho Power filed IPUC Case No. IPC-E-12-29 to temporarily suspend the program to allow time to work with stakeholders and interested parties to determine how the program should operate in the future. These workshops resulted in settlement agreements reached in Idaho Case No. IPC-E-13-14 and Oregon UM 1653. The Irrigation Peak Rewards program was again offered as a demand response program in 2014, with some modifications. Program modifications resulted in an approximately $5 million in savings with only an approximately 9-percent drop in participation.

Per the terms in the settlement agreement, Idaho Power agricultural irrigation customers in both Idaho and Oregon that had service locations that participated in the past were eligible for participation in 2014. Customers could chose between two options: 1) an Automatic Dispatch Option that allows Idaho

Power to remotely turn off participants' pumps or 2) a Manual Dispatch Option designed for large-service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during a load control event. Historically, customers could choose a third option, the Electronic Timer Option. In 2014, this was discontinued. Customers who had service locations that had participated in the past in the Electronic Timer Option had the ability to participate by selecting the Automatic Dispatch Option.

For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. Only service locations that had participated in the past were eligible to participate in the program for 2014. Participating customers were guaranteed to experience at least three events per season. Dispatchable load control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday. The incentive structure consisted of fixed and variable payments. The fixed portion was paid based on participation during each of the first three events. The variable incentive was applied based on participation in events following the first three. Customers who chose to participate until 9:00 p.m. could receive a higher variable incentive for events that occurred after the first three. A control device attached to the customer's individual pump electrical panels allowed Idaho Power to remotely control the pumps. Participants in the Manual Dispatch Option were required to nominate the amount of kW they were enrolling in the program by June 1 of the program year.

Program rules allow participants the ability to opt out of dispatch events up to five times per service point. The first three opt-outs each incur a penalty fee of $5 per kW, while the remaining two opt-outs each incur a penalty fee of $1 per kW based on the current month's billing kW. The opt-out penalty fees may be prorated to correspond with the dates of program operation and are completed through manual bill adjustments. The fees will never exceed the amount of the incentive that would have been paid.

The incentive amounts that participating customers received per participating service location are listed in Table 14.

Table 14. 2014 program incentives

| Option | Fixed Demand Credit ($/billing kW) | Fixed Energy Credit ($/billing kWh) | Variable Energy Credit ($/billing kWh) | Extended Hour Variable Energy Credit ($/billing kWh) |
|---|---|---|---|---|
| Automatic and manual options ..... | $5.00 | $0.0076 | $0.148 | $0.198 |

## 2014 Program and Marketing Activities

After the Irrigation Peak Program suspension in 2013, Idaho Power used workshops, trade shows, and direct customer mailings to make a concerted effort to encourage past participants to re-enroll in 2014. Despite reinstating the program with a reduction in incentive amounts and modifications to the event notification, most past participants re-enrolled to participate in 2014. The number of service points enrolled to participate in the program for 2014 was 2,225. This accounted for approximately 81 percent of the eligible service points. Three load control events occurred in July 2014, with the highest load reduction occurring on July 10 and providing an estimated 295 MW on July 10.

In 2014, the program was only marketed to customers who had service locations that had participated in the program in the past. Idaho Power provided information about the 2014 Irrigation Peak Rewards program at seven workshops throughout the service area. Approximately 250 customers attended workshops in Blackfoot, Aberdeen, Eden, Twin Falls, Mountain Home, Nampa, and Ontario.

Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Shoshone, Hailey, Ontario, and Burley. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. Additionally, numerous one-on-one conversations with Idaho Power ARs informed customers of the 2014 program eligibility requirements and program offering.

An information flyer was made visually more appealing and easier to read by using a brochure format for existing Peak Rewards participants in December 2014. In October *Connections*, the program received recognition in the article *Demand Response Programs Ease Summer Peak*.

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must not be more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 295 MW. The total expense for 2014 was $7,597,213 and would have been approximately $10.8 million if the program was fully used for 60 hours.

## Customer Satisfaction and Evaluations

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load-reduction analysis, cost-effectiveness information, and program changes. A copy is included in *Supplement 2: Evaluation*.

In 2014, Idaho Power contracted PECI to complete an impact evaluation of the 2014 Peak Rewards program. The goals of the impact evaluation were to determine the demand reduction (in MW) during three actual called events and determine the counterfactual realization rate if an event been called on each business day during the program's June 15 through August 15 season.

PECI completed analyses of curtailment events held on July 2, July 10, and July 14, 2014, each containing four dispatch groups that curtailed enrolled irrigation pumps in rolling four-hour increments. The results of the curtailment event analyses showed maximum meter level demand reductions of 257.9 MW, 268.9 MW, and 250.5 MW, respectively, for the three events, which do not include system losses of 9.7 percent.

Due to the Irrigation Peak Rewards program suspension in 2013, annual device maintenance did not occur for nearly two years, resulting in a 7-percent device failure rate, as indicated in the evaluation report, lowering the overall realization rates. The past analysis of the program realization rates indicates they would be higher if device maintenance were at normal levels, resulting in fewer device failures.

As part of the impact evaluation, PECI developed a counterfactual realization rate analysis that demonstrated that the time period within an irrigation season has a large influence on the realization rate. With 2014 device failures excluded, realization rates ranged from 65 percent at the beginning of the program season to a peak realization rate of 74 percent during the first two weeks of July. The counterfactual realization rate in the last quarter of the season (August 1–15) dropped off significantly to 34 percent with device failures included. This was due to a high percentage of pumps being shut off during the first two weeks of August due to crop maturity and uncharacteristically extreme rainfall of 2 to 4 inches in southern and eastern Idaho. This resulted in a skewed realization rate that was an exception to what has been determined in past analyses.

The results of the impact evaluation showed Idaho Power's Irrigation Peak Rewards program functioned as intended, and, if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid. The evaluation also identified opportunities to maximize the demand reduction benefit the program delivers to the electricity grid. First, Idaho Power may increase the program's realization rate by working to address device failure problems. The uncharacteristically high number of device failures in 2014 provided valuable information on how to identify and address device failures. In an effort to increase realization rates by minimizing device failures, Idaho Power may also decide to use more AMI devices for load control in the future.

Finally, as seen in the counterfactual realization rate analysis results, maximum load reduction potential is realized during the peak of the irrigation season. This time period generally equates to the last week of June through the middle of July, which usually correlates to Idaho Powers' overall system peaks.

## *2015 Program and Marketing Strategies*

Idaho Power will continue to work with past participants in this program who are eligible to participate in 2015 to encourage their participation.

Idaho Power will conduct 8 to 10 workshops throughout the company's regions to familiarize customers to the program details and eligibility requirements. Through direct mail, each eligible customer will receive an informational packet containing a personalized letter, sign-up worksheet, informational brochure, and contract agreement encouraging their participation for the 2015 program season. Idaho Power ARs will continue one-on-one customer contact to inform and encourage program participation.

In early 2015, Idaho Power will test the effectiveness of translating various agriculture workshops and presentations into Spanish. The company will look at how this is received and make appropriate decisions moving forward.

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# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates the marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. Idaho Power has been a funding member of NEEA since its inception in 1997.

The fifth year of NEEA's current, five-year funding cycle ended in 2014. As early as 2009 Idaho Power expressed a desire to see a change in the way NEEA services were offered that would differentiate "core" services of market transformation activities from optional services, whereby utilities could elect to support projects and activities that matched their interests and needs. During 2014, the company continued to advocate for this model through multiple meetings with NEEA, by actively participating on the NEEA Board of Directors and exploring alternative funding models, and by chairing and serving on the Alternative Funding Model Working Group Committee of the NEEA Board of Directors. The end result of these efforts was that the NEEA *2015–2019 Business Plan* offered optional programs and activities. Idaho Power executed an agreement to continue its participation in NEEA and chose not to participate in some optional programs and activities where it believes it is providing or can provide the same services at a lower cost or more effectively for the 2015 to 2019 funding cycle. This delivers significant energy-savings potential and ultimately saves Idaho Power customers $3,304,560 when compared to the 2010 to 2014 funding cycle agreement.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports, generally through third-party contractors, for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

Idaho Power has participated by phone, online, or in person in a variety of NEEA activities. In 2014, Idaho Power energy efficiency staff served on NEEA's Board of Directors, the Regional Portfolio Advisory Committee, Residential Advisory Committee, Commercial Advisory Committee, Industrial Advisory Committee, Irrigation Advisory Committee, Cost-Effectiveness and Evaluation Advisory Committee, Consumer Electronics Energy Forward Initiative, Conduit online community, Regional Emerging Technologies Advisory Committee (RETAC), NWRRC, Northwest Heat Pump Water Heater Group, Code Collaborative, and Regional Lighting Strategy Working Group and participated in NEEA-sponsored studies and research.

Idaho Power also participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally. Idaho Power collaborates with regional utilities doing similar program evaluations or that may face similar program challenges.

### *Commercial and Industrial NEEA Activities in Idaho*

NEEA continued to provide support for commercial energy efficiency activities in Idaho in 2014. This included partial funding of the IDL and local BetterBricks® trainings and workshops.

Technical training and education continue to be important to Idaho Power's industrial customers, helping them identify energy efficiency opportunities within their facilities. Seven technical training classes were completed in 2014. Topics included compressed air, air-cooled refrigeration systems, pump systems, and fan system efficiency. The level of attendance at these classes remained high, with 119 participants attending the classes. See the Custom Efficiency program section for more details regarding the technical training classes.

Additionally, 2014 encompassed Phase IV of the webinar pilot plan coordinated by NEEA. Three webinars were presented free to all attendees. Topics included VFDs, efficient industrial lighting, and energy auditing and troubleshooting. There were 24 total Idaho Power region participants that attended the webinar sessions in 2014.

Idaho Power co-sponsored with NEEA a two-day RETA CRES review class training with 13 customers in attendance. The training reviewed refrigeration energy efficiency concepts and prepared the attendees for the RETA CRES Exam.

Idaho Power participated as a member of the NEEA Commercial Lighting Working Group. This group formed through collaboration with stakeholders to identify opportunities and strategic needs to support the region's success in commercial lighting. NEEA launched its first strategy from this report in November 2013, a market test of a midstream RWLR Initiative. The initiative goal is to change the pricing, stocking, and sales practices of reduced-wattage fluorescent T-8 lamps in the maintenance market. Targeted electrical distributors across the region were selected for participation. No distributor in Idaho Power's service area was selected for participation. Results of this pilot will be available in 2015. The pilot results will be used to determine whether NEEA, in coordination with stakeholders, will scale this program in 2015 across the region to try to transform this largely untapped market. NEEA's second strategy, Top-Tier Trade Ally Training, is in the development stage. This strategy will provide advanced lighting training to high-performing trade allies throughout the region, with an end result of achieving deeper energy savings in commercial lighting retrofit projects. Development of this strategy will continue throughout most of 2015, with implementation of pilot trainings in Idaho in 2016.

Idaho Power continued its partnership with BOMA of Boise and NEEA to offer continued coaching and support to the Kilowatt Crackdown™ participants in 2014. In 2013, 43 buildings competed in the competition, which included benchmarking their building in ENERGY STAR® Portfolio Manager and implementing low-cost and no-cost efficiency measures. In 2014, this effort was continued with ongoing coaching and support to further their energy efficiency efforts.

NEEA's pilot project in Idaho for their Existing Building Renewal (EBR) initiative was ongoing in 2014. This initiative is aimed at developing and testing new industry tools for commercial property owners engaging in deep energy retrofits. The Idaho project will be phased in through 2016. Idaho Power worked with The Idaho Statesman's *Business Insider* to feature the EBR initiative as their January cover story, along with other articles about *Retrofitting for the Future*. The issue appeared January 15, the same day Idaho Power issued a press release recognizing a local commercial real estate firm for its participation in the initiative.

In 2014, NEEA continued to have demonstrations on projects on variable-rate irrigation (VRI) and variable-speed irrigation (VSI) at various locations. VRI works by allowing a varied amount of water coming out of each sprinkler along an irrigation pivot. VSI is where the speed of the pivot irrigation system is varied as it makes a rotation for irrigation. The potential for energy savings exists with both technologies if different areas of the field have different water requirements. Information from NEEA indicated additional technical development was required and the adoption of the technology

would be challenging. The NEEA Board of Directors voted to remove the Initiative from the portfolio in the *2015–2019 Business Plan*. NEEA staff completed the 2014 demonstrations and a series of final reports that document the qualitative and quantitative findings from the three years of the Initiative. A copy of the reports will be included on the CD accompanying *Supplement 2: Evaluation* in next year's *Demand-Side Management 2015 Annual Report*.

NEEA also worked with Oregon State University to develop a common set of data standards for vendors or manufactures to better integrate technologies such as soil sensors, flow meters, pumping systems, and pivot systems—including VRI & VSI—to promote the combination of irrigation technologies for increased efficiency of water use. In 2015, through its scanning efforts, NEEA will continue to evaluate the usefulness and usability of the data standards.

## Residential NEEA Activities in Idaho

NEEA supported a variety of residential programs and associated activities in Idaho Power's service area in 2014. NEEA is directly involved in providing additional funding and support for ENERGY STAR® Homes Northwest, the DHP Pilot, and the Heat Pump Water Heater (HPWH) research project. Idaho Power served on workgroups for the DHP, HPWH, Retail Product Portfolio, RETAC, and a short-term dryer specification workgroup. Idaho Power participated in the Conduit online community and the Northwest Regional Retail Collaborative.

NEEA provides ENERGY STAR Homes Northwest builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates the various building specifications and requirements with the EPA and utilities in Idaho, Montana, Oregon, and Washington. Most of these activities are managed through a third-party implementer hired by NEEA.

NEEA is taking energy-efficient homes to the next step above ENERGY STAR with its Next Step Homes pilot program. The goal of this innovative pilot program is to identify the most cost-effective ways to achieve maximum energy savings in residential new construction. NEEA recruited builders throughout the Northwest to build to a high-performance specification, then installed monitoring devices in the homes to track energy-saving performance. NEEA is currently trying to recruit a Next Step Homes builder in Idaho Power's service area.

NEEA has coordinated the DHP Pilot research project since 2009, which includes data collection, design, results analysis, savings calculations, and ongoing promotional activities. Idaho Power was a member of the NEEA Ductless Heat Pump Workgroup during 2014. The goal of the pilot is to encourage the adoption of these products while displacing the use of existing electric-resistance zonal heating systems in homes. NEEA created and launched a regional marketing program, which was conducted during summer and fall 2014. The goal of the program was to increase consumer awareness of DHPs. The promotion included the use of social media, as well as radio, television, and website ads. Idaho Power currently offers a $750 cash incentive for qualified homeowners who install a qualified DHP system.

NEEA coordinated a residential HPWH research project in the Northwest region that started around five years ago. Idaho Power was represented on the NEEA HPWH Workgroup during 2014. A goal of the project is to promote the adoption of higher-efficiency HPWHs over traditional resistance-heat water heaters. Another goal is to provide a business case to the DOE encouraging the DOE to make the federal standards and test methods for domestic electric water heaters more stringent. The research project includes data collection, design, analysis, savings calculations, and promotions. NEEA's promotions included rebates to residential homeowners who had certain HPWHs installed. The promotion required

the HPWH to be installed by a contractor trained by NEEA. NEEA also arranged for a HPWH discount program to be offered through retailers. The research project was conducted in 2014 and will continue in 2015. Idaho Power is monitoring this research closely to determine when a northern tier HPWH will be developed that is reliable and applicable to Idaho Power's climate zones.

NEEA developed a baseline forecast in fall 2012 describing the naturally occurring market adoption of HPWHs over a 20-year span. The baseline forecast excluded any market influence from utilities or NEEA initiatives. NEEA published the *NEEA Heat Pump Water Heater Baseline Forecast Research*, created by Evergreen Economics, on October 23, 2014. A copy of NEEA Report E14-300 is included on the CD accompanying *Supplement 2: Evaluation*.

NEEA performed field research beginning in fall 2013 to evaluate the ability for HPWHs to provide demand response to the electric grid. Field research involved fitting 20 homes in the Northwest with HPWHs. The water heaters received communication control signals from a remote third party. Units were tested for their ability to increase and decrease water heating electric load by adjusting storage tank temperature set points. On September 29, 2014, NEEA published the *Heat Pump Water Heaters for Demand Response and Energy Storage* created by Ecofys. A copy of the NEEA Report E14-296 is included on the CD accompanying *Supplement 2: Evaluation*.

In 2014, NEEA launched the RPP. Idaho Power participated in the advisory workgroup for the RPP. The RPP is based on the Consumer Electronics Energy Forward Initiative, which ended in 2013. The RPP used mid-stream incentives to influence retail stocking practices, ultimately driving manufacturing and standards for a portfolio of energy-efficient products sold through the retail channel.

The 2014 RPP goal was to expand and test the upstream approach with different product categories and different retailer types. To maintain relationships with electronics retailers developed under the Consumer Electronics Energy Forward Initiative, the RPP offered incentives on televisions and home theaters in box/soundbars. To test the model at big box, do-it-yourself retailers, the RPP offered incentives on air purifiers and dishwashers.

Idaho Power also participated in NEEA's Residential Advisory Committee meetings and activities throughout 2014. Additionally, one member of the residential programs team, one member of the commercial/industrial programs team, and one analyst attended NEEA's Efficiency Exchange in May 2014. In September 2014, the DSM residential lighting program specialist and a DSM program analyst participated in a one-day lighting summit hosted by NEEA. Summit participants explored ways to capture full-category retail sales data for light bulbs.

Idaho Power participated in RETAC, the purpose of which is to discuss and provide feedback on various emerging technologies in the region. RETAC met twice in 2014 to review the emerging technology pipeline for BPA, NEEA, and the NWPCC *Seventh Power Plan*. Technologies of particular interest to the group include $CO_2$ heat pumps, high-performance manufactured homes, LEDs and advanced controls, and home energy management systems.

An Idaho Power residential specialist was involved with the NWRRC in 2014. This collaborative forum evaluates and coordinates regional retail strategy. Activities of this group included two multi-year pilot projects. The first was aimed at understanding market lift promotions. The second aimed at improving retail contractors' participation in utility programs. The group also serves as the advisory workgroup to NEEA's RPP initiative.

## NEEA Funding

In 2014, Idaho Power began the fifth year of the 2010 to 2014 *Regional Energy Efficiency Initiative Agreement* with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2014, 100 percent was funded through the Idaho and Oregon riders.

In 2014, Idaho Power paid $3,305,917 to NEEA. The Idaho jurisdictional allocation of the payments was $3,140,621, while $165,296 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid from Idaho and Oregon Riders.

Final NEEA savings for 2014 will be released in June 2015. For the annual report, preliminary funder share savings for 2014 were assumed to be similar to 2013 final savings. In the *Demand-Side Management 2013 Annual Report*, the NEEA preliminary funding share savings reported were 18,346 MWh. The revised estimate included in this report for 2013 final funding share NEEA savings is 20,568 MWh. Preliminary estimates reported by NEEA for 2014 indicate Idaho Power's share of regional market transformation MWh savings for 2014 is 20,000 MWh. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at neea.org.

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# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative promotes energy efficiency to the residential sector. This is achieved by creating and delivering educational materials and programs that result in wise and informed choices regarding energy use and increase Idaho Power's energy efficiency program participation.

The Residential Energy Efficiency Education Initiative continued to produce semiannual energy efficiency guides in 2014. These guides were primarily distributed via insertion in local newspapers and at events across Idaho Power's service area. Process improvements implemented in 2014 include the following:

- Enhanced design elements identified in 2013 were repeated in the 2014 guides to further the publication's identity and strengthen readership recognition.
- Idaho Power's Technical Editing team provided expertise and training to improve readability.
- All past guides were updated to encourage continued use as presentation handouts and one-on-one distribution by Idaho Power's CRs.
- Focus groups provided feedback about the guide's format and content.
- Guide circulation was increased in two ways: 1) the *New Plymouth News* was added to the list of local newspapers distributing the energy efficiency guide and 2) the guide was included with each free, non-subscriber delivery of the *Blackfoot Morning News* and *Meridian Press*.

The *Spring/Summer Energy Efficiency Guide*—Inserted into 14 newspapers and delivered to 215,539 homes on April 27, 2014. The guide focused on helping customers understand how their behavior impacts their electricity bill. The guide highlighted Idaho Power's myAccount as a tool to help learn about energy use, answered questions about how and why weather impacts energy use, offered tips for keeping costs down during extreme weather, and encouraged customers to consider the value proposition for energy efficiency when buying, selling, and remodeling their homes. It also contained a suggested "path" for becoming energy efficient at home.

The *Fall/Winter Energy Efficiency Guide*—Inserted into 16 newspapers and delivered to 237,144 homes on October 26, 2014. The guide focused on ways to keep heating bills down on a limited budget and specifically targeted lighting as an all-around energy efficiency opportunity available to all. The guide offered suggestions for benchmarking home energy use using myAccount and current energy codes. It also presented Idaho Power's various residential programs via a simple, colorful chart to help customers compare relative costs, benefits, and eligibility details for each program.

The release of each guide received public relations support through numerous communication channels, including an item in the weekly *News Briefs* email to all media (April 21 and October 28) and a feature during the monthly live studio energy efficiency segment on KTVB-TV on October 27. The November issue of Idaho Power's *Connections* customer newsletter included an image display for the guide as well.

In 2014, 10,351 additional guides were distributed at energy efficiency presentations and events, up from 3,447 in 2013. This increase is an indication of their ongoing value and success of the strategy to prolong the shelf-life of these guides. Links to current guides were given prominent positions on Idaho Power's website during the appropriate seasons. Additionally, the full selection of energy efficiency guides was made available for viewing and download via Idaho Power's website.

As part of Idaho Power's Account Manager team, the Residential Energy Efficiency Education Initiative staff played a key role by gathering research from neighboring utilities and organizing customer and employee focus groups. These groups provided insight into how customers interacted with the tool and what features might best be used to market the tool. Following the focus groups, the tool's name was changed from Account Manager to myAccount and two of three key messages for the advertising campaign were focused around educating customers about their individual home's energy use.

As a result of customer comments gleaned from the spring focus groups conducted by MDC (discussed in-depth in the Marketing section), marketing tactics were used in November to expand the distribution channels and test the demand for the *Fall Energy Efficiency Guide* and the 96-page booklet *30 Simple Things You Can Do to Save Energy*. The following marketing tactics were used to drive demand for these publications:

- A display image appeared in the November issue of the *Connections* customer newsletter, which was delivered to approximately 415,000 customers.
- Bill inserts were placed in over 40,000 residential customer bills.
- A digital ad campaign ran from October 25 to November 23.

All advertising drove customers to a webpage where they could request printed copies mailed directly to their homes. They could also view the publications online or download printable versions. For those customers without internet access, a toll-free number was provided and an order form was included on the bill insert. Based on the marketing campaign, another 587 *Fall/Winter Energy Efficiency Guides* and 582 *30 Simple Things You Can Do To Save Energy* were mailed by request directly to customers.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of other communication methods during 2014. Increased customer awareness of energy-saving ideas was accomplished via continued distribution of the third printing of the 96-page booklet *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. During the year, 9,070 English and 623 Spanish copies were distributed directly to customers via community events and local libraries; by CRs during in-home visits; by participating contractors in the Home Improvement Program, Energy House Calls, H&CE Program, and See ya later, refrigerator® program; through direct web requests; and in response to inquiries received by Idaho Power's customer service center.

Idaho Power continues to recognize that educated employees are effective advocates for Idaho Power's energy efficiency programs. To keep energy efficiency top-of-mind among employees, an educational video was produced. Each employee received a personal email invitation to view the video and become an ambassador for energy efficiency by learning about the company's energy efficiency programs.

The Kill A Watt™ Meter Program remained active in 2014. Idaho Power's customer service center and field staff continued to encourage customers to learn about the energy used by specific appliances and activities within their homes by visiting a local library to check out a Kill A Watt meter. A second

hands-on table display was developed and made available to assist libraries in engaging patrons, promoting energy efficiency, and increasing circulation of the energy efficiency kits. Additionally, the Kill A Watt meters were featured during a live studio news program on KTVB-TV in Idaho Power's monthly energy efficiency segment with Idaho Power's CR&EE manager.

As in previous years, Idaho Power took the lead in strengthening the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2014, 16 teachers completed the 4-day, 2-credit professional development seminar facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Lab (INL).

Idaho Power continued its co-sponsorship of the US Green Building Council lecture series, *Sustainable Energy Sustainable Homes*. In 2014, Idaho Power provided additional support to extend the reach through web-based video broadcasting of live seminars and recorded content and PowerPoint slides available for online reference. The eight workshops, facilitated by local trade experts, provided information and expertise to encourage energy efficiency upgrades. These sessions continue to be popular with homeowners, builders, developers, and architects, with 143 attending in 2014. Idaho Power also opened discussions regarding a new partnership with the City of Meridian to produce an energy-related video emphasizing wise energy use as part of the city's *It Starts at Home* campaign.

Idaho Power continued to engage communities in energy efficiency discussions at many community events throughout Idaho Power's service area. In April, Idaho Power continued to sponsor the Portneuf Valley Community Environmental Fair and actively promoted attendance at this event with a bill message for communities surrounding Pocatello. Idaho Power's Pocatello CRs staffed the booth and promoted wise energy use and participation in energy efficiency programs.

In September 2014, Idaho Power participated in the FitOne Expo in Boise, Idaho. The event continued to be important due to the size of the audience and because Idaho Power surveys confirmed that the demographics of attendees continued to align with Idaho Power's residential energy efficiency target audience. In 2014, the booth theme capitalized on LED lighting imagery from the integrated campaign launched in August and previewed the energy efficient interactive home graphic in the background. Idaho Power staff at the event educated attendees about the benefits of LED lighting technology and distributed 2,500 LED light bulbs to an engaged and receptive audience.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 116 outreach activities, including events, presentations, trainings, and other outreach activities documented in the Outreach Tracking System. In addition to these activities, Idaho Power field staff throughout Idaho Power's service area delivered 164 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2014, Idaho Power's Community Education team provided 67 presentations on *The Power to Make a Difference* to 1,756 students. The CERs and other staff also completed 32 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 912 seniors in the company's service area. Additionally, Idaho Power's energy efficiency program managers responded with detailed answers to 288 customer questions about energy efficiency and related topics received via Idaho Power's website.

As part of National Energy Awareness Month in October, Idaho Power held its fourth annual student art contest in the Idaho Power service area, bringing energy education into the classroom and inspiring students and families to think more about energy. "Ways to Save Energy" was one of the categories, and both overall and regional winning students and their teachers were recognized.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries. In addition to supplying information for various Idaho Power publications, such as the *News Scan* weekly employee newsletter, the *Connections* customer newsletter, and Idaho Power's Facebook page, articles were written for the North End Neighborhood Association newsletter (circulation 5,300 print/341 electronic). Energy efficiency tips were provided for three of the monthly KTVB-TV news live studio interview segments.

Idaho Power also researched the possibility of working with a vendor to produce energy efficiency kits and age-appropriate curriculum for high school students. The idea was presented to EEAG as a potential new program in the August. With EEAG input, Idaho Power met with local high school teachers to refine the potential offering and revisited it with EEAG again in November. The next step in exploring this potential offering is to convene a committee of teachers for the purpose of gathering input, identifying appropriate deliverables, and preparing an RFP.

The initiative's 2015 goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. In addition to producing and distributing educational materials, the initiative will play an integral role in providing LED lighting education and distributing LED bulbs to customers. Idaho Power will improve the accessibility of educational information available to customers on the company's website and work with the Program Planning Group to explore behavioral program opportunities that may include an enhanced kit program, promotion of myAccount, home energy reports, or a pilot program to test another behavioral message, such as clothes drying rack adoption.

## Student Energy Efficiency Kit Program

The SEEK program provides fourth- to sixth-grade students in schools in Idaho Power's service area with quality, age-appropriate instruction regarding the wise use of electricity. Each child that participates receives an energy efficiency kit. The products in the kit are selected specifically to encourage energy savings at home and engage families in activities that support and reinforce the concepts taught at school.

For the 2013 to 2014 school year addressed in this report, Idaho Power partnered with the National Energy Foundation (NEF) for the 2013 fall semester and Resource Action Programs (RAP) for the 2014 spring semester. NEF's partnership for the fall 2013 semester ended Idaho Power's test year, and RAP was selected as Idaho Power's long-term partner beginning January 2014.

During the 2013 to 2014 school year, 6,312 kits were delivered to 208 classrooms in 73 schools within Idaho Power's service area, resulting in 1,491 MWh of first-year savings. In fall 2013, program participants were recruited by invitation from a regional Idaho Power CER, resulting in 2,419 student participants. In spring 2014, the program was marketed to all elementary schools with open enrollment, resulting in 3,696 student participants.

Once a class enrolled in the program, teachers received curriculum and supporting materials. Students received classroom study materials, a workbook, and a take-home kit containing three CFLs, a high-efficiency showerhead, an LED nightlight, a furnace filter alarm, a digital thermometer for measuring water, refrigerator and freezer temperatures, a water-flow rate test bag, and a shower timer. At the conclusion of the program, students and teachers returned feedback to the vendor indicating how the program was received and which measures had been installed. Each vendor used this feedback to provide a comprehensive program summary report showing program results and savings.

Teachers said they liked the program. Fall feedback indicated 97 percent of teachers said the content was good or excellent and they would recommend the program to colleagues. Spring feedback indicated 100 percent of teachers would recommend the program to other colleagues and 97 percent would conduct the program again. Student engagement was high as well—73 percent of student surveys were returned in the fall and 81 percent were returned in the spring.

Both NEF and RAP calculated annual savings based on information collected from the participants' home surveys and the installation rate of the kit items. Questions on the survey include the number of individuals in each home, water-heater fuel type, flow rate of the old showerhead, and the wattage of the bulb replaced. Based on this information, NEF estimates that fall 2013 participants saved 635,782 kWh per year. RAP estimates that spring 2014 participants saved 855,443 kWh per year. The total annual savings of 1,491,225 kWh appears under the Residential Energy Efficiency Education Initiative in the Appendices.

A copy of the complete report is included in *Supplement 2: Evaluation*.

## Easy Savings Program

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP and provide $125,000 to CAP agencies in the Idaho Power service area on a prorated basis. This order specified that Idaho Power provide educational information to customers who heat their homes with electricity provided by Idaho Power. This is being accomplished through the development and distribution of kits containing low-cost, self-install energy efficiency items and educational materials.

The Easy Savings Program straddles two calendar years. The LIHEAP program starts in November each year at CAP agencies, while Idaho Power summarizes activities based on a January to December cycle. However, the following report summarizes activities from November 2013 through October 2014 and covers future plans for the 2014 to 2015 program.

Three main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes by using energy wisely, allow hands-on experience while installing low-cost measures, and reduce the energy burden for energy assistance/LIHEAP applicants.

Each kit contained the following low-cost/no-cost energy saving items and a survey:

- CFLs (13 W and 18 W)
- Hot-water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers
- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets for the laundry
- *Quick Start Guide* to installation
- Mail-in survey

By April 2014, all 2,127 kits from the 2013 to 2014 program year were distributed by regional CAP agencies to Idaho Power customers approved to receive LIHEAP benefits on their Idaho Power bills.

The mail-in survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits. Returned surveys were used to track the effectiveness and educational impact of the program.

There were 202 completed surveys received from customers describing their experience in installing kit items in their homes during the 2013 to 2014 program. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit as well as questions confirming the installation of kit items.

Ninety-two percent of household respondents reported they have, or will, lower their heat during the day, and 84 percent reported they will lower their heat at night. Eighty-five percent of the households reported installing both CFLs provided in the kit, and another 7 percent said they installed one of the CFLs. Eighty percent of the households reported installing the high-efficiency showerhead.

Overall, survey results showed that over 62 percent of the households that received the kits and returned a survey installed five or more kit items. Seventy-nine percent of the respondent households reported learning a lot about saving energy and money in their home after completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

During the 2013 to 2014 program, three gift certificates valued at $100 each were provided by CAPAI to encourage survey completion. A drawing from all returned surveys was held July 2014. Three households won a $100 gift certificate.

For the 2014 to 2015 program, checks totaling $125,000 were sent by Idaho Power in September 2014 to the five Idaho regional CAP agencies. Each agency used 30 percent of the agency's allotment to cover expenses for administering the program at their agency. By the end of September 2014, an order for 2,067 kits was placed by CAP agencies. Kits were shipped from the vendor and received at CAP agencies in November 2014 for distribution to customers throughout the 2014 to 2015 LIHEAP season. One LED bulb replaced the CFLs this year.

Upon completion of kit distribution and receipt of corresponding survey results for the 2014 to 2015 program, Idaho Power and CAPAI will consider program changes for the future.

## Commercial Education Initiative

Since 2008, the Commercial Education Initiative has informed and educated commercial customers regarding energy efficiency, increased awareness of and participation in existing commercial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives.

This initiative is also used to educate and support trade allies and key stakeholders working in the energy efficiency market. A major strength of the initiative is the emphasis on building strategic relationships. Additionally, program specialists work closely with Idaho Power CRs assigned to commercial market segments to capitalize on their established relationships with customers.

The Commercial Education Initiative oversees the distribution of informational materials and works directly with trade allies and other market players who, in turn, support and promote Idaho Power's

energy efficiency programs. Routinely, individual site visits are conducted to educate customers on energy-saving opportunities at their business.

In 2014, Idaho Power carried out its plan to capitalize on effective customer projects by developing 11 success stories highlighting customers' energy efficiency projects for posting on Idaho Power's website. Copies of the success stories are provided in *Supplement 2: Evaluation*.

Other marketing efforts included a March and a November *ENERGY@WORK* newsletter created and mailed to all commercial customers. These newsletters had business-specific articles of interest, with an emphasis on energy efficiency. Idaho Power's customer newsletter, *Connections*, is distributed monthly in customers' bills. In 2014, two editions were devoted exclusively to energy efficiency content.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency programs. The Commercial Education Initiative works with and supports multiple stakeholders and organizations to increase customers' energy efficiency knowledge. Examples of key stakeholders include the IDL, BOMA, US Green Building Council, ASHRAE, IBOA, and the IFMA Northern Rockies Chapter. Through funding provided by Idaho Power, the IDL performs several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities include sponsoring a BSUG, conducting Lunch & Learn sessions held at various design and engineering firms, and offering a TLL. The TLL gives customers access to equipment that enables them to measure and monitor energy consumption on various systems within their operation.

In 2014, the Commercial Education Initiative supported two organizations that provide professional accreditation to their members. The IBOA offers Building Operator Certification to train building operators in the energy efficiency operation of their facilities. The IFMA teaches four modules of its Facility Management Professional (FMP) credential. The FMP training equips facility managers with the knowledge and skill sets to promote, justify, and implement sustainable and energy efficiency projects and programs within their facilities.

Plans for 2015 include 1) working with Idaho Power marketing specialists to increase customer awareness of the company's energy efficiency programs and their specific offerings; 2) coordinating training opportunities for CRs and trade allies to increase their energy expertise; 3) continuing to support key stakeholders that train, educate, and support the advancement of energy efficiency practices; 4) conducting outreach and education activities through the IDL; and 5) supporting customers via facility walk-throughs, including energy audits.

## Regional Technical Forum

The BPA and the NWPCC established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating on various sub-committees.

The forum's purpose is to advise the BPA; the NWPCC; the region's utilities; and organizations, including NEEA and the Energy Trust of Oregon (ETO); on technical matters related to energy efficiency. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and resource goals. Additionally, the RTF provides feedback and suggestions for improving the effectiveness of regional energy efficiency programs. The RTF also recommends a list of eligible energy efficiency measures and the estimated savings associated with those measures. Idaho Power uses the information provided by the RTF when conducting research and

analysis on new and current measures. The RTF meets monthly to review and provide comments on analyses and other materials prepared by the NWPCC, BPA staff, and RTF contractors. Idaho Power uses the savings estimates and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics. In 2014, Idaho Power staff participated in all of the RTF's meetings and was involved in various sub-committees, including the RTF Policy Advisory Committee.

In 2014, the RTF continued efforts to bring measures and documentation in line with the protocols and guidelines put in place in 2012. Additionally, the RTF wrapped up the work began in 2013 to calibrate the residential building energy model commonly referred to as the SEEM model for existing and new construction single family homes. The results from the region-wide 2011 RBSA study, which included on-site home inspections of a regional representative sample of single-family, multi-family, and manufactured homes, were analyzed by the RTF to calibrate the SEEM model inputs. The SEEM calibration impacts all of Idaho Power's residential weatherization and HVAC measures. Idaho Power participated in the SEEM Affected Measures Workgroup throughout the process and provided feedback on the proposed methodologies and support documentation prepared by RTF contract staff. The results for SEEM calibration for manufactured-home savings are expected to be completed by RTF staff in 2015.

Additionally, Idaho Power representatives participated in the SIS sub-committee. SIS is a behavior-based agricultural program to optimize irrigation. A calculator converts water reduction to kWh savings. The current RTF SIS protocol is out of compliance with the current RTF guidelines. BPA, in partnership with the RTF, developed a research plan and standard protocol to bring the measure into compliance. BPA plans to implement the study during the 2016 growing season with the sample segmented based on the "high" and "medium to low" water-level crops within the two geographic areas in the population: the Columbia Basin and southern Idaho. Idaho Power representatives will continue to participate and lend their expertise to the sub-committee in 2015.

## University of Idaho Integrated Design Lab

Idaho Power is a founding supporter of the IDL. The IDL is dedicated to the development of high-performance energy-efficient buildings in the Intermountain West. Idaho Power has worked with the lab since its inception in 2004 as part of efforts to educate customers about the value of energy efficiency to businesses, as well as to the businesses' customers. On January 21, Idaho Power helped sponsor the 10th anniversary celebration of the IDL in Boise, participating in the open house and tour of the facility. Company representatives recognized the lab's commitment to high-performance energy-efficient building through research, education, and outreach efforts in the Intermountain West. Idaho Power issued a media advisory, inviting members of the press to attend the event and share the story of the IDL's success.

In 2014, Idaho Power entered into an agreement with the IDL to perform the following 14 tasks.

### *Building Metrics Labeling*

The goal of this task was to expand on the 2012 and 2013 development of Building Metrics Labeling (BML), a graphical display of four building metrics on a single sheet. The metrics displayed are Energy Use Intensity (EUI), ENERGY STAR® score, Walkability, and Space Daylit Area. The purpose of the BML sheet is to increase awareness of building energy use and promote energy efficiency during the sale or lease of commercial properties.

In 2013, a beta version web-based portal for self-directed use of a building's data to create BML sheets was created. The final version became available for public use in early 2014.

In addition to finalizing the portal, the IDL followed up with previous users of the BML sheets and supported new users. The IDL promoted the BML sheet at a BOMA monthly luncheon meeting and to the City of Boise in conjunction with an educational Lunch & Learn session. It was also marketed at the 2014 BOMA Symposium and the Kilowatt Crackdown™ Awards ceremony. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Lunch & Learn

The goal of the Lunch & Learn task was to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions. This series includes sessions outside the Treasure Valley.

In 2014, 20 technical training lunches were scheduled in Boise, Pocatello, and Ketchum. The trainings were coordinated directly with architecture and engineering firms and organizations and were attended by a total of 281 architects, engineers, interior designers, project managers, and others. Nineteen sessions were held in 2014. Due to a 2014 scheduling conflict, one remaining session is scheduled for January 29, 2015.

Fourteen sessions were offered in Boise, two in Pocatello, three in Ketchum, and one in Chubbuck. The topics of the lunch sessions (and quantity of each) were: *High Performance Retrofits* (1), *Integrated Design Principle* (2), *Integrated Design Lab Overview* (2), *Radiant System Design Considerations* (2), *Daylight Sensing Electric Lighting Controls* (2), *High Performance Classrooms* (2), *Climate Responsive Design—Tools and Methods* (1), *M&V + Tool Loan Library* (1), *Architectural HVAC Integration Strategies* (2), *Integrated Design Case Studies* (2), *Daylight in Buildings: Schematic Design* (1), *Daylight in Buildings: Getting the Details Right* (1), and *Benchmarking, M&V, + Tool Loan Library* (1). The report is located in the IDL section of *Supplement 2: Evaluation*.

## Fall Educational Series

The goal of the Fall Educational Series was to educate architects, engineers, building owners, building operators, designers, and construction professionals about energy efficiency through a series of publicly available evening lectures.

In 2014, the title of the series was *Design Decisions and Outcomes*, which focused on design decisions and strategies for energy efficiency. Four sessions were held that featured topics that supported this concept. The topics were *Developer Choices and Local Stories, Design for Off: A Seattle HVAC Case Study, Outstanding Local Projects*, and *Integrated Lighting Practices*. Each session consisted of 1.5 hours of lecture followed by time for questions. The sessions were held at Idaho Power's CHQ and were offered live, as well as broadcasted webinars. The live and remotely broadcasted presentations had 92 total participants. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Simulation Users Group

The goal of this task was to facilitate the Idaho BSUG, which is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

In 2014, 11 monthly BSUG sessions were hosted by the IDL. In most cases, the IDL taught the sessions themselves or brought in outside speakers. The sessions were made available remotely and were

attended by 179 professionals in person and 318 professionals remotely. Evaluations forms were completed by attendees for each session. On a scale of 1 to 5, with 5 being excellent and 1 being poor, averaging results from all seven questions, the average session rating was 4.0 for 2014.

Finally, each presentation was archived on the BSUG 2.0 website along with general BSUG-related content. The BSUG 2.0 site logged 2,150 total visits with 1,132 specific to Idaho users in 2014. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Foundational Services

The goal of this task was to provide energy efficiency technical assistance and project-based training to building industry professionals and customers. When the IDL receives requests for their involvement in building projects, the projects are categorized into one of three types. Phase I projects are simple requests that can be addressed with minimal IDL time. Phase II projects are more complex requests that require more involvement and resources from the lab. Phase III projects are significantly more complex and must be co-funded by the customer.

In 2014, the IDL provided technical assistance on 37 Phase I projects, 9 Phase II projects, and 3 Phase III projects. Overall, 35 percent of the projects were on new buildings and 65 percent were on existing buildings. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Efficiency Verification

The goal of this task was to continue random installation verification of over 10 percent of Building Efficiency applications provided incentives. This consisted of conducting a full review of documentation and complete on-site inspections to validate whether noted systems and components had been installed. The purpose of this verification was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations.

This task also included the review of all daylight photo-control incentives to verify site conditions and improve the quality of design and installation.

The IDL completed on-site field verifications for the Building Efficiency program as summarized in the Building Efficiency program's Customer Satisfaction and Evaluations section presented earlier in this *Demand-Side Management 2014 Annual Report*. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Tool Lending Library

The goal of this task was to operate and maintain a measurement equipment TLL, including a web-based equipment tool loan-tracking system, and provide technical training on how each tool is intended to be used.

The inventory of the TLL, which has been built up in previous years, now consists of over 900 individual pieces of equipment. The tools are available for customers, engineers, architects, and contractors in Idaho Power's service area to borrow at no cost to aid in the evaluation of energy efficiency projects and equipment they are considering.

There were 37 tool loan requests in 2014, which included a total of 286 tools loaned. There were 14 tools purchased or acquired in 2014 for the TLL. The tools were loaned to engineering firms or

equipment representatives, educational institutions, industrial plants, and office/commercial facilities. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Simulation Quality Assurance

The goal of this task was to provide energy simulation QA by conducting pre- and post-measurements and verifications to compare modeled savings to realized savings on selected projects. The IDL accomplished this by reviewing energy simulation techniques used to estimate facility consumption, conducting on-site measurements used to calibrate and validate the energy model, performing energy management system data extraction, analyzing actual bill and weather data, and creating a report detailing findings and lessons learned from each project.

The information gained from these activities is conveyed to the local design community through other education and outreach tasks, such as the BSUG and Lunch & Learn sessions, both described above. Additionally, system issues have been uncovered and corrected due to the investigation associated with these efforts, which helps ensure persistence of energy savings. In 2014, four highly visible and innovative projects were analyzed, consisting of a local architectural and engineering firms' new radiant cooling system, a university classroom building, and two mid-sized commercial buildings. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Heat Pump Calculator

The goal of this task was to develop an Excel-based heat pump analysis tool to calculate energy usage and savings based on site-specific variables for commercial buildings. It was determined there was a lack of sophisticated heat pump energy-use calculators available with the capability of comparing the energy use of heat pumps in commercial buildings against other technologies in a quick, simple fashion. The tool was developed in 2013 and underwent testing in early 2014. Feedback from validation testing has been integrated into the current version of the tool. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Planning and Commissioning for Daylight Harvesting

The goal of the Daylight Harvesting task in 2014 was to expand on the previous task of creating a hands-on demonstration and training for electrical contractors by offering on-site classes for them to learn the necessary skills to successfully install and commission daylight harvesting lighting-control systems.

Nine Daylight Harvesting classes were held in 2014. These classes were attended by 29 participants, representing 102 continuing education hours. The various control systems in the IDL space provided a great venue to educate electrical contractors and the design community on daylight-harvesting technology. Classes were held in a two-part series: Part 1 provided in-class training, and Part 2 provided hands-on commissioning education. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Customer Representative Training

The goal of the Idaho Power CR training task in 2014 was to develop and provide training to Idaho Power CRs to identify common energy efficiency opportunities in commercial buildings. The training consisted of three classroom style modules: Module 1: Pre-Walk Benchmarking and Analysis, Module 2: Typical Building Systems and Efficiency Opportunities, and Module 3: Specialty Systems and Efficiency Opportunities. This training was delivered across the Idaho Power

service area. The twelve classroom-style trainings had a total of 55 attendees. Nine on-site field trainings were conducted in conjunction with the classroom-style trainings and had a total of 45 attendees. The report is located in the IDL section of *Supplement 2: Evaluation.*

### Residential Heat Pump Calculator

In 2014, the IDL created a computer-based residential energy calculator. This tool calculates energy consumption for residential houses. It has the ability to accept various descriptive user inputs—for example, attic insulation and window performance in an existing house. It also enables the user to compare the energy consumption of a house with various types of heating and cooling systems. The tool will be evaluated in 2015 to determine if any enhancements are needed.

### Residential Heat Pump Calculator—Weatherization Solutions & Home Improvement Programs Module

The IDL created a computer-based residential energy calculator in 2014. This tool calculates energy consumption for residential houses for pre- and post-weatherization. The tool has the ability to accept various descriptive user inputs to calculate estimated savings based on the interaction between potential upgrades and various heat systems.

### Residential Electronically Commutated Motors

In 2014, the IDL investigated ECMs at the request of Idaho Power. These motors are sometimes used in residential forced-air heating and cooling systems. These motors can be an energy-efficient option when compared to other types of motors used in the air handlers for these systems. An air handler is a device that circulates air through ductwork. Idaho Power is evaluating the ECM motor for a potential new measure to be added to the H&CE Program. The work the IDL performed was to help determine if an ECM motor would be a suitable energy-saving replacement motor for the traditional permanent split capacitor motor. The results of their work will be reviewed in 2015. The report is located in the IDL section of *Supplement 2: Evaluation*.

The contract between Idaho Power and the IDL will continue through 2015. In 2015, the IDL will continue or expand work on the BML sheets, Lunch & Learn sessions, BSUG, foundational services, building efficiency verification, TLL, heat pump calculator, and daylight demonstrations. In addition, they will begin work on four new tasks—Commercial Real Estate Support, IBOA and IFMA Organization/Chapter Support, Targeted Energy Expansion of Daylight Pattern Guide, and Whole House Fan Energy Savings.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs but still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities. Idaho Power received three applications for LEEF in 2014 and awarded funds to one applicant.

Meridian Food Bank requested funding to replace one of their existing upright freezer units with a new, more energy-efficient unit. Idaho Power met with the Meridian Food Bank at their facility to gather more information on the project. Given the ongoing need for this type of replacement at the Food Bank and the positive community impact this operation serves, it was decided that an alternate method of funding would be more appropriate. As of December 31, 2014, the Idaho Power CR for this site worked

with the customer and Idaho Power executives to investigate a potential corporate donation to support this facility's efforts.

A high-performance builder in the Wood River Valley area submitted an application regarding substantial energy efficiency measures associated with a large, new-construction residence. Energy efficiency measures included reduced heating loads due to premium construction methods and materials, highly efficient ground-source heat pumps, and ECMs. Idaho Power convened a working group of residential and commercial engineers and cost-effectiveness analysts from Idaho Power's energy efficiency department to review the application and request additional information. Energy calculations were supported by energy modeling software, RESNET, and an estimated 95,834 kWh per year in heating system savings. After a thorough review of the details surrounding this LEEF request, the team approved funding for $9,100.

The third project submitted regarded potential lighting retrofits in Boise High School's auditorium. A brief review revealed the project would qualify for existing commercial lighting incentives. The applicant was asked to submit the project to Idaho Power's energy efficiency commercial program staff.

## Building-Code Improvement Activity

Since 2005, the State of Idaho has been on a cycle of adopting a state-specific version of the IECC. The Idaho Building Code Board convened another Energy Code Collaborative in 2013 in an effort to address implementation of the new series of building-related codes. Idaho Power participated and offered support in those collaborative meetings, which included members of the building industry, local building officials, code development officials, and other interested stakeholders. The Energy Code Collaborative is an ongoing collaborative in which Idaho Power participates.

The Energy Code Collaborative brought forth its recommendations to the Idaho Building Code Board, which included the adoption of the *2012 IECC Residential Code* with amendments and the *2012 IECC Commercial Code* in 2013. The recommendation was adopted by the Idaho Building Code Board and was presented in the 2014 legislature session. Legislature passed the rules effective March 21, 2014, and the changes will go into effect January 1, 2015.

## Idaho Power's Internal Energy Efficiency Commitment

Several Idaho Power properties were enhanced in 2014 with the goal of improving energy efficiency. During the Payette Operations Center remodel, ceiling insulation was increased from R-20 to R-38, and a Watt-Stopper lighting-control system was added. At four substation buildings across the service area, old black built-up roofs were replaced with white metal roofs for reflection purposes.

Numerous CHQ remodel projects were completed in 2014. Plaza I was remodeled, and the old T-12 and T-8 lighting fixtures were replaced with LED fixtures controlled by a lighting system. Plaza II was remodeled, and the old T-12 system was replaced with LED fixtures. The existing natural gas-fired rooftop unit was replaced with a higher efficiency rooftop packaged heat pump unit rated at an energy efficiency ratio (EER) of 16 that has a payback cost of 14 months. The Plaza II roof was replaced with a reflective, better-insulated thermoplastic polyolefin roof to open the floor plan to the rafters in the barrel-shaped building. All the three-lamp T-12 fixtures on CHQ fourth floor and sixth floor were replaced with two-lamp T-8 fixtures. The CHQ fourth floor was completely remodeled with new recycled carpet, low-VOC paint, and low-partition walls for increased light transmission throughout the floor.

An outcome of the Energy Efficiency Audit conducted at the BOC with Tikker Engineering in 2013 was the installation of building-wide direct digital control system controls at the BOC. While not all of the suggested energy efficiency measures were addressed, the company incorporated measures that would provide the most value. Total energy reduction with the changes implemented at the BOC was estimated at 300,000 kWh annually.

At BCW, the chillers and air handlers were replaced. The new equipment exceeded ASHRAE standards for efficiency and were quieter than the previous chillers. Cooling and heating problems in the Grid Operations area were corrected. While no baseline was taken from the original air handling units (AHU) and chillers, the new air handlers run at 60 percent of the amperage compared to the old equipment. Idaho Power will continue to monitor the performance of the new chillers and AHUs in 2015.

In 2015, Idaho Power will continue with a number of major remodels on the CHQ buildings downtown, starting with the remodel of parts of CHQ sixth floor and seventh floors. The company will begin remodels on the CHQ eighth floor going into 2016. Remodels will incorporate energy efficiency items, such as lower partitions, lighting retrofits, and lighting controls.

Through the Sustainability Initiative Project implemented in 2012, Idaho Power has helped fund and execute sustainable, employee-driven initiatives aimed at increasing efficiencies and lowering company costs. Each year, the Sustainability team puts out a call for projects. Qualifying initiatives must demonstrate a financial benefit to the company, as well as either an environmental or social gain, or preferably both. Approved projects are given financial assistance through “incubation funding,” and the Sustainability team provides consulting services—if necessary—to speed implementation. A new document, available in print and online, catalogues three years of sustainability initiatives, with a brief description of each. From 2012’s Greenleaf wet-meadows project to last year’s rollout of electric vehicles and charging stations, all 26 initiatives are listed.

Employee-suggested sustainability initiative projects yielded several sustainability programs in 2014, including three programs with annual energy savings. At BCW, computer room “occupancy programming” was incorporated into the building management system. This allows one of several air-conditioning units to remain idle when the system detects the room is unoccupied, bringing an annual energy savings estimate at over 33,000 kWh. Idaho Power installed VFDs at the company’s data centers, with a combined savings of over 240,000 kWh annually.

# REGULATORY OVERVIEW

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. By working with its stakeholders and regulators through negotiations and filings, Idaho Power continues to seek to move DSM regulatory treatment toward achieving all of these goals.

## Timely Recovery of DSM Program Costs: Energy Efficiency Rider and Prudence Determination of Expenditures

Since 2002, Idaho Power has recovered most of its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM costs. In addition, since January 1, 2012, funding of Idaho demand response program incentives is included in base rates and tracked in the annual PCA mechanism.

### *Annual DSM Expense Review Filing and Order No. 33161*

On March 14, 2014, Idaho Power filed Case No. IPC-E-14-04 with the IPUC requesting an order finding the company had prudently incurred $25,951,486 in DSM expenses in 2013, including $21,748,331 in Rider expenses and $4,203,155 in demand response program incentive expenses. The filing included three reports: *Demand-Side Management 2013 Annual Report*, *Supplement 1: Cost Effectiveness*, and *Supplement 2: Evaluation*. Due to a previous IPUC decision in Case No. IPC-E-13-08 to decline Idaho Power's request to deem prudent the increases in the company's Rider-funded labor-related expenses for 2011, 2012, and 2013, Idaho Power did not request a prudence determination for labor-related expenses of $269,432 in the filing. In Order No. 33161, dated November 4, 2014, the IPUC deemed $25,951,486 as prudently incurred and stated:

> The Commission notes that Idaho Power issued a strong rebuttal of these claims, offering several reasons to explain the recent decline in its DSM expenditures and a defense of its marketing efforts. While the Commission is cognizant of the recent decline in energy savings, acknowledged by the Company in its Application, we are encouraged by the Company's reply comments that its commitment to cost-effective DSM has not waned and that it has a renewed interest in taking action to procure all cost-effective DSM.

### *Errata to Order No. 33161*

In an Errata to Order No. 33161, dated November 7, 2014, the Commission amended the original Order to read:

> The Commission is cognizant of the recent decline in energy savings, acknowledged by the Company in its Application, and notes that Idaho Power issued a strong rebuttal of these claims, offering several reasons to explain the recent decline in its DSM expenditures and a defense of its marketing efforts. We are encouraged that the reply comments seem to demonstrate the Company's renewed interest in procuring all cost-effective DSM.

> In this case, the Commission restricts its findings to the prudency of the Company's 2013 expenditures. The Commission agrees that the issues raised by Staff and other parties are significant and warrant a more in-depth review. We direct the parties to do so in the context of the Company's next Integrated Resource Plan filing.

## Energy Efficiency Working Group

In response to the Errata, Idaho Power organized an Energy Efficiency Working Group, inviting members of the IRP Advisory Committee (IRPAC), EEAG, and other interested parties to participate. The Energy Efficiency Working Group held two sessions to conduct an in-depth review of the issues referenced in the Errata to Order No. 33161. The sessions were open to the public and held at Idaho Power's CHQ on December 3 and 18.

The first workshop session included a discussion of a broad range of energy efficiency and resource planning issues that can be classified into two general categories: 1) strategies related to program delivery and 2) the treatment of energy efficiency in the resource planning process. Because the IRP process does not address program delivery issues, it was suggested to narrow the focus of the discussion to only the treatment of energy efficiency in the resource planning process. The strategies related to the successful delivery of programs will be better addressed by EEAG.

The second workshop session agenda included a comparison of potential studies from other regional utilities; a description about how Idaho Power's incorporates energy efficiency in the IRP; a comparison of how other regional utilities incorporate energy efficiency in long-range planning; a review of Idaho Power's investigation into including Transmission and Distribution (T&D) investment deferral into the benefits in the energy efficiency cost-effectiveness analysis; and offered an open discussion time to address other issues. The information presented at the second meeting prompted extensive discussion among participants and ultimately served to inform Idaho Power's next steps.

Idaho Power believes its current treatment of energy efficiency in the resource planning process appropriately balances the need for responsible and effective resource planning and the desire to prudently pursue all cost-effective energy efficiency. Idaho Power recognizes that achieving those balanced objectives on an ongoing basis requires continued review and evaluation of the planning process and an awareness of related industry best practices.

Idaho Power is committed to investigate the extent to which transmission and/or distribution benefits result from energy efficiency measures and programs, as well as the approximate value of such benefits. When available, the company will present the results of this investigation to the IRPAC.

The company is also committed to continue to discuss the program delivery issues identified by workshop participants and by IPUC staff and some interveners in comments filed in Case No. IPC-E-14-04. The company plans to use EEAG as the forum to provide customers, IPUC and OPUC staff, and other interested stakeholders an opportunity to provide advice and recommendations to Idaho Power in formulating, implementing, and evaluating energy efficiency and demand response programs and activities.

## Energy Efficiency Rider-Funds Transfer

On April 15, 2014, Idaho Power filed the annual PCA Case No. IPC-E-14-05 with the IPUC. As part of that case, the company proposed that the commission approve a one-time transfer of $20 million of

surplus Idaho Rider funds to customers as a credit, or reduction, in the 2014/2015 PCA on customers' bills. In Order No. 33049, the commission approved the one-time transfer.

## Removal of Financial Disincentives: Fixed-Cost Adjustment

To address the removal of financial disincentives, Idaho Power has in place a fixed-cost adjustment (FCA) mechanism in Idaho. Under the FCA, rates for Idaho residential and small general-service customers are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent general rate case and the fixed costs Idaho Power actually received the previous year through weather-normalized energy sales. This mechanism removes the financial disincentive that exists when Idaho Power promotes energy efficiency programs that are designed to reduce customer usage. The FCA is a permanent mechanism limited to the residential and small general-service customer classes in Idaho in recognition of the fact that, for these customers, a large percentage of fixed costs are recovered through their volumetric energy charges.

On May 30, 2014, the IPUC issued Order No. 33047 approving the company's request to implement FCA rates beginning June 1, 2014, for the 2013 fixed-cost deferrals. The overall rate adjustment was a 1.18 percent increase for residential and small general-service customers to collect a combined $14.9 million. This adjustment was an increase of $6 million from the previous year's FCA. Residential customers experienced a rate increase of 0.1143 cents per kWh, while small general-service customers experienced an increase of 0.1447 cents per kWh. The rate will be in place until May 31, 2015.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power believes rates offered to customers should reflect their cost of service in order to provide cost-based price signals and encourage the wise and efficient use of energy.

Since 2012, Idaho Power has offered a Time-of-Day (TOD) Pilot pricing plan to residential customers in Idaho. The overall goal of this TOD pricing plan is to use the AMI system to offer customers a choice of pricing plans while providing them with better tools to manage their energy usage, provide the company with the opportunity to further study the effects of a time-variant rate on customers' usage, and help shape the company's future communication efforts. The plan provides participants the opportunity to move their usage from higher-priced, on-peak time periods to lower-priced, off-peak time periods and possibly lower their bills. Idaho Power sent out a mailing in late spring of 2014 reminding participants that higher summer rates go into effect June 1. The spring mailing promoted the use of myAccount and reminded customers to use electricity wisely. A description of this plan is at Idaho Power's website (idahopower.com/TOD).

In July 2014, Idaho Power concluded the final impact study of the residential TOD pilot. The study was a customer behavior study that evaluated how the TOD pricing impacted energy consumption for participants in the plan. Participant's response to the TOD pricing signal was determined using a quasi-experimental study design structure with a TOD participant treatment group and a closely matched non-participant control group. Idaho Power also calculated the billing revenue impact of this pilot by calculating a shadow bill for each of the customers on the TOD pricing plan versus the standard residential three-tiered pricing plan in Idaho.

Key findings are summarized below:

- There was no statistically significant change in overall energy consumption observed in the study participants on the TOD rates.

- For the study group as a whole, the data analyzed showed a **reduction** in energy use from peak time periods by the analyzed participants of the pricing plan verses the control group. All but 2 out of 12 months showed statistically significant reductions in energy use during peak periods. Over the 12-month study period, this combined reduction in peak-time-period consumption was approximately 3 percent of the total kWh use.

- For the study group as a whole, the data analyzed showed an **increase** in energy use during off-peak time periods by the analyzed participants of the pricing plan verses the control group. Five out of the 12 months showing statistically significant increases. During the 12-month study period, this combined increase in off-peak time-period consumption was approximately 1 percent of the total kWh.

- The overall response rate to the residential TOD pricing pilot plan solicitation was 1.3 percent.

- The study estimates that there was a revenue reduction of $119,000 when actual TOD energy billings of all TOD pilot participants are compared with standard plan shadow energy bill calculations for all TOD pilot participants during the 12 months of the study, September 2012 through August 2013.

As of the end of 2014, over 1,500 Idaho customers were TOD plan participants.

# APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2014, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency and demand response programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2014. Appendix 4 shows similar data as Appendix 3 but also includes data for past years' program performance and B/C ratios from the UC and TRC perspectives for active programs. Appendix 5 contains program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. In these appendices, the data has been rounded to the nearest whole unit, which may result in minor rounding differences.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost-effectiveness information by program and energy-savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The *2014 DSM Detailed Expenses* by program table reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of Idaho Power's third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information are included with each supplement.

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## **Appendix 1.** Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December, 2014)

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2014 Beginning Balance | $ | 6,685,745 |
| 2014 Funding plus Accrued Interest as of 12-31-14 | | 38,088,113 |
| **Total 2014 Funds** | | **44,773,858** |
| 2014 Expenses as of 12-31-14 | | (25,556,089) |
| Rider Transfer to PCA (IPUC Order 33049) | | (20,000,000) |
| **Ending Balance as of 12-31-2014** | **$** | **(782,231)** |
| **Oregon Energy Efficiency Rider** | | |
| 2014 Beginning Balance | $ | (3,694,183) |
| 2014 Funding plus Accrued Interest as of 12-31-14 | | 1,112,512 |
| **Total 2014 Funds** | | **(2,581,671)** |
| 2014 Expenses as of 12-31-14 | | (1,325,865) |
| **Ending Balance as of 12-31-2014** | **$** | **(3,907,536)** |
| **NEEA Payments** | | |
| 2014 NEEA Payments as of 12-31-2014 | $ | 3,305,917 |
| **Total** | **$** | **3,305,917** |

## **Appendix 2.** 2014 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Non-Rider Funds | Total |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit | $ 962,286 | $ 56,988 | $ 446,372 | $ 1,465,646 |
| Ductless Heat Pump Pilot | 235,099 | 9,614 | 6,733 | 251,446 |
| Energy Efficient Lighting | 1,860,046 | 45,959 | 3,818 | 1,909,823 |
| Energy House Calls | 186,732 | 8,174 | 3,080 | 197,987 |
| ENERGY STAR® Homes Northwest | 330,523 | 7,612 | 5,141 | 343,277 |
| Heating & Cooling Efficiency Program | 340,551 | 14,627 | 6,836 | 362,014 |
| Home Energy Audit | 164,579 | (248) | 6,318 | 170,648 |
| Home Improvement Program | 315,616 | 0 | 9,101 | 324,717 |
| Home Products Program | 212,787 | 9,250 | 5,139 | 227,176 |
| Oregon Residential Weatherization | 0 | 5,234 | 228 | 5,462 |
| Rebate Advantage | 57,155 | 5,323 | 753 | 63,231 |
| See ya later, refrigerator® | 562,002 | 12,410 | 1,639 | 576,051 |
| Shade Tree Program | 143,750 | 66 | 3,474 | 147,290 |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 1,320,112 | 1,320,112 |
| Weatherization Solutions for Eligible Customers | 757,748 | 0 | 33,596 | 791,344 |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,212,907 | 31,052 | 14,315 | 1,258,273 |
| Custom Efficiency | 6,705,219 | 418,537 | 49,299 | 7,173,054 |
| Easy Upgrades | 3,020,323 | 112,623 | 17,996 | 3,150,942 |
| FlexPeak Management | 50,964 | 78,131 | 1,434,116 | 1,563,211 |
| Oregon Commercial Audit | 0 | 9,464 | 0 | 9,464 |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 2,256,235 | 144,392 | 45,880 | 2,446,507 |
| Irrigation Peak Rewards | 1,374,724 | 104,995 | 6,117,494 | 7,597,213 |
| **Energy Efficiency/Demand Response Total** | **$ 20,749,245** | **$ 1,074,203** | **$ 9,531,441** | **$ 31,354,889** |
| **Market Transformation** | | | | |
| NEEA | 3,140,621 | 165,296 | 0 | 3,305,917 |
| **Market Transformation Total** | **$ 3,140,621** | **$ 165,296** | **$ 0** | **$ 3,305,917** |
| **Other Programs and Activities** | | | | |
| **Residential** | | | | |
| Residential Energy Efficiency Education Initiative | 394,895 | 14,844 | 13,352 | 423,091 |
| **Commercial/Industrial** | | | | |
| Commercial Education Initiative | 72,613 | 3,829 | 163 | 76,606 |
| **Other** | | | | |
| Energy Efficient Direct Program Overhead | 427,506 | 21,711 | 29,441 | 478,658 |
| Local Energy Efficiency Funds | 9,100 | 0 | 0 | 9,100 |
| **Other Programs and Activities Total** | **$ 904,114** | **$ 40,384** | **$ 42,956** | **$ 987,455** |
| **Indirect Program Expenses** | | | | |
| Commercial/Industrial Energy Efficient Overhead | 75,578 | 6,209 | 40,612 | 122,399 |
| Energy Efficient Accounting & Analysis | 693,729 | 39,512 | 198,119 | 931,360 |
| Energy Efficiency Advisory Group | 5,702 | 301 | 0 | 6,003 |
| Residential Energy Efficient Overhead | 79,137 | 5,203 | 18,251 | 102,590 |
| Special Accounting Entries | (92,037) | (5,242) | 0 | (97,280) |
| **Indirect Program Expenses Total** | **$ 762,109** | **$ 45,982** | **$ 256,982** | **$ 1,065,072** |
| **Grand Total** | **$ 25,556,089** | **$ 1,325,865** | **$ 9,831,379** | **$ 36,713,333** |

## **Appendix 3.** 2014 DSM program activity

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Demand Response** | | | | | | | | |
| A/C Cool Credit[1] | 29,642 homes | $ 1,465,646 | $ 1,465,646 | n/a | 44 | n/a | n/a | n/a |
| Irrigation Peak Rewards[1] | 2,225 service points | 7,597,213 | 7,597,213 | n/a | 295 | n/a | n/a | n/a |
| FlexPeak Management[1] | 93 sites | 1,563,211 | 1,563,211 | n/a | 40 | n/a | n/a | n/a |
| **Total** | | **$ 10,626,070** | **$ 10,626,070** | **n/a** | **378** | | | |
| **Energy Efficiency** | | | | | | | | |
| **Residential** | | | | | | | | |
| Ductless Heat Pump Pilot | 179 homes | 251,446 | 884,211 | 462,747 | | 15 | $ 0.042 | $ 0.148 |
| Energy Efficient Lighting | 1,161,553 bulbs | 1,909,823 | 7,148,427 | 12,882,151 | | 8 | 0.018 | 0.066 |
| Energy House Calls | 297 homes | 197,987 | 197,987 | 579,126 | | 18 | 0.024 | 0.024 |
| ENERGY STAR® Homes Northwest | 243 homes | 343,277 | 689,021 | 332,682 | | 36 | 0.055 | 0.111 |
| ENERGY STAR® Homes Northwest (gas fuel)[2] | 282 homes | | | 195,372 | | | | |
| Heating & Cooling Efficiency Program | 230 projects | 362,014 | 1,247,560 | 1,099,464 | | 20 | 0.022 | 0.075 |
| Home Energy Audit (direct-install savings)[3] | 354 audits | | | 141,077 | | | | |
| Home Improvement Program | 555 projects | 324,717 | 896,246 | 838,929 | | 45 | 0.020 | 0.055 |
| Home Products Program | 10,061 appliances/showerheads | 227,176 | 302,289 | 652,129 | | 12 | 0.031 | 0.041 |
| Oregon Residential Weatherization | 13 homes | 5,462 | 9,723 | 11,032 | | 30 | 0.028 | 0.050 |
| Rebate Advantage | 44 homes | 63,231 | 89,699 | 269,643 | | 25 | 0.014 | 0.020 |
| See ya later, refrigerator® | 3,194 refrigerators/freezers | 576,051 | 576,051 | 1,390,760 | | 6 | 0.062 | 0.062 |
| Student Energy Efficiency Kits[4] | 6,312 kits | | | 1,491,225 | | | | 0.225 |
| Weatherization Assistance for Qualified Customers | 255 homes/non-profits | 1,320,112 | 1,997,108 | 1,327,171 | | 25 | 0.149 | 0.225 |
| Weatherization Solutions for Eligible Customers | 118 homes | 791,344 | 791,344 | 290,926 | | 25 | 0.163 | 0.163 |
| **Sector Total** | | **$ 6,372,640** | **$ 14,829,666** | **21,171,063** | | **11** | **$ 0.028** | **$ 0.065** |
| **Commercial** | | | | | | | | |
| Building Efficiency | 69 projects | 1,258,273 | 3,972,822 | 9,458,059 | 1.2 | 12 | 0.012 | 0.037 |
| Easy Upgrades | 1,095 projects | 3,150,942 | 5,453,380 | 19,118,494 | | 12 | 0.015 | 0.025 |
| **Sector Total** | | **$ 4,409,215** | **$ 9,426,202** | **28,576,553** | **1.2** | **12** | **$ 0.014** | **$ 0.029** |
| **Industrial** | | | | | | | | |
| Custom Efficiency[5] | 131 projects | 7,173,054 | 13,409,922 | 50,363,052 | 5.6 | 12 | 0.013 | 0.024 |
| **Sector Total** | | **$ 7,173,054** | **$13,409,922** | **50,363,052** | **5.6** | **12** | **$ 0.013** | **$ 0.024** |

## **Appendix 3.** 2014 DSM program activity (continued)

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Irrigation** | | | | | | | | |
| Irrigation Efficiency Rewards[6] | 1,128 projects | 2,446,507 | 18,459,781 | 18,463,611 | 4.6 | 8 | 0.016 | 0.119 |
| **Sector Total** | | **$ 2,446,507** | **$ 18,459,781** | **18,463,611** | **4.6** | **8** | **$ 0.016** | **$ 0.119** |
| **Energy Efficiency Portfolio Total** | | **$ 20,401,416** | **$ 56,125,571** | **118,574,278** | | **11** | **$ 0.016** | **$ 0.044** |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance[7] | | $ 3,305,917 | $ 3,305,917 | 20,000,000 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Home Energy Audit | | 170,648 | 170,648 | | | | | |
| Local Energy Efficiency Funds | | 9,100 | 9,100 | 95,834 | | | | |
| Residential Energy Efficiency Education Initiative | | 423,091 | 423,091 | | | | | |
| Shade Tree Project | | 147,290 | 147,290 | | | | | |
| **Commercial** | | | | | | | | |
| Commercial Education Initiative | | 76,606 | 76,606 | | | | | |
| Oregon Commercial Audits | 16 audits | 9,464 | 9,464 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 478,658 | 478,658 | | | | | |
| **Total Program Direct Expense** | | **$ 35,648,260** | **$ 71,372,415** | **138,670,112** | **390** | | | |
| Indirect Program Expenses | | $ 1,065,072 | | | | | | |
| **Total DSM Expense** | | **$ 36,713,333** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP and calculations include line-loss adjusted energy savings.
[b] The Total Utility Cost is the cost incurred by Idaho Power to implement and manage a DSM program.
[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
[d] Summer Peak Demand is reported where program MW reduction is calculated specifically by project. Demand response program reductions are reported with 9.7-percent peak loss assumptions.
[1] Peak demand represents the peak performance of the program.
[2] Savings claimed for gas-heated certified homes that were not provided a direct incentive payment by Idaho Power.
[3] Savings claimed for direct-install measures during home energy audits.
[4] Savings for energy kits provided as part of the Residential Energy Efficiency Education Initiative program.
[5] Custom Efficiency savings includes 15 Green Motors participants totaling 56,499 kWh of annual savings, not counted in project totals.
[6] Irrigation Efficiency includes 14 Green Motors participants totaling 35,083 kWh of annual savings, not counted in project totals.
[7] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

## **Appendix 4.** Historical DSM expense and performance, 2002–2014

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3.1 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6.3 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12.2 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 25.5 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 38.5 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39.0 | | | | | |
| 2011 | 37,728 | 2,896,542 | 2,896,542 | | | 24.0 | | | | | |
| 2012 | 36,454 | 5,727,994 | 5,727,994 | | | 44.9 | | | | | |
| 2013 | n/a | 663,858 | 663,858 | | | n/a | | | | | |
| 2014 | 29,642 | 1,465,646 | 1,465,646 | | | 43.7 | | | | | |
| **Total** | | **$ 24,156,541** | **$ 24,156,540** | | | | | | | | |
| FlexPeak Management | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19.3 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 47.5 | | | | | |
| 2011 | 111 | 2,057,730 | 2,057,730 | | | 58.8 | | | | | |
| 2012 | 102 | 3,009,822 | 3,009,822 | | | 52.8 | | | | | |
| 2013 | 100 | 2,743,615 | 2,743,615 | | | 48.0 | | | | | |
| 2014 | 93 | 1,563,211 | 1,563,211 | | | 39.6 | | | | | |
| **Total** | | **$ 11,805,739** | **$ 11,805,739** | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 5.6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40.3 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 31.8 | | | | | |
| 2007 | 947 | 1,615,881 | 1,615,881 | | | 37.4 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35.1 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160.2 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,330,826 | | | 249.7 | | | | | |
| 2011 | 2,342 | 12,086,222 | 12,086,222 | | | 320.0 | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2012 | 2,433 | $ 12,423,364 | $ 12,423,364 | | | 339.9 | | | | | |
| 2013 | n/a | 2,072,107 | 2,072,107 | | | n/a | | | | | |
| 2014 | 2,225 | 7,597,213 | 7,597,213 | | | 295.0 | | | | | |
| **Total** | | **$ 63,350,149** | **$ 63,350,149** | | | | | | | | |
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | 202,005 | 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| 2011 | 131 | 191,183 | 550,033 | 458,500 | 0.05 | | 20 | 0.028 | 0.081 | | |
| 2012 | 127 | 159,867 | 617,833 | 444,500 | 0.05 | | 20 | 0.024 | 0.094 | | |
| 2013 | 215 | 237,575 | 992,440 | 589,142 | 0.07 | | 15 | 0.032 | 0.132 | | |
| 2014 | 179 | 251,446 | 884,211 | 462,747 | 0.05 | | 15 | 0.042 | 0.148 | | |
| **Total** | **852** | **$ 1,231,307** | **$ 3,935,681** | **2,728,069** | | | **15** | **$ 0.044** | **$ 0.138** | **2.52** | **0.76** |
| Energy Efficiency Packets | | | | | | | | | | | |
| 2002 | 2,925 | 755 | 755 | 155,757 | 0.02 | | 7 | 0.001 | 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | | |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,618 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,662 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2004 | | | | | | | | | | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| 2011 | 1,039,755 | 1,719,133 | 2,764,623 | 19,694,381 | 2.25 | | 5 | 0.015 | 0.024 | | |
| 2012 | 925,460 | 1,126,836 | 2,407,355 | 16,708,659 | 1.91 | | 5 | 0.012 | 0.025 | | |
| 2013 | 1,085,225 | 1,356,926 | 4,889,501 | 9,995,753 | 1.14 | | 8 | 0.016 | 0.058 | | |
| 2014 | 1,161,553 | 1,909,823 | 7,148,427 | 12,882,151 | 1.47 | | 8 | 0.018 | 0.066 | | |
| **Total** | **6,854,505** | **$ 12,326,880** | **$ 25,292,458** | **137,224,557** | | | **8** | **$ 0.013** | **$ 0.027** | **4.24** | **2.07** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | $ 26,053 | $ 26,053 | 25,989 | 0.00 | | 20 | $ 0.082 | $ 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 336,372 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |
| 2010 | 1,602 | 762,330 | 762,330 | 1,198,655 | 0.14 | | 20 | 0.054 | 0.054 | | |
| 2011 | 881 | 483,375 | 483,375 | 1,214,004 | 0.14 | | 20 | 0.027 | 0.027 | | |
| 2012 | 668 | 275,884 | 275,884 | 1,192,039 | 0.14 | | 18 | 0.016 | 0.016 | | |
| 2013 | 411 | 199,995 | 199,995 | 837,261 | 0.10 | | 18 | 0.017 | 0.017 | | |
| 2014 | 297 | 197,987 | 197,987 | 579,126 | 0.07 | | 18 | 0.024 | 0.024 | | |
| **Total** | **10,779** | **$ 4,941,337** | **$ 4,941,337** | **13,064,406** | | | **18** | **$ 0.033** | **$ 0.033** | **2.31** | **2.31** |
| ENERGY STAR Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | 0 | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | | 25 | 0.038 | 0.049 | | |
| 2007 | 303 | 475,044 | 400,637 | 629,634 | 0.07 | | 25 | 0.056 | 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| 2011 | 308 | 259,762 | 651,249 | 728,030 | 0.08 | | 32 | 0.020 | 0.051 | | |
| 2012 | 410 | 453,186 | 871,310 | 537,447 | 0.06 | | 35 | 0.046 | 0.089 | | |
| 2013 | 267 | 352,882 | 697,682 | 365,370 | 0.04 | | 36 | 0.053 | 0.104 | | |
| 2014 | 243 | 343,277 | 689,021 | 332,682 | 0.04 | | 36 | 0.055 | 0.111 | | |
| **Total** | **3,572** | **$ 3,793,916** | **$ 6,030,020** | **6,080,207** | | | **36** | **$ 0.041** | **$ 0.065** | **2.35** | **1.48** |
| ENERGY STAR Homes Northwest (gas fuel) | | | | | | | | | | | |
| 2014 | 282 | | | 195,372 | | | | | | | |
| **Total** | **282** | **$ 0** | **$ 0** | **195,372** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Heating & Cooling Efficiency | | | | | | | | | | | |
| 2006 | | $ 17,444 | $ 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | $27.344 | $27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,440 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.13 | | 20 | 0.025 | 0.083 | | |
| 2011 | 130 | 195,770 | 614,523 | 733,405 | 0.08 | | 20 | 0.018 | 0.056 | | |
| 2012 | 141 | 182,281 | 676,530 | 688,855 | 0.08 | | 20 | 0.018 | 0.066 | | |
| 2013 | 210 | 329,674 | 741,586 | 1,003,730 | 0.11 | | 20 | 0.022 | 0.050 | | |
| 2014 | 230 | 362,014 | 1,247,560 | 1,099,464 | 0.13 | | 20 | 0.022 | 0.075 | | |
| **Total** | **1,640** | **$ 2,854,988** | **$ 6,230,678** | **6,467,815** | | | **20** | **$ 0.036** | **$ 0.079** | **2.67** | **1.22** |
| Home Improvement Program | | | | | | | | | | | |
| 2008 | 282 | 123,454 | 157,866 | 317,814 | 0.04 | | 25 | 0.029 | 0.037 | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | |
| 2011 | 2,275 | 666,041 | 2,704,816 | 917,519 | 0.10 | | 45 | 0.038 | 0.155 | | |
| 2012 | 840 | 385,091 | 812,827 | 457,353 | 0.05 | | 45 | 0.044 | 0.093 | | |
| 2013 | 365 | 299,497 | 1,061,314 | 616,044 | 0.07 | | 45 | 0.025 | 0.090 | | |
| 2014 | 555 | 324,717 | 896,246 | 838,929 | 0.10 | | 45 | 0.020 | 0.055 | | |
| **Total** | **9,042** | **$ 3,064,656** | **$ 8,295,954** | **8,472,734** | | | **45** | **$ 0.023** | **$ 0.062** | **2.21** | **0.81** |
| Home Products Program | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | 0 | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | 0.06 | | 15 | 0.044 | 0.082 | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | 0.19 | | 15 | 0.031 | 0.051 | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | 0.16 | | 15 | 0.057 | 0.070 | | |
| 2011 | 15,896 | 638,323 | 1,520,977 | 1,485,326 | 0.17 | | 15 | 0.034 | 0.080 | | |
| 2012 | 16,675 | 659,032 | 817,924 | 887,222 | 0.10 | | 14 | 0.061 | 0.075 | | |
| 2013 | 13,792 | 405,515 | 702,536 | 885,980 | 0.10 | | 12 | 0.041 | 0.071 | | |
| 2014 | 10,061 | 227,176 | 302,289 | 652,129 | 0.07 | | 12 | 0.031 | 0.041 | | |
| **Total** | **85,279** | **$ 3,533,655** | **$ 5,691,019** | **7,533,890** | | | **12** | **$ 0.052** | **$ 0.083** | **1.71** | **1.06** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2002 | 24 | $ (662) | $ 23,971 | 4,580 | | | 25 | $ 0.010 | $ 0.389 | | |
| 2003 | | (943) | | | | | | | | | |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | |
| 2005 | 4 | 612 | 3,608 | 7,927 | 0.00 | | 25 | 0.006 | 0.034 | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | |
| 2009 | 1 | 7,645 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | |
| 2011 | 8 | 7,926 | 10,208 | 21,908 | 0.00 | | 30 | 0.021 | 0.027 | | |
| 2012 | 5 | 4,516 | 11,657 | 11,985 | 0.00 | | 30 | 0.022 | 0.056 | | |
| 2013 | 14 | 9,017 | 14,369 | 14,907 | 0.00 | | 30 | 0.035 | 0.055 | | |
| 2014 | 13 | 5,462 | 9,723 | 11,032 | 0.00 | | 30 | 0.028 | 0.050 | | |
| **Total** | **78** | **$ 56,004** | **$ 127,745** | **107,733** | | | **30** | **$ 0.036** | **$ 0.082** | **2.76** | **1.21** |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | 27,372 | 79,399 | 227,434 | 0.03 | | 45 | 0.008 | 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| 2011 | 25 | 63,469 | 85,044 | 159,325 | 0.02 | | 25 | 0.024 | 0.033 | | |
| 2012 | 35 | 37,241 | 71,911 | 187,108 | 0.02 | | 25 | 0.012 | 0.024 | | |
| 2013 | 42 | 60,770 | 92,690 | 269,891 | 0.03 | | 25 | 0.014 | 0.021 | | |
| 2014 | 44 | 63,231 | 89,699 | 269,643 | 0.03 | | 25 | 0.014 | 0.020 | | |
| **Total** | **846** | **$ 672,200** | **$ 1,417,441** | **3,521,454** | | | **25** | **$ 0.014** | **$ 0.030** | **7.67** | **3.64** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | $ 305,401 | $ 305,401 | 1,132,802 | 0.13 | | 8 | $ 0.041 | $ 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| 2011 | 3,449 | 654,393 | 654,393 | 1,712,423 | 0.20 | | 8 | 0.046 | 0.046 | | |
| 2012 | 3,176 | 613,146 | 613,146 | 1,576,426 | 0.18 | | 8 | 0.046 | 0.046 | | |
| 2013 | 3,307 | 589,054 | 589,054 | 1,442,344 | 0.16 | | 6 | 0.061 | 0.061 | | |
| 2014 | 3,194 | $576,051 | 576,051 | 1,390,760 | 0.16 | | 6 | 0.062 | 0.062 | | |
| **Total** | **17,939** | **$ 3,303,124** | **$ 3,303,124** | **8,822,491** | | | **6** | **$ 0.069** | **$ 0.069** | **1.17** | **1.17** |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 52,807 | 71,680 | 0.01 | | 25 | 0.057 | 0.057 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,719 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 228,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| 2011 | 117 | 788,148 | 788,148 | 1,141,194 | 0.13 | | 25 | 0.042 | 0.042 | | |
| 2012 | 141 | 1,070,556 | 1,070,556 | 257,466 | 0.03 | | 25 | 0.254 | 0.254 | | |
| 2013 | 166 | 1,267,791 | 1,267,791 | 303,116 | 0.03 | | 25 | 0.240 | 0.240 | | |
| 2014 | 118 | $791,344 | 791,344 | 290,926 | 0.03 | | 25 | 0.163 | 0.163 | | |
| **Total** | **646** | **$ 4,362,066** | **$ 4,362,066** | **2,589,410** | | | **25** | **$ 0.125** | **$ 0.125** | **0.76** | **0.76** |
| Window AC Trade-Up Pilot | | | | | | | | | | | |
| 2003 | 99 | 6,687 | 10,492 | 14,454 | | | 12 | 0.051 | 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.051** | **$ 0.079** | | |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | 235,048 | 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | 0.029 | 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.033 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.037 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.029 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.025 | 0.032 | | |
| 2009 | 427 | 1,260,922 | 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.021 | 0.033 | | |
| 2010 | 373 | 1,205,446 | 2,782,597 | 3,452,025 | 0.39 | | 25 | 0.026 | 0.060 | | |
| 2011 | 273 | 1,278,112 | 1,861,836 | 2,648,676 | 0.30 | | 25 | 0.036 | 0.053 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2012 | 228 | $ 1,321,927 | $ 1,743,863 | 621,464 | 0.07 | | 25 | $ 0.159 | $ 0.210 | | |
| 2013 | 245 | 1,336,742 | 1,984,173 | 657,580 | 0.08 | | 25 | 0.152 | 0.226 | | |
| 2014 | 244 | 1,267,212 | 1,902,615 | 509,620 | 0.06 | | 25 | 0.185 | 0.277 | | |
| **Total** | **4,410** | **$ 14,158,439** | **$ 21,719,016** | **27,222,529** | | | **25** | **$ 0.039** | **$ 0.059** | **2.91** | **1.89** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.027 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.016 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.035 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.035 | 0.047 | | |
| 2006 | | | | | | | 25 | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.054 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.040 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.023 | 0.031 | | |
| 2010 | 27 | 115,686 | 147,712 | 289,627 | 0.03 | | 25 | 0.030 | 0.038 | | |
| 2011 | 14 | 46,303 | 63,981 | 134,972 | 0.02 | | 25 | 0.026 | 0.035 | | |
| 2012 | 10 | 48,214 | 76,083 | 26,840 | 0.00 | | 25 | 0.134 | 0.212 | | |
| 2013 | 9 | 54,935 | 67,847 | 24,156 | 0.00 | | 25 | 0.170 | 0.210 | | |
| 2014 | 11 | 52,900 | 94,493 | 24,180 | 0.00 | | 25 | 0.162 | 0.290 | | |
| **Total** | **211** | **$ 531,360** | **$ 786,828** | **1,024,387** | | | **25** | **$ 0.038** | **$ 0.057** | **2.79** | **1.89** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.013 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.017 | 0.036 | | |
| 2004 | 40 | 69,409 | 105,021 | 125,919 | 0.01 | | 25 | 0.041 | 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.020** | **$ 0.037** | **5.62** | **2.98** |
| **WAQC—All Total** | | **$ 14,865,069** | **$ 22,836,035** | **28,907,773** | | | **25** | **$ 0.038** | **$ 0.059** | **2.93** | **1.91** |
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | 5,764 | 9,061 | 33,976 | | | 10 | 0.021 | 0.033 | | |
| 2004 | | 344 | 344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.022** | **$ 0.034** | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Building Efficiency | | | | | | | | | | | |
| 2004 | | $ 28,821 | $ 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | $ 0.043 | $ 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 802,839 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,127 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| 2011 | 63 | 1,291,425 | 3,320,015 | 11,514,641 | 1.31 | 0.9 | 12 | 0.010 | 0.026 | | |
| 2012 | 84 | 1,592,572 | 8,204,883 | 20,450,037 | 2.33 | 0.6 | 12 | 0.007 | 0.036 | | |
| 2013 | 59 | 1,507,035 | 3,942,880 | 10,988,934 | 1.25 | 1.1 | 12 | 0.012 | 0.032 | | |
| 2014 | 69 | 1,258,273 | 3,972,822 | 9,458,059 | 1.08 | 1.2 | 12 | 0.012 | 0.037 | | |
| **Total** | **551** | **$ 10,807,051** | **$ 28,309,952** | **79,991,559** | | | **12** | **$ 0.015** | **$ 0.039** | **4.99** | **1.90** |
| Easy Upgrades | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| 2011 | 1,732 | 4,719,466 | 9,519,364 | 38,723,073 | 4.42 | | 12 | 0.011 | 0.022 | | |
| 2012 | 1,838 | 5,349,753 | 9,245,297 | 41,568,672 | 4.75 | | 12 | 0.012 | 0.020 | | |
| 2013 | 1,392 | 3,359,790 | 6,738,645 | 21,061,946 | 2.40 | | 12 | 0.014 | 0.029 | | |
| 2014 | 1,095 | 3,150,942 | 5,453,380 | 19,118,494 | 2.18 | | 12 | 0.015 | 0.025 | | |
| **Total** | **9,586** | **$ 27,615,440** | **$ 60,698,801** | **222,580,306** | | | **12** | **$ 0.014** | **$ 0.030** | **5.48** | **2.49** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| 2011 | 6 | 2,568 | 2,990 | 66,189 | 0.01 | | 10 | 0.004 | 0.005 | | |
| **Total** | **77** | **$ 111,412** | **$ 214,280** | **716,255** | | | **10** | **$ 0.019** | **$ 0.037** | **2.85** | **1.48** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Oregon Commercial Audit | | | | | | | | | | | |
| 2002 | 24 | $ 5,200 | $ 5,200 | | | | | | | | |
| 2003 | 21 | 0 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| 2011 | 12 | 13,597 | 13,597 | | | | | | | | |
| 2012 | 14 | 12,470 | 12,470 | | | | | | | | |
| 2013 | 18 | 5,090 | 5,090 | | | | | | | | |
| 2014 | 16 | 9,464 | 9,464 | | | | | | | | |
| **Total** | **188** | **$ 79,091** | **$ 83,091** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,857** | **223,368** | | | **12** | **$ 0.012** | **$ 0.044** | | |
| **Industrial** | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | |
| 2003 | | 1,303 | 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | 0.058 | 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| 2011 | 166 | 8,783,811 | 19,830,834 | 67,979,157 | 7.76 | 7.8 | 12 | 0.012 | 0.026 | | |
| 2012 | 126 | 7,092,581 | 12,975,629 | 54,253,106 | 6.19 | 7.6 | 12 | 0.012 | 0.021 | | |
| 2013 | 73 | 2,466,225 | 5,771,640 | 21,370,350 | 2.43 | 2.4 | 12 | 0.010 | 0.024 | | |
| 2014 | 131 | 7,173,054 | 13,409,922 | 50,363,052 | 5.75 | 5.6 | 12 | 0.013 | 0.024 | | |
| **Total** | **1,066** | **$ 50,429,705** | **$111,395,170** | **419,668,873** | | | **12** | **$ 0.013** | **$ 0.029** | **5.76** | **2.61** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Program | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |
| 2005 | 38 | 150,577 | 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | 0.014 | 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| 2011 | 880 | 2,360,304 | 13,281,492 | 13,979,833 | 1.60 | 3.8 | 8 | 0.020 | 0.113 | | |
| 2012 | 908 | 2,373,201 | 11,598,185 | 12,617,164 | 1.44 | 3.1 | 8 | 0.022 | 0.110 | | |
| 2013 | 995 | 2,441,386 | 15,223,928 | 18,511,221 | 2.11 | 3.0 | 8 | 0.016 | 0.098 | | |
| 2014 | 1,128 | 2,446,507 | 18,459,781 | 18,463,611 | 2.11 | 4.6 | 8 | 0.016 | 0.119 | | |
| **Total** | **7,960** | **$ 21,313,865** | **$ 96,439,079** | **130,586,841** | | | **8** | **$ 0.024** | **$ 0.108** | **4.65** | **1.54** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | 48,853 | 48,853 | 1,825,000 | 0.21 | | 5 | 0.006 | 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| 2011 | | 89,856 | 89,856 | | | | | | | | |
| 2012 | | 73,788 | 73,788 | | | | | | | | |
| 2013 | | 66,790 | 66,790 | | | | | | | | |
| 2014 | | 76,606 | 76,606 | | | | | | | | |
| **Total** | | **$ 604,110** | **$ 604,110** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Comprehensive Lighting | | | | | | | | | | | |
| 2011 | | $ 2,404 | $ 2,404 | | | | | | | | |
| 2012 | | 64,094 | 64,094 | | | | | | | | |
| **Total** | | **$ 66,498** | **$ 66,498** | | | | | | | | |
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |
| 2008 | | (1,913) | (1,913) | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | 56,909 | 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| 2011 | | 210,477 | 210,477 | | | | | | | | |
| 2012 | | 285,951 | 285,951 | | | | | | | | |
| 2013 | | 380,957 | 380,957 | | | | | | | | |
| 2014 | | 478,658 | 478,658 | | | | | | | | |
| **Total** | | **$ 1,865,694** | **$ 1,865,694** | | | | | | | | |
| Home Energy Audit | | | | | | | | | | | |
| 2013 | | 88,740 | 88,740 | | | | | | | | |
| 2014 | 354 | 170,648 | 170,648 | 141,077 | | | | | | | |
| **Total** | **354** | **$ 259,388** | **$ 259,388** | **141,077** | | | | | | | |
| Shade Tree | | | | | | | | | | | |
| 2014 | 2,041 | 147,290 | 147,290 | | | | | | | | |
| **Total** | **2,041** | **$ 147,290** | **$ 147,290** | | | | | | | | |

**Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | $ 55,722 | $ 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |
| Residential Economizer Pilot | | | | | | | | | | | |
| 2011 | | 101,713 | 101,713 | | | | | | | | |
| 2012 | | 93,491 | 93,491 | | | | | | | | |
| 2013 | | 74,901 | 74,901 | | | | | | | | |
| **Total** | | **$ 270,105** | **$ 270,105** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |
| 2010 | | 222,092 | 222,092 | | | | | | | | |
| 2011 | | 159,645 | 159,645 | | | | | | | | |
| 2012 | | 174,738 | 174,738 | | | | | | | | |
| 2013 | | 416,166 | 416,166 | | | | | | | | |
| 2014 | 6,312 | 423,091 | 423,091 | 1,491,225 | | | | | | | |
| **Total** | **6,312** | **$ 1,804,527** | **$ 1,804,527** | **1,491,225** | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 45,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 45,522** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2003 | 56 | $ 5,100 | $ 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $ 0.024 | $ 0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | 0.009 | 0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | 0.135 | 0.135 | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | | 15 | 0.019 | 0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | | 12 | 0.064 | 0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | | | | | | |
| 2011 | 1 | 1,026 | 2,052 | 2,028 | | | 30 | 0.036 | 0.071 | | |
| 2012 | | | | | | | | | | | |
| 2013 | | | | | | | | | | | |
| 2014 | 1 | 9,100 | 9,100 | 95,834 | | | 18 | | | | |
| **Total** | **545** | **$ 93,385** | **$ 142,061** | **330,160** | | | **14** | **$ 0.028** | **$ 0.043** | **2.71** | **1.78** |
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | $ 1,286,632 | $ 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,279 | 2.40 | | | | | | |
| 2009 | | 968,263 | 968,263 | 10,702,998 | 1.22 | | | | | | |
| 2010 | | 2,391,217 | 2,391,217 | 21,300,366 | 2.43 | | | | | | |
| 2011 | | 3,108,393 | 3,108,393 | 20,161,728 | 2.30 | | | | | | |
| 2012 | | 3,379,756 | 3,379,756 | 19,567,984 | 2.23 | | | | | | |
| 2013 | | 3,313,058 | 3,313,058 | 20,567,965 | 2.35 | | | | | | |
| 2014 | | 3,305,917 | 3,305,917 | 20,000,000 | 2.28 | | | | | | |
| **Total** | | **$ 23,545,294** | **$ 23,545,294** | **235,193,011** | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2009 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | $ 1,932,520 | $ 2,366,591 | 16,791,100 | 1.92 | 0.0 | | | | | |
| 2003 | | 2,566,228 | 3,125,572 | 18,654,343 | 2.12 | 0.0 | | | | | |
| 2004 | | 3,827,213 | 4,860,912 | 19,202,780 | 2.19 | 6.6 | | | | | |
| 2005 | | 6,523,348 | 10,383,577 | 37,978,035 | 4.34 | 44.3 | | | | | |
| 2006 | | 11,174,181 | 20,950,110 | 67,026,303 | 7.65 | 44.4 | | | | | |
| 2007 | | 14,896,816 | 27,123,018 | 91,145,357 | 10.40 | 58.5 | | | | | |
| 2008 | | 20,213,216 | 44,775,829 | 128,508,579 | 14.67 | 74.9 | | | | | |
| 2009 | | 33,821,062 | 53,090,852 | 143,146,365 | 16.34 | 235.5 | | | | | |
| 2010 | | 44,643,541 | 68,981,324 | 193,592,637 | 22.10 | 357.7 | | | | | |
| 2011 | | 44,877,117 | 79,436,532 | 183,476,312 | 20.94 | 419.6 | | | | | |
| 2012 | | 47,991,350 | 77,336,341 | 172,054,327 | 19.64 | 453.6 | | | | | |
| 2013 | | 26,100,091 | 54,803,353 | 109,505,690 | 12.23 | 54.5 | | | | | |
| 2014 | | 35,648,260 | 71,372,414 | 138,670,112 | 15.60 | 389.7 | | | | | |
| **Total Direct Program** | | **$ 294,214,943** | **$518,606,427** | **1,319,751,941** | | | | | | | |
| **Indirect Program Expenses** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | 128,855 | | | | | | | | | |
| 2003 | | (41,543) | | | | | | | | | |
| 2004 | | 142,337 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,310 | | | | | | | | | |
| 2011 | | 1,389,135 | | | | | | | | | |
| 2012 | | 1,335,509 | | | | | | | | | |
| 2013 | | 741,287 | | | | | | | | | |
| 2014 | | $1,065,072 | | | | | | | | | |
| **Total** | | **$ 9,208,988** | | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Total Expenses** | | | | | | | | | | | |
| 2002 | | $ 2,061,375 | | | | | | | | | |
| 2003 | | 2,524,685 | | | | | | | | | |
| 2004 | | 3,969,550 | | | | | | | | | |
| 2005 | | 6,700,972 | | | | | | | | | |
| 2006 | | 11,484,013 | | | | | | | | | |
| 2007 | | 15,662,377 | | | | | | | | | |
| 2008 | | 21,193,521 | | | | | | | | | |
| 2009 | | 34,846,766 | | | | | | | | | |
| 2010 | | 45,832,851 | | | | | | | | | |
| 2011 | | 46,266,252 | | | | | | | | | |
| 2012 | | 49,326,859 | | | | | | | | | |
| 2013 | | 26,841,378 | | | | | | | | | |
| 2014 | | 36,713,333 | | | | | | | | | |
| **Total 2002–2014** | | **$ 303,423,931** | | | | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP and calculations include line loss adjusted energy savings.

[b] Program life benefit/cost ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming peak line losses.

[1] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

## **Appendix 5.** 2014 DSM program activity by state jurisdiction

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs[a] | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Demand Response** | | | **(MW)** | | | **(MW)** |
| A/C Cool Credit | 29,239 homes | $ 1,408,658 | 43.0 | 403 homes | $ 56,988 | 0.6 |
| Irrigation Peak Rewards | 2,194 service points | 7,490,394 | 293.4 | 31 service points | 106,819 | 1.6 |
| FlexPeak Management | 35 sites | 1,485,080 | 28.9 | 5 sites | 78,131 | 10.7 |
| **Total** | | **$ 10,384,132** | **365.3** | | **$ 241,938** | **12.9** |
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Residential** | | | | | | |
| Ductless Heat Pump Pilot | 174 homes | 241,832 | 447,092 | 5 homes | 9,614 | 15,655 |
| Energy Efficient Lighting | 1,128,724 bulbs | 1,863,864 | 12,565,310 | 32,829 bulbs | 45,959 | 316,841 |
| Energy House Calls | 282 homes | 189,812 | 555,081 | 15 homes | 8,174 | 24,045 |
| ENERGY STAR® Homes Northwest | 240 homes | 335,665 | 322,980 | 3 homes | 7,612 | 9,702 |
| ENERGY STAR® Homes Northwest (gas fuel) | 282 homes | 0 | 195,372 | 0 homes | 0 | 0 |
| Heating & Cooling Efficiency Program | 224 projects | 347,387 | 1,067,900 | 6 projects | 14,627 | 31,564 |
| Home Energy Audit (direct install savings) | 381 audits | 0 | 141,077 | 0 audits | 0 | 0 |
| Home Improvement Program | 555 projects | 324,717 | 838,929 | 0 projects | 0 | 0 |
| Home Products Program | 9,794 appliances/ showerheads | 217,926 | 634,244 | 267 appliances/ showerheads | 9,250 | 17,885 |
| Oregon Residential Weatherization | 0 home | 0 | 0 | 13 home | 5,462 | 11,032 |
| Rebate Advantage | 40 homes | 57,907 | 245,109 | 4 homes | 5,323 | 24,534 |
| Student Energy Efficiency Kits | 6,312 kits | 0 | 1,491,225 | 0 kits | 0 | 0 |
| See ya later refrigerator® | 3,138 refrigerators/ freezers | 563,641 | 1,366,044 | 56 refrigerators/ freezers | 12,410 | 24,716 |
| Weatherization Assistance for Qualified Customers | 244 homes/non-profits | 1,267,212 | 509,620 | 11 homes/non-profits | 52,900 | 24,180 |
| Weatherization Solutions for Eligible Customers | 118 homes | 791,344 | 290,926 | 0 homes | 0 | 0 |
| **Sector Total** | | **$ 6,201,308** | **20,670,908** | | **$ 171,332** | **500,154** |
| **Commercial** | | | | | | |
| Building Efficiency | 66 projects | 1,227,222 | 9,377,053 | 3 projects | 31,052 | 81,005 |
| Easy Upgrades | 1,055 projects | 3,038,319 | 18,709,206 | 40 projects | 112,623 | 409,288 |
| **Sector Total** | | **$ 4,265,541** | **28,086,259** | | **$ 143,674** | **490,293** |
| **Industrial** | | | | | | |
| Custom Efficiency | 122 projects | 6,754,517 | 46,194,507 | 9 projects | 418,537 | 4,168,545 |
| **Sector Total** | | **$ 6,754,517** | **46,194,507** | | **$ 418,537** | **4,168,545** |

## **Appendix 5.** 2014 DSM program activity by state jurisdiction (continued)

| Program | Idaho | | | Oregon | | |
|---|---|---|---|---|---|---|
| | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings | Participants | Utility Costs[a] | Demand Reduction/ Annual Energy Savings |
| **Irrigation** | | | | | | |
| Irrigation Efficiency Rewards | 1,093 projects | 2,301,126 | 17,845,297 | 35 projects | 145,381 | 618,314 |
| **Sector Total** | | **$ 2,301,126** | **17,845,297** | | **$ 145,381** | **618,314** |
| **Market Transformation** | | | | | | |
| Northwest Energy Efficiency Alliance[1] | | 3,140,621 | 19,000,000 | | 165,296 | 1,000,000 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Home Energy Audit | | 170,897 | | | (248) | |
| Local Energy Efficiency Funds | | 9,100 | 95,834 | | 0 | |
| Residential Energy Efficiency Education Initiative | | 408,246 | | | 14,845 | |
| Shade Tree Project | | 147,224 | | | 66 | |
| **Commercial** | | | | | | |
| Commercial Education Initiative | | 72,776 | | | 3,829 | |
| Oregon Commercial Audits | | 0 | | | 9,464 | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 456,947 | | | 21,711 | |
| **Total Program Direct Expense** | | **$ 34,312,435** | | | **$ 1,335,825** | |
| Indirect Program Expenses | | 1,012,004 | | | 53,068 | |
| **Total Annual Savings** | | | **131,892,805** | | | **6,777,306** |
| **Total DSM Expense** | | **$ 35,324,439** | | | **$ 1,388,894** | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2011 IRP and calculations include line loss adjusted energy savings.

[1] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

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June 2015

APPENDIX C
Technical Report

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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APPENDIX C
Technical Report

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

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# TABLE OF CONTENTS

Table of Contents ..... i
Introduction ..... 1
IRP Advisory Council and Members ..... 2
IRP Advisory Council Meeting Schedule and Agenda ..... 3
Public Policy Issues ..... 5
Clean Air Act Section 111(d) Sensitivities Assumptions ..... 5
Flow Modeling ..... 7
Sales and Load Forecast Data ..... 10
Average Annual Forecast Growth Rates ..... 10
Expected-Case Load Forecast ..... 11
70th Percentile Load Forecast ..... 20
Load and Resource Balance Data ..... 29
Monthly Average Energy Load and Resource Balance ..... 29
Monthly Average Energy Surplus/Deficit Charts ..... 49
Peak-Hour Load and Resource Balance ..... 50
Peak-Hour Surplus/Deficit Charts ..... 70
Demand-Side Resource Data ..... 71
Cost Effectiveness ..... 71
Resource Development and Evaluation ..... 71
Planning Assumptions and Alternate Costs ..... 72
Forecast and Cost-Effectiveness Data ..... 73
Supply-Side Resource Data ..... 83
Key Financial and Forecast Assumptions ..... 83
Cost Inputs and Operating Assumptions ..... 85
Transmission Cost Assumptions ..... 86
Levelized Cost of Production ..... 89
Peak-Hour Capacity Credit (Contribution to Peak)—Solar and Wind Resources ..... 90
Energy Shape—Solar ..... 91
Schedule 87—Integration Costs for Solar and Wind Resources ..... 92
PURPA Reference Data ..... 119

Renewable Energy Certificate Price Forecast....120
Jim Bridger Units 3 and 4 Selective Catalytic Reduction Analysis....121
Background....121
SCR Construction Progress Update....121
2015 Jim Bridger Units 3 and 4 SCR Analysis....122
Overall Analysis Methodology....123
Option 1 NPV Methodology....123
Option 2 NPV Methodology....124
Analysis Results....124
Conclusions and Recommendations....124
Revenue Requirement Comparison between Jim Bridger Units 3 and 4 SCR Completion and CCCT Replacement....125
Fuel Price Forecast....129
Natural Gas and Coal Price Forecast (nominal $/MMBtu)....129
Existing Resource Data....131
Hydroelectric and Thermal Plant Data....131
Qualifying Facility Data (PURPA)....132
Power Purchase Agreement Data....134
Hydro Modeling Results (PDR580)....135
Portfolio Analysis, Results, and Supporting Documentation....165
Portfolio Emissions....165
Loss of Load Expectation Analysis....167
State of Oregon IRP Guidelines....173
Compliance with State of Oregon IRP Guidelines....181
State of Oregon IRP Electric Vehicles (EV) Guidelines....187
Compliance with EV Guidelines....191
State of Oregon Action Items Regarding Idaho Power's 2013 IRP....192
Compliance with State of Oregon IRP Guidelines....211

# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2015 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2015 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2014 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2015.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2623

irp@idahopower.com

# IRP ADVISORY COUNCIL AND MEMBERS

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2015 IRP, Idaho Power hosted a field trip to the Swan Falls hydroelectric project and museum.. Idaho Power also hosted 12 IRPAC meetings, including a resource portfolio design workshop. Idaho Power and members from the IRPAC also met in several small break-out sessions to discuss certain topics in greater detail. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

### Customer Representatives

| | |
|---|---|
| Agricultural Representative | Sid Erwin |
| Boise State University | Barry Burbank |
| Glanbia | Jim Bergin |
| Idaho National Laboratory | Kurt Myers |
| Micron | Clancy Kelley |
| Simplot | Don Sturtevant/Don Strickler |

### Public Interest Representatives

| | |
|---|---|
| Boise Metro Chamber of Commerce | Ray Stark |
| Idaho Conservation League | Ben Otto |
| Idaho Department of Commerce | Chrissy Bowers |
| Idaho Legislature | Representative Robert Anderst |
| Idaho Office of Energy Resources | John Chatburn |
| Idaho Technology Council | Jay Larsen |
| Northwest Power and Conservation Council | Shirley Lindstrom/Jim Yost |
| Oil and Gas Industry Advisor | David Hawk |
| Oregon State University – Malheur Experiment Station | Clint Shock |
| Snake River Alliance | Ken Miller |
| University of Idaho Center for Ecohydraulics Research | Daniele Tonina |
| University of Idaho Integrated Design Lab | Kevin Van Den Wymelenberg |
| Water Issues Advisor | Vince Alberdi |

### Regulatory Commission Representatives

| | |
|---|---|
| Idaho Public Utilities Commission | Stacey Donohue |
| Public Utility Commission of Oregon | Michael Breish |

# IRP Advisory Council Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2014 | Thursday, August 7 | Introductions/meeting overview<br>Welcome and opening remarks<br>IRP process explanation<br>System load and operation<br>Demand response update<br>Natural gas forecast<br>Solar workgroup recap |
| 2014 | Thursday, September 4 | Review of August IRPAC meeting<br>Solar workgroup recap<br>Coal study workgroup recap<br>Natural gas forecast<br>Overview of Idaho Power generation and transmission<br>Resource stack introduction |
| 2014 | Wednesday, October 1 | Field trip to Swan Falls hydroelectric project and museum |
| 2014 | Thursday, October 2 | Review of September IRPAC meeting<br>2015 IRP load forecast<br>Resource stack capital costs<br>IRP risk factors |
| 2014 | Thursday, November 6 | Review of October IRPAC meeting<br>Coal study<br>Demand-side management<br>Water supply forecast<br>Cloud seeding<br>Hydro generation forecast |
| 2014 | Thursday, December 4 | Review of November IRPAC meeting<br>Recap of DSM working group meeting<br>Clean Air Act Section 111(d)<br>500-kV transmission projects<br>Power markets |
| 2015 | Thursday, January 8 | Review of December IRPAC meeting<br>Recap of DSM working group meetings<br>Energy efficiency potential study final results<br>PURPA/PPA forecast<br>Resource stack |
| 2015 | Wednesday, January 28 | Portfolio design workshop |
| 2015 | Thursday, February 5 | Review of January IRPAC meeting<br>AURORA overview<br>Load and resource balance<br>Portfolio design |
| 2015 | Thursday, March 12 | Review of February IRPAC meeting<br>Conservation voltage reduction update<br>2015 IRP resource portfolios<br>Portfolio analysis overview |

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2015 | Thursday, April 2 | Review of March IRPAC meeting<br>Portfolio analysis results<br>Sustainability at Idaho Power<br>Hells Canyon Complex relicensing |
| 2015 | Thursday, May 7 | Review of April IRPAC meeting<br>Clean Air Act Section 111(d) sensitivity analysis<br>Stochastic risk analysis<br>Asset replacement deferment<br>End of feeder solar project<br>Flexibility analysis<br>Operational impacts of oversupply |
| 2015 | Thursday, June 4 | Review of May IRPAC meeting<br>Preferred portfolio discussion<br>Tipping point analysis<br>Natural gas outlook from Potential Gas Committee<br>Shoshone Falls expansion<br>Loss of load expectation analysis<br>2015 IRP action plan<br>Input for the 2017 IRP and public process |

# PUBLIC POLICY ISSUES

## Clean Air Act Section 111(d) Sensitivities Assumptions

### *Section 111(d) Sensitivities*

Because of the uncertainty associated with the EPA's proposed regulation of $CO_2$ under the *Clean Air Act of 1970* (CAA) Section 111(d), a range of sensitivities was modeled. Each sensitivity is based on multiple assumptions as provided in this section. It is noted that portfolio cost results associated with each sensitivity are contingent upon underlying assumptions of the sensitivity; stipulations for the final CAA Section 111(d) regulation may differ greatly from those assumed for these sensitivities, leading possibly to markedly different costs in practice.

#### Null Sensitivity (No CAA Section 111(d))

- No existing regulations require any modifications to operations or equipment
- No pending or future regulations (i.e., CAA Section 111(d)) will require any modifications to operations or equipment
- Analyzed to provide a comparison with portfolios complying with CAA Section 111(d)-based regulations on $CO_2$ emissions

#### State-by-State Mass-Based Compliance

- Compliance determined within state boundaries
- Compliance cannot cross state lines and plant reductions cannot be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Generation is capped at the target levels
    - North Valmy targets—574,382 MWh/year for 2020-2029 and 533,343 MWh/year for 2030 through IRP planning period end
    - Jim Bridger targets—3,914,502 MWh/year for 2020-2029 and 3,675,608 MWh/year for 2030 through IRP planning period end
    - Langley Gulch target alternatives
        - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
        - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
        - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

### System-Wide Mass-Based Compliance

- Determine total $CO_2$ reduction for Idaho Power system
- Compliance is determined by meeting Idaho Power system $CO_2$ emission target
- Compliance can cross state lines and plant $CO_2$ reductions can be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Idaho Power system emissions are capped at the target levels
    - 6,332,020 tons $CO_2$ for 2020–2029
    - 5,925,874 tons $CO_2$ for 2030 through IRP planning period end
- Early shutdown of units enables other units to increase generation

### Emissions Intensity Compliance Utilizing the EPA's Compliance Building Blocks

- All building blocks required to meet compliance
- Rate reductions established based on the goal calculations by the EPA
- The state of Idaho is able to count previously constructed PURPA projects as part of building block 3
- Renewable energy (building block 3) and energy efficiency (building block 4) in Idaho grow to EPA projected levels
- No renewable energy or energy efficiency requirements for states where Idaho Power has no customers (Wyoming, Nevada)
- CAA Section 111(d) $CO_2$ attributes can cross state lines
- Affected unit generation and renewable energy/energy efficiency are variable as long as interim and final rates are met
- Idaho Power is not responsible for meeting interim or final goals for Wyoming, Nevada, or Oregon
- Since Boardman has an agreed upon closure date, Idaho Power has no rate requirements to meet in Oregon
- Interim goals are relaxed with agreed upon retirement dates for Boardman and North Valmy set at 2020 and 2025 respectively (note that pre-2025 North Valmy retirement also allows a relaxing of interim goals)
- Building block 1 (6 percent efficiency improvement) cannot be met or sustained and is reset to 0 percent
- Jim Bridger generation reduced from 2012 levels for pro-rata share of 95 MW natural gas plant under construction in Wyoming (building block 2)
- Generation capped at the target levels
    - North Valmy target—814,264 MWh/year until retirement (retirement no later than 2025)

- Jim Bridger target—4,488,392 MW/year for 2020 through IRP planning period end
- Langley Gulch target alternatives
  - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
  - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
  - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

# Flow Modeling

## Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

## Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2011 and 2013 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dam demonstrated a statistically significant decline for the period of 1980 to 2013. Reach gains into American Falls Reservoir declined on average 23 cubic feet per second per month (cfs/month) with declines ranging from 12 to 34 cfs/month. Reach gains from Milner Dam to Lower Salmon Falls Dam for American declined on average 34 cubic feet per second per month (cfs/month) with declines ranging from 22 to 53 cfs/month. Declines in these two reaches met strict, predefined criteria and were therefore included as inputs into the model.

Weather modification was added to the model at different levels of development. For IRP years 2015 through 2019, weather modification was increased to reflect projected levels of fully built-out programs in Eastern Idaho, the Wood River Valley, and the Boise Basin. Beyond IRP year 2019, weather modification levels in these three basins were held constant through the rest of the IRP forecast period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP forecast period. The amount of weather modification added to each year is

based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 271,567 acre-ft/year. The Upper Snake, Wood River, and Boise Basins, respectively, add an average of 453,130 acre-ft/year; 108,900 acre-ft/year; and 218,249 acre-ft/year by IRP year 2019.

Aquifer recharge was added to the model at levels reflected in the 2014 Idaho Water Resource Board Preliminary Draft—Managed Recharge Plan. In the 2015 IRP, recharge expanded to include wintertime recharge from winter time diversions at Milner Dam. Recharge peaks in IRP year 2021 at approximately 209,839 acre-ft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

System conversion projects involve the conversion of ground water supplied irrigated land to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources (IDWR). The current model assumes a total of 14,767 acres of converted land on the ESPA with a total water savings of 2.0 acre-ft or water per acre of irrigated land (acre-ft/ac). Additional conversion projects are added to the model and from 2020 to 2034 they are held constant at 16,687 acres. Diversions for conversion projects are limited by water availability to meet the demand. Diversions for conversion projects peak in 2020 at 32,440 acre-ft. Diversions for conversion project generally declines after 2020 at declines in reach gains reduces water availability for diversion.

The model accounts for approximately 15,140 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acre-ft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions. Also included in this model run are 750 acres of short-term projects to reduce water use by ground water appropriators. The projects may include the elimination of end gun on center pivots or drying pivot corners. These short-term projects run from 2015 to 2023.

## Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2015 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2015 through 2019 in response to increased weather modification in the Upper Snake, Wood and Boise River Basins. Flows peak in 2019 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.9 million acre-ft/year. In 2034, those flows have declined to approximately 11.3 million acre-ft/year,

with most of the declines attributable to declining flows into American Falls and the Milner to Lower Salmon Falls reach.

## 2015 Model Parameters

| IRP Year | Managed Recharge (acft/yr) | | | Weather Modification (acft/yr) | System Conversions (Ac) | CREP (Ac) | Reach Declines (acft/yr) | |
|---|---|---|---|---|---|---|---|---|
| | Above American Falls | Below American Falls | Total | | | | American Falls Inflows | Below Milner Inflows |
| 2015 | 34,060 | 29,793 | 63,852 | 715,209 | 14,767 | 15,890 | 102,644 | 152,147 |
| 2016 | 33,896 | 29,772 | 63,668 | 840,784 | 14,767 | 15,890 | 119,751 | 177,504 |
| 2017 | 34,339 | 69,965 | 104,304 | 960,948 | 14,767 | 15,890 | 136,858 | 202,862 |
| 2018 | 35,417 | 94,061 | 129,478 | 1,017,289 | 15,407 | 15,890 | 153,966 | 228,220 |
| 2019 | 43,433 | 168,533 | 211,966 | 1,051,936 | 16,047 | 15,890 | 171,073 | 253,578 |
| 2020 | 42,926 | 167,127 | 210,052 | 1,051,936 | 16,687 | 12,033 | 188,180 | 278,936 |
| 2021 | 42,989 | 166,850 | 209,839 | 1,051,936 | 16,687 | 8,312 | 205,287 | 304,293 |
| 2022 | 42,795 | 166,640 | 209,435 | 1,051,936 | 16,687 | 4,531 | 222,395 | 329,651 |
| 2023 | 42,599 | 166,983 | 209,582 | 1,051,936 | 16,687 | 2,056 | 239,502 | 355,009 |
| 2024 | 42,265 | 164,705 | 206,970 | 1,051,936 | 16,687 | 0 | 256,609 | 380,367 |
| 2025 | 42,272 | 164,293 | 206,565 | 1,051,936 | 16,687 | 0 | 273,717 | 405,724 |
| 2026 | 42,271 | 163,541 | 205,812 | 1,051,936 | 16,687 | 0 | 290,824 | 431,082 |
| 2027 | 42,021 | 162,395 | 204,416 | 1,051,936 | 16,687 | 0 | 307,931 | 456,440 |
| 2028 | 42,240 | 162,839 | 205,079 | 1,051,936 | 16,687 | 0 | 325,039 | 481,798 |
| 2029 | 42,389 | 163,178 | 205,567 | 1,051,936 | 16,687 | 0 | 342,146 | 507,156 |
| 2030 | 42,129 | 162,217 | 204,346 | 1,051,936 | 16,687 | 0 | 359,253 | 532,513 |
| 2031 | 41,716 | 161,734 | 203,450 | 1,051,936 | 16,687 | 0 | 376,360 | 557,871 |
| 2032 | 41,715 | 161,600 | 203,315 | 1,051,936 | 16,687 | 0 | 393,468 | 583,229 |
| 2033 | 41,887 | 161,659 | 203,545 | 1,051,936 | 16,687 | 0 | 410,575 | 608,587 |
| 2034 | 42,189 | 163,380 | 205,570 | 1,051,936 | 16,687 | 0 | 427,682 | 633,944 |

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2015–2020 | 2015–2025 | 2015–2034 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.57% | 1.40% | 1.33% |
| Commercial Sales | 1.02% | 1.00% | 0.98% |
| Irrigation Sales | 0.62% | 0.51% | 0.49% |
| Industrial Sales | 2.91% | 2.36% | 1.99% |
| Additional Firm Sales | 0.89% | 1.35% | 0.64% |
| System Sales | 1.48% | 1.34% | 1.20% |
| Total Sales | 1.48% | 1.34% | 1.20% |
| **Loads** | | | |
| Residential Load | 1.56% | 1.40% | 1.32% |
| Commercial Load | 1.02% | 0.99% | 0.98% |
| Irrigation Load | 0.56% | 0.51% | 0.49% |
| Industrial Load | 2.78% | 2.32% | 1.97% |
| Additional Firm Sales | 0.89% | 1.35% | 0.64% |
| System Load Losses | 1.37% | 1.25% | 1.16% |
| System Load | 1.43% | 1.32% | 1.19% |
| Total Load | 1.43% | 1.32% | 1.19% |
| **Peaks** | | | |
| System Peak | 1.78% | 1.66% | 1.53% |
| Total Peak | 1.78% | 1.66% | 1.53% |
| Winter Peak | 0.91% | 0.93% | 0.88% |
| Summer Peak | 1.78% | 1.66% | 1.53% |
| **Customers** | | | |
| Residential Customers | 2.13% | 1.88% | 1.62% |
| Commercial Customers | 2.03% | 1.91% | 1.72% |
| Irrigation Customers | 1.40% | 1.35% | 1.28% |
| Industrial Customers | 0.53% | 0.69% | 0.66% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 753 | 705 | 609 | 510 | 440 | 462 | 669 | 543 | 457 | 481 | 590 | 843 |
| Commercial | 482 | 470 | 446 | 433 | 428 | 454 | 534 | 475 | 461 | 453 | 448 | 503 |
| Irrigation | 2 | 2 | 5 | 89 | 302 | 536 | 659 | 544 | 311 | 77 | 5 | 3 |
| Industrial | 277 | 274 | 276 | 262 | 256 | 281 | 279 | 282 | 279 | 288 | 283 | 285 |
| Additional Firm | 105 | 103 | 99 | 101 | 95 | 100 | 98 | 98 | 101 | 100 | 104 | 103 |
| Loss | 139 | 133 | 122 | 119 | 131 | 160 | 199 | 171 | 138 | 118 | 121 | 150 |
| **System Load** | **1,759** | **1,688** | **1,556** | **1,513** | **1,652** | **1,994** | **2,438** | **2,113** | **1,747** | **1,517** | **1,551** | **1,887** |
| Light Load | 1,634 | 1,551 | 1,421 | 1,369 | 1,493 | 1,801 | 2,206 | 1,870 | 1,557 | 1,365 | 1,429 | 1,741 |
| Heavy Load | 1,858 | 1,791 | 1,663 | 1,618 | 1,790 | 2,135 | 2,621 | 2,304 | 1,898 | 1,627 | 1,658 | 2,002 |
| **Total Load** | **1,759** | **1,688** | **1,556** | **1,513** | **1,652** | **1,994** | **2,438** | **2,113** | **1,747** | **1,517** | **1,551** | **1,887** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,264 | 2,342 | 2,072 | 2,017 | 2,649 | 3,109 | 3,537 | 2,995 | 2,887 | 2,117 | 2,170 | 2,603 |
| **Total Peak Load** | **2,264** | **2,342** | **2,072** | **2,017** | **2,649** | **3,109** | **3,537** | **2,995** | **2,887** | **2,117** | **2,170** | **2,603** |

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 771 | 721 | 623 | 521 | 451 | 475 | 688 | 558 | 468 | 492 | 603 | 860 |
| Commercial | 490 | 477 | 453 | 440 | 435 | 462 | 543 | 483 | 469 | 461 | 456 | 509 |
| Irrigation | 2 | 2 | 5 | 90 | 308 | 547 | 673 | 556 | 317 | 79 | 5 | 3 |
| Industrial | 296 | 283 | 294 | 279 | 273 | 300 | 297 | 301 | 298 | 307 | 302 | 293 |
| Additional Firm | 110 | 105 | 105 | 104 | 97 | 94 | 101 | 101 | 99 | 101 | 105 | 109 |
| Loss | 143 | 136 | 125 | 122 | 135 | 164 | 204 | 175 | 142 | 121 | 124 | 153 |
| **System Load** | **1,813** | **1,724** | **1,605** | **1,557** | **1,700** | **2,042** | **2,507** | **2,175** | **1,794** | **1,561** | **1,594** | **1,927** |
| Light Load | 1,683 | 1,584 | 1,466 | 1,409 | 1,536 | 1,844 | 2,268 | 1,924 | 1,600 | 1,404 | 1,469 | 1,778 |
| Heavy Load | 1,924 | 1,828 | 1,706 | 1,666 | 1,841 | 2,186 | 2,712 | 2,355 | 1,950 | 1,684 | 1,695 | 2,044 |
| **Total Load** | **1,813** | **1,724** | **1,605** | **1,557** | **1,700** | **2,042** | **2,507** | **2,175** | **1,794** | **1,561** | **1,594** | **1,927** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,334 | 2,378 | 2,125 | 2,072 | 2,714 | 3,211 | 3,630 | 3,087 | 2,978 | 2,167 | 2,218 | 2,640 |
| **Total Peak Load** | **2,334** | **2,378** | **2,125** | **2,072** | **2,714** | **3,211** | **3,630** | **3,087** | **2,978** | **2,167** | **2,218** | **2,640** |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 785 | 733 | 634 | 531 | 460 | 485 | 704 | 571 | 478 | 500 | 613 | 873 |
| Commercial | 495 | 481 | 457 | 444 | 439 | 466 | 547 | 488 | 474 | 466 | 460 | 514 |
| Irrigation | 2 | 2 | 5 | 91 | 311 | 551 | 678 | 560 | 320 | 79 | 5 | 3 |
| Industrial | 304 | 300 | 302 | 287 | 280 | 308 | 305 | 309 | 306 | 315 | 310 | 299 |
| Additional Firm | 111 | 110 | 106 | 105 | 97 | 94 | 102 | 102 | 100 | 101 | 105 | 109 |
| Loss | 145 | 139 | 127 | 123 | 137 | 166 | 207 | 178 | 144 | 123 | 126 | 155 |
| **System Load** | 1,842 | 1,765 | 1,630 | 1,581 | 1,725 | 2,071 | 2,543 | 2,207 | 1,822 | 1,585 | 1,619 | 1,953 |
| Light Load | 1,710 | 1,621 | 1,489 | 1,431 | 1,558 | 1,871 | 2,301 | 1,953 | 1,624 | 1,426 | 1,492 | 1,802 |
| Heavy Load | 1,955 | 1,872 | 1,732 | 1,701 | 1,856 | 2,217 | 2,752 | 2,390 | 1,980 | 1,710 | 1,722 | 2,082 |
| **Total Load** | 1,842 | 1,765 | 1,630 | 1,581 | 1,725 | 2,071 | 2,543 | 2,207 | 1,822 | 1,585 | 1,619 | 1,953 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,360 | 2,414 | 2,148 | 2,093 | 2,755 | 3,266 | 3,696 | 3,137 | 3,027 | 2,193 | 2,242 | 2,664 |
| **Total Peak Load** | 2,360 | 2,414 | 2,148 | 2,093 | 2,755 | 3,266 | 3,696 | 3,137 | 3,027 | 2,193 | 2,242 | 2,664 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 794 | 741 | 641 | 537 | 467 | 493 | 715 | 580 | 485 | 506 | 620 | 884 |
| Commercial | 498 | 483 | 459 | 447 | 442 | 470 | 551 | 492 | 478 | 469 | 463 | 518 |
| Irrigation | 2 | 2 | 5 | 91 | 311 | 552 | 679 | 560 | 320 | 79 | 5 | 3 |
| Industrial | 309 | 306 | 308 | 292 | 286 | 314 | 311 | 315 | 312 | 321 | 316 | 304 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 147 | 140 | 129 | 125 | 138 | 168 | 209 | 179 | 146 | 124 | 127 | 157 |
| **System Load** | **1,863** | **1,783** | **1,647** | **1,597** | **1,741** | **2,090** | **2,568** | **2,228** | **1,841** | **1,602** | **1,637** | **1,975** |
| Light Load | 1,730 | 1,638 | 1,504 | 1,445 | 1,573 | 1,888 | 2,323 | 1,972 | 1,641 | 1,441 | 1,508 | 1,823 |
| Heavy Load | 1,968 | 1,892 | 1,750 | 1,719 | 1,874 | 2,238 | 2,778 | 2,413 | 2,015 | 1,718 | 1,740 | 2,106 |
| **Total Load** | **1,863** | **1,783** | **1,647** | **1,597** | **1,741** | **2,090** | **2,568** | **2,228** | **1,841** | **1,602** | **1,637** | **1,975** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,367 | 2,425 | 2,157 | 2,099 | 2,786 | 3,302 | 3,752 | 3,170 | 3,062 | 2,212 | 2,250 | 2,681 |
| **Total Peak Load** | **2,367** | **2,425** | **2,157** | **2,099** | **2,786** | **3,302** | **3,752** | **3,170** | **3,062** | **2,212** | **2,250** | **2,681** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 803 | 748 | 647 | 543 | 473 | 500 | 727 | 589 | 492 | 511 | 626 | 893 |
| Commercial | 502 | 487 | 462 | 450 | 446 | 474 | 556 | 496 | 483 | 473 | 467 | 523 |
| Irrigation | 2 | 2 | 5 | 91 | 310 | 551 | 677 | 559 | 319 | 79 | 5 | 3 |
| Industrial | 315 | 311 | 313 | 297 | 291 | 319 | 316 | 320 | 317 | 327 | 321 | 309 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 149 | 142 | 130 | 126 | 139 | 169 | 211 | 181 | 147 | 126 | 129 | 159 |
| **System Load** | **1,883** | **1,800** | **1,664** | **1,612** | **1,756** | **2,107** | **2,589** | **2,247** | **1,858** | **1,618** | **1,654** | **1,996** |
| Light Load | 1,748 | 1,654 | 1,519 | 1,459 | 1,587 | 1,903 | 2,342 | 1,989 | 1,656 | 1,455 | 1,523 | 1,842 |
| Heavy Load | 1,989 | 1,910 | 1,777 | 1,725 | 1,890 | 2,270 | 2,783 | 2,434 | 2,034 | 1,735 | 1,758 | 2,128 |
| **Total Load** | **1,883** | **1,800** | **1,664** | **1,612** | **1,756** | **2,107** | **2,589** | **2,247** | **1,858** | **1,618** | **1,654** | **1,996** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |
| **Total Peak Load** | **2,514** | **2,388** | **2,072** | **1,992** | **2,950** | **3,362** | **3,555** | **3,161** | **2,907** | **2,090** | **2,260** | **2,668** |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 810 | 753 | 652 | 547 | 477 | 505 | 735 | 596 | 497 | 515 | 630 | 901 |
| Commercial | 507 | 490 | 466 | 454 | 450 | 479 | 561 | 501 | 488 | 478 | 471 | 528 |
| Irrigation | 2 | 2 | 5 | 92 | 312 | 554 | 681 | 562 | 321 | 80 | 5 | 3 |
| Industrial | 320 | 306 | 318 | 302 | 296 | 325 | 322 | 326 | 322 | 332 | 327 | 315 |
| Additional Firm | 113 | 108 | 107 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 111 |
| Loss | 150 | 142 | 131 | 127 | 140 | 171 | 213 | 183 | 149 | 127 | 130 | 161 |
| **System Load** | **1,902** | **1,801** | **1,680** | **1,628** | **1,774** | **2,129** | **2,615** | **2,271** | **1,878** | **1,634** | **1,670** | **2,019** |
| Light Load | 1,766 | 1,655 | 1,534 | 1,473 | 1,603 | 1,923 | 2,366 | 2,009 | 1,674 | 1,470 | 1,539 | 1,863 |
| Heavy Load | 2,009 | 1,909 | 1,794 | 1,742 | 1,921 | 2,279 | 2,811 | 2,477 | 2,041 | 1,753 | 1,786 | 2,142 |
| **Total Load** | **1,902** | **1,801** | **1,680** | **1,628** | **1,774** | **2,129** | **2,615** | **2,271** | **1,878** | **1,634** | **1,670** | **2,019** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,414 | 2,457 | 2,193 | 2,135 | 2,848 | 3,372 | 3,862 | 3,236 | 3,129 | 2,248 | 2,288 | 2,725 |
| **Total Peak Load** | **2,414** | **2,457** | **2,193** | **2,135** | **2,848** | **3,372** | **3,862** | **3,236** | **3,129** | **2,248** | **2,288** | **2,725** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 818 | 759 | 658 | 552 | 483 | 512 | 746 | 604 | 503 | 520 | 636 | 911 |
| Commercial | 512 | 494 | 470 | 458 | 455 | 483 | 566 | 506 | 494 | 482 | 476 | 534 |
| Irrigation | 2 | 2 | 5 | 92 | 314 | 557 | 685 | 566 | 323 | 80 | 5 | 3 |
| Industrial | 326 | 323 | 324 | 308 | 301 | 331 | 328 | 332 | 328 | 338 | 333 | 320 |
| Additional Firm | 113 | 112 | 108 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 112 |
| Loss | 152 | 144 | 132 | 128 | 142 | 173 | 215 | 185 | 150 | 128 | 131 | 162 |
| **System Load** | **1,923** | **1,834** | **1,697** | **1,645** | **1,793** | **2,152** | **2,643** | **2,296** | **1,899** | **1,652** | **1,688** | **2,041** |
| Light Load | 1,785 | 1,685 | 1,550 | 1,489 | 1,620 | 1,944 | 2,391 | 2,032 | 1,693 | 1,486 | 1,555 | 1,884 |
| Heavy Load | 2,041 | 1,946 | 1,803 | 1,760 | 1,942 | 2,304 | 2,842 | 2,504 | 2,064 | 1,782 | 1,795 | 2,166 |
| **Total Load** | **1,923** | **1,834** | **1,697** | **1,645** | **1,793** | **2,152** | **2,643** | **2,296** | **1,899** | **1,652** | **1,688** | **2,041** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,429 | 2,473 | 2,207 | 2,148 | 2,882 | 3,415 | 3,922 | 3,275 | 3,168 | 2,268 | 2,302 | 2,744 |
| **Total Peak Load** | **2,429** | **2,473** | **2,207** | **2,148** | **2,882** | **3,415** | **3,922** | **3,275** | **3,168** | **2,268** | **2,302** | **2,744** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 825 | 765 | 663 | 557 | 488 | 518 | 756 | 612 | 508 | 524 | 641 | 920 |
| Commercial | 516 | 498 | 474 | 462 | 459 | 488 | 571 | 511 | 499 | 487 | 480 | 539 |
| Irrigation | 2 | 2 | 5 | 92 | 315 | 559 | 687 | 567 | 324 | 80 | 5 | 3 |
| Industrial | 332 | 329 | 330 | 314 | 307 | 337 | 334 | 338 | 334 | 345 | 339 | 326 |
| Additional Firm | 119 | 117 | 112 | 111 | 102 | 99 | 106 | 106 | 104 | 107 | 112 | 117 |
| Loss | 153 | 146 | 134 | 130 | 143 | 174 | 217 | 187 | 152 | 129 | 133 | 164 |
| **System Load** | **1,948** | **1,856** | **1,718** | **1,666** | **1,814** | **2,176** | **2,672** | **2,322** | **1,922** | **1,672** | **1,710** | **2,070** |
| Light Load | 1,809 | 1,705 | 1,569 | 1,507 | 1,639 | 1,965 | 2,417 | 2,055 | 1,714 | 1,505 | 1,575 | 1,910 |
| Heavy Load | 2,067 | 1,969 | 1,825 | 1,781 | 1,964 | 2,330 | 2,890 | 2,515 | 2,089 | 1,805 | 1,818 | 2,196 |
| **Total Load** | **1,948** | **1,856** | **1,718** | **1,666** | **1,814** | **2,176** | **2,672** | **2,322** | **1,922** | **1,672** | **1,710** | **2,070** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,448 | 2,491 | 2,225 | 2,162 | 2,917 | 3,456 | 3,981 | 3,313 | 3,207 | 2,291 | 2,320 | 2,770 |
| **Total Peak Load** | **2,448** | **2,491** | **2,225** | **2,162** | **2,917** | **3,456** | **3,981** | **3,313** | **3,207** | **2,291** | **2,320** | **2,770** |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 834 | 772 | 670 | 563 | 494 | 526 | 767 | 622 | 515 | 529 | 647 | 933 |
| Commercial | 521 | 502 | 478 | 466 | 463 | 493 | 576 | 516 | 505 | 492 | 485 | 545 |
| Irrigation | 2 | 2 | 5 | 92 | 315 | 559 | 688 | 568 | 324 | 81 | 5 | 3 |
| Industrial | 338 | 335 | 336 | 319 | 312 | 343 | 340 | 344 | 340 | 351 | 345 | 332 |
| Additional Firm | 123 | 121 | 116 | 114 | 105 | 102 | 109 | 109 | 107 | 110 | 115 | 121 |
| Loss | 155 | 147 | 135 | 131 | 145 | 176 | 220 | 188 | 154 | 131 | 134 | 166 |
| **System Load** | **1,974** | **1,879** | **1,740** | **1,686** | **1,835** | **2,199** | **2,700** | **2,347** | **1,945** | **1,693** | **1,732** | **2,100** |
| Light Load | 1,833 | 1,726 | 1,589 | 1,526 | 1,658 | 1,987 | 2,443 | 2,077 | 1,734 | 1,524 | 1,595 | 1,938 |
| Heavy Load | 2,095 | 1,994 | 1,848 | 1,814 | 1,974 | 2,355 | 2,921 | 2,542 | 2,114 | 1,827 | 1,841 | 2,239 |
| **Total Load** | **1,974** | **1,879** | **1,740** | **1,686** | **1,835** | **2,199** | **2,700** | **2,347** | **1,945** | **1,693** | **1,732** | **2,100** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,475 | 2,514 | 2,247 | 2,183 | 2,953 | 3,498 | 4,041 | 3,352 | 3,246 | 2,314 | 2,343 | 2,799 |
| **Total Peak Load** | **2,475** | **2,514** | **2,247** | **2,183** | **2,953** | **3,498** | **4,041** | **3,352** | **3,246** | **2,314** | **2,343** | **2,799** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 845 | 782 | 678 | 571 | 501 | 535 | 781 | 633 | 523 | 536 | 655 | 946 |
| Commercial | 526 | 506 | 482 | 470 | 468 | 498 | 582 | 521 | 511 | 497 | 490 | 550 |
| Irrigation | 2 | 2 | 5 | 93 | 317 | 562 | 691 | 571 | 326 | 81 | 5 | 3 |
| Industrial | 344 | 329 | 342 | 325 | 318 | 349 | 346 | 350 | 346 | 357 | 351 | 338 |
| Additional Firm | 126 | 119 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 157 | 148 | 137 | 133 | 147 | 178 | 222 | 191 | 155 | 133 | 136 | 169 |
| **System Load** | **2,001** | **1,886** | **1,762** | **1,708** | **1,857** | **2,226** | **2,733** | **2,376** | **1,970** | **1,715** | **1,755** | **2,130** |
| Light Load | 1,858 | 1,733 | 1,609 | 1,545 | 1,678 | 2,011 | 2,472 | 2,103 | 1,757 | 1,543 | 1,617 | 1,966 |
| Heavy Load | 2,114 | 1,999 | 1,882 | 1,826 | 1,999 | 2,398 | 2,938 | 2,574 | 2,157 | 1,840 | 1,866 | 2,271 |
| **Total Load** | **2,001** | **1,886** | **1,762** | **1,708** | **1,857** | **2,226** | **2,733** | **2,376** | **1,970** | **1,715** | **1,755** | **2,130** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,507 | 2,537 | 2,272 | 2,208 | 2,991 | 3,546 | 4,105 | 3,397 | 3,291 | 2,338 | 2,370 | 2,830 |
| **Total Peak Load** | **2,507** | **2,537** | **2,272** | **2,208** | **2,991** | **3,546** | **4,105** | **3,397** | **3,291** | **2,338** | **2,370** | **2,830** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 857 | 791 | 687 | 578 | 509 | 544 | 795 | 644 | 532 | 543 | 663 | 959 |
| Commercial | 531 | 510 | 486 | 474 | 472 | 504 | 587 | 527 | 516 | 502 | 494 | 556 |
| Irrigation | 2 | 2 | 5 | 94 | 319 | 566 | 696 | 574 | 328 | 81 | 5 | 3 |
| Industrial | 350 | 347 | 348 | 331 | 323 | 355 | 352 | 357 | 353 | 364 | 358 | 344 |
| Additional Firm | 126 | 124 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 159 | 150 | 138 | 134 | 148 | 180 | 225 | 193 | 157 | 134 | 137 | 171 |
| **System Load** | **2,025** | **1,924** | **1,783** | **1,727** | **1,879** | **2,252** | **2,766** | **2,405** | **1,995** | **1,736** | **1,776** | **2,157** |
| Light Load | 1,881 | 1,768 | 1,628 | 1,563 | 1,698 | 2,034 | 2,502 | 2,129 | 1,779 | 1,562 | 1,636 | 1,991 |
| Heavy Load | 2,140 | 2,041 | 1,904 | 1,847 | 2,022 | 2,427 | 2,973 | 2,624 | 2,168 | 1,861 | 1,898 | 2,288 |
| **Total Load** | **2,025** | **1,924** | **1,783** | **1,727** | **1,879** | **2,252** | **2,766** | **2,405** | **1,995** | **1,736** | **1,776** | **2,157** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,535 | 2,559 | 2,294 | 2,230 | 3,027 | 3,594 | 4,168 | 3,442 | 3,335 | 2,361 | 2,394 | 2,857 |
| **Total Peak Load** | **2,535** | **2,559** | **2,294** | **2,230** | **3,027** | **3,594** | **4,168** | **3,442** | **3,335** | **2,361** | **2,394** | **2,857** |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 868 | 801 | 696 | 586 | 517 | 553 | 809 | 655 | 540 | 550 | 671 | 973 |
| Commercial | 536 | 514 | 490 | 478 | 477 | 509 | 593 | 532 | 522 | 507 | 499 | 562 |
| Irrigation | 2 | 2 | 5 | 94 | 321 | 569 | 700 | 578 | 330 | 82 | 5 | 3 |
| Industrial | 356 | 353 | 354 | 337 | 329 | 362 | 358 | 363 | 359 | 370 | 364 | 350 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 161 | 152 | 140 | 136 | 150 | 182 | 227 | 195 | 159 | 136 | 139 | 173 |
| **System Load** | **2,050** | **1,945** | **1,803** | **1,747** | **1,900** | **2,278** | **2,798** | **2,434** | **2,019** | **1,756** | **1,796** | **2,184** |
| Light Load | 1,903 | 1,787 | 1,646 | 1,581 | 1,717 | 2,058 | 2,532 | 2,154 | 1,800 | 1,580 | 1,654 | 2,015 |
| Heavy Load | 2,165 | 2,064 | 1,926 | 1,868 | 2,058 | 2,439 | 3,008 | 2,655 | 2,194 | 1,883 | 1,920 | 2,317 |
| **Total Load** | **2,050** | **1,945** | **1,803** | **1,747** | **1,900** | **2,278** | **2,798** | **2,434** | **2,019** | **1,756** | **1,796** | **2,184** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,561 | 2,578 | 2,315 | 2,251 | 3,064 | 3,643 | 4,231 | 3,486 | 3,379 | 2,384 | 2,416 | 2,883 |
| **Total Peak Load** | 2,561 | 2,578 | 2,315 | 2,251 | 3,064 | 3,643 | 4,231 | 3,486 | 3,379 | 2,384 | 2,416 | 2,883 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 880 | 810 | 704 | 593 | 524 | 562 | 823 | 667 | 548 | 557 | 679 | 987 |
| Commercial | 541 | 518 | 493 | 482 | 481 | 514 | 598 | 537 | 528 | 511 | 504 | 567 |
| Irrigation | 2 | 2 | 5 | 95 | 323 | 573 | 704 | 581 | 332 | 82 | 5 | 3 |
| Industrial | 363 | 359 | 360 | 342 | 335 | 368 | 364 | 369 | 365 | 376 | 370 | 356 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 163 | 154 | 141 | 137 | 152 | 184 | 230 | 198 | 161 | 137 | 141 | 175 |
| **System Load** | **2,074** | **1,966** | **1,823** | **1,766** | **1,922** | **2,304** | **2,830** | **2,462** | **2,043** | **1,776** | **1,816** | **2,211** |
| Light Load | 1,926 | 1,806 | 1,664 | 1,598 | 1,736 | 2,081 | 2,560 | 2,179 | 1,821 | 1,598 | 1,673 | 2,041 |
| Heavy Load | 2,202 | 2,086 | 1,937 | 1,889 | 2,081 | 2,467 | 3,043 | 2,686 | 2,220 | 1,916 | 1,931 | 2,346 |
| **Total Load** | **2,074** | **1,966** | **1,823** | **1,766** | **1,922** | **2,304** | **2,830** | **2,462** | **2,043** | **1,776** | **1,816** | **2,211** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,587 | 2,598 | 2,335 | 2,271 | 3,100 | 3,690 | 4,293 | 3,530 | 3,423 | 2,406 | 2,437 | 2,910 |
| **Total Peak Load** | **2,587** | **2,598** | **2,335** | **2,271** | **3,100** | **3,690** | **4,293** | **3,530** | **3,423** | **2,406** | **2,437** | **2,910** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 892 | 820 | 713 | 601 | 532 | 572 | 838 | 678 | 557 | 564 | 687 | 1,000 |
| Commercial | 546 | 522 | 498 | 486 | 486 | 519 | 603 | 542 | 534 | 517 | 508 | 573 |
| Irrigation | 2 | 2 | 5 | 95 | 324 | 575 | 708 | 584 | 334 | 83 | 5 | 3 |
| Industrial | 369 | 352 | 367 | 348 | 340 | 374 | 371 | 375 | 371 | 383 | 376 | 362 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 165 | 155 | 143 | 139 | 153 | 186 | 233 | 200 | 163 | 139 | 142 | 178 |
| **System Load** | **2,098** | **1,969** | **1,843** | **1,785** | **1,943** | **2,329** | **2,862** | **2,490** | **2,067** | **1,796** | **1,837** | **2,239** |
| Light Load | 1,948 | 1,809 | 1,683 | 1,616 | 1,755 | 2,104 | 2,590 | 2,204 | 1,843 | 1,615 | 1,692 | 2,066 |
| Heavy Load | 2,227 | 2,088 | 1,958 | 1,921 | 2,090 | 2,494 | 3,097 | 2,697 | 2,246 | 1,938 | 1,953 | 2,387 |
| **Total Load** | **2,098** | **1,969** | **1,843** | **1,785** | **1,943** | **2,329** | **2,862** | **2,490** | **2,067** | **1,796** | **1,837** | **2,239** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,615 | 2,617 | 2,357 | 2,293 | 3,137 | 3,738 | 4,355 | 3,574 | 3,466 | 2,428 | 2,460 | 2,937 |
| **Total Peak Load** | **2,615** | **2,617** | **2,357** | **2,293** | **3,137** | **3,738** | **4,355** | **3,574** | **3,466** | **2,428** | **2,460** | **2,937** |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 904 | 830 | 722 | 609 | 540 | 581 | 852 | 690 | 566 | 571 | 696 | 1,013 |
| Commercial | 551 | 526 | 502 | 491 | 491 | 524 | 609 | 548 | 540 | 522 | 513 | 579 |
| Irrigation | 2 | 2 | 5 | 96 | 326 | 579 | 712 | 588 | 336 | 83 | 5 | 3 |
| Industrial | 375 | 371 | 373 | 354 | 346 | 381 | 377 | 382 | 378 | 389 | 383 | 367 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 167 | 157 | 145 | 140 | 155 | 188 | 235 | 202 | 165 | 140 | 144 | 180 |
| **System Load** | **2,124** | **2,009** | **1,864** | **1,806** | **1,965** | **2,356** | **2,896** | **2,520** | **2,092** | **1,817** | **1,858** | **2,265** |
| Light Load | 1,972 | 1,846 | 1,702 | 1,634 | 1,775 | 2,128 | 2,620 | 2,230 | 1,865 | 1,634 | 1,712 | 2,090 |
| Heavy Load | 2,244 | 2,131 | 1,980 | 1,943 | 2,114 | 2,523 | 3,133 | 2,730 | 2,291 | 1,948 | 1,976 | 2,415 |
| **Total Load** | **2,124** | **2,009** | **1,864** | **1,806** | **1,965** | **2,356** | **2,896** | **2,520** | **2,092** | **1,817** | **1,858** | **2,265** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,642 | 2,638 | 2,378 | 2,314 | 3,174 | 3,788 | 4,419 | 3,621 | 3,512 | 2,452 | 2,483 | 2,963 |
| **Total Peak Load** | **2,642** | **2,638** | **2,378** | **2,314** | **3,174** | **3,788** | **4,419** | **3,621** | **3,512** | **2,452** | **2,483** | **2,963** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 914 | 838 | 729 | 616 | 547 | 589 | 865 | 701 | 573 | 577 | 702 | 1,024 |
| Commercial | 556 | 530 | 506 | 495 | 496 | 530 | 615 | 554 | 546 | 527 | 518 | 585 |
| Irrigation | 2 | 2 | 5 | 96 | 328 | 582 | 716 | 591 | 338 | 84 | 5 | 3 |
| Industrial | 381 | 377 | 379 | 360 | 352 | 387 | 383 | 388 | 384 | 395 | 389 | 373 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 169 | 159 | 146 | 142 | 157 | 190 | 238 | 205 | 167 | 142 | 145 | 182 |
| **System Load** | **2,147** | **2,029** | **1,883** | **1,825** | **1,986** | **2,381** | **2,927** | **2,548** | **2,115** | **1,836** | **1,878** | **2,290** |
| Light Load | 1,994 | 1,864 | 1,720 | 1,651 | 1,794 | 2,151 | 2,648 | 2,255 | 1,886 | 1,652 | 1,730 | 2,113 |
| Heavy Load | 2,268 | 2,153 | 2,012 | 1,951 | 2,137 | 2,565 | 3,147 | 2,759 | 2,316 | 1,969 | 1,997 | 2,442 |
| **Total Load** | **2,147** | **2,029** | **1,883** | **1,825** | **1,986** | **2,381** | **2,927** | **2,548** | **2,115** | **1,836** | **1,878** | **2,290** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,666 | 2,657 | 2,398 | 2,333 | 3,210 | 3,834 | 4,481 | 3,663 | 3,554 | 2,473 | 2,504 | 2,987 |
| **Total Peak Load** | **2,666** | **2,657** | **2,398** | **2,333** | **3,210** | **3,834** | **4,481** | **3,663** | **3,554** | **2,473** | **2,504** | **2,987** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 923 | 845 | 736 | 621 | 553 | 597 | 877 | 710 | 580 | 582 | 708 | 1,035 |
| Commercial | 561 | 534 | 510 | 499 | 500 | 535 | 620 | 559 | 552 | 532 | 523 | 591 |
| Irrigation | 2 | 2 | 5 | 97 | 329 | 584 | 719 | 593 | 339 | 84 | 5 | 3 |
| Industrial | 387 | 382 | 384 | 365 | 357 | 392 | 389 | 394 | 389 | 401 | 395 | 378 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 170 | 160 | 148 | 143 | 158 | 192 | 240 | 207 | 169 | 143 | 147 | 184 |
| **System Load** | **2,169** | **2,047** | **1,901** | **1,842** | **2,005** | **2,404** | **2,956** | **2,573** | **2,137** | **1,854** | **1,896** | **2,314** |
| Light Load | 2,014 | 1,880 | 1,736 | 1,666 | 1,811 | 2,172 | 2,674 | 2,277 | 1,905 | 1,668 | 1,747 | 2,135 |
| Heavy Load | 2,281 | 2,172 | 2,030 | 1,970 | 2,144 | 2,590 | 3,159 | 2,807 | 2,307 | 1,988 | 2,016 | 2,443 |
| **Total Load** | **2,169** | **2,047** | **1,901** | **1,842** | **2,005** | **2,404** | **2,956** | **2,573** | **2,137** | **1,854** | **1,896** | **2,314** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,685 | 2,672 | 2,414 | 2,349 | 3,244 | 3,877 | 4,540 | 3,703 | 3,594 | 2,493 | 2,521 | 3,009 |
| **Total Peak Load** | **2,685** | **2,672** | **2,414** | **2,349** | **3,244** | **3,877** | **4,540** | **3,703** | **3,594** | **2,493** | **2,521** | **3,009** |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 932 | 852 | 742 | 627 | 559 | 605 | 889 | 720 | 587 | 587 | 714 | 1,045 |
| Commercial | 566 | 538 | 514 | 503 | 505 | 540 | 626 | 564 | 558 | 537 | 528 | 597 |
| Irrigation | 2 | 2 | 5 | 97 | 330 | 586 | 721 | 595 | 340 | 84 | 6 | 3 |
| Industrial | 392 | 375 | 390 | 370 | 362 | 398 | 394 | 399 | 395 | 407 | 400 | 384 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 172 | 160 | 149 | 144 | 160 | 194 | 242 | 209 | 170 | 145 | 148 | 186 |
| **System Load** | **2,189** | **2,045** | **1,917** | **1,858** | **2,023** | **2,426** | **2,983** | **2,598** | **2,158** | **1,871** | **1,913** | **2,338** |
| Light Load | 2,033 | 1,879 | 1,751 | 1,681 | 1,828 | 2,191 | 2,699 | 2,299 | 1,924 | 1,683 | 1,763 | 2,157 |
| Heavy Load | 2,302 | 2,181 | 2,037 | 1,987 | 2,177 | 2,598 | 3,189 | 2,833 | 2,329 | 2,019 | 2,024 | 2,468 |
| **Total Load** | **2,189** | **2,045** | **1,917** | **1,858** | **2,023** | **2,426** | **2,983** | **2,598** | **2,158** | **1,871** | **1,913** | **2,338** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,706 | 2,687 | 2,430 | 2,365 | 3,277 | 3,918 | 4,599 | 3,741 | 3,633 | 2,513 | 2,538 | 3,032 |
| **Total Peak Load** | **2,706** | **2,687** | **2,430** | **2,365** | **3,277** | **3,918** | **4,599** | **3,741** | **3,633** | **2,513** | **2,538** | **3,032** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 941 | 859 | 749 | 633 | 566 | 613 | 902 | 730 | 594 | 593 | 721 | 1,056 |
| Commercial | 572 | 543 | 518 | 508 | 510 | 546 | 632 | 570 | 564 | 543 | 533 | 604 |
| Irrigation | 2 | 2 | 5 | 97 | 332 | 589 | 724 | 598 | 342 | 85 | 6 | 3 |
| Industrial | 398 | 394 | 396 | 376 | 367 | 404 | 400 | 405 | 401 | 413 | 406 | 389 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 174 | 163 | 150 | 146 | 161 | 196 | 245 | 211 | 172 | 146 | 150 | 187 |
| **System Load** | **2,212** | **2,083** | **1,936** | **1,876** | **2,043** | **2,450** | **3,013** | **2,624** | **2,181** | **1,890** | **1,932** | **2,362** |
| Light Load | 2,054 | 1,914 | 1,768 | 1,697 | 1,846 | 2,213 | 2,726 | 2,322 | 1,945 | 1,700 | 1,780 | 2,180 |
| Heavy Load | 2,336 | 2,210 | 2,057 | 2,006 | 2,198 | 2,623 | 3,240 | 2,842 | 2,354 | 2,039 | 2,044 | 2,494 |
| **Total Load** | **2,212** | **2,083** | **1,936** | **1,876** | **2,043** | **2,450** | **3,013** | **2,624** | **2,181** | **1,890** | **1,932** | **2,362** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,728 | 2,704 | 2,448 | 2,383 | 3,312 | 3,963 | 4,659 | 3,782 | 3,674 | 2,534 | 2,557 | 3,055 |
| **Total Peak Load** | **2,728** | **2,704** | **2,448** | **2,383** | **3,312** | **3,963** | **4,659** | **3,782** | **3,674** | **2,534** | **2,557** | **3,055** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 950 | 866 | 756 | 639 | 572 | 621 | 915 | 740 | 602 | 598 | 727 | 1,067 |
| Commercial | 577 | 547 | 523 | 513 | 515 | 552 | 638 | 576 | 571 | 548 | 538 | 610 |
| Irrigation | 2 | 2 | 5 | 98 | 333 | 591 | 727 | 600 | 343 | 85 | 6 | 3 |
| Industrial | 403 | 399 | 401 | 381 | 372 | 409 | 405 | 411 | 406 | 419 | 412 | 395 |
| Additional Firm | 124 | 122 | 117 | 115 | 106 | 102 | 110 | 110 | 107 | 110 | 116 | 122 |
| Loss | 176 | 164 | 152 | 147 | 163 | 198 | 247 | 213 | 174 | 147 | 151 | 189 |
| **System Load** | **2,233** | **2,100** | **1,953** | **1,893** | **2,061** | **2,473** | **3,042** | **2,650** | **2,203** | **1,907** | **1,950** | **2,387** |
| Light Load | 2,073 | 1,930 | 1,783 | 1,713 | 1,863 | 2,234 | 2,752 | 2,345 | 1,964 | 1,716 | 1,796 | 2,202 |
| Heavy Load | 2,359 | 2,229 | 2,075 | 2,037 | 2,205 | 2,648 | 3,271 | 2,870 | 2,377 | 2,058 | 2,062 | 2,532 |
| **Total Load** | **2,233** | **2,100** | **1,953** | **1,893** | **2,061** | **2,473** | **3,042** | **2,650** | **2,203** | **1,907** | **1,950** | **2,387** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,749 | 2,720 | 2,464 | 2,399 | 3,345 | 4,005 | 4,719 | 3,822 | 3,714 | 2,553 | 2,575 | 3,077 |
| **Total Peak Load** | **2,749** | **2,720** | **2,464** | **2,399** | **3,345** | **4,005** | **4,719** | **3,822** | **3,714** | **2,553** | **2,575** | **3,077** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,144,709 | 5,270,572 | 5,372,014 | 5,441,649 | 5,508,610 | 5,556,959 | 5,616,876 | 5,673,430 | 5,740,794 | 5,823,961 |
| Commercial | 4,076,100 | 4,144,898 | 4,182,636 | 4,212,195 | 4,247,398 | 4,285,793 | 4,327,161 | 4,369,098 | 4,410,017 | 4,452,065 |
| Irrigation | 1,863,039 | 1,902,156 | 1,915,919 | 1,918,336 | 1,913,727 | 1,924,815 | 1,937,547 | 1,941,972 | 1,944,197 | 1,953,855 |
| Industrial | 2,413,190 | 2,573,787 | 2,642,594 | 2,692,807 | 2,738,789 | 2,786,007 | 2,837,470 | 2,889,584 | 2,942,288 | 2,994,216 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,377,538 | 14,793,313 | 15,019,064 | 15,174,487 | 15,318,124 | 15,474,174 | 15,641,753 | 15,831,584 | 16,023,896 | 16,230,898 |
| **Total Sales** | **14,377,538** | **14,793,313** | **15,019,064** | **15,174,487** | **15,318,124** | **15,474,174** | **15,641,753** | **15,831,584** | **16,023,896** | **16,230,898** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,154,280 | 5,295,641 | 5,377,433 | 5,446,875 | 5,512,460 | 5,579,744 | 5,621,345 | 5,678,710 | 5,747,258 | 5,849,294 |
| Commercial | 4,079,899 | 4,158,522 | 4,184,382 | 4,214,240 | 4,249,614 | 4,299,933 | 4,329,571 | 4,371,459 | 4,412,441 | 4,466,707 |
| Irrigation | 1,863,058 | 1,902,215 | 1,915,920 | 1,918,334 | 1,913,732 | 1,924,874 | 1,937,549 | 1,941,973 | 1,944,202 | 1,953,915 |
| Industrial | 2,426,435 | 2,579,462 | 2,646,735 | 2,696,599 | 2,742,683 | 2,790,251 | 2,841,768 | 2,893,931 | 2,946,571 | 2,998,631 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,404,172 | 14,837,741 | 15,030,370 | 15,185,549 | 15,328,090 | 15,515,403 | 15,652,934 | 15,843,573 | 16,037,072 | 16,275,347 |
| **Total Sales** | **14,404,172** | **14,837,741** | **15,030,370** | **15,185,549** | **15,328,090** | **15,515,403** | **15,652,934** | **15,843,573** | **16,037,072** | **16,275,347** |
| Loss | 1,244,160 | 1,278,960 | 1,294,764 | 1,307,629 | 1,319,635 | 1,335,210 | 1,346,414 | 1,360,666 | 1,375,528 | 1,395,261 |
| **Required Generation** | 15,648,332 | 16,116,700 | 16,325,134 | 16,493,178 | 16,647,725 | 16,850,613 | 16,999,348 | 17,204,238 | 17,412,599 | 17,670,608 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 588 | 603 | 614 | 622 | 629 | 635 | 642 | 648 | 656 | 666 |
| Commercial | 466 | 473 | 478 | 481 | 485 | 490 | 494 | 499 | 504 | 509 |
| Irrigation | 213 | 217 | 219 | 219 | 218 | 219 | 221 | 222 | 222 | 222 |
| Industrial | 277 | 294 | 302 | 308 | 313 | 318 | 324 | 330 | 336 | 341 |
| Additional Firm | 101 | 103 | 103 | 104 | 104 | 105 | 105 | 109 | 113 | 115 |
| Loss | 142 | 146 | 148 | 149 | 151 | 152 | 154 | 155 | 157 | 159 |
| **System Load** | 1,786 | 1,835 | 1,864 | 1,883 | 1,900 | 1,918 | 1,941 | 1,964 | 1,988 | 2,012 |
| Light Load | 1,621 | 1,665 | 1,691 | 1,709 | 1,725 | 1,741 | 1,761 | 1,782 | 1,804 | 1,826 |
| Heavy Load | 1,916 | 1,968 | 2,000 | 2,020 | 2,038 | 2,057 | 2,081 | 2,106 | 2,133 | 2,157 |
| **Total Load** | **1,786** | **1,835** | **1,864** | **1,883** | **1,900** | **1,918** | **1,941** | **1,964** | **1,988** | **2,012** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 3,537 | 3,630 | 3,696 | 3,752 | 3,805 | 3,862 | 3,922 | 3,981 | 4,041 | 4,105 |
| **Total Peak Load** | **3,537** | **3,630** | **3,696** | **3,752** | **3,805** | **3,862** | **3,922** | **3,981** | **4,041** | **4,105** |

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,908,438 | 5,993,931 | 6,078,974 | 6,166,782 | 6,253,879 | 6,328,432 | 6,396,305 | 6,464,673 | 6,535,425 | 6,605,069 |
| Commercial | 4,495,518 | 4,538,294 | 4,579,379 | 4,623,210 | 4,669,570 | 4,713,503 | 4,755,847 | 4,800,838 | 4,849,140 | 4,896,765 |
| Irrigation | 1,966,693 | 1,979,082 | 1,990,214 | 2,000,471 | 2,012,334 | 2,022,468 | 2,031,444 | 2,038,333 | 2,047,116 | 2,054,980 |
| Industrial | 3,047,748 | 3,101,332 | 3,154,544 | 3,207,964 | 3,263,009 | 3,314,431 | 3,364,294 | 3,412,358 | 3,461,829 | 3,509,388 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,425,196 | 16,616,739 | 16,807,211 | 16,997,227 | 17,197,592 | 17,382,934 | 17,551,990 | 17,715,002 | 17,892,310 | 18,059,702 |
| **Total Sales** | **16,425,196** | **16,616,739** | **16,807,211** | **16,997,227** | **17,197,592** | **17,382,934** | **17,551,990** | **17,715,002** | **17,892,310** | **18,059,702** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,915,091 | 6,000,558 | 6,085,816 | 6,193,260 | 6,259,745 | 6,333,805 | 6,401,722 | 6,490,712 | 6,540,950 | 6,610,536 |
| Commercial | 4,497,988 | 4,540,679 | 4,581,913 | 4,638,404 | 4,672,117 | 4,715,970 | 4,758,459 | 4,816,547 | 4,851,901 | 4,899,689 |
| Irrigation | 1,966,699 | 1,979,087 | 1,990,219 | 2,000,532 | 2,012,339 | 2,022,472 | 2,031,447 | 2,038,393 | 2,047,120 | 2,054,984 |
| Industrial | 3,052,167 | 3,105,721 | 3,158,950 | 3,212,504 | 3,267,250 | 3,318,543 | 3,368,258 | 3,416,438 | 3,465,751 | 3,513,496 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,438,745 | 16,630,145 | 16,820,998 | 17,043,500 | 17,210,252 | 17,394,891 | 17,563,986 | 17,760,890 | 17,904,522 | 18,072,204 |
| **Total Sales** | **16,438,745** | **16,630,145** | **16,820,998** | **17,043,500** | **17,210,252** | **17,394,891** | **17,563,986** | **17,760,890** | **17,904,522** | **18,072,204** |
| Loss | 1,409,006 | 1,425,605 | 1,441,996 | 1,461,742 | 1,475,765 | 1,491,301 | 1,505,731 | 1,523,214 | 1,535,214 | 1,549,909 |
| **Required Generation** | 17,847,751 | 18,055,750 | 18,262,994 | 18,505,242 | 18,686,016 | 18,886,192 | 19,069,716 | 19,284,105 | 19,439,736 | 19,622,113 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 675 | 685 | 695 | 705 | 715 | 723 | 731 | 739 | 747 | 755 |
| Commercial | 513 | 518 | 523 | 528 | 533 | 538 | 543 | 548 | 554 | 559 |
| Irrigation | 225 | 226 | 227 | 228 | 230 | 231 | 232 | 232 | 234 | 235 |
| Industrial | 348 | 355 | 361 | 366 | 373 | 379 | 385 | 389 | 396 | 401 |
| Additional Firm | 115 | 115 | 115 | 114 | 114 | 115 | 115 | 114 | 114 | 113 |
| Loss | 161 | 163 | 165 | 166 | 168 | 170 | 172 | 173 | 175 | 177 |
| **System Load** | 2,037 | 2,061 | 2,085 | 2,107 | 2,133 | 2,156 | 2,177 | 2,195 | 2,219 | 2,240 |
| Light Load | 1,849 | 1,871 | 1,892 | 1,912 | 1,936 | 1,957 | 1,976 | 1,992 | 2,014 | 2,033 |
| Heavy Load | 2,185 | 2,210 | 2,236 | 2,260 | 2,288 | 2,312 | 2,328 | 2,347 | 2,373 | 2,396 |
| **Total Load** | **2,037** | **2,061** | **2,085** | **2,107** | **2,133** | **2,156** | **2,177** | **2,195** | **2,219** | **2,240** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 4,168 | 4,231 | 4,293 | 4,355 | 4,419 | 4,481 | 4,540 | 4,599 | 4,659 | 4,719 |
| **Total Peak Load** | 4,168 | 4,231 | 4,293 | 4,355 | 4,419 | 4,481 | 4,540 | 4,599 | 4,659 | 4,719 |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 781 | 730 | 622 | 519 | 460 | 491 | 698 | 565 | 472 | 492 | 606 | 863 |
| Commercial | 492 | 479 | 450 | 440 | 437 | 462 | 541 | 481 | 467 | 457 | 452 | 507 |
| Irrigation | 2 | 2 | 6 | 106 | 348 | 577 | 678 | 555 | 324 | 84 | 5 | 3 |
| Industrial | 277 | 274 | 276 | 262 | 256 | 281 | 279 | 282 | 279 | 288 | 283 | 285 |
| Additional Firm | 105 | 103 | 99 | 101 | 95 | 100 | 98 | 98 | 101 | 100 | 104 | 103 |
| Loss | 143 | 137 | 124 | 122 | 138 | 168 | 205 | 174 | 142 | 120 | 123 | 153 |
| **System Load** | **1,800** | **1,724** | **1,575** | **1,549** | **1,734** | **2,079** | **2,498** | **2,156** | **1,785** | **1,541** | **1,573** | **1,914** |
| Light Load | 1,672 | 1,584 | 1,438 | 1,402 | 1,567 | 1,878 | 2,260 | 1,908 | 1,591 | 1,387 | 1,449 | 1,766 |
| Heavy Load | 1,902 | 1,829 | 1,683 | 1,657 | 1,878 | 2,226 | 2,686 | 2,351 | 1,940 | 1,653 | 1,682 | 2,030 |
| **Total Load** | **1,800** | **1,724** | **1,575** | **1,549** | **1,734** | **2,079** | **2,498** | **2,156** | **1,785** | **1,541** | **1,573** | **1,914** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,330 | 2,400 | 2,128 | 2,027 | 2,682 | 3,163 | 3,576 | 3,029 | 2,901 | 2,133 | 2,233 | 2,625 |
| **Total Peak Load** | **2,330** | **2,400** | **2,128** | **2,027** | **2,682** | **3,163** | **3,576** | **3,029** | **2,901** | **2,133** | **2,233** | **2,625** |

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 799 | 745 | 636 | 531 | 472 | 505 | 718 | 581 | 484 | 504 | 619 | 881 |
| Commercial | 500 | 486 | 457 | 447 | 444 | 470 | 550 | 489 | 475 | 465 | 459 | 514 |
| Irrigation | 2 | 2 | 6 | 108 | 355 | 588 | 692 | 567 | 331 | 85 | 6 | 3 |
| Industrial | 296 | 283 | 294 | 279 | 273 | 300 | 297 | 301 | 298 | 307 | 302 | 293 |
| Additional Firm | 110 | 105 | 105 | 104 | 97 | 94 | 101 | 101 | 99 | 101 | 105 | 109 |
| Loss | 147 | 139 | 127 | 125 | 142 | 172 | 210 | 179 | 145 | 123 | 126 | 156 |
| **System Load** | **1,854** | **1,761** | **1,624** | **1,594** | **1,782** | **2,128** | **2,568** | **2,218** | **1,833** | **1,585** | **1,617** | **1,954** |
| Light Load | 1,722 | 1,618 | 1,483 | 1,443 | 1,611 | 1,922 | 2,324 | 1,963 | 1,634 | 1,426 | 1,489 | 1,803 |
| Heavy Load | 1,968 | 1,867 | 1,726 | 1,705 | 1,930 | 2,279 | 2,779 | 2,403 | 1,992 | 1,711 | 1,719 | 2,073 |
| **Total Load** | **1,854** | **1,761** | **1,624** | **1,594** | **1,782** | **2,128** | **2,568** | **2,218** | **1,833** | **1,585** | **1,617** | **1,954** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,400 | 2,437 | 2,181 | 2,082 | 2,748 | 3,266 | 3,669 | 3,122 | 2,992 | 2,183 | 2,281 | 2,663 |
| **Total Peak Load** | **2,400** | **2,437** | **2,181** | **2,082** | **2,748** | **3,266** | **3,669** | **3,122** | **2,992** | **2,183** | **2,281** | **2,663** |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 814 | 758 | 647 | 540 | 481 | 516 | 734 | 594 | 494 | 512 | 630 | 894 |
| Commercial | 505 | 490 | 460 | 451 | 448 | 475 | 555 | 494 | 480 | 469 | 464 | 518 |
| Irrigation | 2 | 2 | 6 | 109 | 357 | 592 | 697 | 571 | 333 | 86 | 6 | 3 |
| Industrial | 304 | 300 | 302 | 287 | 280 | 308 | 305 | 309 | 306 | 315 | 310 | 299 |
| Additional Firm | 111 | 110 | 106 | 105 | 97 | 94 | 102 | 102 | 100 | 101 | 105 | 109 |
| Loss | 149 | 142 | 129 | 127 | 144 | 174 | 213 | 182 | 148 | 125 | 128 | 158 |
| **System Load** | **1,884** | **1,802** | **1,649** | **1,618** | **1,808** | **2,159** | **2,606** | **2,251** | **1,861** | **1,609** | **1,642** | **1,980** |
| Light Load | 1,750 | 1,656 | 1,506 | 1,464 | 1,634 | 1,950 | 2,358 | 1,992 | 1,659 | 1,448 | 1,513 | 1,827 |
| Heavy Load | 2,000 | 1,912 | 1,752 | 1,741 | 1,946 | 2,312 | 2,820 | 2,439 | 2,022 | 1,737 | 1,746 | 2,111 |
| **Total Load** | **1,884** | **1,802** | **1,649** | **1,618** | **1,808** | **2,159** | **2,606** | **2,251** | **1,861** | **1,609** | **1,642** | **1,980** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,426 | 2,472 | 2,204 | 2,103 | 2,788 | 3,320 | 3,736 | 3,172 | 3,042 | 2,209 | 2,305 | 2,686 |
| **Total Peak Load** | **2,426** | **2,472** | **2,204** | **2,103** | **2,788** | **3,320** | **3,736** | **3,172** | **3,042** | **2,209** | **2,305** | **2,686** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 823 | 766 | 654 | 547 | 488 | 524 | 747 | 604 | 501 | 518 | 636 | 905 |
| Commercial | 508 | 492 | 463 | 454 | 452 | 478 | 559 | 498 | 485 | 473 | 467 | 523 |
| Irrigation | 2 | 2 | 6 | 109 | 357 | 593 | 698 | 571 | 334 | 86 | 6 | 3 |
| Industrial | 309 | 306 | 308 | 292 | 286 | 314 | 311 | 315 | 312 | 321 | 316 | 304 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 151 | 144 | 130 | 128 | 145 | 176 | 215 | 183 | 149 | 126 | 129 | 160 |
| **System Load** | **1,906** | **1,821** | **1,667** | **1,635** | **1,826** | **2,180** | **2,631** | **2,274** | **1,880** | **1,626** | **1,660** | **2,003** |
| Light Load | 1,770 | 1,673 | 1,522 | 1,479 | 1,650 | 1,969 | 2,381 | 2,012 | 1,676 | 1,463 | 1,529 | 1,848 |
| Heavy Load | 2,013 | 1,931 | 1,771 | 1,759 | 1,965 | 2,334 | 2,847 | 2,463 | 2,059 | 1,744 | 1,765 | 2,136 |
| **Total Load** | **1,906** | **1,821** | **1,667** | **1,635** | **1,826** | **2,180** | **2,631** | **2,274** | **1,880** | **1,626** | **1,660** | **2,003** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,433 | 2,483 | 2,213 | 2,109 | 2,820 | 3,356 | 3,793 | 3,205 | 3,076 | 2,228 | 2,313 | 2,703 |
| **Total Peak Load** | **2,433** | **2,483** | **2,213** | **2,109** | **2,820** | **3,356** | **3,793** | **3,205** | **3,076** | **2,228** | **2,313** | **2,703** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 833 | 774 | 661 | 553 | 495 | 533 | 759 | 614 | 508 | 523 | 643 | 913 |
| Commercial | 512 | 496 | 466 | 457 | 455 | 483 | 564 | 503 | 490 | 477 | 471 | 528 |
| Irrigation | 2 | 2 | 6 | 109 | 356 | 592 | 696 | 570 | 333 | 86 | 6 | 3 |
| Industrial | 315 | 311 | 313 | 297 | 291 | 319 | 316 | 320 | 317 | 327 | 321 | 309 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 152 | 145 | 132 | 129 | 147 | 177 | 217 | 185 | 151 | 128 | 131 | 161 |
| **System Load** | **1,926** | **1,838** | **1,683** | **1,650** | **1,842** | **2,198** | **2,654** | **2,294** | **1,898** | **1,642** | **1,677** | **2,024** |
| Light Load | 1,789 | 1,689 | 1,537 | 1,493 | 1,664 | 1,985 | 2,401 | 2,030 | 1,692 | 1,478 | 1,545 | 1,867 |
| Heavy Load | 2,035 | 1,950 | 1,798 | 1,765 | 1,982 | 2,368 | 2,853 | 2,484 | 2,078 | 1,761 | 1,783 | 2,158 |
| **Total Load** | **1,926** | **1,838** | **1,683** | **1,650** | **1,842** | **2,198** | **2,654** | **2,294** | **1,898** | **1,642** | **1,677** | **2,024** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,456 | 2,500 | 2,231 | 2,127 | 2,849 | 3,387 | 3,847 | 3,234 | 3,108 | 2,246 | 2,332 | 2,723 |
| **Total Peak Load** | **2,456** | **2,500** | **2,231** | **2,127** | **2,849** | **3,387** | **3,847** | **3,234** | **3,108** | **2,246** | **2,332** | **2,723** |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 779 | 665 | 557 | 500 | 539 | 769 | 621 | 513 | 527 | 647 | 922 |
| Commercial | 517 | 500 | 470 | 461 | 460 | 487 | 569 | 507 | 495 | 482 | 475 | 533 |
| Irrigation | 2 | 2 | 6 | 109 | 358 | 595 | 700 | 573 | 335 | 86 | 6 | 3 |
| Industrial | 320 | 306 | 318 | 302 | 296 | 325 | 322 | 326 | 322 | 332 | 327 | 315 |
| Additional Firm | 113 | 108 | 107 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 111 |
| Loss | 154 | 145 | 133 | 130 | 148 | 179 | 219 | 187 | 152 | 129 | 132 | 163 |
| **System Load** | **1,946** | **1,839** | **1,700** | **1,667** | **1,860** | **2,221** | **2,681** | **2,318** | **1,919** | **1,659** | **1,693** | **2,047** |
| Light Load | 1,807 | 1,690 | 1,552 | 1,508 | 1,681 | 2,006 | 2,425 | 2,051 | 1,710 | 1,493 | 1,560 | 1,889 |
| Heavy Load | 2,055 | 1,950 | 1,816 | 1,782 | 2,015 | 2,378 | 2,882 | 2,528 | 2,085 | 1,779 | 1,811 | 2,171 |
| **Total Load** | **1,946** | **1,839** | **1,700** | **1,667** | **1,860** | **2,221** | **2,681** | **2,318** | **1,919** | **1,659** | **1,693** | **2,047** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,479 | 2,515 | 2,249 | 2,145 | 2,882 | 3,426 | 3,905 | 3,270 | 3,143 | 2,264 | 2,351 | 2,747 |
| **Total Peak Load** | **2,479** | **2,515** | **2,249** | **2,145** | **2,882** | **3,426** | **3,905** | **3,270** | **3,143** | **2,264** | **2,351** | **2,747** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 847 | 785 | 671 | 562 | 506 | 547 | 780 | 630 | 520 | 532 | 653 | 931 |
| Commercial | 522 | 504 | 474 | 465 | 464 | 493 | 574 | 513 | 501 | 486 | 480 | 539 |
| Irrigation | 2 | 2 | 6 | 110 | 360 | 599 | 704 | 577 | 337 | 87 | 6 | 3 |
| Industrial | 326 | 323 | 324 | 308 | 301 | 331 | 328 | 332 | 328 | 338 | 333 | 320 |
| Additional Firm | 113 | 112 | 108 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 112 |
| Loss | 155 | 147 | 134 | 132 | 150 | 181 | 221 | 189 | 154 | 130 | 133 | 165 |
| **System Load** | **1,967** | **1,873** | **1,717** | **1,684** | **1,880** | **2,245** | **2,710** | **2,344** | **1,940** | **1,677** | **1,711** | **2,070** |
| Light Load | 1,826 | 1,721 | 1,568 | 1,524 | 1,699 | 2,028 | 2,452 | 2,074 | 1,730 | 1,509 | 1,577 | 1,910 |
| Heavy Load | 2,088 | 1,987 | 1,824 | 1,801 | 2,036 | 2,404 | 2,914 | 2,557 | 2,109 | 1,810 | 1,819 | 2,195 |
| **Total Load** | **1,967** | **1,873** | **1,717** | **1,684** | **1,880** | **2,245** | **2,710** | **2,344** | **1,940** | **1,677** | **1,711** | **2,070** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,495 | 2,531 | 2,263 | 2,158 | 2,916 | 3,469 | 3,965 | 3,310 | 3,182 | 2,284 | 2,365 | 2,766 |
| **Total Peak Load** | **2,495** | **2,531** | **2,263** | **2,158** | **2,916** | **3,469** | **3,965** | **3,310** | **3,182** | **2,284** | **2,365** | **2,766** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 855 | 791 | 677 | 567 | 512 | 554 | 791 | 639 | 526 | 536 | 658 | 941 |
| Commercial | 527 | 508 | 478 | 469 | 469 | 498 | 580 | 518 | 506 | 491 | 484 | 544 |
| Irrigation | 2 | 2 | 6 | 110 | 361 | 600 | 706 | 578 | 338 | 87 | 6 | 3 |
| Industrial | 332 | 329 | 330 | 314 | 307 | 337 | 334 | 338 | 334 | 345 | 339 | 326 |
| Additional Firm | 119 | 117 | 112 | 111 | 102 | 99 | 106 | 106 | 104 | 107 | 112 | 117 |
| Loss | 157 | 149 | 135 | 133 | 151 | 182 | 223 | 191 | 155 | 132 | 135 | 167 |
| **System Load** | **1,992** | **1,895** | **1,738** | **1,704** | **1,902** | **2,270** | **2,740** | **2,371** | **1,964** | **1,698** | **1,733** | **2,098** |
| Light Load | 1,850 | 1,741 | 1,587 | 1,542 | 1,718 | 2,050 | 2,479 | 2,098 | 1,751 | 1,527 | 1,597 | 1,936 |
| Heavy Load | 2,115 | 2,011 | 1,847 | 1,823 | 2,060 | 2,430 | 2,964 | 2,567 | 2,134 | 1,832 | 1,843 | 2,226 |
| **Total Load** | **1,992** | **1,895** | **1,738** | **1,704** | **1,902** | **2,270** | **2,740** | **2,371** | **1,964** | **1,698** | **1,733** | **2,098** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,513 | 2,550 | 2,281 | 2,173 | 2,952 | 3,510 | 4,026 | 3,348 | 3,221 | 2,307 | 2,383 | 2,792 |
| **Total Peak Load** | **2,513** | **2,550** | **2,281** | **2,173** | **2,952** | **3,510** | **4,026** | **3,348** | **3,221** | **2,307** | **2,383** | **2,792** |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 864 | 798 | 684 | 574 | 518 | 562 | 803 | 649 | 533 | 542 | 664 | 954 |
| Commercial | 532 | 512 | 482 | 473 | 473 | 503 | 585 | 523 | 512 | 496 | 489 | 550 |
| Irrigation | 2 | 2 | 6 | 110 | 361 | 600 | 707 | 579 | 338 | 87 | 6 | 3 |
| Industrial | 338 | 335 | 336 | 319 | 312 | 343 | 340 | 344 | 340 | 351 | 345 | 332 |
| Additional Firm | 123 | 121 | 116 | 114 | 105 | 102 | 109 | 109 | 107 | 110 | 115 | 121 |
| Loss | 159 | 151 | 137 | 134 | 153 | 184 | 226 | 193 | 157 | 133 | 136 | 169 |
| **System Load** | **2,019** | **1,918** | **1,760** | **1,725** | **1,923** | **2,294** | **2,769** | **2,397** | **1,987** | **1,719** | **1,755** | **2,128** |
| Light Load | 1,874 | 1,762 | 1,607 | 1,561 | 1,738 | 2,072 | 2,505 | 2,121 | 1,772 | 1,546 | 1,617 | 1,964 |
| Heavy Load | 2,143 | 2,035 | 1,870 | 1,857 | 2,070 | 2,457 | 2,996 | 2,596 | 2,159 | 1,855 | 1,866 | 2,270 |
| **Total Load** | **2,019** | **1,918** | **1,760** | **1,725** | **1,923** | **2,294** | **2,769** | **2,397** | **1,987** | **1,719** | **1,755** | **2,128** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,541 | 2,572 | 2,303 | 2,194 | 2,987 | 3,552 | 4,086 | 3,387 | 3,261 | 2,330 | 2,406 | 2,822 |
| **Total Peak Load** | **2,541** | **2,572** | **2,303** | **2,194** | **2,987** | **3,552** | **4,086** | **3,387** | **3,261** | **2,330** | **2,406** | **2,822** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 876 | 808 | 692 | 581 | 527 | 572 | 817 | 661 | 541 | 548 | 672 | 967 |
| Commercial | 537 | 516 | 486 | 477 | 478 | 508 | 590 | 528 | 518 | 501 | 494 | 556 |
| Irrigation | 2 | 2 | 6 | 111 | 363 | 603 | 710 | 582 | 340 | 88 | 6 | 3 |
| Industrial | 344 | 329 | 342 | 325 | 318 | 349 | 346 | 350 | 346 | 357 | 351 | 338 |
| Additional Firm | 126 | 119 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 161 | 151 | 139 | 136 | 154 | 186 | 228 | 195 | 159 | 135 | 138 | 171 |
| **System Load** | **2,046** | **1,925** | **1,783** | **1,747** | **1,947** | **2,322** | **2,803** | **2,427** | **2,013** | **1,741** | **1,778** | **2,159** |
| Light Load | 1,900 | 1,769 | 1,628 | 1,581 | 1,759 | 2,097 | 2,536 | 2,148 | 1,794 | 1,566 | 1,638 | 1,992 |
| Heavy Load | 2,161 | 2,041 | 1,904 | 1,869 | 2,095 | 2,502 | 3,014 | 2,629 | 2,204 | 1,867 | 1,891 | 2,302 |
| **Total Load** | **2,046** | **1,925** | **1,783** | **1,747** | **1,947** | **2,322** | **2,803** | **2,427** | **2,013** | **1,741** | **1,778** | **2,159** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,573 | 2,596 | 2,328 | 2,218 | 3,025 | 3,600 | 4,151 | 3,431 | 3,305 | 2,354 | 2,433 | 2,853 |
| **Total Peak Load** | **2,573** | **2,596** | **2,328** | **2,218** | **3,025** | **3,600** | **4,151** | **3,431** | **3,305** | **2,354** | **2,433** | **2,853** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 887 | 817 | 701 | 589 | 535 | 582 | 832 | 672 | 550 | 555 | 680 | 981 |
| Commercial | 542 | 520 | 490 | 482 | 483 | 513 | 596 | 534 | 524 | 506 | 499 | 561 |
| Irrigation | 2 | 2 | 6 | 111 | 365 | 607 | 715 | 586 | 342 | 88 | 6 | 3 |
| Industrial | 350 | 347 | 348 | 331 | 323 | 355 | 352 | 357 | 353 | 364 | 358 | 344 |
| Additional Firm | 126 | 124 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 163 | 154 | 140 | 138 | 156 | 189 | 231 | 198 | 161 | 136 | 140 | 173 |
| **System Load** | **2,071** | **1,964** | **1,803** | **1,767** | **1,969** | **2,349** | **2,837** | **2,457** | **2,037** | **1,761** | **1,799** | **2,186** |
| Light Load | 1,923 | 1,804 | 1,647 | 1,599 | 1,779 | 2,122 | 2,567 | 2,174 | 1,817 | 1,585 | 1,658 | 2,017 |
| Heavy Load | 2,188 | 2,084 | 1,926 | 1,890 | 2,119 | 2,531 | 3,050 | 2,679 | 2,214 | 1,889 | 1,924 | 2,319 |
| **Total Load** | **2,071** | **1,964** | **1,803** | **1,767** | **1,969** | **2,349** | **2,837** | **2,457** | **2,037** | **1,761** | **1,799** | **2,186** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,601 | 2,617 | 2,350 | 2,240 | 3,062 | 3,648 | 4,215 | 3,476 | 3,349 | 2,377 | 2,456 | 2,880 |
| **Total Peak Load** | **2,601** | **2,617** | **2,350** | **2,240** | **3,062** | **3,648** | **4,215** | **3,476** | **3,349** | **2,377** | **2,456** | **2,880** |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 899 | 827 | 709 | 597 | 543 | 592 | 847 | 684 | 558 | 562 | 688 | 994 |
| Commercial | 547 | 524 | 494 | 486 | 487 | 518 | 602 | 539 | 530 | 511 | 503 | 567 |
| Irrigation | 2 | 2 | 6 | 112 | 367 | 610 | 719 | 589 | 344 | 89 | 6 | 3 |
| Industrial | 356 | 353 | 354 | 337 | 329 | 362 | 358 | 363 | 359 | 370 | 364 | 350 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 165 | 156 | 142 | 139 | 158 | 191 | 234 | 200 | 163 | 138 | 141 | 176 |
| **System Load** | **2,095** | **1,985** | **1,823** | **1,787** | **1,991** | **2,376** | **2,871** | **2,486** | **2,062** | **1,781** | **1,820** | **2,213** |
| Light Load | 1,946 | 1,824 | 1,665 | 1,617 | 1,799 | 2,146 | 2,597 | 2,200 | 1,838 | 1,603 | 1,677 | 2,042 |
| Heavy Load | 2,214 | 2,106 | 1,948 | 1,911 | 2,157 | 2,544 | 3,086 | 2,712 | 2,241 | 1,911 | 1,946 | 2,348 |
| **Total Load** | **2,095** | **1,985** | **1,823** | **1,787** | **1,991** | **2,376** | **2,871** | **2,486** | **2,062** | **1,781** | **1,820** | **2,213** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,627 | 2,637 | 2,370 | 2,261 | 3,099 | 3,697 | 4,278 | 3,521 | 3,393 | 2,399 | 2,479 | 2,906 |
| **Total Peak Load** | **2,627** | **2,637** | **2,370** | **2,261** | **3,099** | **3,697** | **4,278** | **3,521** | **3,393** | **2,399** | **2,479** | **2,906** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 910 | 836 | 718 | 604 | 551 | 602 | 862 | 697 | 567 | 569 | 696 | 1,008 |
| Commercial | 552 | 528 | 498 | 490 | 492 | 524 | 607 | 544 | 535 | 516 | 508 | 573 |
| Irrigation | 2 | 2 | 6 | 112 | 369 | 614 | 723 | 592 | 346 | 89 | 6 | 3 |
| Industrial | 363 | 359 | 360 | 342 | 335 | 368 | 364 | 369 | 365 | 376 | 370 | 356 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 167 | 157 | 143 | 141 | 160 | 193 | 236 | 202 | 165 | 139 | 143 | 178 |
| **System Load** | **2,120** | **2,006** | **1,843** | **1,806** | **2,013** | **2,403** | **2,904** | **2,515** | **2,086** | **1,801** | **1,840** | **2,241** |
| Light Load | 1,969 | 1,843 | 1,683 | 1,635 | 1,819 | 2,170 | 2,627 | 2,226 | 1,860 | 1,621 | 1,696 | 2,068 |
| Heavy Load | 2,250 | 2,129 | 1,959 | 1,932 | 2,180 | 2,573 | 3,122 | 2,743 | 2,267 | 1,944 | 1,957 | 2,377 |
| **Total Load** | **2,120** | **2,006** | **1,843** | **1,806** | **2,013** | **2,403** | **2,904** | **2,515** | **2,086** | **1,801** | **1,840** | **2,241** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,653 | 2,656 | 2,391 | 2,281 | 3,136 | 3,744 | 4,341 | 3,565 | 3,437 | 2,422 | 2,500 | 2,932 |
| **Total Peak Load** | **2,653** | **2,656** | **2,391** | **2,281** | **3,136** | **3,744** | **4,341** | **3,565** | **3,437** | **2,422** | **2,500** | **2,932** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 922 | 846 | 727 | 612 | 560 | 612 | 877 | 709 | 576 | 576 | 705 | 1,022 |
| Commercial | 558 | 532 | 502 | 494 | 497 | 529 | 613 | 550 | 541 | 521 | 513 | 579 |
| Irrigation | 2 | 2 | 6 | 113 | 371 | 617 | 727 | 595 | 347 | 89 | 6 | 3 |
| Industrial | 369 | 352 | 367 | 348 | 340 | 374 | 371 | 375 | 371 | 383 | 376 | 362 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 169 | 158 | 145 | 142 | 161 | 195 | 239 | 205 | 167 | 141 | 144 | 180 |
| **System Load** | **2,145** | **2,010** | **1,864** | **1,826** | **2,035** | **2,429** | **2,937** | **2,544** | **2,111** | **1,822** | **1,861** | **2,268** |
| Light Load | 1,991 | 1,846 | 1,702 | 1,652 | 1,839 | 2,194 | 2,657 | 2,251 | 1,882 | 1,639 | 1,714 | 2,093 |
| Heavy Load | 2,276 | 2,130 | 1,980 | 1,965 | 2,190 | 2,601 | 3,177 | 2,755 | 2,294 | 1,966 | 1,979 | 2,419 |
| **Total Load** | **2,145** | **2,010** | **1,864** | **1,826** | **2,035** | **2,429** | **2,937** | **2,544** | **2,111** | **1,822** | **1,861** | **2,268** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,680 | 2,675 | 2,412 | 2,303 | 3,172 | 3,792 | 4,404 | 3,609 | 3,481 | 2,444 | 2,523 | 2,960 |
| **Total Peak Load** | **2,680** | **2,675** | **2,412** | **2,303** | **3,172** | **3,792** | **4,404** | **3,609** | **3,481** | **2,444** | **2,523** | **2,960** |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 934 | 856 | 736 | 620 | 568 | 622 | 893 | 721 | 585 | 583 | 713 | 1,034 |
| Commercial | 563 | 537 | 506 | 499 | 502 | 535 | 619 | 556 | 548 | 526 | 518 | 585 |
| Irrigation | 2 | 2 | 6 | 113 | 372 | 620 | 731 | 599 | 349 | 90 | 6 | 3 |
| Industrial | 375 | 371 | 373 | 354 | 346 | 381 | 377 | 382 | 378 | 389 | 383 | 367 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 171 | 161 | 147 | 144 | 163 | 197 | 242 | 207 | 169 | 143 | 146 | 182 |
| **System Load** | **2,170** | **2,050** | **1,885** | **1,847** | **2,058** | **2,457** | **2,972** | **2,575** | **2,136** | **1,843** | **1,883** | **2,294** |
| Light Load | 2,015 | 1,883 | 1,721 | 1,671 | 1,860 | 2,220 | 2,688 | 2,279 | 1,905 | 1,658 | 1,734 | 2,117 |
| Heavy Load | 2,293 | 2,174 | 2,002 | 1,987 | 2,215 | 2,631 | 3,215 | 2,789 | 2,339 | 1,976 | 2,002 | 2,447 |
| **Total Load** | **2,170** | **2,050** | **1,885** | **1,847** | **2,058** | **2,457** | **2,972** | **2,575** | **2,136** | **1,843** | **1,883** | **2,294** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,708 | 2,697 | 2,434 | 2,325 | 3,210 | 3,842 | 4,469 | 3,655 | 3,527 | 2,468 | 2,546 | 2,985 |
| **Total Peak Load** | **2,708** | **2,697** | **2,434** | **2,325** | **3,210** | **3,842** | **4,469** | **3,655** | **3,527** | **2,468** | **2,546** | **2,985** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 944 | 864 | 743 | 627 | 575 | 631 | 907 | 732 | 593 | 589 | 720 | 1,045 |
| Commercial | 568 | 541 | 511 | 503 | 507 | 540 | 625 | 561 | 554 | 532 | 523 | 591 |
| Irrigation | 2 | 2 | 6 | 114 | 374 | 623 | 734 | 602 | 351 | 90 | 6 | 3 |
| Industrial | 381 | 377 | 379 | 360 | 352 | 387 | 383 | 388 | 384 | 395 | 389 | 373 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 173 | 162 | 148 | 145 | 165 | 199 | 245 | 209 | 171 | 144 | 148 | 184 |
| **System Load** | **2,194** | **2,070** | **1,904** | **1,866** | **2,080** | **2,483** | **3,004** | **2,603** | **2,160** | **1,862** | **1,902** | **2,320** |
| Light Load | 2,037 | 1,902 | 1,739 | 1,688 | 1,879 | 2,243 | 2,717 | 2,304 | 1,926 | 1,675 | 1,753 | 2,141 |
| Heavy Load | 2,318 | 2,196 | 2,034 | 1,995 | 2,238 | 2,676 | 3,229 | 2,819 | 2,365 | 1,997 | 2,023 | 2,474 |
| **Total Load** | **2,194** | **2,070** | **1,904** | **1,866** | **2,080** | **2,483** | **3,004** | **2,603** | **2,160** | **1,862** | **1,902** | **2,320** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,732 | 2,715 | 2,453 | 2,344 | 3,246 | 3,888 | 4,531 | 3,698 | 3,569 | 2,489 | 2,567 | 3,009 |
| **Total Peak Load** | **2,732** | **2,715** | **2,453** | **2,344** | **3,246** | **3,888** | **4,531** | **3,698** | **3,569** | **2,489** | **2,567** | **3,009** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 953 | 871 | 750 | 633 | 582 | 640 | 919 | 743 | 600 | 594 | 726 | 1,056 |
| Commercial | 573 | 545 | 514 | 508 | 511 | 545 | 630 | 567 | 560 | 537 | 528 | 597 |
| Irrigation | 2 | 2 | 6 | 114 | 376 | 626 | 738 | 604 | 353 | 91 | 6 | 3 |
| Industrial | 387 | 382 | 384 | 365 | 357 | 392 | 389 | 394 | 389 | 401 | 395 | 378 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 175 | 164 | 149 | 147 | 166 | 201 | 247 | 211 | 173 | 145 | 149 | 186 |
| **System Load** | **2,216** | **2,088** | **1,922** | **1,883** | **2,099** | **2,507** | **3,033** | **2,629** | **2,182** | **1,880** | **1,920** | **2,344** |
| Light Load | 2,057 | 1,918 | 1,755 | 1,704 | 1,897 | 2,265 | 2,744 | 2,327 | 1,945 | 1,691 | 1,769 | 2,163 |
| Heavy Load | 2,330 | 2,215 | 2,053 | 2,014 | 2,246 | 2,702 | 3,242 | 2,868 | 2,355 | 2,016 | 2,042 | 2,474 |
| **Total Load** | **2,216** | **2,088** | **1,922** | **1,883** | **2,099** | **2,507** | **3,033** | **2,629** | **2,182** | **1,880** | **1,920** | **2,344** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,751 | 2,730 | 2,469 | 2,359 | 3,280 | 3,931 | 4,592 | 3,737 | 3,608 | 2,509 | 2,584 | 3,031 |
| **Total Peak Load** | **2,751** | **2,730** | **2,469** | **2,359** | **3,280** | **3,931** | **4,592** | **3,737** | **3,608** | **2,509** | **2,584** | **3,031** |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 962 | 878 | 756 | 639 | 589 | 648 | 932 | 753 | 607 | 600 | 732 | 1,067 |
| Commercial | 579 | 549 | 519 | 512 | 516 | 551 | 636 | 572 | 566 | 542 | 533 | 603 |
| Irrigation | 2 | 2 | 6 | 115 | 377 | 627 | 740 | 606 | 354 | 91 | 6 | 3 |
| Industrial | 392 | 375 | 390 | 370 | 362 | 398 | 394 | 399 | 395 | 407 | 400 | 384 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 176 | 164 | 151 | 148 | 168 | 203 | 249 | 214 | 174 | 147 | 150 | 188 |
| **System Load** | **2,236** | **2,087** | **1,939** | **1,900** | **2,118** | **2,530** | **3,062** | **2,654** | **2,203** | **1,897** | **1,938** | **2,367** |
| Light Load | 2,076 | 1,917 | 1,770 | 1,719 | 1,914 | 2,286 | 2,770 | 2,349 | 1,965 | 1,707 | 1,785 | 2,185 |
| Heavy Load | 2,352 | 2,224 | 2,060 | 2,032 | 2,280 | 2,709 | 3,273 | 2,895 | 2,378 | 2,047 | 2,050 | 2,499 |
| **Total Load** | **2,236** | **2,087** | **1,939** | **1,900** | **2,118** | **2,530** | **3,062** | **2,654** | **2,203** | **1,897** | **1,938** | **2,367** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,772 | 2,745 | 2,486 | 2,375 | 3,313 | 3,972 | 4,651 | 3,776 | 3,647 | 2,529 | 2,601 | 3,054 |
| **Total Peak Load** | **2,772** | **2,745** | **2,486** | **2,375** | **3,313** | **3,972** | **4,651** | **3,776** | **3,647** | **2,529** | **2,601** | **3,054** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 971 | 885 | 763 | 645 | 596 | 657 | 946 | 764 | 614 | 605 | 738 | 1,078 |
| Commercial | 584 | 554 | 523 | 517 | 522 | 557 | 642 | 578 | 572 | 547 | 538 | 609 |
| Irrigation | 2 | 2 | 6 | 115 | 378 | 630 | 743 | 609 | 355 | 91 | 6 | 3 |
| Industrial | 398 | 394 | 396 | 376 | 367 | 404 | 400 | 405 | 401 | 413 | 406 | 389 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 178 | 167 | 152 | 149 | 170 | 205 | 252 | 216 | 176 | 148 | 152 | 190 |
| **System Load** | **2,259** | **2,124** | **1,957** | **1,918** | **2,139** | **2,556** | **3,093** | **2,682** | **2,227** | **1,916** | **1,957** | **2,392** |
| Light Load | 2,097 | 1,952 | 1,787 | 1,735 | 1,933 | 2,308 | 2,798 | 2,373 | 1,985 | 1,724 | 1,803 | 2,208 |
| Heavy Load | 2,386 | 2,254 | 2,079 | 2,051 | 2,302 | 2,736 | 3,325 | 2,905 | 2,403 | 2,068 | 2,070 | 2,525 |
| **Total Load** | **2,259** | **2,124** | **1,957** | **1,918** | **2,139** | **2,556** | **3,093** | **2,682** | **2,227** | **1,916** | **1,957** | **2,392** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,794 | 2,763 | 2,504 | 2,393 | 3,348 | 4,017 | 4,713 | 3,817 | 3,688 | 2,549 | 2,620 | 3,077 |
| **Total Peak Load** | **2,794** | **2,763** | **2,504** | **2,393** | **3,348** | **4,017** | **4,713** | **3,817** | **3,688** | **2,549** | **2,620** | **3,077** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 980 | 892 | 769 | 651 | 603 | 666 | 959 | 774 | 622 | 610 | 744 | 1,089 |
| Commercial | 590 | 559 | 528 | 521 | 527 | 563 | 648 | 584 | 579 | 553 | 543 | 616 |
| Irrigation | 2 | 2 | 6 | 115 | 379 | 632 | 746 | 611 | 356 | 92 | 6 | 3 |
| Industrial | 403 | 399 | 401 | 381 | 372 | 409 | 405 | 411 | 406 | 419 | 412 | 395 |
| Additional Firm | 124 | 122 | 117 | 115 | 106 | 102 | 110 | 110 | 107 | 110 | 116 | 122 |
| Loss | 180 | 168 | 153 | 151 | 171 | 207 | 254 | 218 | 178 | 150 | 153 | 192 |
| **System Load** | **2,280** | **2,142** | **1,974** | **1,935** | **2,159** | **2,579** | **3,123** | **2,708** | **2,249** | **1,934** | **1,974** | **2,416** |
| Light Load | 2,117 | 1,968 | 1,803 | 1,751 | 1,950 | 2,330 | 2,825 | 2,396 | 2,005 | 1,740 | 1,819 | 2,230 |
| Heavy Load | 2,409 | 2,273 | 2,098 | 2,082 | 2,309 | 2,762 | 3,357 | 2,933 | 2,427 | 2,087 | 2,088 | 2,563 |
| **Total Load** | **2,280** | **2,142** | **1,974** | **1,935** | **2,159** | **2,579** | **3,123** | **2,708** | **2,249** | **1,934** | **1,974** | **2,416** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,815 | 2,778 | 2,520 | 2,409 | 3,382 | 4,060 | 4,773 | 3,857 | 3,728 | 2,569 | 2,638 | 3,100 |
| **Total Peak Load** | **2,815** | **2,778** | **2,520** | **2,409** | **3,382** | **4,060** | **4,773** | **3,857** | **3,728** | **2,569** | **2,638** | **3,100** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,317,055 | 5,447,177 | 5,552,704 | 5,625,914 | 5,695,969 | 5,747,179 | 5,809,857 | 5,869,137 | 5,939,209 | 6,025,044 |
| Commercial | 4,131,001 | 4,201,012 | 4,239,992 | 4,270,776 | 4,307,093 | 4,346,536 | 4,388,927 | 4,431,884 | 4,473,825 | 4,516,895 |
| Irrigation | 1,977,605 | 2,016,722 | 2,030,485 | 2,032,902 | 2,028,293 | 2,039,381 | 2,052,113 | 2,056,538 | 2,058,763 | 2,068,421 |
| Industrial | 2,413,190 | 2,573,787 | 2,642,594 | 2,692,807 | 2,738,789 | 2,786,007 | 2,837,470 | 2,889,584 | 2,942,288 | 2,994,216 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,719,352 | 15,140,599 | 15,371,675 | 15,531,900 | 15,679,743 | 15,839,703 | 16,011,067 | 16,204,643 | 16,400,686 | 16,611,376 |
| **Total Sales** | **14,719,352** | **15,140,599** | **15,371,675** | **15,531,900** | **15,679,743** | **15,839,703** | **16,011,067** | **16,204,643** | **16,400,686** | **16,611,376** |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,326,729 | 5,472,945 | 5,558,208 | 5,631,202 | 5,699,862 | 5,770,615 | 5,814,359 | 5,874,448 | 5,945,701 | 6,051,025 |
| Commercial | 4,134,835 | 4,214,880 | 4,241,773 | 4,272,855 | 4,309,340 | 4,360,932 | 4,391,367 | 4,434,274 | 4,476,279 | 4,531,807 |
| Irrigation | 1,977,624 | 2,016,781 | 2,030,486 | 2,032,900 | 2,028,299 | 2,039,440 | 2,052,115 | 2,056,539 | 2,058,768 | 2,068,481 |
| Industrial | 2,426,435 | 2,579,462 | 2,646,735 | 2,696,599 | 2,742,683 | 2,790,251 | 2,841,768 | 2,893,931 | 2,946,571 | 2,998,631 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,746,123 | 15,185,968 | 15,383,103 | 15,543,056 | 15,689,784 | 15,881,839 | 16,022,310 | 16,216,691 | 16,413,918 | 16,656,744 |
| **Total Sales** | **14,746,123** | **15,185,968** | **15,383,103** | **15,543,056** | **15,689,784** | **15,881,839** | **16,022,310** | **16,216,691** | **16,413,918** | **16,656,744** |
| Loss | 1,276,987 | 1,312,390 | 1,328,626 | 1,341,950 | 1,354,358 | 1,370,388 | 1,381,874 | 1,396,485 | 1,411,705 | 1,431,876 |
| **Required Generation** | 16,023,110 | 16,498,358 | 16,711,729 | 16,885,006 | 17,044,142 | 17,252,227 | 17,404,184 | 17,613,176 | 17,825,623 | 18,088,620 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 608 | 623 | 634 | 643 | 651 | 657 | 664 | 671 | 679 | 689 |
| Commercial | 472 | 480 | 484 | 488 | 492 | 496 | 501 | 506 | 511 | 516 |
| Irrigation | 226 | 230 | 232 | 232 | 232 | 232 | 234 | 235 | 235 | 235 |
| Industrial | 277 | 294 | 302 | 308 | 313 | 318 | 324 | 330 | 336 | 341 |
| Additional Firm | 101 | 103 | 103 | 104 | 104 | 105 | 105 | 109 | 113 | 115 |
| Loss | 146 | 149 | 152 | 153 | 155 | 156 | 158 | 159 | 161 | 163 |
| **System Load** | 1,829 | 1,878 | 1,908 | 1,928 | 1,946 | 1,964 | 1,987 | 2,011 | 2,035 | 2,059 |
| Light Load | 1,660 | 1,705 | 1,731 | 1,749 | 1,766 | 1,782 | 1,803 | 1,825 | 1,847 | 1,869 |
| Heavy Load | 1,962 | 2,014 | 2,047 | 2,068 | 2,087 | 2,106 | 2,131 | 2,157 | 2,183 | 2,208 |
| **Total Load** | **1,829** | **1,878** | **1,908** | **1,928** | **1,946** | **1,964** | **1,987** | **2,011** | **2,035** | **2,059** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 3,576 | 3,669 | 3,736 | 3,793 | 3,847 | 3,905 | 3,965 | 4,026 | 4,086 | 4,151 |
| **Total Peak Load** | **3,576** | **3,669** | **3,736** | **3,793** | **3,847** | **3,905** | **3,965** | **4,026** | **4,086** | **4,151** |

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,112,140 | 6,200,195 | 6,287,755 | 6,378,017 | 6,467,506 | 6,544,386 | 6,614,509 | 6,685,063 | 6,757,939 | 6,829,662 |
| Commercial | 4,561,364 | 4,605,150 | 4,647,240 | 4,692,068 | 4,739,417 | 4,784,329 | 4,827,637 | 4,873,585 | 4,922,833 | 4,971,401 |
| Irrigation | 2,081,259 | 2,093,648 | 2,104,780 | 2,115,037 | 2,126,900 | 2,137,034 | 2,146,010 | 2,152,899 | 2,161,682 | 2,169,546 |
| Industrial | 3,047,748 | 3,101,332 | 3,154,544 | 3,207,964 | 3,263,009 | 3,314,431 | 3,364,294 | 3,412,358 | 3,461,829 | 3,509,388 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,809,311 | 17,004,425 | 17,198,419 | 17,391,886 | 17,595,632 | 17,784,280 | 17,956,550 | 18,122,705 | 18,303,083 | 18,473,496 |
| **Total Sales** | **16,809,311** | **17,004,425** | **17,198,419** | **17,391,886** | **17,595,632** | **17,784,280** | **17,956,550** | **18,122,705** | **18,303,083** | **18,473,496** |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,118,814 | 6,206,840 | 6,294,611 | 6,405,135 | 6,473,380 | 6,549,762 | 6,619,925 | 6,711,729 | 6,763,457 | 6,835,118 |
| Commercial | 4,563,863 | 4,607,563 | 4,649,803 | 4,707,547 | 4,741,992 | 4,786,824 | 4,830,276 | 4,889,591 | 4,925,621 | 4,974,352 |
| Irrigation | 2,081,265 | 2,093,654 | 2,104,785 | 2,115,098 | 2,126,905 | 2,137,039 | 2,146,014 | 2,152,960 | 2,161,686 | 2,169,550 |
| Industrial | 3,052,167 | 3,105,721 | 3,158,950 | 3,212,504 | 3,267,250 | 3,318,543 | 3,368,258 | 3,416,438 | 3,465,751 | 3,513,496 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,822,910 | 17,017,877 | 17,212,249 | 17,439,084 | 17,608,327 | 17,796,269 | 17,968,573 | 18,169,518 | 18,315,315 | 18,486,015 |
| **Total Sales** | **16,822,910** | **17,017,877** | **17,212,249** | **17,439,084** | **17,608,327** | **17,796,269** | **17,968,573** | **18,169,518** | **18,315,315** | **18,486,015** |
| Loss | 1,445,886 | 1,462,827 | 1,479,556 | 1,499,718 | 1,513,980 | 1,529,833 | 1,544,571 | 1,562,443 | 1,574,650 | 1,589,634 |
| **Required Generation** | 18,268,795 | 18,480,705 | 18,691,805 | 18,938,803 | 19,122,307 | 19,326,102 | 19,513,144 | 19,731,961 | 19,889,966 | 20,075,650 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 698 | 709 | 719 | 729 | 739 | 748 | 756 | 764 | 772 | 780 |
| Commercial | 521 | 526 | 531 | 536 | 541 | 546 | 551 | 557 | 562 | 568 |
| Irrigation | 238 | 239 | 240 | 241 | 243 | 244 | 245 | 245 | 247 | 248 |
| Industrial | 348 | 355 | 361 | 366 | 373 | 379 | 385 | 389 | 396 | 401 |
| Additional Firm | 115 | 115 | 115 | 114 | 114 | 115 | 115 | 114 | 114 | 113 |
| Loss | 165 | 167 | 169 | 171 | 173 | 175 | 176 | 178 | 180 | 181 |
| **System Load** | 2,085 | 2,110 | 2,134 | 2,156 | 2,183 | 2,206 | 2,228 | 2,246 | 2,271 | 2,292 |
| Light Load | 1,893 | 1,915 | 1,936 | 1,957 | 1,981 | 2,002 | 2,022 | 2,039 | 2,061 | 2,080 |
| Heavy Load | 2,237 | 2,263 | 2,288 | 2,313 | 2,342 | 2,366 | 2,382 | 2,402 | 2,428 | 2,452 |
| **Total Load** | **2,085** | **2,110** | **2,134** | **2,156** | **2,183** | **2,206** | **2,228** | **2,246** | **2,271** | **2,292** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 4,215 | 4,278 | 4,341 | 4,404 | 4,469 | 4,531 | 4,592 | 4,651 | 4,713 | 4,773 |
| **Total Peak Load** | **4,215** | **4,278** | **4,341** | **4,404** | **4,469** | **4,531** | **4,592** | **4,651** | **4,713** | **4,773** |

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 11 | 11 | 11 | 11 | 13 | 15 | 16 | 15 | 12 | 10 | 10 | 11 |
| Load Forecast (70th% w/EE) | (1,800) | (1,724) | (1,575) | (1,549) | (1,734) | (2,079) | (2,498) | (2,156) | (1,785) | (1,541) | (1,573) | (1,914) |
| Total non-forecasted trended EE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (1,800) | (1,724) | (1,575) | (1,549) | (1,734) | (2,079) | (2,498) | (2,156) | (1,785) | (1,541) | (1,573) | (1,914) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 960 | 960 | 933 | 777 | 867 | 960 | 960 | 960 | 812 | 789 | 936 | 960 |
| **Total Gas** | 516 | 286 | 280 | 281 | 279 | 516 | 496 | 515 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 569 | 702 | 591 | 720 | 873 | 601 | 526 | 369 | 455 | 407 | 343 | 483 |
| Hydro (70th%)—Other | 217 | 291 | 237 | 263 | 314 | 328 | 279 | 210 | 224 | 219 | 202 | 208 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 786 | 994 | 828 | 983 | 1,187 | 929 | 876 | 580 | 679 | 626 | 545 | 691 |
| **CSPP (PURPA)** | 202 | 244 | 248 | 303 | 299 | 301 | 258 | 219 | 241 | 223 | 205 | 198 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **76** | **73** | **54** | **49** | **62** | **65** | **62** | **61** | **55** | **36** | **46** | **74** |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,538 | 2,556 | 2,342 | 2,393 | 2,694 | 2,771 | 2,651 | 2,334 | 2,063 | 1,955 | 2,015 | 2,447 |
| **Monthly Surplus/Deficit** | 738 | 832 | 767 | 844 | 960 | 692 | 153 | 178 | 278 | 414 | 442 | 534 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 738 | 832 | 767 | 844 | 960 | 692 | 153 | 178 | 278 | 414 | 442 | 534 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 19 | 18 | 18 | 18 | 21 | 23 | 24 | 23 | 19 | 17 | 17 | 18 |
| Load Forecast (70th% w/EE) | (1,854) | (1,761) | (1,624) | (1,594) | (1,782) | (2,128) | (2,568) | (2,218) | (1,833) | (1,585) | (1,617) | (1,954) |
| Total non-forecasted trended EE | 7 | 7 | 7 | 7 | 8 | 9 | 9 | 9 | 7 | 7 | 7 | 7 |
| **Net Load Forecast (70th% w/ EE)** | (1,847) | (1,754) | (1,618) | (1,587) | (1,775) | (2,120) | (2,559) | (2,209) | (1,825) | (1,579) | (1,610) | (1,947) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 725 | 607 | 735 | 958 | 958 | 958 | 799 | 788 | 945 | 958 |
| **Total Gas** | 516 | 286 | 280 | 281 | 279 | 516 | 496 | 515 | 277 | 281 | 284 | 516 |
| Hydro (70th%)—HCC | 570 | 713 | 596 | 728 | 883 | 606 | 525 | 369 | 453 | 406 | 344 | 483 |
| Hydro (70th%)—Other | 218 | 307 | 243 | 265 | 316 | 328 | 279 | 210 | 224 | 219 | 202 | 208 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 1,019 | 839 | 994 | 1,198 | 934 | 804 | 579 | 677 | 625 | 545 | 690 |
| **CSPP (PURPA)** | 208 | 253 | 258 | 315 | 313 | 316 | 304 | 263 | 277 | 251 | 221 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,539 | 2,583 | 2,168 | 2,257 | 2,578 | 2,779 | 2,614 | 2,369 | 2,080 | 1,999 | 2,058 | 2,493 |
| **Monthly Surplus/Deficit** | 692 | 829 | 551 | 670 | 803 | 659 | 55 | 159 | 255 | 421 | 448 | 546 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 692 | 829 | 551 | 670 | 803 | 659 | 55 | 159 | 255 | 421 | 448 | 546 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 24 | 24 | 23 | 23 | 26 | 28 | 30 | 29 | 24 | 22 | 22 | 24 |
| Load Forecast (70th% w/EE) | (1,884) | (1,802) | (1,649) | (1,618) | (1,808) | (2,159) | (2,606) | (2,251) | (1,861) | (1,609) | (1,642) | (1,980) |
| Total non-forecasted trended EE | 19 | 19 | 18 | 18 | 20 | 22 | 24 | 22 | 19 | 17 | 17 | 19 |
| **Net Load Forecast (70th% w/ EE)** | (1,865) | (1,784) | (1,632) | (1,600) | (1,788) | (2,137) | (2,583) | (2,229) | (1,842) | (1,592) | (1,625) | (1,961) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 926 | 751 | 754 | 958 | 958 | 958 | 958 | 958 | 958 | 958 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 507 | 505 | 515 | 277 | 281 | 284 | 516 |
| Hydro (70th%)—HCC | 567 | 710 | 601 | 731 | 895 | 614 | 526 | 370 | 449 | 407 | 343 | 486 |
| Hydro (70th%)—Other | 215 | 311 | 240 | 268 | 318 | 329 | 279 | 211 | 224 | 219 | 193 | 203 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 782 | 1,021 | 841 | 999 | 1,213 | 943 | 805 | 581 | 673 | 626 | 536 | 689 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,598 | 2,671 | 2,485 | 2,546 | 2,770 | 2,949 | 2,773 | 2,507 | 2,352 | 2,263 | 2,121 | 2,492 |
| **Monthly Surplus/Deficit** | 733 | 888 | 854 | 946 | 982 | 812 | 191 | 278 | 511 | 671 | 496 | 531 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 733 | 888 | 854 | 946 | 982 | 812 | 191 | 278 | 511 | 671 | 496 | 531 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 32 | 31 | 29 | 31 | 36 | 41 | 43 | 41 | 33 | 29 | 29 | 31 |
| Load Forecast (70th% w/EE) | (1,906) | (1,821) | (1,667) | (1,635) | (1,826) | (2,180) | (2,631) | (2,274) | (1,880) | (1,626) | (1,660) | (2,003) |
| Total non-forecasted trended EE | 29 | 29 | 27 | 28 | 33 | 37 | 40 | 37 | 31 | 26 | 26 | 29 |
| **Net Load Forecast (70th% w/ EE)** | (1,876) | (1,792) | (1,640) | (1,606) | (1,793) | (2,142) | (2,592) | (2,237) | (1,850) | (1,600) | (1,633) | (1,974) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 893 | 738 | 784 | 958 | 958 | 958 | 958 | 958 | 957 | 958 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 507 | 505 | 506 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 567 | 710 | 600 | 733 | 900 | 612 | 525 | 369 | 447 | 408 | 343 | 485 |
| Hydro (70th%)—Other | 216 | 309 | 234 | 270 | 319 | 329 | 279 | 211 | 224 | 220 | 192 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 783 | 1,019 | 834 | 1,003 | 1,219 | 941 | 804 | 580 | 671 | 628 | 535 | 685 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,599 | 2,669 | 2,445 | 2,537 | 2,806 | 2,947 | 2,772 | 2,497 | 2,350 | 2,264 | 2,120 | 2,497 |
| **Monthly Surplus/Deficit** | 722 | 877 | 806 | 931 | 1,013 | 805 | 180 | 260 | 500 | 664 | 486 | 522 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 722 | 877 | 806 | 931 | 1,013 | 805 | 180 | 260 | 500 | 664 | 486 | 522 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 39 | 38 | 36 | 37 | 43 | 48 | 51 | 48 | 40 | 34 | 35 | 38 |
| Load Forecast (70th% w/EE) | (1,926) | (1,838) | (1,683) | (1,650) | (1,842) | (2,198) | (2,654) | (2,294) | (1,898) | (1,642) | (1,677) | (2,024) |
| Total non-forecasted trended EE | 41 | 40 | 38 | 40 | 47 | 52 | 55 | 52 | 43 | 37 | 37 | 40 |
| **Net Load Forecast (70th% w/ EE)** | (1,885) | (1,798) | (1,645) | (1,610) | (1,795) | (2,146) | (2,598) | (2,242) | (1,855) | (1,606) | (1,640) | (1,983) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 956 | 956 | 909 | 838 | 733 | 956 | 956 | 956 | 956 | 956 | 956 | 956 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 516 | 505 | 506 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 569 | 711 | 600 | 735 | 907 | 616 | 526 | 370 | 442 | 409 | 344 | 479 |
| Hydro (70th%)—Other | 215 | 302 | 221 | 263 | 321 | 330 | 280 | 211 | 224 | 221 | 186 | 193 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 784 | 1,012 | 821 | 998 | 1,227 | 946 | 806 | 581 | 666 | 629 | 530 | 671 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,598 | 2,660 | 2,448 | 2,632 | 2,764 | 2,959 | 2,773 | 2,497 | 2,343 | 2,264 | 2,113 | 2,481 |
| **Monthly Surplus/Deficit** | 713 | 863 | 802 | 1,021 | 969 | 814 | 175 | 255 | 488 | 659 | 473 | 498 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 713 | 863 | 802 | 1,021 | 969 | 814 | 175 | 255 | 488 | 659 | 473 | 498 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 48 | 47 | 44 | 47 | 54 | 61 | 66 | 62 | 50 | 43 | 43 | 47 |
| Load Forecast (70th% w/EE) | (1,946) | (1,839) | (1,700) | (1,667) | (1,860) | (2,221) | (2,681) | (2,318) | (1,919) | (1,659) | (1,693) | (2,047) |
| Total non-forecasted trended EE | 47 | 45 | 43 | 45 | 53 | 59 | 64 | 60 | 48 | 42 | 42 | 45 |
| **Net Load Forecast (70th% w/ EE)** | (1,899) | (1,794) | (1,657) | (1,622) | (1,808) | (2,161) | (2,617) | (2,258) | (1,870) | (1,618) | (1,652) | (2,001) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 807 | 786 | 54 | 54 | 337 | 811 | 851 | 807 | 781 | 348 | 394 | 807 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 566 | 709 | 600 | 733 | 905 | 614 | 525 | 369 | 436 | 409 | 344 | 472 |
| Hydro (70th%)—Other | 213 | 291 | 218 | 261 | 320 | 329 | 279 | 210 | 222 | 220 | 186 | 193 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 779 | 1,000 | 818 | 994 | 1,224 | 943 | 804 | 579 | 658 | 628 | 529 | 665 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 259 | 58 | 0 | 0 | 0 | 0 | 0 | 243 | 295 | 0 |
| **Existing Resource Subtotal** | 2,413 | 2,336 | 1,657 | 1,622 | 2,173 | 2,804 | 2,655 | 2,351 | 2,018 | 1,618 | 1,652 | 2,304 |
| **Monthly Surplus/Deficit** | 514 | 542 | 0 | 0 | 365 | 643 | 38 | 93 | 148 | 0 | 0 | 303 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 514 | 542 | 0 | 0 | 365 | 643 | 38 | 93 | 148 | 0 | 0 | 303 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 55 | 54 | 51 | 54 | 63 | 71 | 76 | 71 | 58 | 49 | 50 | 54 |
| Load Forecast (70th% w/EE) | (1,967) | (1,873) | (1,717) | (1,684) | (1,880) | (2,245) | (2,710) | (2,344) | (1,940) | (1,677) | (1,711) | (2,070) |
| Total non-forecasted trended EE | 55 | 53 | 51 | 53 | 62 | 70 | 75 | 70 | 57 | 49 | 49 | 53 |
| **Net Load Forecast (70th% w/ EE)** | (1,912) | (1,820) | (1,666) | (1,631) | (1,819) | (2,175) | (2,636) | (2,274) | (1,884) | (1,628) | (1,662) | (2,016) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 407 | 753 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 564 | 707 | 589 | 731 | 903 | 611 | 524 | 367 | 430 | 409 | 344 | 469 |
| Hydro (70th%)—Other | 211 | 285 | 208 | 259 | 319 | 328 | 278 | 209 | 221 | 219 | 185 | 192 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 775 | 992 | 797 | 990 | 1,222 | 939 | 802 | 576 | 651 | 627 | 529 | 661 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 345 | 126 | 0 | 0 | 37 | 0 | 0 | 309 | 293 | 0 |
| **Existing Resource Subtotal** | 2,355 | 2,274 | 1,666 | 1,631 | 2,116 | 2,746 | 2,636 | 2,294 | 1,957 | 1,628 | 1,662 | 2,237 |
| **Monthly Surplus/Deficit** | 443 | 455 | 0 | 0 | 297 | 571 | 0 | 20 | 73 | 0 | 0 | 221 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 443 | 455 | 0 | 0 | 297 | 571 | 0 | 20 | 73 | 0 | 0 | 221 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 62 | 60 | 57 | 60 | 70 | 79 | 85 | 79 | 64 | 55 | 56 | 60 |
| Load Forecast (70th% w/EE) | (1,992) | (1,895) | (1,738) | (1,704) | (1,902) | (2,270) | (2,740) | (2,371) | (1,964) | (1,698) | (1,733) | (2,098) |
| Total non-forecasted trended EE | 64 | 63 | 60 | 62 | 73 | 82 | 88 | 82 | 67 | 57 | 58 | 63 |
| **Net Load Forecast (70th% w/ EE)** | (1,928) | (1,833) | (1,679) | (1,642) | (1,829) | (2,188) | (2,652) | (2,288) | (1,897) | (1,640) | (1,675) | (2,035) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 371 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 562 | 705 | 587 | 728 | 901 | 608 | 522 | 366 | 425 | 409 | 343 | 467 |
| Hydro (70th%)—Other | 210 | 286 | 203 | 257 | 318 | 327 | 278 | 208 | 220 | 218 | 184 | 191 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 771 | 991 | 790 | 986 | 1,219 | 935 | 800 | 574 | 645 | 627 | 528 | 658 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 363 | 142 | 0 | 0 | 56 | 0 | 0 | 322 | 344 | 0 |
| **Existing Resource Subtotal** | 2,360 | 2,273 | 1,679 | 1,642 | 2,113 | 2,743 | 2,652 | 2,292 | 1,950 | 1,640 | 1,675 | 2,234 |
| **Monthly Surplus/Deficit** | 433 | 441 | 0 | 0 | 284 | 555 | 0 | 3 | 53 | 0 | (0) | 199 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 433 | 441 | 0 | 0 | 284 | 555 | 0 | 3 | 53 | 0 | (0) | 199 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 68 | 67 | 63 | 66 | 77 | 87 | 93 | 87 | 71 | 61 | 61 | 67 |
| Load Forecast (70th% w/EE) | (2,019) | (1,918) | (1,760) | (1,725) | (1,923) | (2,294) | (2,769) | (2,397) | (1,987) | (1,719) | (1,755) | (2,128) |
| Total non-forecasted trended EE | 75 | 73 | 69 | 72 | 84 | 95 | 102 | 95 | 77 | 66 | 67 | 73 |
| **Net Load Forecast (70th% w/ EE)** | (1,944) | (1,845) | (1,691) | (1,653) | (1,839) | (2,199) | (2,667) | (2,302) | (1,910) | (1,652) | (1,688) | (2,055) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 385 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 501 | 503 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 559 | 703 | 586 | 726 | 899 | 605 | 521 | 364 | 419 | 409 | 344 | 459 |
| Hydro (70th%)—Other | 208 | 266 | 203 | 256 | 316 | 326 | 277 | 207 | 218 | 217 | 183 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 767 | 969 | 789 | 982 | 1,215 | 931 | 798 | 571 | 637 | 626 | 527 | 649 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 377 | 156 | 0 | 0 | 64 | 12 | 0 | 335 | 343 | 0 |
| **Existing Resource Subtotal** | 2,356 | 2,251 | 1,691 | 1,653 | 2,109 | 2,730 | 2,667 | 2,302 | 1,942 | 1,652 | 1,688 | 2,225 |
| **Monthly Surplus/Deficit** | 413 | 406 | 0 | 0 | 270 | 531 | 0 | 0 | 32 | 0 | (0) | 170 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 413 | 406 | 0 | 0 | 270 | 531 | 0 | 0 | 32 | 0 | (0) | 170 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 75 | 73 | 69 | 72 | 84 | 95 | 102 | 95 | 77 | 66 | 67 | 73 |
| Load Forecast (70th% w/EE) | (2,046) | (1,925) | (1,783) | (1,747) | (1,947) | (2,322) | (2,803) | (2,427) | (2,013) | (1,741) | (1,778) | (2,159) |
| Total non-forecasted trended EE | 86 | 83 | 79 | 82 | 96 | 109 | 117 | 109 | 88 | 76 | 77 | 83 |
| **Net Load Forecast (70th% w/ EE)** | (1,960) | (1,842) | (1,703) | (1,665) | (1,851) | (2,213) | (2,687) | (2,318) | (1,925) | (1,665) | (1,702) | (2,075) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 402 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 503 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 556 | 696 | 585 | 724 | 897 | 602 | 519 | 362 | 412 | 409 | 343 | 450 |
| Hydro (70th%)—Other | 208 | 254 | 204 | 252 | 316 | 325 | 276 | 206 | 217 | 216 | 183 | 189 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 764 | 950 | 789 | 976 | 1,213 | 927 | 795 | 568 | 628 | 625 | 526 | 639 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 389 | 173 | 0 | 0 | 86 | 41 | 0 | 348 | 341 | 0 |
| **Existing Resource Subtotal** | 2,353 | 2,232 | 1,703 | 1,665 | 2,107 | 2,735 | 2,687 | 2,318 | 1,934 | 1,665 | 1,702 | 2,224 |
| **Monthly Surplus/Deficit** | 392 | 389 | 0 | 0 | 256 | 522 | 0 | 0 | 9 | 0 | (0) | 149 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 392 | 389 | 0 | 0 | 256 | 522 | 0 | 0 | 9 | 0 | (0) | 149 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 80 | 78 | 74 | 77 | 88 | 99 | 107 | 100 | 81 | 71 | 72 | 78 |
| Load Forecast (70th% w/EE) | (2,071) | (1,964) | (1,803) | (1,767) | (1,969) | (2,349) | (2,837) | (2,457) | (2,037) | (1,761) | (1,799) | (2,186) |
| Total non-forecasted trended EE | 97 | 94 | 89 | 92 | 106 | 119 | 128 | 120 | 98 | 85 | 87 | 94 |
| **Net Load Forecast (70th% w/ EE)** | (1,974) | (1,870) | (1,714) | (1,675) | (1,864) | (2,230) | (2,709) | (2,337) | (1,940) | (1,676) | (1,713) | (2,092) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 419 | 753 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 512 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 554.8 | 693.9 | 583.8 | 722.3 | 895.1 | 598.3 | 518.1 | 361.0 | 407.5 | 401.0 | 344.3 | 446.8 |
| Hydro (70th%)—Other | 206.5 | 242.5 | 202.4 | 250.8 | 315.1 | 324.5 | 275.2 | 204.8 | 214.9 | 214.9 | 181.7 | 187.3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 761 | 936 | 786 | 973 | 1,210 | 923 | 793 | 566 | 622 | 616 | 526 | 634 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 341 | 278 | 257 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 402 | 187 | 0 | 0 | 101 | 62 | 12 | 371 | 338 | 0 |
| **Existing Resource Subtotal** | 2,342 | 2,219 | 1,714 | 1,675 | 2,104 | 2,730 | 2,709 | 2,337 | 1,940 | 1,676 | 1,713 | 2,217 |
| **Monthly Surplus/Deficit** | 367 | 349 | 0 | 0 | 241 | 500 | 0 | 0 | 0 | 0 | (0) | 124 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 567 | 549 | 200 | 500 | 741 | 1,000 | 500 | 500 | 500 | 200 | 200 | 324 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 86 | 83 | 79 | 81 | 92 | 103 | 111 | 104 | 85 | 75 | 77 | 83 |
| Load Forecast (70th% w/EE) | (2,095) | (1,985) | (1,823) | (1,787) | (1,991) | (2,376) | (2,871) | (2,486) | (2,062) | (1,781) | (1,820) | (2,213) |
| Total non-forecasted trended EE | 108 | 105 | 100 | 102 | 116 | 130 | 140 | 131 | 108 | 94 | 97 | 105 |
| **Net Load Forecast (70th% w/ EE)** | (1,988) | (1,880) | (1,724) | (1,685) | (1,876) | (2,246) | (2,731) | (2,355) | (1,954) | (1,687) | (1,723) | (2,108) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 512 |
| Hydro (70th%)—HCC | 553 | 689 | 583 | 720 | 893 | 597 | 517 | 359 | 403 | 401 | 344 | 446 |
| Hydro (70th%)—Other | 206 | 223 | 200 | 246 | 314 | 323 | 274 | 204 | 214 | 214 | 181 | 187 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 759 | 912 | 783 | 966 | 1,207 | 919 | 791 | 563 | 617 | 615 | 525 | 633 |
| **CSPP (PURPA)** | 260 | 336 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 422 | 210 | 0 | 0 | 257 | 177 | 111 | 386 | 336 | 0 |
| **Existing Resource Subtotal** | 2,234 | 2,110 | 1,724 | 1,685 | 2,024 | 2,618 | 2,697 | 2,355 | 1,954 | 1,687 | 1,591 | 2,119 |
| **Monthly Surplus/Deficit** | 246 | 230 | 0 | 0 | 148 | 372 | (34) | 0 | 0 | 0 | (132) | 11 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 446 | 430 | 200 | 500 | 648 | 872 | 466 | 500 | 500 | 200 | 68 | 211 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 91 | 88 | 84 | 85 | 95 | 107 | 116 | 108 | 89 | 79 | 81 | 88 |
| Load Forecast (70th% w/EE) | (2,120) | (2,006) | (1,843) | (1,806) | (2,013) | (2,403) | (2,904) | (2,515) | (2,086) | (1,801) | (1,840) | (2,241) |
| Total non-forecasted trended EE | 119 | 116 | 110 | 112 | 126 | 141 | 153 | 143 | 118 | 104 | 107 | 116 |
| **Net Load Forecast (70th% w/ EE)** | (2,001) | (1,890) | (1,733) | (1,694) | (1,887) | (2,262) | (2,751) | (2,372) | (1,968) | (1,698) | (1,733) | (2,124) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 551 | 679 | 582 | 719 | 892 | 595 | 515 | 358 | 398 | 401 | 344 | 445 |
| Hydro (70th%)—Other | 205 | 211 | 199 | 243 | 313 | 322 | 274 | 203 | 211 | 213 | 180 | 185 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 756 | 891 | 780 | 962 | 1,205 | 917 | 789 | 561 | 610 | 614 | 524 | 630 |
| **CSPP (PURPA)** | 257 | 333 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 434 | 224 | 0 | 0 | 254 | 197 | 132 | 397 | 334 | 26 |
| **Existing Resource Subtotal** | 2,237 | 2,086 | 1,733 | 1,694 | 2,021 | 2,616 | 2,692 | 2,372 | 1,968 | 1,698 | 1,588 | 2,124 |
| **Monthly Surplus/Deficit** | 236 | 196 | 0 | 0 | 134 | 354 | (59) | 0 | 0 | 0 | (146) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 436 | 396 | 200 | 500 | 634 | 854 | 441 | 500 | 500 | 200 | 54 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 92 | 88 | 89 | 99 | 111 | 120 | 112 | 93 | 82 | 85 | 92 | 92 |
| Load Forecast (70th% w/EE) | (2,010) | (1,864) | (1,826) | (2,035) | (2,429) | (2,937) | (2,544) | (2,111) | (1,822) | (1,861) | (2,268) | (2,010) |
| Total non-forecasted trended EE | 128 | 122 | 123 | 137 | 153 | 166 | 156 | 129 | 114 | 118 | 128 | 128 |
| **Net Load Forecast (70th% w/ EE)** | (1,881) | (1,742) | (1,703) | (1,898) | (2,276) | (2,771) | (2,388) | (1,982) | (1,707) | (1,743) | (2,140) | (1,881) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 | 651 |
| **Total Gas** | 145 | 87 | – | 87 | 501 | 503 | 512 | 135 | – | 90 | 494 | 145 |
| Hydro (70th%)—HCC | 675 | 581 | 717 | 890 | 593 | 514 | 357 | 393 | 402 | 344 | 442 | 675 |
| Hydro (70th%)—Other | 210 | 194 | 244 | 313 | 321 | 273 | 201 | 210 | 212 | 178 | 184 | 210 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 885 | 775 | 961 | 1,203 | 915 | 787 | 558 | 603 | 614 | 523 | 626 | 885 |
| **CSPP (PURPA)** | 333 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 | 333 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 | 24 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 | 33 |
| **Market Purchases** | 0 | 441 | 267 | 0 | 0 | 249 | 249 | 179 | 405 | 331 | 80 | 0 |
| **Existing Resource Subtotal** | 2,046 | 1,699 | 1,703 | 1,989 | 2,573 | 2,659 | 2,388 | 1,982 | 1,676 | 1,551 | 2,140 | 2,046 |
| **Monthly Surplus/Deficit** | 165 | (43) | 0 | 91 | 297 | (112) | 0 | 0 | (31) | (192) | 0 | 165 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 365 | 157 | 500 | 591 | 797 | 388 | 500 | 500 | 169 | 8 | 200 | 365 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 99 | 97 | 92 | 92 | 102 | 114 | 123 | 116 | 96 | 86 | 89 | 97 |
| Load Forecast (70th% w/EE) | (2,170) | (2,050) | (1,885) | (1,847) | (2,058) | (2,457) | (2,972) | (2,575) | (2,136) | (1,843) | (1,883) | (2,294) |
| Total non-forecasted trended EE | 144 | 140 | 133 | 134 | 148 | 165 | 179 | 168 | 140 | 124 | 129 | 140 |
| **Net Load Forecast (70th% w/ EE)** | (2,026) | (1,910) | (1,752) | (1,713) | (1,911) | (2,292) | (2,793) | (2,407) | (1,996) | (1,718) | (1,753) | (2,154) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 323 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 501 | 503 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 547 | 672 | 580 | 715 | 888 | 591 | 513 | 355 | 384 | 401 | 344 | 441 |
| Hydro (70th%)—Other | 204 | 208 | 193 | 240 | 312 | 320 | 272 | 200 | 209 | 211 | 178 | 182 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 751 | 880 | 773 | 955 | 1,201 | 911 | 785 | 556 | 593 | 612 | 522 | 623 |
| **CSPP (PURPA)** | 247 | 322 | 352 | 431 | 452 | 469 | 442 | 391 | 380 | 327 | 261 | 241 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 440 | 300 | 0 | 0 | 245 | 286 | 214 | 403 | 329 | 102 |
| **Existing Resource Subtotal** | 2,186 | 2,031 | 1,683 | 1,713 | 1,972 | 2,555 | 2,643 | 2,407 | 1,996 | 1,661 | 1,553 | 2,154 |
| **Monthly Surplus/Deficit** | 159 | 121 | (68) | 0 | 61 | 263 | (149) | 0 | 0 | (57) | (200) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 359 | 321 | 132 | 500 | 561 | 763 | 351 | 500 | 500 | 143 | 0 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 104 | 102 | 97 | 97 | 106 | 118 | 129 | 121 | 101 | 90 | 94 | 102 |
| Load Forecast (70th% w/EE) | (2,194) | (2,070) | (1,904) | (1,866) | (2,080) | (2,483) | (3,004) | (2,603) | (2,160) | (1,862) | (1,902) | (2,320) |
| Total non-forecasted trended EE | 152 | 147 | 140 | 140 | 154 | 172 | 187 | 175 | 146 | 130 | 136 | 147 |
| **Net Load Forecast (70th% w/ EE)** | (2,043) | (1,922) | (1,764) | (1,725) | (1,926) | (2,312) | (2,817) | (2,428) | (2,014) | (1,732) | (1,767) | (2,172) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 439 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 503 | 503 | 90 | – | – | 503 |
| Hydro (70th%)—HCC | 546 | 670 | 579 | 713 | 887 | 590 | 511 | 355 | 379 | 401 | 345 | 438 |
| Hydro (70th%)—Other | 202 | 207 | 194 | 233 | 312 | 318 | 271 | 200 | 208 | 210 | 177 | 181 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 748 | 877 | 773 | 946 | 1,198 | 908 | 783 | 555 | 587 | 612 | 521 | 620 |
| **CSPP (PURPA)** | 244 | 319 | 349 | 431 | 452 | 459 | 435 | 386 | 373 | 320 | 251 | 233 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 60 | 438 | 321 | 0 | 0 | 242 | 305 | 289 | 402 | 327 | 131 |
| **Existing Resource Subtotal** | 2,180 | 1,922 | 1,677 | 1,725 | 1,969 | 2,551 | 2,631 | 2,421 | 2,014 | 1,569 | 1,567 | 2,172 |
| **Monthly Surplus/Deficit** | 137 | 0 | (87) | 0 | 43 | 240 | (186) | (7) | 0 | (163) | (200) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 337 | 200 | 113 | 500 | 543 | 740 | 314 | 493 | 500 | 37 | 0 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 110 | 107 | 101 | 101 | 110 | 123 | 134 | 126 | 105 | 94 | 98 | 107 |
| Load Forecast (70th% w/EE) | (2,216) | (2,088) | (1,922) | (1,883) | (2,099) | (2,507) | (3,033) | (2,629) | (2,182) | (1,880) | (1,920) | (2,344) |
| Total non-forecasted trended EE | 159 | 154 | 147 | 146 | 160 | 178 | 194 | 182 | 152 | 136 | 142 | 154 |
| **Net Load Forecast (70th% w/ EE)** | (2,057) | (1,934) | (1,775) | (1,737) | (1,940) | (2,329) | (2,839) | (2,447) | (2,030) | (1,744) | (1,778) | (2,189) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 247 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 512 | 503 | 90 | – | – | 503 |
| Hydro (70th%)—HCC | 544 | 669 | 578 | 711 | 885 | 588 | 510 | 355 | 374 | 401 | 344 | 435 |
| Hydro (70th%)—Other | 202 | 205 | 193 | 226 | 311 | 317 | 271 | 199 | 206 | 209 | 176 | 181 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 746 | 874 | 770 | 937 | 1,196 | 905 | 781 | 553 | 580 | 610 | 521 | 616 |
| **CSPP (PURPA)** | 213 | 249 | 279 | 352 | 378 | 395 | 388 | 351 | 329 | 269 | 188 | 171 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 145 | 436 | 420 | 47 | 0 | 238 | 303 | 302 | 400 | 324 | 214 |
| **Existing Resource Subtotal** | 2,137 | 1,934 | 1,603 | 1,737 | 1,940 | 2,484 | 2,588 | 2,382 | 1,976 | 1,515 | 1,309 | 2,189 |
| **Monthly Surplus/Deficit** | 80 | 0 | (172) | 0 | 0 | 155 | (251) | (65) | (54) | (229) | (470) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 550 | 470 | 298 | 770 | 770 | 925 | 519 | 705 | 716 | 241 | 0 | 470 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 114 | 111 | 106 | 105 | 114 | 128 | 140 | 131 | 109 | 98 | 103 | 111 |
| Load Forecast (70th% w/EE) | (2,236) | (2,087) | (1,939) | (1,900) | (2,118) | (2,530) | (3,062) | (2,654) | (2,203) | (1,897) | (1,938) | (2,367) |
| Total non-forecasted trended EE | 166 | 161 | 153 | 152 | 166 | 185 | 202 | 189 | 158 | 142 | 148 | 161 |
| **Net Load Forecast (70th% w/ EE)** | (2,071) | (1,926) | (1,786) | (1,747) | (1,953) | (2,346) | (2,860) | (2,465) | (2,045) | (1,756) | (1,790) | (2,206) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 261 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 543 | 667 | 576 | 709 | 883 | 586 | 509 | 353 | 369 | 401 | 344 | 434 |
| Hydro (70th%)—Other | 201 | 204 | 191 | 222 | 310 | 316 | 270 | 198 | 205 | 208 | 175 | 179 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 743 | 871 | 767 | 931 | 1,193 | 902 | 779 | 551 | 574 | 610 | 520 | 613 |
| **CSPP (PURPA)** | 171 | 232 | 265 | 336 | 371 | 388 | 382 | 346 | 323 | 263 | 187 | 170 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 156 | 434 | 435 | 70 | 0 | 234 | 299 | 302 | 399 | 322 | 243 |
| **Existing Resource Subtotal** | 2,094 | 1,926 | 1,583 | 1,729 | 1,953 | 2,474 | 2,558 | 2,380 | 1,964 | 1,507 | 1,319 | 2,206 |
| **Monthly Surplus/Deficit** | 23 | 0 | (202) | (18) | 0 | 128 | (303) | (85) | (82) | (248) | (470) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 493 | 470 | 268 | 752 | 770 | 898 | 467 | 685 | 688 | 222 | (0) | 470 |

# Monthly Average Energy Load and Resource Balance (continued)

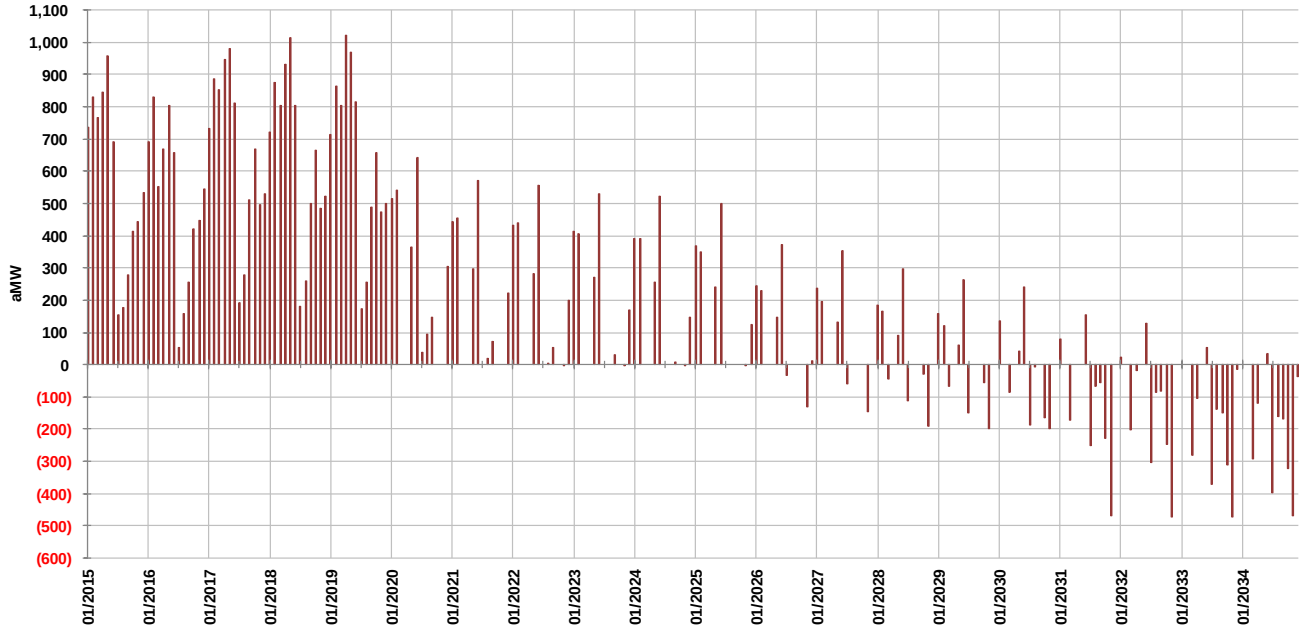
| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 119 | 116 | 110 | 109 | 118 | 132 | 145 | 136 | 113 | 102 | 107 | 116 |
| Load Forecast (70th% w/EE) | (2,259) | (2,124) | (1,957) | (1,918) | (2,139) | (2,556) | (3,093) | (2,682) | (2,227) | (1,916) | (1,957) | (2,392) |
| Total non-forecasted trended EE | 173 | 168 | 159 | 158 | 171 | 191 | 209 | 196 | 164 | 147 | 154 | 168 |
| **Net Load Forecast (70th% w/ EE)** | (2,086) | (1,956) | (1,798) | (1,759) | (1,968) | (2,364) | (2,884) | (2,485) | (2,062) | (1,769) | (1,802) | (2,224) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 313 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 542 | 665 | 571 | 707 | 882 | 584 | 507 | 352 | 364 | 401 | 345 | 432 |
| Hydro (70th%)—Other | 199 | 203 | 189 | 220 | 309 | 314 | 269 | 197 | 204 | 208 | 174 | 178 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 741 | 868 | 760 | 927 | 1,191 | 899 | 777 | 549 | 568 | 608 | 520 | 610 |
| **CSPP (PURPA)** | 130 | 175 | 208 | 268 | 319 | 335 | 343 | 319 | 280 | 220 | 151 | 134 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 28 | 247 | 433 | 433 | 139 | 0 | 230 | 296 | 302 | 396 | 319 | 285 |
| **Existing Resource Subtotal** | 2,086 | 1,956 | 1,519 | 1,656 | 1,968 | 2,418 | 2,512 | 2,347 | 1,915 | 1,460 | 1,332 | 2,209 |
| **Monthly Surplus/Deficit** | 0 | 0 | (279) | (104) | 0 | 54 | (371) | (138) | (148) | (309) | (470) | (16) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 470 | 470 | 191 | 666 | 770 | 824 | 399 | 632 | 622 | 161 | (0) | 454 |

# Monthly Average Energy Load and Resource Balance (continued)

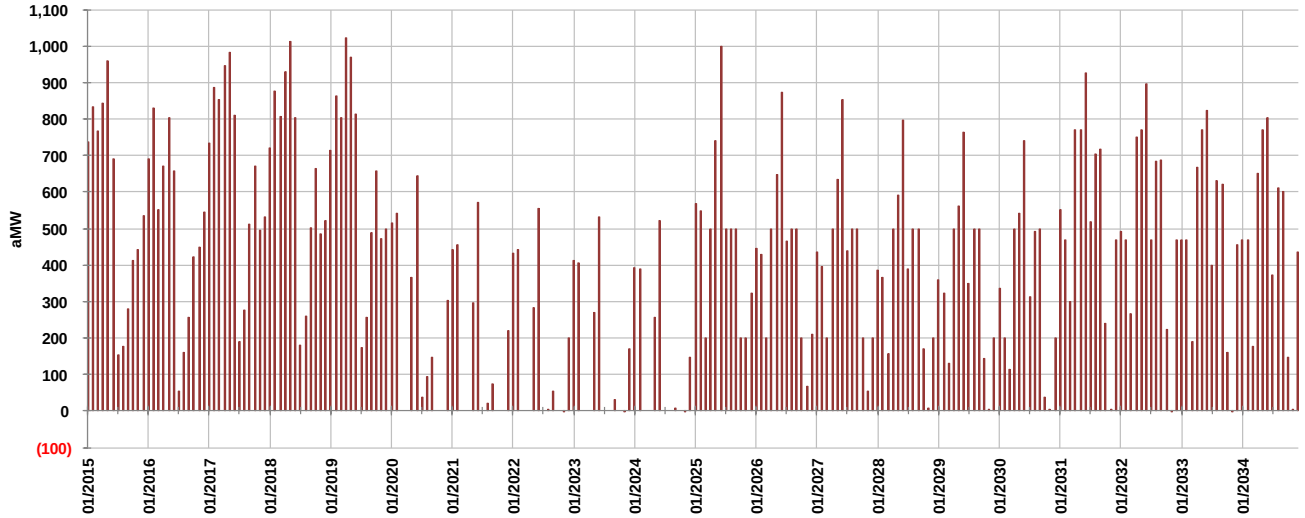
| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 124 | 120 | 114 | 113 | 122 | 136 | 149 | 140 | 117 | 105 | 111 | 120 |
| Load Forecast (70th% w/EE) | (2,280) | (2,142) | (1,974) | (1,935) | (2,159) | (2,579) | (3,123) | (2,708) | (2,249) | (1,934) | (1,974) | (2,416) |
| Total non-forecasted trended EE | 179 | 174 | 166 | 164 | 177 | 198 | 217 | 203 | 170 | 153 | 161 | 174 |
| **Net Load Forecast (70th% w/ EE)** | (2,101) | (1,968) | (1,808) | (1,771) | (1,981) | (2,382) | (2,906) | (2,505) | (2,079) | (1,781) | (1,814) | (2,242) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 327 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 542 | 664 | 569 | 706 | 881 | 582 | 506 | 350 | 359 | 401 | 345 | 432 |
| Hydro (70th%)—Other | 197 | 200 | 187 | 218 | 308 | 313 | 269 | 196 | 203 | 207 | 173 | 177 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 739 | 864 | 756 | 924 | 1,189 | 896 | 775 | 546 | 562 | 607 | 518 | 609 |
| **CSPP (PURPA)** | 130 | 175 | 208 | 268 | 319 | 335 | 343 | 319 | 280 | 220 | 151 | 134 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 44 | 262 | 433 | 433 | 154 | 0 | 230 | 296 | 302 | 396 | 319 | 285 |
| **Existing Resource Subtotal** | 2,101 | 1,968 | 1,515 | 1,653 | 1,981 | 2,415 | 2,510 | 2,345 | 1,909 | 1,459 | 1,344 | 2,207 |
| **Monthly Surplus/Deficit** | 0 | 0 | (293) | (118) | 0 | 33 | (396) | (160) | (170) | (322) | (470) | (35) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 470 | 470 | 177 | 652 | 770 | 803 | 374 | 610 | 600 | 148 | 0 | 435 |

# Monthly Average Energy Surplus/Deficit Charts

**Average energy monthly surpluses and deficits with existing DSM and existing resources**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources**



# Peak-Hour Load and Resource Balance

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,343) | (2,412) | (2,137) | (2,039) | (2,697) | (3,181) | (3,597) | (3,044) | (2,918) | (2,141) | (2,245) | (2,637) |
| Existing DSM (EE) | 12 | 12 | 10 | 12 | 15 | 18 | 21 | 15 | 17 | 8 | 12 | 12 |
| Load Forecast (95th% w/DSM and EE) | (2,330) | (2,400) | (2,128) | (2,027) | (2,682) | (3,163) | (3,576) | (3,029) | (2,901) | (2,133) | (2,233) | (2,625) |
| Non-forecasted trended EE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,330) | (2,400) | (2,128) | (2,027) | (2,682) | (2,773) | (3,186) | (2,692) | (2,901) | (2,133) | (2,233) | (2,625) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,087 | 1,078 | 1,003 | 1,072 | 1,119 | 995 | 1,000 | 724 | 789 | 878 | 709 | 802 |
| Hydro (90th%)—Other | 207 | 209 | 187 | 204 | 303 | 313 | 281 | 208 | 215 | 214 | 200 | 207 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,294 | 1,287 | 1,190 | 1,276 | 1,422 | 1,307 | 1,281 | 932 | 1,004 | 1,092 | 909 | 1,009 |
| **CSPP (PURPA)** | 72 | 74 | 77 | 109 | 150 | 157 | 156 | 147 | 135 | 107 | 79 | 75 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 44 | 44 | 23 | 21 | 37 | 38 | 33 | 33 | 33 | 11 | 18 | 44 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,147 | 3,141 | 3,027 | 3,143 | 3,345 | 3,240 | 3,207 | 2,849 | 2,909 | 2,947 | 2,743 | 2,865 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 817 | 742 | 899 | 1,116 | 663 | 467 | 21 | 157 | 8 | 814 | 510 | 239 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,419) | (2,458) | (2,201) | (2,102) | (2,771) | (3,294) | (3,695) | (3,147) | (3,018) | (2,202) | (2,295) | (2,681) |
| Existing DSM (EE) | 19 | 21 | 20 | 20 | 24 | 28 | 26 | 25 | 25 | 20 | 14 | 18 |
| Load Forecast (95th% w/DSM and EE) | (2,400) | (2,437) | (2,181) | (2,082) | (2,748) | (3,266) | (3,669) | (3,122) | (2,992) | (2,183) | (2,281) | (2,663) |
| Non-forecasted trended EE | 7 | 8 | 8 | 8 | 9 | 11 | 10 | 10 | 10 | 8 | 5 | 7 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,393) | (2,429) | (2,173) | (2,075) | (2,738) | (2,865) | (3,270) | (2,775) | (2,982) | (2,175) | (2,276) | (2,656) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,086 | 1,094 | 1,003 | 1,073 | 1,133 | 993 | 1,000 | 722 | 785 | 880 | 710 | 801 |
| Hydro (90th%)—Other | 207 | 210 | 187 | 204 | 303 | 312 | 281 | 208 | 215 | 215 | 200 | 207 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,292 | 1,304 | 1,189 | 1,277 | 1,437 | 1,305 | 1,281 | 930 | 1,000 | 1,095 | 910 | 1,008 |
| **CSPP (PURPA)** | 72 | 74 | 88 | 120 | 170 | 221 | 220 | 211 | 192 | 139 | 111 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 8 | 0 | 25 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,140 | 3,153 | 3,051 | 3,167 | 3,370 | 3,291 | 3,270 | 2,904 | 2,982 | 3,000 | 2,792 | 2,861 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 748 | 724 | 877 | 1,092 | 632 | 426 | 0 | 129 | 0 | 825 | 516 | 206 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,453) | (2,498) | (2,227) | (2,130) | (2,819) | (3,356) | (3,773) | (3,205) | (3,072) | (2,236) | (2,329) | (2,714) |
| Existing DSM (EE) | 27 | 26 | 23 | 27 | 31 | 36 | 36 | 33 | 30 | 27 | 24 | 28 |
| Load Forecast (95th% w/DSM and EE) | (2,426) | (2,472) | (2,204) | (2,103) | (2,788) | (3,320) | (3,736) | (3,172) | (3,042) | (2,209) | (2,305) | (2,686) |
| Non-forecasted trended EE | 21 | 20 | 18 | 21 | 25 | 28 | 28 | 26 | 23 | 21 | 19 | 22 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,405) | (2,452) | (2,185) | (2,083) | (2,763) | (2,902) | (3,318) | (2,809) | (3,018) | (2,189) | (2,286) | (2,665) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,083 | 1,098 | 995 | 1,089 | 1,143 | 994 | 1,000 | 722 | 780 | 880 | 712 | 794 |
| Hydro (90th%)—Other | 204 | 209 | 186 | 205 | 305 | 313 | 282 | 208 | 216 | 215 | 196 | 202 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,286 | 1,307 | 1,181 | 1,295 | 1,448 | 1,306 | 1,282 | 930 | 996 | 1,095 | 907 | 997 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,137 | 3,159 | 3,156 | 3,299 | 3,587 | 3,477 | 3,447 | 3,089 | 3,121 | 3,094 | 2,883 | 2,850 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 732 | 706 | 971 | 1,216 | 823 | 575 | 129 | 280 | 102 | 906 | 597 | 186 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,468) | (2,518) | (2,246) | (2,143) | (2,861) | (3,403) | (3,847) | (3,255) | (3,118) | (2,263) | (2,347) | (2,739) |
| Existing DSM (EE) | 35 | 35 | 33 | 34 | 42 | 47 | 54 | 50 | 41 | 35 | 34 | 36 |
| Load Forecast (95th% w/DSM and EE) | (2,433) | (2,483) | (2,213) | (2,109) | (2,820) | (3,356) | (3,793) | (3,205) | (3,076) | (2,228) | (2,313) | (2,703) |
| Non-forecasted trended EE | 32 | 32 | 31 | 31 | 38 | 44 | 50 | 46 | 38 | 32 | 31 | 33 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,401) | (2,451) | (2,182) | (2,078) | (2,781) | (2,922) | (3,353) | (2,822) | (3,038) | (2,196) | (2,282) | (2,670) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,077 | 1,108 | 991 | 1,090 | 1,147 | 992 | 1,000 | 720 | 774 | 878 | 711 | 791 |
| Hydro (90th%)—Other | 204 | 208 | 186 | 205 | 305 | 313 | 281 | 208 | 216 | 216 | 195 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,281 | 1,316 | 1,177 | 1,295 | 1,453 | 1,305 | 1,281 | 928 | 990 | 1,094 | 906 | 991 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,131 | 3,168 | 3,153 | 3,300 | 3,591 | 3,476 | 3,446 | 3,087 | 3,114 | 3,094 | 2,882 | 2,845 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 731 | 716 | 971 | 1,221 | 810 | 554 | 93 | 265 | 77 | 898 | 600 | 175 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,494) | (2,533) | (2,272) | (2,160) | (2,900) | (3,447) | (3,907) | (3,287) | (3,162) | (2,284) | (2,372) | (2,763) |
| Existing DSM (EE) | 38 | 33 | 42 | 34 | 51 | 60 | 61 | 53 | 55 | 38 | 41 | 40 |
| Load Forecast (95th% w/DSM and EE) | (2,456) | (2,500) | (2,231) | (2,127) | (2,849) | (3,387) | (3,847) | (3,234) | (3,108) | (2,246) | (2,332) | (2,723) |
| Non-forecasted trended EE | 41 | 36 | 45 | 36 | 54 | 65 | 65 | 57 | 59 | 41 | 44 | 43 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,415) | (2,464) | (2,186) | (2,090) | (2,795) | (2,932) | (3,391) | (2,841) | (3,049) | (2,205) | (2,288) | (2,681) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,077 | 1,123 | 977 | 1,088 | 1,155 | 996 | 1,000 | 720 | 769 | 880 | 712 | 772 |
| Hydro (90th%)—Other | 203 | 208 | 195 | 204 | 306 | 314 | 281 | 208 | 216 | 217 | 189 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,280 | 1,331 | 1,172 | 1,293 | 1,462 | 1,309 | 1,281 | 928 | 985 | 1,098 | 902 | 961 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,131 | 3,183 | 3,147 | 3,297 | 3,600 | 3,480 | 3,446 | 3,087 | 3,109 | 3,097 | 2,878 | 2,815 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 716 | 718 | 962 | 1,207 | 805 | 548 | 55 | 246 | 60 | 892 | 590 | 134 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,521) | (2,563) | (2,289) | (2,195) | (2,945) | (3,504) | (3,991) | (3,331) | (3,218) | (2,298) | (2,401) | (2,796) |
| Existing DSM (EE) | 42 | 47 | 40 | 50 | 63 | 78 | 86 | 61 | 75 | 34 | 50 | 50 |
| Load Forecast (95th% w/DSM and EE) | (2,479) | (2,515) | (2,249) | (2,145) | (2,882) | (3,426) | (3,905) | (3,270) | (3,143) | (2,264) | (2,351) | (2,747) |
| Non-forecasted trended EE | 40 | 46 | 38 | 48 | 61 | 76 | 83 | 59 | 73 | 33 | 48 | 48 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,439) | (2,470) | (2,210) | (2,097) | (2,821) | (2,961) | (3,432) | (2,874) | (3,071) | (2,231) | (2,303) | (2,699) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 55 | 55 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 758 | 758 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,073 | 1,098 | 977 | 1,084 | 1,152 | 992 | 1,000 | 716 | 760 | 880 | 710 | 771 |
| Hydro (90th%)—Other | 203 | 207 | 194 | 204 | 305 | 312 | 281 | 207 | 214 | 216 | 189 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,276 | 1,305 | 1,171 | 1,288 | 1,457 | 1,304 | 1,281 | 924 | 974 | 1,097 | 899 | 961 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 29 | 70 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,127 | 3,157 | 2,210 | 2,097 | 3,596 | 3,475 | 3,446 | 3,082 | 3,098 | 2,533 | 2,612 | 2,815 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 688 | 687 | 0 | 0 | 774 | 514 | 13 | 208 | 28 | 302 | 309 | 116 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,551) | (2,594) | (2,316) | (2,213) | (2,983) | (3,549) | (4,051) | (3,386) | (3,260) | (2,330) | (2,417) | (2,824) |
| Existing DSM (EE) | 57 | 63 | 53 | 55 | 67 | 79 | 85 | 76 | 78 | 46 | 52 | 57 |
| Load Forecast (95th% w/DSM and EE) | (2,495) | (2,531) | (2,263) | (2,158) | (2,916) | (3,469) | (3,965) | (3,310) | (3,182) | (2,284) | (2,365) | (2,766) |
| Non-forecasted trended EE | 56 | 62 | 52 | 54 | 66 | 78 | 84 | 75 | 77 | 46 | 51 | 56 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,439) | (2,469) | (2,211) | (2,104) | (2,850) | (3,001) | (3,491) | (2,897) | (3,105) | (2,238) | (2,314) | (2,710) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,070 | 1,072 | 968 | 1,083 | 1,149 | 988 | 1,000 | 713 | 748 | 879 | 710 | 770 |
| Hydro (90th%)—Other | 201 | 205 | 194 | 203 | 304 | 311 | 280 | 206 | 213 | 215 | 188 | 189 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,271 | 1,277 | 1,162 | 1,286 | 1,454 | 1,300 | 1,280 | 919 | 961 | 1,094 | 898 | 959 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 94 | 135 | 0 | 0 | 102 | 0 | 75 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,067 | 3,074 | 2,211 | 2,104 | 3,537 | 3,415 | 3,491 | 3,023 | 3,105 | 2,476 | 2,556 | 2,757 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 628 | 605 | 0 | 0 | 687 | 414 | 0 | 125 | 0 | 237 | 242 | 47 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,620) | (2,348) | (2,236) | (3,029) | (3,610) | (4,117) | (3,431) | (3,308) | (2,371) | (2,431) | (2,852) | (2,620) |
| Existing DSM (EE) | 70 | 67 | 64 | 77 | 100 | 91 | 83 | 87 | 64 | 48 | 60 | 70 |
| Load Forecast (95th% w/DSM and EE) | (2,550) | (2,281) | (2,173) | (2,952) | (3,510) | (4,026) | (3,348) | (3,221) | (2,307) | (2,383) | (2,792) | (2,550) |
| Non-forecasted trended EE | 73 | 70 | 66 | 81 | 103 | 94 | 86 | 91 | 67 | 50 | 62 | 73 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,477) | (2,211) | (2,107) | (2,871) | (3,017) | (3,541) | (2,925) | (3,130) | (2,240) | (2,333) | (2,729) | (2,477) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 | 966 |
| **Total Gas** | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,061 | 964 | 1,081 | 1,147 | 986 | 1,000 | 709 | 736 | 879 | 711 | 768 | 1,061 |
| Hydro (90th%)—Other | 204 | 192 | 203 | 304 | 310 | 279 | 205 | 211 | 214 | 187 | 188 | 204 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,265 | 1,156 | 1,283 | 1,450 | 1,296 | 1,279 | 914 | 947 | 1,093 | 898 | 956 | 1,265 |
| **CSPP (PURPA)** | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 | 24 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 | 38 |
| **Market Purchases** | 0 | 100 | 140 | 0 | 0 | 152 | 0 | 113 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,062 | 2,211 | 2,107 | 3,534 | 3,412 | 3,541 | 3,018 | 3,130 | 2,474 | 2,556 | 2,755 | 3,062 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 585 | 0 | 0 | 663 | 395 | 0 | 93 | 0 | 234 | 222 | 25 | 585 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,617) | (2,647) | (2,374) | (2,271) | (3,080) | (3,664) | (4,201) | (3,485) | (3,346) | (2,405) | (2,477) | (2,903) |
| Existing DSM (EE) | 76 | 74 | 71 | 77 | 92 | 112 | 114 | 99 | 85 | 75 | 70 | 82 |
| Load Forecast (95th% w/DSM and EE) | (2,541) | (2,572) | (2,303) | (2,194) | (2,987) | (3,552) | (4,086) | (3,387) | (3,261) | (2,330) | (2,406) | (2,822) |
| Non-forecasted trended EE | 83 | 82 | 78 | 85 | 101 | 123 | 125 | 108 | 93 | 82 | 77 | 90 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,457) | (2,491) | (2,225) | (2,109) | (2,886) | (3,039) | (3,571) | (2,941) | (3,167) | (2,248) | (2,329) | (2,732) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,063 | 1,058 | 961 | 1,079 | 1,144 | 984 | 1,000 | 706 | 724 | 877 | 712 | 766 |
| Hydro (90th%)—Other | 199 | 202 | 191 | 202 | 303 | 309 | 278 | 204 | 210 | 211 | 186 | 187 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,262 | 1,260 | 1,152 | 1,281 | 1,447 | 1,293 | 1,278 | 910 | 934 | 1,088 | 898 | 952 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 119 | 144 | 0 | 0 | 183 | 0 | 163 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,058 | 3,057 | 2,225 | 2,109 | 3,531 | 3,408 | 3,571 | 3,014 | 3,167 | 2,469 | 2,556 | 2,751 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 601 | 566 | 0 | 0 | 645 | 369 | 0 | 72 | 0 | 221 | 226 | 19 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,658) | (2,679) | (2,413) | (2,283) | (3,120) | (3,721) | (4,268) | (3,534) | (3,412) | (2,428) | (2,514) | (2,931) |
| Existing DSM (EE) | 85 | 83 | 85 | 65 | 95 | 121 | 117 | 103 | 107 | 74 | 81 | 79 |
| Load Forecast (95th% w/DSM and EE) | (2,573) | (2,596) | (2,328) | (2,218) | (3,025) | (3,600) | (4,151) | (3,431) | (3,305) | (2,354) | (2,433) | (2,853) |
| Non-forecasted trended EE | 98 | 95 | 97 | 75 | 109 | 139 | 134 | 118 | 122 | 85 | 93 | 90 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,475) | (2,500) | (2,231) | (2,143) | (2,917) | (3,071) | (3,626) | (2,976) | (3,183) | (2,269) | (2,340) | (2,762) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,060 | 1,054 | 958 | 1,077 | 1,141 | 982 | 1,000 | 703 | 716 | 877 | 711 | 767 |
| Hydro (90th%)—Other | 198 | 202 | 191 | 202 | 302 | 308 | 277 | 203 | 208 | 209 | 185 | 186 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,258 | 1,256 | 1,149 | 1,279 | 1,443 | 1,290 | 1,277 | 905 | 924 | 1,086 | 896 | 953 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 127 | 181 | 0 | 0 | 239 | 0 | 189 | 0 | 0 | 11 |
| **Existing Resource Subtotal** | 3,054 | 3,053 | 2,231 | 2,143 | 3,527 | 3,405 | 3,626 | 3,009 | 3,183 | 2,467 | 2,554 | 2,762 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 579 | 552 | 0 | 0 | 610 | 335 | 0 | 33 | 0 | 198 | 214 | 0 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,673) | (2,698) | (2,438) | (2,308) | (3,164) | (3,773) | (4,350) | (3,571) | (3,454) | (2,453) | (2,533) | (2,970) |
| Existing DSM (EE) | 72 | 81 | 89 | 67 | 101 | 124 | 136 | 94 | 105 | 76 | 76 | 90 |
| Load Forecast (95th% w/DSM and EE) | (2,601) | (2,617) | (2,350) | (2,240) | (3,062) | (3,648) | (4,215) | (3,476) | (3,349) | (2,377) | (2,456) | (2,880) |
| Non-forecasted trended EE | 86 | 97 | 106 | 81 | 121 | 149 | 163 | 113 | 126 | 92 | 92 | 108 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,515) | (2,520) | (2,243) | (2,159) | (2,941) | (3,109) | (3,661) | (3,026) | (3,224) | (2,285) | (2,365) | (2,772) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,052 | 1,050 | 956 | 1,075 | 1,133 | 981 | 1,000 | 699 | 708 | 874 | 713 | 765 |
| Hydro (90th%)—Other | 197 | 202 | 190 | 201 | 296 | 302 | 277 | 202 | 207 | 209 | 184 | 185 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,250 | 1,252 | 1,146 | 1,276 | 1,430 | 1,283 | 1,277 | 901 | 914 | 1,082 | 897 | 950 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 142 | 200 | 0 | 0 | 261 | 21 | 240 | 0 | 0 | 24 |
| **Existing Resource Subtotal** | 3,045 | 3,048 | 2,243 | 2,159 | 3,513 | 3,398 | 3,648 | 3,026 | 3,224 | 2,463 | 2,555 | 2,772 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (14) | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 731 | 728 | 200 | 500 | 1,072 | 789 | 486 | 500 | 500 | 378 | 390 | 200 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,723) | (2,734) | (2,444) | (2,348) | (3,203) | (3,830) | (4,425) | (3,623) | (3,522) | (2,461) | (2,571) | (2,995) |
| Existing DSM (EE) | 96 | 97 | 73 | 87 | 103 | 133 | 147 | 103 | 129 | 61 | 93 | 89 |
| Load Forecast (95th% w/DSM and EE) | (2,627) | (2,637) | (2,370) | (2,261) | (3,099) | (3,697) | (4,278) | (3,521) | (3,393) | (2,399) | (2,479) | (2,906) |
| Non-forecasted trended EE | 121 | 122 | 92 | 109 | 130 | 168 | 185 | 129 | 162 | 77 | 117 | 112 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,506) | (2,515) | (2,278) | (2,152) | (2,969) | (3,139) | (3,703) | (3,054) | (3,231) | (2,322) | (2,362) | (2,794) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,047 | 1,047 | 954 | 1,073 | 1,131 | 979 | 1,000 | 696 | 697 | 874 | 713 | 762 |
| Hydro (90th%)—Other | 197 | 201 | 190 | 200 | 293 | 299 | 276 | 201 | 205 | 208 | 183 | 184 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,244 | 1,247 | 1,143 | 1,274 | 1,424 | 1,278 | 1,276 | 897 | 902 | 1,082 | 896 | 947 |
| **CSPP (PURPA)** | 74 | 76 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 181 | 196 | 0 | 10 | 257 | 305 | 302 | 0 | 0 | 301 |
| **Existing Resource Subtotal** | 2,776 | 2,781 | 2,278 | 2,152 | 3,243 | 3,139 | 3,379 | 3,042 | 3,010 | 2,462 | 2,553 | 2,782 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (324) | (13) | (221) | 0 | 0 | (12) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 470 | 466 | 200 | 500 | 774 | 500 | 176 | 487 | 279 | 340 | 391 | 188 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,748) | (2,762) | (2,480) | (2,368) | (3,239) | (3,863) | (4,476) | (3,681) | (3,558) | (2,498) | (2,588) | (3,026) |
| Existing DSM (EE) | 95 | 106 | 89 | 86 | 103 | 119 | 134 | 117 | 121 | 77 | 88 | 94 |
| Load Forecast (95th% w/DSM and EE) | (2,653) | (2,656) | (2,391) | (2,281) | (3,136) | (3,744) | (4,341) | (3,565) | (3,437) | (2,422) | (2,500) | (2,932) |
| Non-forecasted trended EE | 125 | 139 | 118 | 114 | 136 | 157 | 177 | 154 | 160 | 101 | 116 | 124 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,528) | (2,517) | (2,273) | (2,167) | (2,999) | (3,197) | (3,774) | (3,074) | (3,277) | (2,321) | (2,384) | (2,809) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,044 | 1,039 | 949 | 1,071 | 1,128 | 978 | 1,000 | 692 | 687 | 874 | 711 | 761 |
| Hydro (90th%)—Other | 196 | 198 | 190 | 200 | 292 | 298 | 275 | 200 | 204 | 207 | 183 | 183 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,240 | 1,237 | 1,139 | 1,271 | 1,421 | 1,276 | 1,275 | 892 | 890 | 1,080 | 894 | 944 |
| **CSPP (PURPA)** | 73 | 75 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 181 | 214 | 0 | 70 | 254 | 305 | 302 | 0 | 0 | 298 |
| **Existing Resource Subtotal** | 2,771 | 2,770 | 2,273 | 2,167 | 3,240 | 3,197 | 3,375 | 3,037 | 2,998 | 2,461 | 2,551 | 2,777 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (399) | (37) | (279) | 0 | 0 | (32) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 444 | 453 | 200 | 500 | 741 | 500 | 101 | 463 | 221 | 340 | 367 | 168 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,780) | (2,786) | (2,507) | (2,406) | (3,278) | (3,930) | (4,558) | (3,721) | (3,597) | (2,542) | (2,629) | (3,059) |
| Existing DSM (EE) | 100 | 111 | 95 | 103 | 106 | 138 | 153 | 112 | 116 | 98 | 106 | 100 |
| Load Forecast (95th% w/DSM and EE) | (2,680) | (2,675) | (2,412) | (2,303) | (3,172) | (3,792) | (4,404) | (3,609) | (3,481) | (2,444) | (2,523) | (2,960) |
| Non-forecasted trended EE | 139 | 154 | 132 | 142 | 148 | 192 | 212 | 155 | 161 | 136 | 147 | 138 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,541) | (2,521) | (2,281) | (2,161) | (3,025) | (3,210) | (3,802) | (3,117) | (3,320) | (2,308) | (2,377) | (2,821) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,040 | 1,041 | 945 | 1,070 | 1,126 | 976 | 1,000 | 689 | 673 | 872 | 713 | 756 |
| Hydro (90th%)—Other | 195 | 197 | 189 | 199 | 292 | 297 | 275 | 199 | 202 | 206 | 181 | 182 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,236 | 1,238 | 1,134 | 1,269 | 1,418 | 1,274 | 1,275 | 888 | 875 | 1,078 | 895 | 938 |
| **CSPP (PURPA)** | 73 | 75 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 198 | 214 | 0 | 90 | 249 | 305 | 302 | 0 | 0 | 295 |
| **Existing Resource Subtotal** | 2,762 | 2,766 | 2,281 | 2,161 | 3,233 | 3,210 | 3,364 | 3,028 | 2,977 | 2,453 | 2,547 | 2,762 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (438) | (88) | (343) | 0 | 0 | (59) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 421 | 445 | 200 | 500 | 708 | 500 | 62 | 412 | 157 | 345 | 370 | 141 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,823) | (2,808) | (2,544) | (2,426) | (3,328) | (3,988) | (4,631) | (3,814) | (3,643) | (2,572) | (2,657) | (3,105) |
| Existing DSM (EE) | 115 | 111 | 110 | 102 | 118 | 146 | 162 | 159 | 117 | 104 | 111 | 120 |
| Load Forecast (95th% w/DSM and EE) | (2,708) | (2,697) | (2,434) | (2,325) | (3,210) | (3,842) | (4,469) | (3,655) | (3,527) | (2,468) | (2,546) | (2,985) |
| Non-forecasted trended EE | 167 | 161 | 160 | 148 | 171 | 212 | 235 | 230 | 169 | 151 | 160 | 174 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,541) | (2,535) | (2,274) | (2,177) | (3,039) | (3,240) | (3,844) | (3,088) | (3,357) | (2,316) | (2,386) | (2,811) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,037 | 1,037 | 941 | 1,068 | 1,124 | 975 | 1,000 | 686 | 663 | 872 | 712 | 752 |
| Hydro (90th%)—Other | 195 | 196 | 189 | 199 | 288 | 292 | 274 | 198 | 200 | 205 | 180 | 180 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,232 | 1,233 | 1,130 | 1,267 | 1,411 | 1,267 | 1,274 | 884 | 863 | 1,077 | 892 | 933 |
| **CSPP (PURPA)** | 71 | 73 | 200 | 231 | 371 | 402 | 401 | 392 | 355 | 229 | 201 | 73 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 197 | 235 | 0 | 130 | 245 | 305 | 302 | 0 | 0 | 293 |
| **Existing Resource Subtotal** | 2,757 | 2,759 | 2,274 | 2,177 | 3,223 | 3,240 | 3,357 | 3,021 | 2,962 | 2,450 | 2,542 | 2,753 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (487) | (66) | (395) | 0 | 0 | (58) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 416 | 424 | 200 | 500 | 684 | 500 | 13 | 434 | 105 | 334 | 356 | 142 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,838) | (2,809) | (2,575) | (2,432) | (3,366) | (4,045) | (4,677) | (3,829) | (3,711) | (2,589) | (2,682) | (3,121) |
| Existing DSM (EE) | 106 | 94 | 122 | 88 | 120 | 157 | 146 | 131 | 142 | 99 | 115 | 112 |
| Load Forecast (95th% w/DSM and EE) | (2,732) | (2,715) | (2,453) | (2,344) | (3,246) | (3,888) | (4,531) | (3,698) | (3,569) | (2,489) | (2,567) | (3,009) |
| Non-forecasted trended EE | 154 | 136 | 177 | 128 | 174 | 228 | 211 | 190 | 206 | 144 | 167 | 162 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,578) | (2,579) | (2,276) | (2,216) | (3,071) | (3,270) | (3,930) | (3,171) | (3,363) | (2,346) | (2,400) | (2,847) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,035 | 1,034 | 938 | 1,066 | 1,121 | 973 | 1,000 | 682 | 652 | 873 | 712 | 752 |
| Hydro (90th%)—Other | 194 | 194 | 188 | 198 | 288 | 292 | 273 | 197 | 199 | 204 | 180 | 180 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,229 | 1,228 | 1,126 | 1,264 | 1,409 | 1,265 | 1,273 | 879 | 851 | 1,077 | 892 | 931 |
| **CSPP (PURPA)** | 71 | 73 | 200 | 231 | 371 | 401 | 400 | 390 | 353 | 227 | 199 | 72 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 204 | 277 | 0 | 163 | 242 | 305 | 302 | 0 | 161 | 291 |
| **Existing Resource Subtotal** | 2,754 | 2,753 | 2,276 | 2,216 | 3,221 | 3,270 | 3,352 | 3,015 | 2,949 | 2,448 | 2,400 | 2,748 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (579) | (156) | (414) | 0 | 0 | (99) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 520 | 580 | 580 | 580 | 520 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 375 | 374 | 200 | 500 | 669 | 580 | 1 | 424 | 106 | 302 | 200 | 101 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,852) | (2,842) | (2,592) | (2,448) | (3,407) | (4,091) | (4,764) | (3,855) | (3,744) | (2,614) | (2,691) | (3,150) |
| Existing DSM (EE) | 101 | 112 | 123 | 89 | 127 | 160 | 172 | 118 | 135 | 104 | 108 | 119 |
| Load Forecast (95th% w/DSM and EE) | (2,751) | (2,730) | (2,469) | (2,359) | (3,280) | (3,931) | (4,592) | (3,737) | (3,608) | (2,509) | (2,584) | (3,031) |
| Non-forecasted trended EE | 145 | 162 | 178 | 129 | 184 | 232 | 250 | 170 | 196 | 151 | 156 | 172 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,606) | (2,569) | (2,292) | (2,230) | (3,095) | (3,309) | (3,952) | (3,230) | (3,412) | (2,358) | (2,428) | (2,859) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,034 | 1,029 | 935 | 1,064 | 1,119 | 972 | 1,000 | 679 | 641 | 869 | 714 | 749 |
| Hydro (90th%)—Other | 193 | 193 | 187 | 197 | 287 | 291 | 272 | 196 | 197 | 202 | 179 | 178 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,226 | 1,222 | 1,122 | 1,262 | 1,406 | 1,262 | 1,272 | 876 | 839 | 1,071 | 893 | 926 |
| **CSPP (PURPA)** | 66 | 63 | 190 | 221 | 360 | 391 | 390 | 381 | 344 | 218 | 189 | 61 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 233 | 304 | 0 | 214 | 238 | 303 | 302 | 0 | 198 | 289 |
| **Existing Resource Subtotal** | 2,746 | 2,737 | 2,292 | 2,230 | 3,207 | 3,309 | 3,338 | 3,000 | 2,927 | 2,433 | 2,428 | 2,730 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (615) | (230) | (485) | 0 | 0 | (129) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 640 | 668 | 500 | 800 | 932 | 880 | 265 | 650 | 335 | 575 | 500 | 371 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,902) | (2,877) | (2,599) | (2,481) | (3,438) | (4,114) | (4,818) | (3,916) | (3,798) | (2,625) | (2,715) | (3,172) |
| Existing DSM (EE) | 130 | 132 | 113 | 106 | 125 | 141 | 167 | 140 | 151 | 97 | 114 | 119 |
| Load Forecast (95th% w/DSM and EE) | (2,772) | (2,745) | (2,486) | (2,375) | (3,313) | (3,972) | (4,651) | (3,776) | (3,647) | (2,529) | (2,601) | (3,054) |
| Non-forecasted trended EE | 188 | 191 | 164 | 153 | 181 | 205 | 241 | 203 | 218 | 140 | 165 | 171 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,584) | (2,554) | (2,322) | (2,223) | (3,132) | (3,377) | (4,020) | (3,236) | (3,429) | (2,389) | (2,437) | (2,882) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,032 | 1,025 | 932 | 1,063 | 1,118 | 971 | 1,000 | 676 | 630 | 869 | 714 | 746 |
| Hydro (90th%)—Other | 192 | 192 | 187 | 196 | 285 | 289 | 272 | 195 | 196 | 201 | 178 | 176 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,224 | 1,218 | 1,119 | 1,259 | 1,403 | 1,259 | 1,272 | 871 | 826 | 1,070 | 892 | 922 |
| **CSPP (PURPA)** | 59 | 60 | 187 | 219 | 359 | 390 | 389 | 380 | 343 | 216 | 188 | 61 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 269 | 301 | 0 | 287 | 234 | 299 | 302 | 0 | 208 | 287 |
| **Existing Resource Subtotal** | 2,736 | 2,730 | 2,322 | 2,223 | 3,203 | 3,377 | 3,331 | 2,990 | 2,914 | 2,431 | 2,437 | 2,724 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (689) | (245) | (515) | 0 | 0 | (158) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 652 | 677 | 500 | 800 | 890 | 880 | 191 | 635 | 305 | 542 | 500 | 342 |

# Peak-Hour Load and Resource Balance (continued)

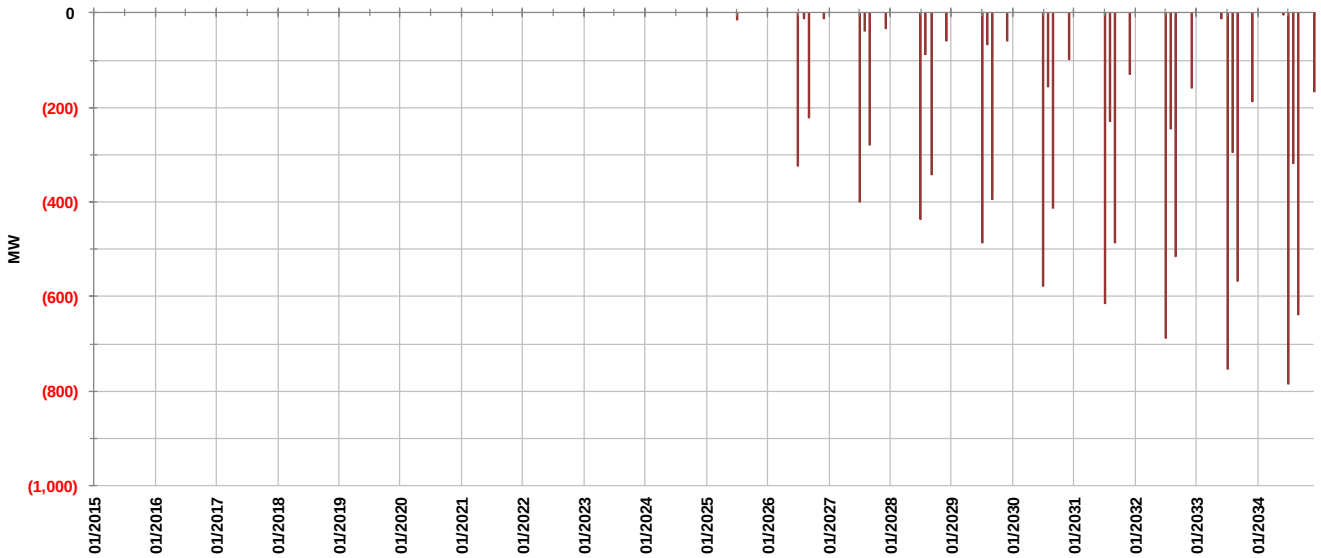
| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,920) | (2,903) | (2,622) | (2,502) | (3,478) | (4,163) | (4,886) | (3,962) | (3,845) | (2,650) | (2,739) | (3,200) |
| Existing DSM (EE) | 126 | 141 | 118 | 109 | 129 | 146 | 173 | 145 | 157 | 101 | 119 | 123 |
| Load Forecast (95th% w/DSM and EE) | (2,794) | (2,763) | (2,504) | (2,393) | (3,348) | (4,017) | (4,713) | (3,817) | (3,688) | (2,549) | (2,620) | (3,077) |
| Non-forecasted trended EE | 183 | 204 | 171 | 158 | 187 | 212 | 251 | 210 | 228 | 146 | 172 | 179 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,611) | (2,559) | (2,332) | (2,235) | (3,161) | (3,415) | (4,071) | (3,270) | (3,461) | (2,404) | (2,448) | (2,899) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,030 | 1,004 | 929 | 1,061 | 1,116 | 969 | 1,000 | 673 | 620 | 870 | 712 | 745 |
| Hydro (90th%)—Other | 191 | 191 | 186 | 196 | 282 | 285 | 271 | 194 | 195 | 200 | 177 | 175 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,221 | 1,195 | 1,115 | 1,257 | 1,398 | 1,254 | 1,271 | 867 | 814 | 1,070 | 889 | 921 |
| **CSPP (PURPA)** | 50 | 52 | 178 | 210 | 350 | 381 | 380 | 371 | 334 | 208 | 179 | 52 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 292 | 324 | 0 | 328 | 230 | 296 | 302 | 0 | 231 | 285 |
| **Existing Resource Subtotal** | 2,724 | 2,699 | 2,332 | 2,235 | 3,189 | 3,404 | 3,318 | 2,974 | 2,893 | 2,422 | 2,448 | 2,712 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (11) | (754) | (296) | (568) | 0 | 0 | (187) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 613 | 640 | 500 | 800 | 848 | 869 | 126 | 584 | 252 | 518 | 500 | 313 |

# Peak-Hour Load and Resource Balance (continued)

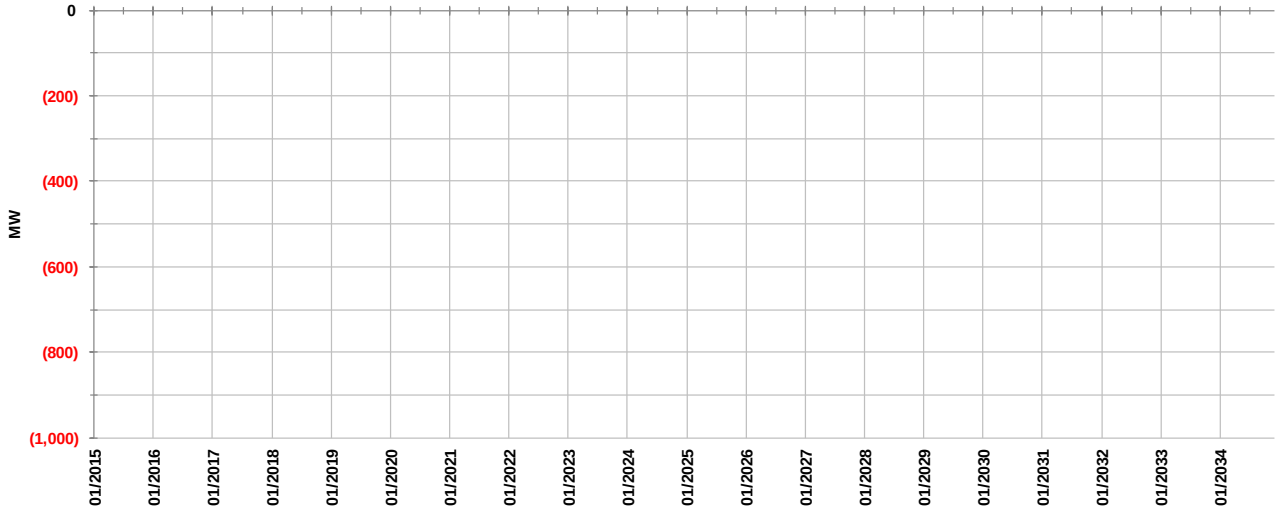
| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,955) | (2,917) | (2,652) | (2,539) | (3,531) | (4,241) | (4,966) | (4,017) | (3,870) | (2,698) | (2,768) | (3,256) |
| Existing DSM (EE) | 141 | 139 | 132 | 130 | 149 | 181 | 193 | 160 | 142 | 129 | 131 | 156 |
| Load Forecast (95th% w/DSM and EE) | (2,815) | (2,778) | (2,520) | (2,409) | (3,382) | (4,060) | (4,773) | (3,857) | (3,728) | (2,569) | (2,638) | (3,100) |
| Non-forecasted trended EE | 204 | 202 | 192 | 189 | 217 | 264 | 280 | 232 | 206 | 188 | 190 | 226 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,610) | (2,576) | (2,328) | (2,220) | (3,166) | (3,406) | (4,103) | (3,287) | (3,522) | (2,381) | (2,448) | (2,873) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,028 | 992 | 926 | 1,059 | 1,114 | 968 | 1,000 | 669 | 612 | 868 | 712 | 743 |
| Hydro (90th%)—Other | 190 | 190 | 186 | 195 | 278 | 283 | 270 | 193 | 194 | 200 | 176 | 174 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,219 | 1,181 | 1,112 | 1,254 | 1,392 | 1,251 | 1,270 | 862 | 806 | 1,068 | 888 | 917 |
| **CSPP (PURPA)** | 50 | 52 | 178 | 210 | 350 | 381 | 380 | 371 | 334 | 208 | 179 | 52 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 291 | 313 | 0 | 328 | 230 | 296 | 302 | 0 | 232 | 285 |
| **Existing Resource Subtotal** | 2,721 | 2,685 | 2,328 | 2,220 | 3,183 | 3,401 | 3,317 | 2,970 | 2,884 | 2,420 | 2,448 | 2,708 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (5) | (786) | (318) | (638) | 0 | 0 | (165) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 611 | 609 | 500 | 800 | 837 | 875 | 94 | 562 | 182 | 538 | 500 | 335 |

# Peak-Hour Surplus/Deficit Charts

**Peak-hour monthly deficits with existing DSM and existing resources**




**Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources**



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

For the 2015 IRP, non-energy related benefits (NEB) were included in the cost-effectiveness analysis of the program forecasts. NEB include savings from the customer's perspective, including water savings, deferred maintenance and operational costs, health and safety benefits, avoided supplemental fuels, and other quantifiable benefits apart from avoided energy production. NEB were applied to the energy efficiency forecast at the sector level based on cost-effectiveness analysis of the 2014 portfolio of programs. For a complete list of NEB and sources that Idaho Power currently uses for its program cost-effectiveness, see *Demand-Side Management 2014 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) *Understanding Cost-Effectiveness of Energy Efficiency Programs,* and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

## Resource Development and Evaluation

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program

parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Sometimes Idaho Power launches pilot programs or limited-scale programs; to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant verifies the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations. Recent evaluations from the 2014 program year can be reviewed in the *Demand-Side Management 2014 Annual Report* and its *Supplement 2: Evaluations*, (idahopower.com/EnergyEfficiency/reports.cfm).

## Planning Assumptions and Alternate Costs

The financial assumptions used in the analysis for the 2015 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. Table DSM-1 lists the financial assumptions The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

The prices of avoided energy throughout the 20-year planning period were simulated using 2015 IRP Portfolio 6b. Portfolio 6b was run assuming 111d sensitivity #5 within the AURORA model. The AURORA model is a production cost tool that simulates hourly economic dispatch and commitment of supply-side, demand-side, and transmission resources. Idaho Power's setup of the AURORA model forecasts electric market prices throughout the Western Electricity Coordinating Council (WECC) region. AURORA also forecasts marginal electricity costs for Idaho Power. Marginal electricity costs are set by the highest variable cost resource that is dispatched in any given forecasted hour. Variable costs include variable O&M and variable fuel costs. Idaho Power modeled hourly, marginal electricity costs for the years 2015 through 2034 to estimate the potential system benefit of avoiding production of the next unit of energy. An initial run of marginal costs are run during the preliminary analysis phase of the IRP process. The preliminary runs will combine updated planning assumptions including load and natural gas price forecasts run against the current preferred resource portfolio from the previous IRP. After the selection of the preferred portfolio which for the 2015 IRP is portfolio 6b, a final run of marginal prices are run which become the avoided energy prices for DSM energy valuation until the next IRP cycle.

The forward prices are placed into five homogenous pricing categories for the convenience of cost-effectiveness calculation the categories follow the pattern of heavy and light load pricing throughout each year of the planning period. The resulting categories include the following:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods when valuing energy efficiency. The estimated levelized capacity cost of a new SCCT is approximately $119 per kW over a 30-year period. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 hours depending on the year. When the levelized capacity cost of a new SCCT ($119/kW) is multiplied by the Effective Load Carry Capacity (ELCC) of 89 percent which is the estimated percent of top 100 peak load hours that demand response can cover, the annual avoided capacity cost is $106/kW. For demand response or direct load control DSM programs $106 per kW becomes the cost threshold for program cost-effectiveness on an annual per kW basis.

Annual benefits for demand response are also established as part of the IRP process once the value of the 170 MW SCCT is determined. The method for determining cost-effectiveness for demand response programs was updated in 2014 as part of a series of public workshop supporting IPUC Case No. IP-E-13-14 resulting in orders from both the IPUPC (No. 32980) and Oregon (No.13-482). The orders established that through the IRP process IPC will establish an annual operating cost ceiling tied to the levelized annual benefit of a 170-MW SCCT. The updated established annual value for the 2015 IRP is $18.5 million which is an increase from 16.7 million from the 2013 IRP. While the intent of the benefit calculation provides guidance for annual cost limit to operating demand response in years with no anticipated peak deficits, actual 2014 operating costs of demand response programs were considerable less at 10.6 million.

## Forecast and Cost-Effectiveness Data

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 2.2 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 lists the 20-year cumulative forecasted impact of average energy (aMW) and on-peak reduction (MW) by customer class.

Table DSM-7 details the 20-year estimated utility or program administrator costs to support the achievable potential forecast by customer class.

Table DSM-8 details the 20-year estimated TRC that accounts for both program administration costs and incremental costs to acquire efficient measures and equipments by customers listed by customer class.

Table DSM-9 outlines the 20-year flow of total benefits attributed to energy efficiency programs including NEB associated with the forecast.

Table DSM-10 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided 30-Year Levelized Capacity Costs** | |
| SCCT | $119/kW |
| **Financial Assumptions** | |
| Weighted average cost of capital (2014 year ending after tax) | 6.74% |
| Financial escalation factor | 2.20% |
| **Transmission Losses** | |
| Non-summer secondary losses | 9.60% |
| Summer peak loss | 9.70% |

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak* (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2015 | $62.94 | $44.84 | $39.58 | $31.67 | $25.98 |
| 2016 | $59.05 | $40.44 | $31.86 | $33.75 | $27.20 |
| 2017 | $59.90 | $39.64 | $29.55 | $35.44 | $28.21 |
| 2018 | $65.19 | $43.78 | $31.37 | $38.82 | $30.39 |
| 2019 | $69.96 | $43.83 | $32.20 | $38.74 | $30.94 |
| 2020 | $72.48 | $42.68 | $36.40 | $38.06 | $30.90 |
| 2021 | $75.10 | $47.16 | $39.39 | $41.11 | $33.13 |
| 2022 | $77.01 | $49.12 | $41.30 | $43.02 | $34.72 |
| 2023 | $80.16 | $51.53 | $46.42 | $44.43 | $36.23 |
| 2024 | $82.91 | $53.18 | $46.25 | $46.27 | $38.89 |
| 2025 | $85.45 | $48.50 | $40.63 | $47.50 | $40.33 |
| 2026 | $85.22 | $51.66 | $42.84 | $48.75 | $42.18 |
| 2027 | $86.54 | $53.57 | $44.94 | $49.64 | $43.66 |
| 2028 | $89.52 | $55.95 | $46.56 | $51.45 | $45.72 |
| 2029 | $93.32 | $59.08 | $49.66 | $53.69 | $48.05 |
| 2030 | $98.68 | $64.01 | $53.60 | $56.72 | $51.40 |
| 2031 | $103.53 | $64.37 | $56.15 | $58.55 | $53.88 |
| 2032 | $106.22 | $66.04 | $58.74 | $61.52 | $56.57 |
| 2033 | $110.98 | $71.21 | $63.23 | $64.96 | $60.09 |
| 2034 | $119.66 | $78.44 | $67.91 | $68.39 | $62.98 |

* Estimated average annual variable operations and management costs of a 170 MW capacity SCCT.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. Cumulative existing energy efficiency forecast 2015–2034**
*(aMW w/transmission losses)*

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | 3 | 8 | 1 | 12 |
| 2016 | 8 | 17 | 3 | 27 |
| 2017 | 14 | 26 | 4 | 45 |
| 2018 | 21 | 35 | 9 | 65 |
| 2019 | 28 | 46 | 11 | 84 |
| 2020 | 33 | 55 | 13 | 101 |
| 2021 | 38 | 64 | 15 | 117 |
| 2022 | 43 | 74 | 17 | 134 |
| 2023 | 49 | 83 | 19 | 152 |
| 2024 | 55 | 93 | 22 | 169 |
| 2025 | 61 | 102 | 22 | 185 |
| 2026 | 67 | 111 | 22 | 200 |
| 2027 | 73 | 120 | 22 | 215 |
| 2028 | 79 | 129 | 22 | 231 |
| 2029 | 85 | 138 | 23 | 246 |
| 2030 | 91 | 144 | 23 | 257 |
| 2031 | 96 | 150 | 23 | 269 |
| 2032 | 101 | 156 | 23 | 280 |
| 2033 | 106 | 161 | 23 | 290 |
| 2034 | 111 | 167 | 23 | 301 |

**Table DSM-6. Cumulative Energy Efficiency On-Peak Forecast 2015–2034**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | 3 | 13 | 4 | 21 |
| 2016 | 9 | 18 | 8 | 35 |
| 2017 | 16 | 36 | 13 | 65 |
| 2018 | 22 | 56 | 25 | 103 |
| 2019 | 17 | 75 | 34 | 126 |
| 2020 | 41 | 87 | 41 | 168 |
| 2021 | 54 | 66 | 49 | 169 |
| 2022 | 55 | 79 | 51 | 185 |
| 2023 | 66 | 114 | 60 | 240 |
| 2024 | 34 | 149 | 69 | 252 |
| 2025 | 67 | 160 | 71 | 299 |
| 2026 | 93 | 170 | 70 | 333 |
| 2027 | 118 | 121 | 73 | 311 |
| 2028 | 107 | 187 | 71 | 366 |
| 2029 | 120 | 209 | 68 | 397 |
| 2030 | 58 | 227 | 72 | 357 |
| 2031 | 114 | 233 | 75 | 422 |
| 2032 | 176 | 156 | 75 | 408 |
| 2033 | 187 | 162 | 76 | 425 |
| 2034 | 175 | 226 | 72 | 473 |

**Table DSM-7. Energy Efficiency Total Utility (Program Administrator) Costs 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $7,055 | $9,469 | $1,467 | $17,991 |
| 2016 | $9,976 | $10,289 | $1,509 | $21,773 |
| 2017 | $12,738 | $11,386 | $1,529 | $25,653 |
| 2018 | $13,667 | $11,539 | $4,878 | $30,085 |
| 2019 | $14,999 | $13,288 | $2,501 | $30,787 |
| 2020 | $13,339 | $12,356 | $2,527 | $28,221 |
| 2021 | $14,535 | $12,302 | $2,576 | $29,413 |
| 2022 | $16,012 | $12,806 | $2,700 | $31,518 |
| 2023 | $17,772 | $13,611 | $2,813 | $34,197 |
| 2024 | $18,220 | $13,886 | $2,902 | $35,009 |
| 2025 | $18,358 | $12,850 | $229 | $31,438 |
| 2026 | $18,771 | $13,405 | $232 | $32,408 |
| 2027 | $19,463 | $13,776 | $267 | $33,506 |
| 2028 | $20,865 | $14,197 | $260 | $35,322 |
| 2029 | $20,510 | $14,352 | $252 | $35,114 |
| 2030 | $18,994 | $9,813 | $228 | $29,035 |
| 2031 | $18,935 | $9,602 | $266 | $28,803 |
| 2032 | $18,928 | $9,742 | $264 | $28,934 |
| 2033 | $18,862 | $9,550 | $272 | $28,684 |
| 2034 | $18,719 | $10,081 | $197 | $28,998 |
| **20-Year NPV** | **$165,579** | **$128,817** | **$18,449** | **$312,845** |

**Table DSM-8. Energy Efficiency Total Resource Costs 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $16,326 | $18,669 | $11,067 | $46,061 |
| 2016 | $29,583 | $20,286 | $11,385 | $61,254 |
| 2017 | $38,737 | $22,450 | $11,533 | $72,720 |
| 2018 | $42,651 | $22,751 | $36,805 | $102,207 |
| 2019 | $42,679 | $26,199 | $18,868 | $87,746 |
| 2020 | $30,400 | $24,361 | $19,067 | $73,829 |
| 2021 | $34,094 | $24,255 | $19,435 | $77,784 |
| 2022 | $38,590 | $25,249 | $20,369 | $84,208 |
| 2023 | $42,024 | $26,837 | $21,228 | $90,089 |
| 2024 | $42,358 | $27,379 | $21,898 | $91,635 |
| 2025 | $47,611 | $25,336 | $1,731 | $74,678 |
| 2026 | $46,892 | $26,430 | $1,752 | $75,074 |
| 2027 | $48,215 | $27,161 | $2,016 | $77,391 |
| 2028 | $52,314 | $27,992 | $1,958 | $82,264 |
| 2029 | $50,857 | $28,297 | $1,900 | $81,054 |
| 2030 | $46,970 | $19,348 | $1,722 | $68,040 |
| 2031 | $47,774 | $18,931 | $2,009 | $68,714 |
| 2032 | $46,959 | $19,208 | $1,994 | $68,161 |
| 2033 | $47,981 | $18,830 | $2,051 | $68,862 |
| 2034 | $44,098 | $19,877 | $1,486 | $65,461 |
| **20-Year NPV** | **$425,360** | **$253,982** | **$139,206** | **$818,548** |

**Table DSM-9. Total Energy Efficiency Benefits 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $21,699 | $36,952 | $14,660 | $73,310 |
| 2016 | $38,766 | $38,720 | $14,574 | $92,061 |
| 2017 | $49,147 | $41,059 | $14,219 | $104,426 |
| 2018 | $52,146 | $52,256 | $43,698 | $148,101 |
| 2019 | $49,827 | $47,230 | $21,487 | $118,544 |
| 2020 | $33,160 | $42,650 | $20,917 | $96,727 |
| 2021 | $35,039 | $40,544 | $20,306 | $95,888 |
| 2022 | $37,416 | $40,278 | $20,249 | $97,943 |
| 2023 | $38,390 | $40,571 | $20,011 | $98,971 |
| 2024 | $36,462 | $39,329 | $19,573 | $95,364 |
| 2025 | $38,695 | $27,735 | $1,465 | $67,895 |
| 2026 | $35,732 | $27,415 | $1,403 | $64,550 |
| 2027 | $34,540 | $26,725 | $1,526 | $62,790 |
| 2028 | $35,273 | $26,015 | $1,401 | $62,690 |
| 2029 | $32,236 | $24,768 | $1,283 | $58,287 |
| 2030 | $27,963 | $15,185 | $1,097 | $44,244 |
| 2031 | $26,665 | $13,946 | $1,204 | $41,814 |
| 2032 | $24,523 | $13,256 | $1,121 | $38,901 |
| 2033 | $23,395 | $12,098 | $1,081 | $36,574 |
| 2034 | $20,077 | $11,902 | $734 | $32,712 |
| **20-Year NPV** | **$691,151** | **$618,633** | **$222,009** | **$1,531,793** |

**Table DSM-10. Total energy efficiency cost-effectiveness summary**

| | 2034 Load Reduction (aMW) | Utility Costs ($000s) (20-Year NPV) | Resource Costs ($000s) (20-Year NPV) | Total Benefits ($000s) (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs (cents/kWh) |
|---|---|---|---|---|---|---|
| Residential | 111 | $165,579 | $425,360 | $691,151 | 1.6 | 9.8 |
| Industrial/Commercial/ Special Contract | 167 | $128,817 | $253,982 | $618,633 | 2.4 | 3.3 |
| Irrigation | 23 | $18,449 | $139,206 | $222,009 | 1.6 | 10.3 |
| **Total** | **301** | **$312,845** | **$818,548** | **$1,531,793** | **1.9** | **6.1** |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.04% |
| Preferred | 0.00% |
| Common | 49.96% |
| **Total** | **100.00%** |
| **Cost** | |
| Debt | 5.73% |
| Preferred | 0.00% |
| Common | 10.00% |
| Average Weighted Cost | 7.86% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | Expected Life of the Asset |
| Discount rate (weighted average cost of capital[1]) | 6.74% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 2.20% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.75% |

[1] Incorporates tax effects.

| Emission Intensity Rate (lbs per MWh by technology) | |
|---|---|
| | $CO_2$ |
| Small aeroderivative SCCT | 1,115 |
| Large aeroderivative SCCT | 1,047 |
| Large frame SCCT | 1,413 |
| CCCT 1x1 | 809 |
| CCCT 2x1 | 809 |
| Combined heat and power (CHP) | 1,115 |
| Distributed generation–gas fired | 1,115 |
| Pulverized coal | 1,901 |
| IGCC | 2,279 |
| IGCC w/carbon sequestration | 421 |

| Fuel Forecast Base Case (Nominal, $ per MMBtu) | | | |
|---|---|---|---|
| **Year** | **Natural Gas** | **Generic Coal** | **Nuclear** |
| 2015 | $5.10 | $1.47 | $0.51 |
| 2016 | $4.70 | $1.52 | $0.52 |
| 2017 | $4.76 | $1.55 | $0.53 |
| 2018 | $5.25 | $1.58 | $0.54 |
| 2019 | $5.69 | $1.61 | $0.56 |
| 2020 | $5.91 | $1.64 | $0.57 |
| 2021 | $6.14 | $1.69 | $0.58 |
| 2022 | $6.30 | $1.74 | $0.59 |
| 2023 | $6.58 | $1.78 | $0.61 |
| 2024 | $6.82 | $1.83 | $0.62 |
| 2025 | $7.04 | $1.87 | $0.63 |
| 2026 | $6.99 | $1.91 | $0.65 |
| 2027 | $7.09 | $1.98 | $0.66 |
| 2028 | $7.35 | $2.00 | $0.68 |
| 2029 | $7.69 | $2.07 | $0.69 |
| 2030 | $8.18 | $2.12 | $0.71 |
| 2031 | $8.62 | $2.16 | $0.72 |
| 2032 | $8.85 | $2.21 | $0.74 |
| 2033 | $9.28 | $2.27 | $0.75 |
| 2034 | $10.09 | $2.32 | $0.77 |
| 2035 | $10.15 | $2.34 | $0.79 |
| 2036 | $10.21 | $2.35 | $0.81 |
| 2037 | $10.27 | $2.37 | $0.82 |
| 2038 | $10.33 | $2.38 | $0.83 |
| 2039 | $10.39 | $2.39 | $0.83 |
| 2040 | $10.46 | $2.41 | $0.84 |
| 2041 | $10.52 | $2.42 | $0.84 |
| 2042 | $10.58 | $2.44 | $0.85 |
| 2043 | $10.65 | $2.45 | $0.85 |
| 2044 | $10.71 | $2.47 | $0.86 |

# Cost Inputs and Operating Assumptions

(All costs in 2015 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Transmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Variable O&M $/kW | Other $/MWh | Heat Rate Btu/kWh | Economic Life |
|---|---|---|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | 1,100 | 4,350 | 441 | $4,791 | $7,266 | 95 | 0 | 0 | 10,450 | 40 |
| Battery Storage (6 MW) | 6 | 3,000 | 0 | $3,000 | $3,059 | 28 | 0 | 0 | NA | 10 |
| Biomass Direct—Woody Residue (35 MW) | 35 | 2,622 | 357 | $2,979 | $3,189 | 95 | 15 | 0 | 14,500 | 30 |
| Biomass Indirect—Anaerobic Digester (3 MW) | 3 | 4,761 | 133 | $4,894 | $5,239 | 43 | 14 | 0 | 10,250 | 25 |
| Boardman to Hemingway (350 MW) | 350 | 0 | 703 | $703 | $703 | 0 | 0 | 0 | NA | 55 |
| Canal Drop Hydro (1.28 MW) | 1 | 3,600 | 70 | $3,670 | $4,371 | 20 | 0 | 0 | NA | 75 |
| CCCT (1x1) F Class with Duct Firing (270 MW) | 270 | 1,145 | 122 | $1,267 | $1,484 | 8 | 2 | 0 | 6,714 | 30 |
| CCCT (2x1) F Class (580 MW) | 580 | 899 | 101 | $1,000 | $1,172 | 6 | 4 | 0 | 6,700 | 30 |
| CHP (45 MW) | 45 | 2,123 | 57 | $2,180 | $2,334 | 47 | 5 | 0 | 6,060 | 40 |
| IGCC (580 MW) | 580 | 3,257 | 745 | $4,002 | $4,773 | 62 | 7 | 0 | 8,800 | 35 |
| IGCC with Carbon Capture (580 MW) | 580 | 6,390 | 744 | $7,134 | $8,510 | 73 | 9 | 0 | 10,520 | 35 |
| Geothermal (30 MW) | 30 | 4,021 | 850 | $4,871 | $5,402 | 0 | 30 | 0 | NA | 25 |
| ICE Thermal Storage (10 MW) | 10 | 1,500 | 0 | $1,500 | $1,529 | 30 | 0 | 0 | NA | 20 |
| Pumped Storage (150 MW) | 150 | 5,000 | 1,095 | $6,095 | $7,259 | 20 | 0 | 0 | NA | 50 |
| Reciprocating Gas Engine (18.8 MW) | 19 | 500 | 73 | $573 | $610 | 2 | 4 | 0 | 7,329 | 40 |
| SCCT—Aeroderivative (47 MW) | 47 | 1,000 | 46 | $1,046 | $1,114 | 25 | 8 | 0 | 9,000 | 35 |
| SCCT—Frame F Class (170 MW) | 170 | 800 | 194 | $994 | $1,059 | 5 | 5 | 0 | 10,300 | 35 |
| Shoshone Falls Upgrade (49.5 MW) | 50 | 2,255 | 269 | $2,524 | $2,825 | 2 | 0 | 0 | NA | 75 |
| Small Modular Nuclear (250 MW) | 600 | 5,000 | 520 | $5,520 | $8,371 | 0 | 23 | 0 | 11,493 | 40 |
| Solar Power Tower (110 MW) | 110 | 6,250 | 330 | $6,580 | $7,710 | 82 | 3 | 6 | NA | 20 |
| Solar PV—Distr Residential Fixed S (10 MW) | 10 | 3,500 | 0 | $3,500 | $3,639 | 25 | 0 | 6 | NA | 20 |
| Solar PV—Distr C&I Fixed S (10 MW) | 10 | 2,500 | 0 | $2,500 | $2,599 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Distr C&I Fixed SW (10 MW) | 10 | 2,500 | 0 | $2,500 | $2,599 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale Fixed S (10 MW) | 10 | 1,500 | 305 | $1,805 | $1,877 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale Fixed SW (10 MW) | 10 | 1,500 | 305 | $1,805 | $1,877 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | 10 | 1,750 | 305 | $2,055 | $2,136 | 20 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | 10 | 1,860 | 305 | $2,165 | $2,251 | 24 | 0 | 6 | NA | 20 |
| TurboPhase (23.6 MW) | 24 | 400 | 0 | $400 | $403 | 0 | 4 | 0 | 7,824 | 35 |
| Wind (100 MW) | 100 | 1,800 | 330 | $2,130 | $2,276 | 40 | 0 | 15 | NA | 25 |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

# Transmission Cost Assumptions

## *Cost Assumptions by Supply-Side Resource Type*

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Battery Storage | | | | |
| 6 | $0 | Assume location in or near existing substation. | No transmission upgrades required. | No backbone upgrades required. |
| Biomass Direct—Woody Residue | | | | |
| 35 | $357 | Assume a 20-mile, 138-kV line to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades. | Assume a 20-mile, 138-kV line interconnection to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades. | No backbone upgrades required. |
| Biomass Indirect—Anaerobic Digester | | | | |
| 3 | $133 | Assume distribution feeder location with no backbone transmission upgrades required. | Assume $300k of distribution feeder upgrades and $100k in substation upgrades. | No backbone upgrades required. |
| Coal—Integrated Gasification Combined Cycle (IGCC) | | | | |
| 580 | $745 | Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion. | Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation. | Pro-rata share of Gateway. |
| Coal—IGCC with Carbon Capture and Sequestration | | | | |
| 600 | $744 | Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion . | Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation. | Pro-rata share of Gateway. |
| Geothermal (binary-cycle)—Idaho | | | | |
| 30 | $850 | Assume Raft River area. Requires 45-mile, 138-kV line to existing Minidoka substation. Assume capacity fits on existing backbone. | New 45-mile, 138-kV line to Minidoka substation with new 138-kV substation line terminal bay. | No backbone upgrades required. |
| Hydro—Canal Drop (Seasonal) | | | | |
| 10 | $70 | Assume 46-kV sub-transmission or local feeder interconnection. Feeder rebuild or 46-kV upgrade would likely be required. | Assume 4 miles of distribution rebuild at $150k per mile plus $100k in substation upgrades. | No backbone upgrades required. |
| Hydro—Shoshone Falls Expansion | | | | |
| 50 | $269 | Line and station modifications required. New substation above existing power plant. | Assume $2 million for transmission line modifications, $7 million for station upgrades, and $4.3 million for Cliff substation modifications. | Part of Generation Interconnect Cluster Study. No further backbone upgrades required. |
| Hydro—Hydrokinetic (In stream) | | | | |
| 1 | $100 | Assume minor upgrades required to distribution feeder or substation. | Assume $100k in substation upgrades. | No backbone upgrades required. |
| ICE Thermal Storage | | | | |
| 10 | $0 | No transmission upgrades required. | No transmission upgrades required. | No backbone upgrades required. |
| Natural Gas—Simple Cycle Combustion Turbine (SCCT) Aeroderivative | | | | |
| 47 | $46 | Assume plant located at or near existing Bennett Mountain plant. Capacity would fit within existing transmission system between Bennett Mountain and Boise. | New 230-kV substation terminal and station modifications. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Natural Gas—SCCT Frame F Class (Idaho Power's peaker plants use this technology) | | | | |
| 170 | $194 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line. | No backbone upgrades required. |
| Natural Gas—Reciprocating Gas Engine Wartsila 34SG | | | | |
| 4.1 | $73 | Assume distribution feeder location with no backbone transmission upgrades required. | Assume $300k of distribution feeder upgrades. | No backbone upgrades required. |
| Natural Gas—CCCT (1x1) F Class with Duct Firing | | | | |
| 270 | $122 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line. | No backbone upgrades required. |
| Natural Gas—CCCT (2x1) F Class | | | | |
| 580 | $101 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile; 230-kV line to Boise Bench Substation and 28-mile, 230-kV line to Hubbard Substation. | No backbone upgrades required. Entire project assumed as backbone upgrade. |
| Natural Gas—Combined Heat and Power (CHP) | | | | |
| 45 | $57 | Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation (or large upgrade to existing substation). | Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation. | No backbone upgrades required. |
| Nuclear—Small Modular Reactor (SMR) | | | | |
| 45 | $358 | Tie into nearby 230-kV transmission substation. Backbone transmission uprgrades required. | Assume 2 mile, 138-kV interconnection to existing Antelope substation and one new 138-kV terminal. | Pro rata share of Gateway West upgrade from Populus to Cedar Hill to Hemingway. Assume 2.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Nuclear—SMR | | | | |
| 250 | $520 | Tie into nearby 230-kV transmission substation. Build new 55 mile, 230-kV line. Backbone transmission uprgrades required. | Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 230-kV transformer terminal. New parallel 55-mile, 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. | Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 12.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Nuclear—Advanced Nuclear | | | | |
| 1,100 | $441 | Two new 345kV transmission lines required. One 55 mile line from site to Borah Substation. One 85 mile line from site to Kinport Substation via Goshen Substation. | New 345 kV station. New 55 mile 345kV transmission line to existing Borah substation and new 345kV line terminal. New 85 mile transmission line to existing Kinport Substation through existing Goshen Substation and three new 345 kV line terminals. | Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 50% ownership of the 280 mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Pumped Storage—new upper reservoir and new generation/pumping plant (pumping water from an existing lower reservoir to a new upper reservoir then running the water through a new power plant) | | | | |
| 100 | $1,095 | Tie into existing Oxbow 230-/ 138-kV switchyard. New 230-kV transmission line required from Oxbow to Treasure Valley (no existing backbone capacity). | Assume 0.5 mile tap off of Oxbow 138-kV line. | New 110 mile, 230-kV line from Oxbow to Treasure Valley. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Solar Thermal—Solar Power Tower with storage | | | | |
| 100 | $330 | Assume Mountain Home desert area with 20-mile, 138-kV line to new substation intersecting existing Danskin—Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1-mile, 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | No backbone upgrades required. |
| Solar PV—Distributed Residential Fixed-Tilt (S Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small residential installations. | Assume that no upgrades are required for small residential installations. | No backbone upgrades required. |
| Solar PV—Distributed C&I Fixed-Tilt (S Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small C&I installations. | Assume that no upgrades are required for small C&I installations. | No backbone upgrades required. |
| Solar PV—Distributed C&I Fixed-Tilt (SW Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small C&I installations. | Assume that no upgrades are required for small C&I installations. | No backbone upgrades required. |
| Solar PV—Utility Scale Fixed-Tilt (S Orientation) | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale Fixed-Tilt (SW Orientation) | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale 1-Axis Tracking | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale 2-Axis Tracking | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Transmission—Boardman to Hemingway | | | | |
| Inbound<br>350—Average<br>500—Summer<br>350—Winter | $711 | Per the B2H Funding Agreement, Idaho Power's share of the project is roughly 21.2% of total project cost. Assume approximately $16 million in B2H 230-kV integration costs. | New 230-kV transmission circuit from Hemingway Substation to Bowmont Substation. New 230-kV line from Bowmont Substation to Hubbard Substation and 138-kV line re-configuration. | Pro-rata share of B2H project. |
| Wind—Idaho | | | | |
| 100 | $330 | Assume location near Midpoint Substation or Justice Substation. Estimated $1.5 million for upgrades at Midpoint or Justice Substation plus 100 MW pro-rata share of 2,000-MW Gateway West 500-kV project from Midpoint/Cedar Hill Substation to Hemingway Substation. | Assume 10 miles of 138-kV local transmission to project site with 138-kV substation and 138-/ 230-kV transformer. | Assume $1.5 million for upgrades at Midpoint Substation or Justice Substation. Assume 5% share of estimated $425 million Gateway West 500kV project from Midpoint/Cedar Hill Substation to Hemingway Substation. |

# Levelized Cost of Production

**30-Year Levelized Cost of Production (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Net of Tax Credit/Steam sales/Integration | Total Cost per MWh | Capacity Factor |
|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | $88 | $25 | $7 | $0 | $0 | $119 | 90% |
| Battery Storage (6 MW) | $216 | $24 | $0 | $46 | $0 | $285 | 25% |
| Biomass Direct—Woody Residue (35 MW) | $44 | $40 | $19 | $0 | $0 | $102 | 85% |
| Biomass Indirect— Anaerobic Digester (3 MW) | $87 | $33 | $0 | $0 | $0 | $119 | 75% |
| Boardman to Hemingway (350 MW) | $21 | $2 | $0 | $54 | $0 | $78 | 33% |
| Canal Drop Hydro (1.28 MW) | $135 | $24 | $0 | $0 | $0 | $159 | 33% |
| CCCT (1x1) F Class with Duct Firing (270 MW) | $25 | $6 | $49 | $0 | $0 | $79 | 70% |
| CCCT (2x1) F Class (580 MW) | $20 | $7 | $48 | $0 | $0 | $75 | 70% |
| CHP (45 MW) | $32 | $19 | $46 | $0 | -$16 | $81 | 80% |
| IGCC (580 MW) | $71 | $28 | $17 | $0 | $0 | $116 | 75% |
| IGCC with Carbon Capture (580 MW) | $127 | $37 | $21 | $0 | $0 | $184 | 75% |
| Geothermal (30 MW) | $64 | $43 | $0 | $0 | -$6 | $101 | 90% |
| ICE Thermal Storage (10 MW) | $171 | $53 | $0 | $0 | $0 | $224 | 10% |
| Pumped Storage (150 MW) | $304 | $42 | $0 | $57 | $0 | $403 | 25% |
| Reciprocating Gas Engine (18.8 MW) | $66 | $14 | $55 | $0 | $0 | $136 | 10% |
| SCCT—Aeroderivative (47 MW) | $124 | $59 | $67 | $0 | $0 | $250 | 10% |
| SCCT—Frame F Class (170 MW) | $118 | $24 | $76 | $0 | $0 | $219 | 10% |
| Shoshone Falls Upgrade (49.5 MW) | $66 | $8 | $0 | $0 | $0 | $74 | 43% |
| Small Modular Nuclear (250 MW) | $96 | $39 | $208 | $0 | $0 | $343 | 95% |
| Solar Power Tower (110 MW) | $325 | $69 | $0 | $0 | -$21 | $372 | 28% |
| Solar PV—Distr Residential Fixed S (10 MW) | $212 | $33 | $0 | $0 | -$11 | $234 | 20% |
| Solar PV—Distr C&I Fixed S (10 MW) | $148 | $20 | $0 | $0 | -$6 | $162 | 21% |
| Solar PV—Distr C&I Fixed SW (10 MW) | $155 | $21 | $0 | $0 | -$6 | $170 | 20% |
| Solar PV—Utility Scale Fixed S (10 MW) | $103 | $16 | $0 | $0 | -$2 | $118 | 21% |
| Solar PV—Utility Scale Fixed SW (10 MW) | $109 | $17 | $0 | $0 | -$2 | $124 | 20% |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | $92 | $17 | $0 | $0 | -$1 | $109 | 27% |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | $88 | $18 | $0 | $0 | $0 | $105 | 30% |
| TurboPhase (23.6 MW) | $45 | $8 | $58 | $0 | $0 | $111 | 10% |
| Wind (100 MW) | $86 | $28 | $0 | $0 | $21 | $135 | 28% |

[1] Non Fuel O&M includes fixed and variable costs, property taxes.

| 30-Year Levelized Capacity (fixed) Cost per kW/Month | | | | | |
|---|---|---|---|---|---|
| **Supply-Side Resources** | **Cost of Capital** | **Non-Fuel O&M** | **Fuel** | **Net of Tax Credit/Steam sales/Integration** | **Total Cost per kW** |
| Advanced Nuclear (250 MW) | $57 | $16 | $0 | $0 | $73 |
| Battery Storage (6 MW) | $39 | $4 | $0 | $0 | $44 |
| Biomass Direct—Woody Residue (35 MW) | $27 | $12 | $0 | $0 | $40 |
| Biomass Indirect—Anaerobic Digester (3 MW) | $48 | $8 | $0 | $0 | $55 |
| Boardman to Hemingway (350 MW) | $5 | $1 | $0 | $0 | $6 |
| Canal Drop Hydro (1.28 MW) | $32 | $6 | $0 | $0 | $38 |
| CCCT (1x1) F Class with Duct Firing (270 MW) | $13 | $2 | $0 | $0 | $14 |
| CCCT (2x1) F Class (580 MW) | $10 | $1 | $0 | $0 | $11 |
| CHP (45 MW) | $18 | $7 | $0 | $0 | $26 |
| IGCC (580 MW) | $39 | $10 | $0 | $0 | $49 |
| IGCC with Carbon Capture (580 MW) | $69 | $14 | $0 | $0 | $83 |
| Geothermal (30 MW) | $42 | $0 | $0 | $0 | $42 |
| ICE Thermal Storage (10 MW) | $13 | $4 | $0 | $0 | $17 |
| Pumped Storage (150 MW) | $55 | $8 | $0 | $0 | $63 |
| Reciprocating Gas Engine (18.8 MW) | $5 | $1 | $0 | $0 | $5 |
| SCCT—Aeroderivative (47 MW) | $9 | $4 | $0 | $0 | $13 |
| SCCT—Frame F Class (170 MW) | $9 | $1 | $0 | $0 | $10 |
| Shoshone Falls Upgrade (49.5 MW) | $21 | $2 | $0 | $0 | $23 |
| Small Modular Nuclear (250 MW) | $66 | $6 | $0 | $0 | $72 |
| Solar Power Tower (110 MW) | $66 | $7 | $0 | $0 | $73 |
| Solar PV—Distr Residential Fixed S (10 MW) | $31 | $2 | $0 | $0 | $33 |
| Solar PV—Distr C&I Fixed S (10 MW) | $22 | $1 | $0 | $0 | $23 |
| Solar PV—Distr C&I Fixed SW (10 MW) | $22 | $1 | $0 | $0 | $23 |
| Solar PV—Utility Scale Fixed S (10 MW) | $16 | $1 | $0 | $0 | $17 |
| Solar PV—Utility Scale Fixed SW (10 MW) | $16 | $1 | $0 | $0 | $17 |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | $18 | $2 | $0 | $0 | $20 |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | $19 | $2 | $0 | $0 | $21 |
| TurboPhase (23.6 MW) | $3 | $0 | $0 | $0 | $4 |
| Wind (100 MW) | $18 | $6 | $0 | $0 | $23 |

## Peak-Hour Capacity Credit (Contribution to Peak)—Solar and Wind Resources

Peak hour capacity credit (contribution to peak) for new IRP intermittent generation resources:

| New IRP intermittent generation—Peak hour capacity credit | |
|---|---|
| **Resource** | **Peak Hour Capacity Credit** |
| PV solar south orientation | 28.4% |
| PV solar southwest orientation | 45.4% |
| PV solar single-axis tracking | 51.3% |
| Wind | 5.0% |

# Energy Shape—Solar

## *2015 IRP Assumed Solar Capacity Factors*

| Month | Utility Scale, Single Axis Tracking | Residential, Fixed Tilt |
|---|---|---|
| January | 12% | 7% |
| February | 19% | 11% |
| March | 26% | 16% |
| April | 32% | 20% |
| May | 37% | 23% |
| June | 41% | 25% |
| July | 42% | 26% |
| August | 39% | 24% |
| September | 33% | 20% |
| October | 25% | 16% |
| November | 14% | 9% |
| December | 11% | 7% |
| **Annual Capacity Factor** | **27.5%** | **17.0%** |

# Schedule 87—Integration Costs for Solar and Wind Resources

## *Solar*

| 0–100 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates* |
| 2014 | 0.54 | 2014 | 0.43 |
| 2015 | 0.56 | 2015 | 0.44 |
| 2016 | 0.58 | 2016 | 0.46 |
| 2017 | 0.59 | 2017 | 0.47 |
| 2018 | 0.61 | 2018 | 0.48 |
| 2019 | 0.63 | 2019 | 0.50 |
| | | 2020 | 0.51 |
| | | 2021 | 0.53 |
| | | 2022 | 0.54 |
| | | 2023 | 0.56 |
| | | 2024 | 0.58 |
| | | 2025 | 0.60 |
| | | 2026 | 0.61 |
| | | 2027 | 0.63 |
| | | 2028 | 0.65 |
| | | 2029 | 0.67 |
| | | 2030 | 0.69 |
| | | 2031 | 0.71 |
| | | 2032 | 0.73 |
| | | 2033 | 0.75 |
| | | 2034 | 0.78 |
| | | 2035 | 0.80 |
| | | 2036 | 0.82 |
| | | 2037 | 0.85 |
| | | 2038 | 0.87 |
| | | 2039 | 0.90 |

*$/MWh

| 101–200 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 1.49 | 2014 | 1.18 |
| 2015 | 1.53 | 2015 | 1.22 |
| 2016 | 1.58 | 2016 | 1.25 |
| 2017 | 1.63 | 2017 | 1.29 |
| 2018 | 1.68 | 2018 | 1.33 |
| 2019 | 1.73 | 2019 | 1.37 |
| | | 2020 | 1.41 |
| | | 2021 | 1.45 |
| | | 2022 | 1.50 |
| | | 2023 | 1.54 |
| | | 2024 | 1.59 |
| | | 2025 | 1.63 |
| | | 2026 | 1.68 |
| | | 2027 | 1.73 |
| | | 2028 | 1.79 |
| | | 2029 | 1.84 |
| | | 2030 | 1.89 |
| | | 2031 | 1.95 |
| | | 2032 | 2.01 |
| | | 2033 | 2.07 |
| | | 2034 | 2.13 |
| | | 2035 | 2.20 |
| | | 2036 | 2.26 |
| | | 2037 | 2.33 |
| | | 2038 | 2.40 |
| | | 2039 | 2.47 |

*$/MWh

| 201–300 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 2.32 | 2014 | 1.84 |
| 2015 | 2.39 | 2015 | 1.89 |
| 2016 | 2.46 | 2016 | 1.95 |
| 2017 | 2.54 | 2017 | 2.01 |
| 2018 | 2.61 | 2018 | 2.07 |
| 2019 | 2.69 | 2019 | 2.13 |
| | | 2020 | 2.20 |
| | | 2021 | 2.26 |
| | | 2022 | 2.33 |
| | | 2023 | 2.40 |
| | | 2024 | 2.47 |
| | | 2025 | 2.55 |
| | | 2026 | 2.62 |
| | | 2027 | 2.70 |
| | | 2028 | 2.78 |
| | | 2029 | 2.87 |
| | | 2030 | 2.95 |
| | | 2031 | 3.04 |
| | | 2032 | 3.13 |
| | | 2033 | 3.23 |
| | | 2034 | 3.32 |
| | | 2035 | 3.42 |
| | | 2036 | 3.52 |
| | | 2037 | 3.63 |
| | | 2038 | 3.74 |
| | | 2039 | 3.85 |

*$/MWh

| 301–400 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 3.12 | 2014 | 2.48 |
| 2015 | 3.22 | 2015 | 2.55 |
| 2016 | 3.32 | 2016 | 2.63 |
| 2017 | 3.41 | 2017 | 2.71 |
| 2018 | 3.52 | 2018 | 2.79 |
| 2019 | 3.62 | 2019 | 2.87 |
| | | 2020 | 2.96 |
| | | 2021 | 3.05 |
| | | 2022 | 3.14 |
| | | 2023 | 3.23 |
| | | 2024 | 3.33 |
| | | 2025 | 3.43 |
| | | 2026 | 3.53 |
| | | 2027 | 3.64 |
| | | 2028 | 3.75 |
| | | 2029 | 3.86 |
| | | 2030 | 3.97 |
| | | 2031 | 4.09 |
| | | 2032 | 4.22 |
| | | 2033 | 4.34 |
| | | 2034 | 4.47 |
| | | 2035 | 4.61 |
| | | 2036 | 4.75 |
| | | 2037 | 4.89 |
| | | 2038 | 5.03 |
| | | 2039 | 5.19 |

*$/MWh

| 401–500 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 3.94 | 2014 | 3.12 |
| 2015 | 4.06 | 2015 | 3.22 |
| 2016 | 4.18 | 2016 | 3.31 |
| 2017 | 4.31 | 2017 | 3.41 |
| 2018 | 4.44 | 2018 | 3.52 |
| 2019 | 4.57 | 2019 | 3.62 |
| | | 2020 | 3.73 |
| | | 2021 | 3.84 |
| | | 2022 | 3.96 |
| | | 2023 | 4.08 |
| | | 2024 | 4.20 |
| | | 2025 | 4.32 |
| | | 2026 | 4.45 |
| | | 2027 | 4.59 |
| | | 2028 | 4.72 |
| | | 2029 | 4.87 |
| | | 2030 | 5.01 |
| | | 2031 | 5.16 |
| | | 2032 | 5.32 |
| | | 2033 | 5.48 |
| | | 2034 | 5.64 |
| | | 2035 | 5.81 |
| | | 2036 | 5.98 |
| | | 2037 | 6.16 |
| | | 2038 | 6.35 |
| | | 2039 | 6.54 |

*$/MWh

**501–600 MW Solar Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| **On-line Year** | **20-Year Contract Term Levelized Rates*** | **Contract year** | **Non-Levelized Rates** |
| 2014 | 4.76 | 2014 | 3.78 |
| 2015 | 4.91 | 2015 | 3.89 |
| 2016 | 5.05 | 2016 | 4.01 |
| 2017 | 5.21 | 2017 | 4.13 |
| 2018 | 5.36 | 2018 | 4.25 |
| 2019 | 5.52 | 2019 | 4.38 |
| | | 2020 | 4.51 |
| | | 2021 | 4.64 |
| | | 2022 | 4.78 |
| | | 2023 | 4.93 |
| | | 2024 | 5.07 |
| | | 2025 | 5.23 |
| | | 2026 | 5.38 |
| | | 2027 | 5.55 |
| | | 2028 | 5.71 |
| | | 2029 | 5.88 |
| | | 2030 | 6.06 |
| | | 2031 | 6.24 |
| | | 2032 | 6.43 |
| | | 2033 | 6.62 |
| | | 2034 | 6.82 |
| | | 2035 | 7.02 |
| | | 2036 | 7.24 |
| | | 2037 | 7.45 |
| | | 2038 | 7.68 |
| | | 2039 | 7.91 |

*$/MWh

| 601–700 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 5.54 | 2014 | 4.39 |
| 2015 | 5.71 | 2015 | 4.53 |
| 2016 | 5.88 | 2016 | 4.66 |
| 2017 | 6.06 | 2017 | 4.80 |
| 2018 | 6.24 | 2018 | 4.95 |
| 2019 | 6.43 | 2019 | 5.09 |
| | | 2020 | 5.25 |
| | | 2021 | 5.40 |
| | | 2022 | 5.57 |
| | | 2023 | 5.73 |
| | | 2024 | 5.91 |
| | | 2025 | 6.08 |
| | | 2026 | 6.26 |
| | | 2027 | 6.45 |
| | | 2028 | 6.65 |
| | | 2029 | 6.85 |
| | | 2030 | 7.05 |
| | | 2031 | 7.26 |
| | | 2032 | 7.48 |
| | | 2033 | 7.70 |
| | | 2034 | 7.94 |
| | | 2035 | 8.17 |
| | | 2036 | 8.42 |
| | | 2037 | 8.67 |
| | | 2038 | 8.93 |
| | | 2039 | 9.20 |

*$/MWh

| 701–800 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 6.70 | 2014 | 5.31 |
| 2015 | 6.91 | 2015 | 5.47 |
| 2016 | 7.11 | 2016 | 5.64 |
| 2017 | 7.33 | 2017 | 5.81 |
| 2018 | 7.55 | 2018 | 5.98 |
| 2019 | 7.77 | 2019 | 6.16 |
| | | 2020 | 6.35 |
| | | 2021 | 6.54 |
| | | 2022 | 6.73 |
| | | 2023 | 6.93 |
| | | 2024 | 7.14 |
| | | 2025 | 7.36 |
| | | 2026 | 7.58 |
| | | 2027 | 7.80 |
| | | 2028 | 8.04 |
| | | 2029 | 8.28 |
| | | 2030 | 8.53 |
| | | 2031 | 8.78 |
| | | 2032 | 9.05 |
| | | 2033 | 9.32 |
| | | 2034 | 9.60 |
| | | 2035 | 9.89 |
| | | 2036 | 10.18 |
| | | 2037 | 10.49 |
| | | 2038 | 10.80 |
| | | 2039 | 11.13 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 801–900 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 7.98 | 2014 | 6.32 |
| 2015 | 8.21 | 2015 | 6.51 |
| 2016 | 8.46 | 2016 | 6.71 |
| 2017 | 8.71 | 2017 | 6.91 |
| 2018 | 8.98 | 2018 | 7.11 |
| 2019 | 9.25 | 2019 | 7.33 |
| | | 2020 | 7.55 |
| | | 2021 | 7.77 |
| | | 2022 | 8.01 |
| | | 2023 | 8.25 |
| | | 2024 | 8.50 |
| | | 2025 | 8.75 |
| | | 2026 | 9.01 |
| | | 2027 | 9.28 |
| | | 2028 | 9.56 |
| | | 2029 | 9.85 |
| | | 2030 | 10.14 |
| | | 2031 | 10.45 |
| | | 2032 | 10.76 |
| | | 2033 | 11.08 |
| | | 2034 | 11.42 |
| | | 2035 | 11.76 |
| | | 2036 | 12.11 |
| | | 2037 | 12.48 |
| | | 2038 | 12.85 |
| | | 2039 | 13.24 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 901–1,000 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 9.52 | 2014 | 7.54 |
| 2015 | 9.80 | 2015 | 7.77 |
| 2016 | 10.10 | 2016 | 8.00 |
| 2017 | 10.40 | 2017 | 8.24 |
| 2018 | 10.71 | 2018 | 8.49 |
| 2019 | 11.03 | 2019 | 8.74 |
| | | 2020 | 9.01 |
| | | 2021 | 9.28 |
| | | 2022 | 9.55 |
| | | 2023 | 9.84 |
| | | 2024 | 10.14 |
| | | 2025 | 10.44 |
| | | 2026 | 10.75 |
| | | 2027 | 11.08 |
| | | 2028 | 11.41 |
| | | 2029 | 11.75 |
| | | 2030 | 12.10 |
| | | 2031 | 12.47 |
| | | 2032 | 12.84 |
| | | 2033 | 13.23 |
| | | 2034 | 13.62 |
| | | 2035 | 14.03 |
| | | 2036 | 14.45 |
| | | 2037 | 14.89 |
| | | 2038 | 15.33 |
| | | 2039 | 15.79 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,001–1,100 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 11.38 | 2014 | 9.02 |
| 2015 | 11.72 | 2015 | 9.29 |
| 2016 | 12.07 | 2016 | 9.56 |
| 2017 | 12.43 | 2017 | 9.85 |
| 2018 | 12.80 | 2018 | 10.15 |
| 2019 | 13.19 | 2019 | 10.45 |
| | | 2020 | 10.77 |
| | | 2021 | 11.09 |
| | | 2022 | 11.42 |
| | | 2023 | 11.76 |
| | | 2024 | 12.12 |
| | | 2025 | 12.48 |
| | | 2026 | 12.85 |
| | | 2027 | 13.24 |
| | | 2028 | 13.64 |
| | | 2029 | 14.05 |
| | | 2030 | 14.47 |
| | | 2031 | 14.90 |
| | | 2032 | 15.35 |
| | | 2033 | 15.81 |
| | | 2034 | 16.28 |
| | | 2035 | 16.77 |
| | | 2036 | 17.28 |
| | | 2037 | 17.79 |
| | | 2038 | 18.33 |
| | | 2039 | 18.88 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,101–1,200 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 13.61 | 2014 | 10.78 |
| 2015 | 14.01 | 2015 | 11.11 |
| 2016 | 14.43 | 2016 | 11.44 |
| 2017 | 14.87 | 2017 | 11.78 |
| 2018 | 15.31 | 2018 | 12.14 |
| 2019 | 15.77 | 2019 | 12.50 |
| | | 2020 | 12.88 |
| | | 2021 | 13.26 |
| | | 2022 | 13.66 |
| | | 2023 | 14.07 |
| | | 2024 | 14.49 |
| | | 2025 | 14.93 |
| | | 2026 | 15.37 |
| | | 2027 | 15.84 |
| | | 2028 | 16.31 |
| | | 2029 | 16.80 |
| | | 2030 | 17.30 |
| | | 2031 | 17.82 |
| | | 2032 | 18.36 |
| | | 2033 | 18.91 |
| | | 2034 | 19.48 |
| | | 2035 | 20.06 |
| | | 2036 | 20.66 |
| | | 2037 | 21.28 |
| | | 2038 | 21.92 |
| | | 2039 | 22.58 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,201–1,300 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 16.26 | 2014 | 12.89 |
| 2015 | 16.75 | 2015 | 13.28 |
| 2016 | 17.25 | 2016 | 13.67 |
| 2017 | 17.77 | 2017 | 14.08 |
| 2018 | 18.30 | 2018 | 14.51 |
| 2019 | 18.85 | 2019 | 14.94 |
| | | 2020 | 15.39 |
| | | 2021 | 15.85 |
| | | 2022 | 16.33 |
| | | 2023 | 16.82 |
| | | 2024 | 17.32 |
| | | 2025 | 17.84 |
| | | 2026 | 18.38 |
| | | 2027 | 18.93 |
| | | 2028 | 19.50 |
| | | 2029 | 20.08 |
| | | 2030 | 20.68 |
| | | 2031 | 21.30 |
| | | 2032 | 21.94 |
| | | 2033 | 22.60 |
| | | 2034 | 23.28 |
| | | 2035 | 23.98 |
| | | 2036 | 24.70 |
| | | 2037 | 25.44 |
| | | 2038 | 26.20 |
| | | 2039 | 26.99 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,301–1,400 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 19.40 | 2014 | 15.38 |
| 2015 | 19.98 | 2015 | 15.84 |
| 2016 | 20.58 | 2016 | 16.31 |
| 2017 | 21.20 | 2017 | 16.80 |
| 2018 | 21.84 | 2018 | 17.31 |
| 2019 | 22.49 | 2019 | 17.83 |
| | | 2020 | 18.36 |
| | | 2021 | 18.91 |
| | | 2022 | 19.48 |
| | | 2023 | 20.06 |
| | | 2024 | 20.66 |
| | | 2025 | 21.28 |
| | | 2026 | 21.92 |
| | | 2027 | 22.58 |
| | | 2028 | 23.26 |
| | | 2029 | 23.96 |
| | | 2030 | 24.67 |
| | | 2031 | 25.41 |
| | | 2032 | 26.18 |
| | | 2033 | 26.96 |
| | | 2034 | 27.77 |
| | | 2035 | 28.60 |
| | | 2036 | 29.46 |
| | | 2037 | 30.35 |
| | | 2038 | 31.26 |
| | | 2039 | 32.19 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,301–1,400 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 23.07 | 2014 | 18.29 |
| 2015 | 23.77 | 2015 | 18.84 |
| 2016 | 24.48 | 2016 | 19.40 |
| 2017 | 25.21 | 2017 | 19.98 |
| 2018 | 25.97 | 2018 | 20.58 |
| 2019 | 26.75 | 2019 | 21.20 |
| | | 2020 | 21.84 |
| | | 2021 | 22.49 |
| | | 2022 | 23.17 |
| | | 2023 | 23.86 |
| | | 2024 | 24.58 |
| | | 2025 | 25.31 |
| | | 2026 | 26.07 |
| | | 2027 | 26.86 |
| | | 2028 | 27.66 |
| | | 2029 | 28.49 |
| | | 2030 | 29.35 |
| | | 2031 | 30.23 |
| | | 2032 | 31.13 |
| | | 2033 | 32.07 |
| | | 2034 | 33.03 |
| | | 2035 | 34.02 |
| | | 2036 | 35.04 |
| | | 2037 | 36.09 |
| | | 2038 | 37.18 |
| | | 2039 | 38.29 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

## Wind

| 0–100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 0.27 | 2014 | 0.21 |
| 2015 | 0.27 | 2015 | 0.22 |
| 2016 | 0.28 | 2016 | 0.23 |
| 2017 | 0.29 | 2017 | 0.23 |
| 2018 | 0.30 | 2018 | 0.24 |
| 2019 | 0.31 | 2019 | 0.25 |
| | | 2020 | 0.25 |
| | | 2021 | 0.26 |
| | | 2022 | 0.27 |
| | | 2023 | 0.28 |
| | | 2024 | 0.29 |
| | | 2025 | 0.29 |
| | | 2026 | 0.30 |
| | | 2027 | 0.31 |
| | | 2028 | 0.32 |
| | | 2029 | 0.33 |
| | | 2030 | 0.34 |
| | | 2031 | 0.35 |
| | | 2032 | 0.36 |
| | | 2033 | 0.37 |
| | | 2034 | 0.38 |
| | | 2035 | 0.40 |
| | | 2036 | 0.41 |
| | | 2037 | 0.42 |
| | | 2038 | 0.43 |
| | | 2039 | 0.45 |

*$/MWh

| 101–200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 1.22 | 2014 | 0.98 |
| 2015 | 1.25 | 2015 | 1.00 |
| 2016 | 1.29 | 2016 | 1.04 |
| 2017 | 1.33 | 2017 | 1.07 |
| 2018 | 1.37 | 2018 | 1.10 |
| 2019 | 1.41 | 2019 | 1.13 |
| | | 2020 | 1.16 |
| | | 2021 | 1.20 |
| | | 2022 | 1.24 |
| | | 2023 | 1.27 |
| | | 2024 | 1.31 |
| | | 2025 | 1.35 |
| | | 2026 | 1.39 |
| | | 2027 | 1.43 |
| | | 2028 | 1.48 |
| | | 2029 | 1.52 |
| | | 2030 | 1.57 |
| | | 2031 | 1.61 |
| | | 2032 | 1.66 |
| | | 2033 | 1.71 |
| | | 2034 | 1.76 |
| | | 2035 | 1.81 |
| | | 2036 | 1.87 |
| | | 2037 | 1.93 |
| | | 2038 | 1.98 |
| | | 2039 | 2.04 |

*$/MWh

| 201–300 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 2.78 | 2014 | 2.23 |
| 2015 | 2.87 | 2015 | 2.30 |
| 2016 | 2.95 | 2016 | 2.37 |
| 2017 | 3.04 | 2017 | 2.44 |
| 2018 | 3.13 | 2018 | 2.51 |
| 2019 | 3.23 | 2019 | 2.59 |
| | | 2020 | 2.67 |
| | | 2021 | 2.75 |
| | | 2022 | 2.83 |
| | | 2023 | 2.92 |
| | | 2024 | 3.00 |
| | | 2025 | 3.09 |
| | | 2026 | 3.19 |
| | | 2027 | 3.28 |
| | | 2028 | 3.38 |
| | | 2029 | 3.48 |
| | | 2030 | 3.59 |
| | | 2031 | 3.69 |
| | | 2032 | 3.80 |
| | | 2033 | 3.92 |
| | | 2034 | 4.04 |
| | | 2035 | 4.16 |
| | | 2036 | 4.28 |
| | | 2037 | 4.41 |
| | | 2038 | 4.54 |
| | | 2039 | 4.68 |

*$/MWh

| 301–400 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 4.95 | 2014 | 3.98 |
| 2015 | 5.10 | 2015 | 4.10 |
| 2016 | 5.26 | 2016 | 4.22 |
| 2017 | 5.41 | 2017 | 4.35 |
| 2018 | 5.58 | 2018 | 4.48 |
| 2019 | 5.74 | 2019 | 4.61 |
| | | 2020 | 4.75 |
| | | 2021 | 4.89 |
| | | 2022 | 5.04 |
| | | 2023 | 5.19 |
| | | 2024 | 5.34 |
| | | 2025 | 5.51 |
| | | 2026 | 5.67 |
| | | 2027 | 5.84 |
| | | 2028 | 6.02 |
| | | 2029 | 6.20 |
| | | 2030 | 6.38 |
| | | 2031 | 6.57 |
| | | 2032 | 6.77 |
| | | 2033 | 6.97 |
| | | 2034 | 7.18 |
| | | 2035 | 7.40 |
| | | 2036 | 7.62 |
| | | 2037 | 7.85 |
| | | 2038 | 8.08 |
| | | 2039 | 8.33 |

*$/MWh

| 401–500 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 7.71 | 2014 | 6.19 |
| 2015 | 7.95 | 2015 | 6.38 |
| 2016 | 8.18 | 2016 | 6.57 |
| 2017 | 8.43 | 2017 | 6.77 |
| 2018 | 8.68 | 2018 | 6.97 |
| 2019 | 8.94 | 2019 | 7.18 |
| | | 2020 | 7.39 |
| | | 2021 | 7.62 |
| | | 2022 | 7.84 |
| | | 2023 | 8.08 |
| | | 2024 | 8.32 |
| | | 2025 | 8.57 |
| | | 2026 | 8.83 |
| | | 2027 | 9.09 |
| | | 2028 | 9.37 |
| | | 2029 | 9.65 |
| | | 2030 | 9.94 |
| | | 2031 | 10.23 |
| | | 2032 | 10.54 |
| | | 2033 | 10.86 |
| | | 2034 | 11.18 |
| | | 2035 | 11.52 |
| | | 2036 | 11.86 |
| | | 2037 | 12.22 |
| | | 2038 | 12.59 |
| | | 2039 | 12.96 |

*$/MWh

| 501–600 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 11.05 | 2014 | 8.87 |
| 2015 | 11.38 | 2015 | 9.13 |
| 2016 | 11.72 | 2016 | 9.41 |
| 2017 | 12.07 | 2017 | 9.69 |
| 2018 | 12.43 | 2018 | 9.98 |
| 2019 | 12.81 | 2019 | 10.28 |
| | | 2020 | 10.59 |
| | | 2021 | 10.91 |
| | | 2022 | 11.23 |
| | | 2023 | 11.57 |
| | | 2024 | 11.92 |
| | | 2025 | 12.28 |
| | | 2026 | 12.64 |
| | | 2027 | 13.02 |
| | | 2028 | 13.41 |
| | | 2029 | 13.82 |
| | | 2030 | 14.23 |
| | | 2031 | 14.66 |
| | | 2032 | 15.10 |
| | | 2033 | 15.55 |
| | | 2034 | 16.02 |
| | | 2035 | 16.50 |
| | | 2036 | 16.99 |
| | | 2037 | 17.50 |
| | | 2038 | 18.03 |
| | | 2039 | 18.57 |

*$/MWh

| 601–700 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 14.94 | 2014 | 11.99 |
| 2015 | 15.39 | 2015 | 12.35 |
| 2016 | 15.85 | 2016 | 12.72 |
| 2017 | 16.33 | 2017 | 13.10 |
| 2018 | 16.82 | 2018 | 13.50 |
| 2019 | 17.32 | 2019 | 13.90 |
| | | 2020 | 14.32 |
| | | 2021 | 14.75 |
| | | 2022 | 15.19 |
| | | 2023 | 15.65 |
| | | 2024 | 16.12 |
| | | 2025 | 16.60 |
| | | 2026 | 17.10 |
| | | 2027 | 17.61 |
| | | 2028 | 18.14 |
| | | 2029 | 18.68 |
| | | 2030 | 19.24 |
| | | 2031 | 19.82 |
| | | 2032 | 20.42 |
| | | 2033 | 21.03 |
| | | 2034 | 21.66 |
| | | 2035 | 22.31 |
| | | 2036 | 22.98 |
| | | 2037 | 23.67 |
| | | 2038 | 24.38 |
| | | 2039 | 25.11 |

*$/MWh

| 701–800 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 19.38 | 2014 | 15.55 |
| 2015 | 19.96 | 2015 | 16.02 |
| 2016 | 20.56 | 2016 | 16.50 |
| 2017 | 21.17 | 2017 | 17.00 |
| 2018 | 21.81 | 2018 | 17.51 |
| 2019 | 22.46 | 2019 | 18.03 |
| | | 2020 | 18.57 |
| | | 2021 | 19.13 |
| | | 2022 | 19.70 |
| | | 2023 | 20.29 |
| | | 2024 | 20.90 |
| | | 2025 | 21.53 |
| | | 2026 | 22.18 |
| | | 2027 | 22.84 |
| | | 2028 | 23.53 |
| | | 2029 | 24.23 |
| | | 2030 | 24.96 |
| | | 2031 | 25.71 |
| | | 2032 | 26.48 |
| | | 2033 | 27.27 |
| | | 2034 | 28.09 |
| | | 2035 | 28.93 |
| | | 2036 | 29.80 |
| | | 2037 | 30.70 |
| | | 2038 | 31.62 |
| | | 2039 | 32.57 |

*$/MWh

| 801–900 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 24.34 | 2014 | 19.54 |
| 2015 | 25.07 | 2015 | 20.13 |
| 2016 | 25.83 | 2016 | 20.73 |
| 2017 | 26.60 | 2017 | 21.35 |
| 2018 | 27.40 | 2018 | 21.99 |
| 2019 | 28.22 | 2019 | 22.65 |
| | | 2020 | 23.33 |
| | | 2021 | 24.03 |
| | | 2022 | 24.75 |
| | | 2023 | 25.50 |
| | | 2024 | 26.26 |
| | | 2025 | 27.05 |
| | | 2026 | 27.86 |
| | | 2027 | 28.70 |
| | | 2028 | 29.56 |
| | | 2029 | 30.44 |
| | | 2030 | 31.36 |
| | | 2031 | 32.30 |
| | | 2032 | 33.27 |
| | | 2033 | 34.26 |
| | | 2034 | 35.29 |
| | | 2035 | 36.35 |
| | | 2036 | 37.44 |
| | | 2037 | 38.56 |
| | | 2038 | 39.72 |
| | | 2039 | 40.91 |

*$/MWh

| 901–1,000 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 29.82 | 2014 | 23.94 |
| 2015 | 30.72 | 2015 | 24.66 |
| 2016 | 31.64 | 2016 | 25.40 |
| 2017 | 32.59 | 2017 | 26.16 |
| 2018 | 33.57 | 2018 | 26.94 |
| 2019 | 34.57 | 2019 | 27.75 |
| | | 2020 | 28.59 |
| | | 2021 | 29.44 |
| | | 2022 | 30.33 |
| | | 2023 | 31.24 |
| | | 2024 | 32.17 |
| | | 2025 | 33.14 |
| | | 2026 | 34.13 |
| | | 2027 | 35.16 |
| | | 2028 | 36.21 |
| | | 2029 | 37.30 |
| | | 2030 | 38.42 |
| | | 2031 | 39.57 |
| | | 2032 | 40.76 |
| | | 2033 | 41.98 |
| | | 2034 | 43.24 |
| | | 2035 | 44.54 |
| | | 2036 | 45.87 |
| | | 2037 | 47.25 |
| | | 2038 | 48.66 |
| | | 2039 | 50.12 |

*$/MWh

| 1,001–1,100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 35.81 | 2014 | 28.74 |
| 2015 | 36.88 | 2015 | 29.60 |
| 2016 | 37.99 | 2016 | 30.49 |
| 2017 | 39.13 | 2017 | 31.41 |
| 2018 | 40.30 | 2018 | 32.35 |
| 2019 | 41.51 | 2019 | 33.32 |
| | | 2020 | 34.32 |
| | | 2021 | 35.35 |
| | | 2022 | 36.41 |
| | | 2023 | 37.50 |
| | | 2024 | 38.63 |
| | | 2025 | 39.78 |
| | | 2026 | 40.98 |
| | | 2027 | 42.21 |
| | | 2028 | 43.47 |
| | | 2029 | 44.78 |
| | | 2030 | 46.12 |
| | | 2031 | 47.51 |
| | | 2032 | 48.93 |
| | | 2033 | 50.40 |
| | | 2034 | 51.91 |
| | | 2035 | 53.47 |
| | | 2036 | 55.07 |
| | | 2037 | 56.72 |
| | | 2038 | 58.43 |
| | | 2039 | 60.18 |

*$/MWh

| 1,101–1,200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 42.27 | 2014 | 33.93 |
| 2015 | 43.54 | 2015 | 34.95 |
| 2016 | 44.85 | 2016 | 36.00 |
| 2017 | 46.19 | 2017 | 37.08 |
| 2018 | 47.58 | 2018 | 38.19 |
| 2019 | 49.01 | 2019 | 39.34 |
| | | 2020 | 40.52 |
| | | 2021 | 41.73 |
| | | 2022 | 42.98 |
| | | 2023 | 44.27 |
| | | 2024 | 45.60 |
| | | 2025 | 46.97 |
| | | 2026 | 48.38 |
| | | 2027 | 49.83 |
| | | 2028 | 51.33 |
| | | 2029 | 52.87 |
| | | 2030 | 54.45 |
| | | 2031 | 56.09 |
| | | 2032 | 57.77 |
| | | 2033 | 59.50 |
| | | 2034 | 61.29 |
| | | 2035 | 63.12 |
| | | 2036 | 65.02 |
| | | 2037 | 66.97 |
| | | 2038 | 68.98 |
| | | 2039 | 71.05 |

*$/MWh

# PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P6(b)

## *Resource portfolio P6(b)*

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Demand response | 60 MW | 60 MW |
| 2030 | Ice-based TES | 20 MW | 20 MW |
| 2031 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 880 MW |
| | | Net peak-hour capacity | 618 MW |

2. Deficiency period under preferred portfolio

   1st capacity deficit = (14) MW July 2025
   1st energy deficit = (34) MW July 2026

   Note—Above deficits are based on 461 MW of installed PV solar capacity under contract at the time of portfolio design, and do not reflect the April 2015 cancellation of 141 MW of PV solar PURPA contracts. With removal of the 141 MW of PV solar PURPA contracts, the first deficits for capacity and energy are respectively (47) MW in July 2024 and (76) MW in July 2026.

3. Intermittent generation integration costs

   See integration cost schedule included in *Appendix C—Technical Appendix*, section *Schedule 87—Integration Costs for Solar and Wind Resources*.

# Renewable Energy Certificate Price Forecast

| Year | Nominal ($/MWh) |
|---|---|
| 2015 | $3.04 |
| 2016 | $3.06 |
| 2017 | $3.95 |
| 2018 | $3.95 |
| 2019 | $4.70 |
| 2020 | $5.23 |
| 2021 | $5.48 |
| 2022 | $5.73 |
| 2023 | $5.98 |
| 2024 | $6.33 |
| 2025 | $6.68 |
| 2026 | $7.05 |
| 2027 | $7.45 |
| 2028 | $7.83 |
| 2029 | $8.22 |
| 2030 | $8.64 |
| 2031 | $9.06 |
| 2032 | $9.49 |
| 2033 | $9.93 |
| 2034 | $10.38 |

# JIM BRIDGER UNITS 3 AND 4 SELECTIVE CATALYTIC REDUCTION ANALYSIS

The 2015 Jim Bridger Plant units 3 and 4 Selective Catalytic Reduction (SCR) Analysis (2015 SCR Analysis) is intended to satisfy the conditions set forth by the Idaho Public Utilities Commission (IPUC) in Order No. 32929 approving the Certificate of Public Convenience and Necessity (CPCN) for the investment in SCR controls on Jim Bridger units 3 and 4. Commission Order No. 32929 directs Idaho Power to be "continuously analyzing the impact of changing environmental regulations on its upgrade project." (Order No. 32929, p. 11). In addition to the above requirement, the company files quarterly reports in Docket No. IPC-E-13-16 providing updates as to the current status of environmental policies that are relevant to the construction of the SCR controls at Jim Bridger units 3 and 4, construction progress updates, and any other pertinent updates related to the SCRs.

The company's 2015 SCR Analysis evaluates the impacts of new environmental regulations proposed since the company filed its Coal Unit Environmental Analysis in 2013 (2013 Coal Study) as well as the cost-effectiveness of continuing the installation of the SCRs compared to shutting down units 3 and 4 and replacing that generation with an alternate generation resource.

## Background

The Jim Bridger coal-fired power plant (Jim Bridger Plant) consists of four units and is located near Rock Springs, Wyoming. Idaho Power owns one-third of the Jim Bridger Plant with the other two-thirds owned by PacifiCorp. The plant is maintained and operated by PacifiCorp. Units 3 and 4 have nominal net generation capacities of 523 and 530 megawatts (MW) respectively, and Idaho Power's share of the generation capacity is approximately 351 MW from both units.

Currently, the Jim Bridger Plant is required to meet SCR-based emission limits of 0.07 lb/MMBtu for nitrogen oxides (NOx) for all four units to comply with the U.S. Environmental Protection Agency (EPA) Regional Haze (RH) rules and the resulting Wyoming State Implementation Plan (SIP). SCRs are used to facilitate a chemical reaction between NOx (created during combustion) and ammonia to create nitrogen and water.

In 2013, as part of the 2011 IRP Update, the company filed its 2013 Coal Study which examined future investments required for environmental compliance in existing coal units and compared those investments to the costs of alternative replacement resources. The results of the 2013 Coal Study analysis for Jim Bridger identified additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represented the lowest cost and least-risk option when compared to the other investment alternatives. The company used the results of the 2013 Coal Study to support its Application for approval of a CPCN for the investment in SCRs on units 3 and 4. Subsequently, the IPUC issued its approval of the CPCN in December 2013 and construction of the SCRs began shortly after.

## SCR Construction Progress Update

The major components of an SCR upgrade consist of: large particle ash collection, ammonia injection grid, the SCR reactor vessel (which contains the catalyst modules), and all added flue gas path ductwork. In addition to the SCR, Unit 4 will require larger induced draft fans to compensate for the flow restriction of the SCR reactor.

Construction of the SCRs is ongoing; as of May 2015, 99 percent of the 2,588 tons of the Unit 3 structural steel and 83 percent of the 7,570 linear feet of the SCR reactor piping has been completed. For Unit 4, 63 percent of the 3,031 tons of structural steel has been completed.

The Unit 3 SCR is scheduled to be completed by November 5, 2015, with a Wyoming SIP compliance deadline of December 31, 2015. Unit 4 is scheduled for completion by November 3, 2016, with a Wyoming SIP compliance date of December 31, 2016.

## 2015 Jim Bridger Units 3 and 4 SCR Analysis

The 2015 SCR Analysis re-examines the previous conclusion that installation of the SCRs on units 3 and 4 is the least-cost and least-risk means of ensuring that units 3 and 4 comply with state and federal emissions regulations. The 2015 SCR Analysis had two objectives:

1. Evaluate changes in environmental requirements since the 2013 Coal Study that may have an impact on the cost-effectiveness and/or viability of the SCRs on units 3 and 4, and

2. Determine the cost-effectiveness of installing the SCRs compared to the fixed costs of replacing the coal-fired generation from units 3 and 4 with a combined-cycle combustion turbine (CCCT) generation resource alternative.

### *Changes in Environmental Regulations*

On June 2, 2014, the EPA released its draft proposal to regulate carbon dioxide ($CO_2$) emissions from existing power plants. In the rule, the EPA proposes enforceable $CO_2$ performance goals that are based on a bottom-up, multi-factor analysis that reflects a system-wide approach of four building blocks, including increasing efficiency of the existing coal-fired generation, natural gas re-dispatch, renewable energy deployment, and demand-side energy efficiency. The goals take the form of state-wide carbon intensity rates for the state's electric power sector. Each state's goal reflects an emissions target (stated as lbs of $CO_2$/MWh of generation) that EPA has determined to be reasonable based upon the theoretical application of the "best system of emission reduction" for fossil-fueled power plants.

The proposal directs states to submit plans for meeting their goals. States may also work together to submit a single, coordinated multi-state plan. States and multi-state groups have a June 2016 deadline for submitting their plans, with the possibility of a 1- or 2-year extension depending on the plan type. Under the proposed rule, each state's plan must be approved by the EPA, based on modeling projections by the state that demonstrate, to the agency's satisfaction, that the plan will be adequate to meet EPA's determination of the state's interim and final goals. State plans do not need to rely upon the four building block measures EPA used to construct each state's goal. Rather, each state has relatively broad discretion to determine the policy measures on which it will rely to meet its goal.

There are several alternative approaches to 111(d) compliance. The individual states where the generators are physically located will determine the final impact to each of the affected units. Idaho Power has reviewed the Wyoming intensity targets and alternative approaches to compliance, and the company believes that there will be minimal impact on the normal operation of Jim Bridger units 3 and 4.

### *SCR Cost-Effectiveness*

To determine if the SCRs on units 3 and 4 continue to be the least-cost and least-risk option for compliance, the 2015 SCR Analysis compared the costs of two compliance options:

**Option 1**—Continue to install SCRs for compliance with state and federal environmental regulations

**Option 2**—Stop installation of SCRs and replace the coal-fired generation from units 3 and 4 with a CCCT.

## Overall Analysis Methodology

The study approach examined the costs and benefits of each option. The company's share of the nominal generation capacity at units 3 and 4 of 351 MW was assumed to be replaced with a CCCT with the same capacity. Incremental capital investment and fixed operations and maintenance (O&M) were included in the analysis. In addition, the fuel and variable O&M were forecasted for the duration of the study period to forecast the total cost of generation, both fixed and variable, for each compliance option.

The 2015 SCR Analysis utilized a 20-year study period over which the costs of both options are calculated. One difference between the 2015 SCR Analysis and the 2013 Coal Study is the inclusion of the return on investment in the net present value (NPV) calculations. In the 2013 Coal Study, the Science Applications International Corporation (SAIC) capital evaluation approach evaluated the capital costs of construction *without* the associated return on investment that is included in the company's regulatory revenue requirement determinations.

## Option 1 NPV Methodology

The company determined the cost of Option 1 by calculating the revenue requirement of the existing investment in units 3 and 4, incremental capital additions over the study period, the SCR capital costs (total SCR construction costs and fixed O&M) over the study period, and decommissioning costs. The additional costs of fuel and O&M related to operating the units over the study period were added to the revenue requirement of the capital investments.

The revenue requirement associated with the existing investment in units 3 and 4 includes the return on the existing investment for units 3 and 4, O&M, and fuel costs over the study period. The O&M information used in the analysis comes from the company's 10-year budget information from the Jim Bridger Plant forecast through the end of the study period. The company used data from its coal price forecast over the study period to determine the annual fuel expense including transportation costs. The company's coal price forecast is based on long-term contracts for supplying coal to the Jim Bridger Plant. The incremental capital additions include the cost of the SCRs as well as routine capital expenditures for maintenance and repairs throughout the study period. Also included as part of the costs of Option 1 are the decommissioning costs for units 3 and 4 that will be required when the units are retired. The company took the present value of the annual cost stream over the study period to determine the cost of Option 1. The cost of continuing to install the SCRs for compliance is $1.42 billion over the study period.

## Option 2 NPV Methodology

The costs of Option 2 is the combination of the costs to shutdown units 3 and 4 and build a CCCT to replace the generation from those shuttered units. The shutdown costs of units 3 and 4 include the accelerated recovery of the existing investment at units 3 and 4, accelerated recovery of the costs-to-date of the SCRs (dollars committed including cancelation penalties as of December 31, 2014), and decommissioning costs. By shutting down units 3 and 4 early, future ongoing capital costs on units 3 and 4 are avoided. The revenue requirement of the CCCT includes construction costs, fixed O&M, and return on investment over a 20-year period. The cost of the CCCT was based on the costs identified in the 2015 IRP for this type of resource. The assumption is that the CCCT would be sized to exactly replace the MW capacity of units 3 and 4. The CCCT in the analysis has an 85 percent capacity factor with an assumed heat rate of 6,714 Btu/kWh. The natural gas price forecast used in the analysis is an Idaho Citygate price forecast based on the 2015 IRP. The Idaho Citygate price is a Henry hub gas price with a Sumas hub differential applied plus transportation costs. It is assumed the CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho Citygate. The costs of shuttering units 3 and 4 and replacing that capacity with a CCCT are $2.496 billion over the study period.

## Analysis Results

Over the study period, the NPV of Option 1 is $1.420 billion and the NPV of Option 2 is $2.496 billion. Option 1, continuing to install the SCRs for compliance, is $1.076 billion less than compliance alternative Option 2.

The company performed additional analyses on the results to determine the main drivers of the $1.076 billion difference. As shown in the table below, $793 million was due to higher fuel costs in Option 2, $186 million was due to a higher return on capital investment in Option 2 due to the higher capital costs, O&M costs were $35 million less than Option 1 as a CCCT would be less O&M intensive than the Jim Bridger Plant, and capital costs for Option 2 were $132 million higher.

### *Option 2 Impact of Various Cost Drivers*

| | |
|---|---|
| Impact from fuel costs: | $793,308,007 |
| Impact from ROI: | 185,890,627 |
| Impact from difference in O&M: | (35,319,989) |
| Impact due to difference in capital costs: | 132,407,174 |
| **Total** | **$1,076,285,819** |

## Conclusions and Recommendations

Based on the 2015 SCR Analysis, continuing with the installation of the SCRs on units 3 and 4 represents a cost savings of $1.076 billion compared to shuttering units 3 and 4 and replacing that generation with a CCCT resource. The company evaluated the changes in environmental regulations proposed since the 2013 Coal Study and believes there will be little impact to the normal operation of units 3 and 4. The SCRs remain the least-cost and least risk option for compliance and the company will continue the installation of the SCRs on units 3 and 4.

# Revenue Requirement Comparison between Jim Bridger Units 3 and 4 SCR Completion and CCCT Replacement

## *Revenue Requirement on Existing Investments*

| Year | Existing Investments |
|---|---|
| 2015 | $101,017,077 |
| 2016 | $101,191,683 |
| 2017 | $102,260,140 |
| 2018 | $102,958,825 |
| 2019 | $103,167,948 |
| 2020 | $94,039,451 |
| 2021 | $91,247,597 |
| 2022 | $91,513,087 |
| 2023 | $94,069,370 |
| 2024 | $107,116,956 |
| 2025 | $108,120,849 |
| 2026 | $109,746,974 |
| 2027 | $111,413,380 |
| 2028 | $113,148,724 |
| 2029 | $114,824,751 |
| 2030 | $116,577,779 |
| 2031 | $118,486,952 |
| 2032 | $120,459,297 |
| 2033 | $122,496,977 |
| 2034 | $124,607,408 |
| **Total** | **$2,148,465,226** |

## Revenue Requirement on Incremental Investments

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | $14,340,755 | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | $13,838,158 | $7,184,838 | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | $13,335,560 | $6,923,888 | $2,204,363 | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | $12,832,963 | $6,662,937 | $2,121,284 | $3,037,499 | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | $12,330,366 | $6,401,986 | $2,038,205 | $2,918,537 | $2,451,064 |
| 2020 | 9,596,002 | 15 | 12/31/2020 | $11,827,769 | $6,141,035 | $1,955,126 | $2,799,575 | $2,351,156 |
| 2021 | 7,181,971 | 14 | 12/31/2021 | $11,325,172 | $5,880,084 | $1,872,047 | $2,680,613 | $2,251,249 |
| 2022 | 5,935,721 | 13 | 12/31/2022 | $10,822,575 | $5,619,133 | $1,788,968 | $2,561,650 | $2,151,341 |
| 2023 | 7,897,482 | 12 | 12/31/2023 | $10,319,978 | $5,358,183 | $1,705,889 | $2,442,688 | $2,051,434 |
| 2024 | 7,633,488 | 11 | 12/31/2024 | $9,817,381 | $5,097,232 | $1,622,810 | $2,323,726 | $1,951,526 |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $9,314,784 | $4,836,281 | $1,539,730 | $2,204,764 | $1,851,618 |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $8,812,187 | $4,575,330 | $1,456,651 | $2,085,801 | $1,751,711 |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $8,309,589 | $4,314,379 | $1,373,572 | $1,966,839 | $1,651,803 |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $7,806,992 | $4,053,428 | $1,290,493 | $1,847,877 | $1,551,895 |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $7,304,395 | $3,792,477 | $1,207,414 | $1,728,914 | $1,451,988 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $6,801,798 | $3,531,527 | $1,124,335 | $1,609,952 | $1,352,080 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $6,299,201 | $3,270,576 | $1,041,256 | $1,490,990 | $1,252,172 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $5,796,604 | $3,009,625 | $958,177 | $1,372,028 | $1,152,265 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $5,294,007 | $2,748,674 | $875,097 | $1,253,065 | $1,052,357 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $4,791,410 | $2,487,723 | $792,018 | $1,134,103 | $952,450 |
| **Total** | | | | **$191,321,644** | **$91,889,335** | **$26,967,437** | **$35,458,621** | **$27,228,109** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | $1,666,615 | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | $1,595,796 | $1,279,658 | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | $1,524,977 | $1,222,868 | $1,088,414 | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | $1,454,157 | $1,166,079 | $1,037,869 | $1,495,959 | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | $1,383,338 | $1,109,289 | $987,323 | $1,423,104 | $1,500,581 |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $1,312,518 | $1,052,500 | $936,777 | $1,350,249 | $1,423,759 |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $1,241,699 | $995,710 | $886,232 | $1,277,393 | $1,346,938 |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $1,170,879 | $938,920 | $835,686 | $1,204,538 | $1,270,116 |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $1,100,060 | $882,131 | $785,141 | $1,131,683 | $1,193,294 |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $1,029,240 | $825,341 | $734,595 | $1,058,827 | $1,116,473 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $958,421 | $768,551 | $684,049 | $985,972 | $1,039,651 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $887,602 | $711,762 | $633,504 | $913,117 | $962,829 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $816,782 | $654,972 | $582,958 | $840,262 | $886,008 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $745,963 | $598,182 | $532,412 | $767,406 | $809,186 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $675,143 | $541,393 | $481,867 | $694,551 | $732,364 |
| **Total** | | | | **$12,747,356** | **$10,206,828** | **$13,143,061** | **$12,281,200** | **$11,882,675** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | — | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | — | — | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | — | — | — | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | — | — | — | — | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | — | — | — | — | — |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $1,569,304 | — | — | — | — |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $1,484,629 | $1,565,606 | — | — | — |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $1,399,955 | $1,476,313 | $1,664,400 | — | — |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $1,315,280 | $1,387,020 | $1,563,731 | $1,852,921 | — |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $1,230,605 | $1,297,726 | $1,463,061 | $1,733,634 | $2,003,557 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $1,145,930 | $1,208,433 | $1,362,392 | $1,614,347 | $1,865,697 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $1,061,255 | $1,119,140 | $1,261,722 | $1,495,060 | $1,727,838 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $976,580 | $1,029,846 | $1,161,053 | $1,375,773 | $1,589,978 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $891,906 | $940,553 | $1,060,383 | $1,256,486 | $1,452,118 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $807,231 | $851,260 | $959,713 | $1,137,199 | $1,314,259 |
| **Total** | | | | **$11,882,675** | **$10,875,898** | **$10,496,455** | **$10,465,423** | **$9,953,447** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | — | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | — | — | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | — | — | — | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | — | — | — | — | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | — | — | — | — | — |
| 2025 | 7,648,933 | 10 | 12/31/2025 | — | — | — | — | — |
| 2026 | 7,259,519 | 9 | 12/31/2026 | — | — | — | — | — |
| 2027 | 7,275,029 | 8 | 12/31/2027 | — | — | — | — | — |
| 2028 | 7,542,890 | 7 | 12/31/2028 | — | — | — | — | — |
| 2029 | 7,471,972 | 6 | 12/31/2029 | — | — | — | — | — |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $2,229,158 | — | — | — | — |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $2,064,441 | $2,566,035 | — | — | — |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $1,899,725 | $2,361,297 | $3,160,168 | — | — |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $1,735,008 | $2,156,560 | $2,886,164 | $4,346,789 | — |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $1,570,292 | $1,951,823 | $2,612,160 | $3,934,118 | $7,849,803 |
| **Total** | | | | **$9,498,625** | **$9,035,714** | **$8,658,492** | **$8,280,906** | **$7,849,803** |

## Revenue Requirement on Decommissioning Costs

| | Decommissioning Costs (Estimated in 2034 dollars) |
|---|---|
| 2034 Costs | $52,244,513 |
| Present Value | $29,794,316 |
| Annual Payment | $1,241,717 |

## Total Payments—Comparison between Option 1 & 2

| | Option 1 | Option 2 | | | |
|---|---|---|---|---|---|
| Year | Continue w/SCR | Total Payments Accelerated Shutdown* | Costs of Replacement CCCT | Total Annual Costs | Difference between Option 1 & 2 |
| 2015 | $116,599,549 | $335,842,318 | $169,233,797 | $505,076,115 | $388,476,567 |
| 2016 | $123,456,396 | $351,737,422 | $159,080,882 | $510,818,304 | $387,361,908 |
| 2017 | $125,965,668 | | $158,051,633 | $158,051,633 | $32,085,964 |
| 2018 | $128,855,226 | | $164,658,910 | $164,658,910 | $35,803,683 |
| 2019 | $130,549,824 | | $170,473,692 | $170,473,692 | $39,923,868 |
| 2020 | $122,022,445 | | $172,507,122 | $172,507,122 | $50,484,678 |
| 2021 | $119,373,933 | | $174,789,729 | $174,789,729 | $55,415,797 |
| 2022 | $119,534,731 | | $175,912,781 | $175,912,781 | $56,378,050 |
| 2023 | $122,343,322 | | $179,087,087 | $179,087,087 | $56,743,766 |
| 2024 | $135,574,982 | | $181,551,652 | $181,551,652 | $45,976,670 |
| 2025 | $136,754,850 | | $183,671,759 | $183,671,759 | $46,916,909 |
| 2026 | $138,468,578 | | $181,060,725 | $181,060,725 | $42,592,147 |
| 2027 | $140,232,087 | | $181,088,595 | $181,088,595 | $40,856,508 |
| 2028 | $142,152,387 | | $183,931,004 | $183,931,004 | $41,778,617 |
| 2029 | $144,044,717 | | $188,184,330 | $188,184,330 | $44,139,613 |
| 2030 | $146,101,790 | | $195,077,058 | $195,077,058 | $48,975,268 |
| 2031 | $148,487,168 | | $201,099,893 | $201,099,893 | $52,612,724 |
| 2032 | $151,325,114 | | $203,445,436 | $203,445,436 | $52,120,322 |
| 2033 | $155,141,012 | | $209,308,283 | $209,308,283 | $54,167,271 |
| 2034 | $162,120,005 | | $58,279,478** | $58,279,478 | $(103,840,527) |
| **NPV** | **$1,419,569,231** | | | **$2,495,855,049** | **$1,076,285,818** |

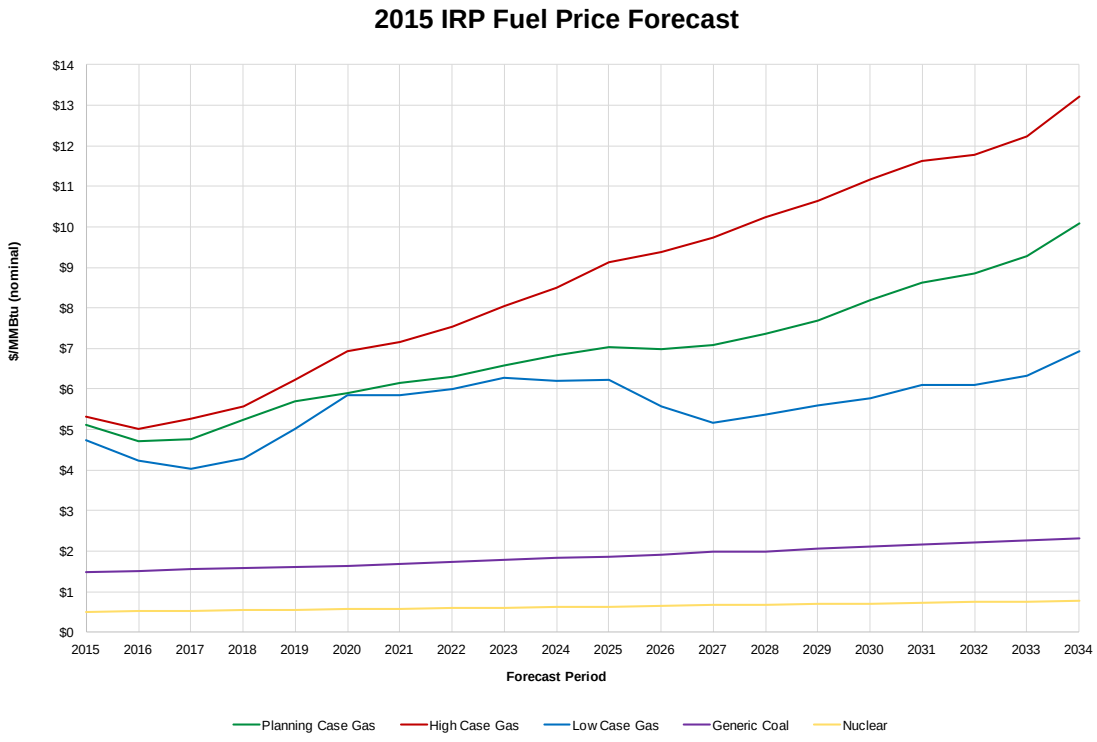
*Bridger SCR 3 and 4 Stacked PWorth—accelerated

**Residual value (Book value) included in the final year: (163,567,666)

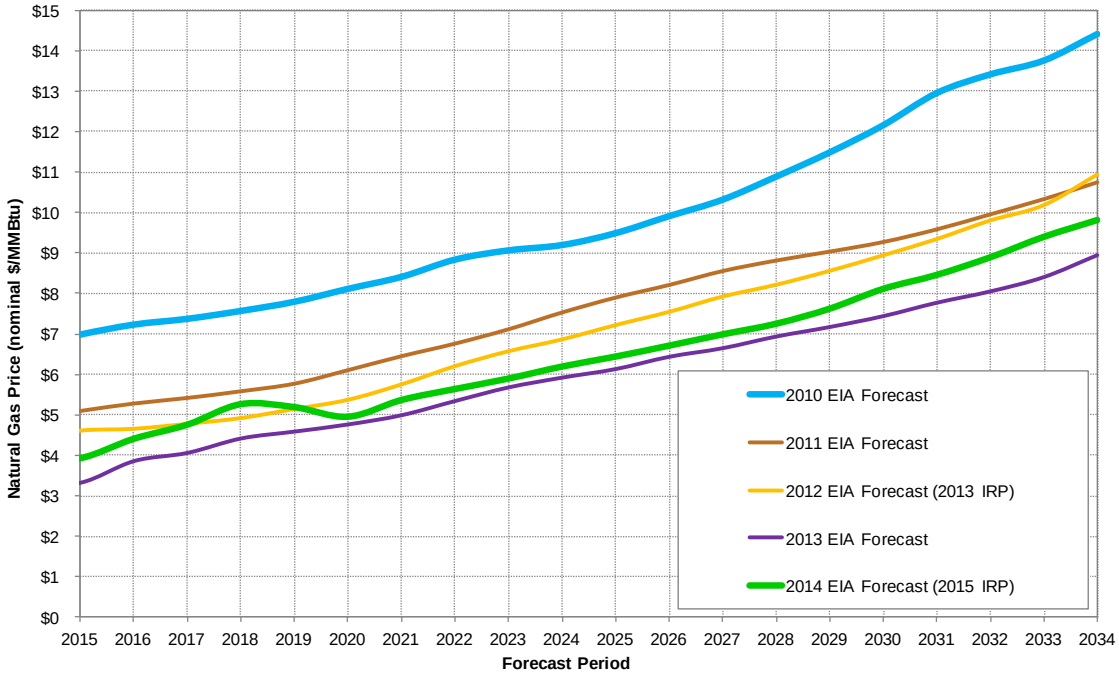
# FUEL PRICE FORECAST

## Natural Gas and Coal Price Forecast (nominal $/MMBtu)

| | Idaho Citygate Natural Gas | | | | |
|---|---|---|---|---|---|
| Year | Planning Case | High Case | Low Case | Generic Coal | Nuclear |
| 2015 | $5.10 | $5.32 | $4.74 | $1.47 | $0.51 |
| 2016 | $4.70 | $5.02 | $4.24 | $1.52 | $0.52 |
| 2017 | $4.76 | $5.26 | $4.02 | $1.55 | $0.53 |
| 2018 | $5.25 | $5.56 | $4.27 | $1.58 | $0.54 |
| 2019 | $5.69 | $6.22 | $5.02 | $1.61 | $0.56 |
| 2020 | $5.91 | $6.94 | $5.85 | $1.64 | $0.57 |
| 2021 | $6.14 | $7.17 | $5.85 | $1.69 | $0.58 |
| 2022 | $6.30 | $7.54 | $5.99 | $1.74 | $0.59 |
| 2023 | $6.58 | $8.04 | $6.27 | $1.78 | $0.61 |
| 2024 | $6.82 | $8.49 | $6.21 | $1.83 | $0.62 |
| 2025 | $7.04 | $9.13 | $6.24 | $1.87 | $0.63 |
| 2026 | $6.99 | $9.38 | $5.57 | $1.91 | $0.65 |
| 2027 | $7.09 | $9.73 | $5.17 | $1.98 | $0.66 |
| 2028 | $7.35 | $10.24 | $5.38 | $2.00 | $0.68 |
| 2029 | $7.69 | $10.64 | $5.60 | $2.07 | $0.69 |
| 2030 | $8.18 | $11.18 | $5.77 | $2.12 | $0.71 |
| 2031 | $8.62 | $11.62 | $6.10 | $2.16 | $0.72 |
| 2032 | $8.85 | $11.78 | $6.09 | $2.21 | $0.74 |
| 2033 | $9.28 | $12.24 | $6.33 | $2.27 | $0.75 |
| 2034 | $10.09 | $13.21 | $6.94 | $2.32 | $0.77 |



**Historical EIA Henry Hub Spot Price Forecasts**




*all values taken from EIA Annual Energy Outlook reports:
http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a

# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 106,190 |
| Bliss | 86,250 | 75,000 | 75,000 | 84,860 |
| Brownlee | 650,444 | 585,400 | 585,400 | 678,040 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,280 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 95,420 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,430 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 449,580 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 69,140 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 13,500 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,400 |
| Milner | 62,890 | 59,448 | 59,448 | 61,880 |
| Oxbow | 211,112 | 190,000 | 190,000 | 218,520 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 12,500 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800 | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 54,170 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,000 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 16,560 |
| **Total Hydro** | **1,897,046** | **1,709,045** | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC)[6,7] kW | Net Dependable Capability (NDC)[6,7] Summer kW | Net Dependable Capability (NDC)[6,7] Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,501 | | 707,667 | 707,667 |
| Boardman (Idaho Power share) | 67,600 | 64,200 | | 57,550 | 58,050 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 260,000 | 260,000 |
| **Total Thermal** | **1,193,653** | **1,118,201** | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit #1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,405 | | |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,066 | | |
| Langley Gulch CT | 220,000 | 187,000 | 176,880 | | |
| Langley Gulch ST | 154,650 | 131,452 | 122,765 | | |
| **Total Natural Gas** | **867,650** | **762,152** | | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,965,229** | **3,594,398** | | | |

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Status as of May 26, 2015.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Littlewood / Arkoosh | 0.87 | Aug-1986 | Aug-2021 |
| Birch Creek | 0.05 | Nov-1984 | Nov-2019 | Low Line Canal | 7.97 | May-1985 | May-2020 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Low Line Midway Hydro | 2.50 | Aug-2007 | Aug-2027 |
| Black Canyon Bliss Hydro | 0.03 | Nov-2014 | Estimated | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Blind Canyon | 1.63 | Dec-2014 | Dec-2034 | Magic Reservoir | 9.07 | Jun-1989 | Jun-2024 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Malad River | 0.62 | May-1984 | May-2019 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Marco Ranches | 1.20 | Aug-1985 | Aug-2020 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mile 28 | 1.50 | Jun-1994 | Jun-2029 |
| Canyon Springs | 0.13 | Oct-1984 | Oct-2040 | Mill Creek Hydroelectric | 0.80 | Oct-2011 | Jun-2017 |
| Cedar Draw | 1.55 | Jun-1984 | Jun-2019 | Mitchell Butte | 2.09 | May-1989 | Dec-2033 |
| Clark Canyon Hydroelectric | 7.55 | Jun-2017 | Estimated | Mora Drop Small Hydro Fac | 1.85 | Sep-2006 | Sep-2026 |
| Clear Springs Trout | 0.52 | Nov-1983 | Nov-2018 | Mud Creek/S&S | 0.52 | Feb-1982 | Jan-2017 |
| Crystal Springs | 2.44 | Apr-1986 | Apr-2021 | Mud Creek/White | 0.21 | Jan-1986 | Jan-2021 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Owyhee Dam Cspp | 5.00 | Aug-1985 | May-2033 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Eightmile Hydro Project | 0.36 | Oct-2014 | Oct-2034 | Pristine Springs #1 2005 | 0.13 | May-2005 | May-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Pristine Springs #3 2005 | 0.20 | May-2005 | May-2015 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Fargo Drop Hydroelectric | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #2 | 1.90 | Apr-1989 | Apr-2024 |
| Fisheries Dev. | 0.26 | Jul-1990 | Jul-2040 | Sagebrush | 0.43 | Sep-1985 | Sep-2020 |
| Geo-Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sahko Hydro | 0.50 | Feb-2011 | Feb-2021 |
| Hailey Cspp | 0.06 | Jun-1985 | Jun-2020 | Schaffner | 0.53 | Aug-1986 | Aug-2021 |
| Hazelton A | 8.10 | Mar-2011 | Mar-2026 | Shingle Creek | 0.22 | Aug-1983 | Aug-2017 |
| Hazelton B | 7.60 | May-1993 | May-2028 | Shoshone #2 | 0.58 | May-1996 | May-2031 |
| Head of U Canal Project | 1.28 | May-2015 | Estimated | Shoshone Cspp | 0.37 | Jun-1982 | Feb-2017 |
| Horseshoe Bend Hydro | 9.50 | Sep-1995 | Sep-2030 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Snedigar | 0.54 | Jan-1985 | Jan-2020 |
| Kasel & Witherspoon | 0.90 | Mar-1984 | Mar-2019 | Tiber Dam | 7.50 | Jun-2004 | Jun-2024 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Apr-2019 | Trout-Co | 0.24 | Dec-1986 | Dec-2021 |
| Lateral # 10 | 2.06 | May-1985 | May-2020 | Tunnel #1 | 7.00 | Jun-1993 | Feb-2035 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | White Water Ranch | 0.16 | Aug-1985 | Aug-2020 |
| Little Wood River Ranch II | 1.25 | Jun-2015 | Estimated | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 153.81 MW** | | | | | | | |
| **Thermal Projects** | | | | | | | |
| Magic Valley Natural Gas | 10.00 | Nov-1996 | Nov-2016 | TASCO—Nampa Natural Gas | 2.00 | Sep-2003 | Non firm |
| Simplot Pocatello Cogen | 15.90 | Mar-2013 | Feb-2016 | TASCO—Twin Falls Natural Gas | 3.00 | Aug-2001 | Non firm |
| **Total Thermal Nameplate Rating 30.90 MW** | | | | | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2010 | Aug-2020 | Fighting Creek Landfill | 3.06 | Apr-2014 | Apr-2029 |
| Bannock County Landfill | 3.20 | May-2014 | May-2034 | Hidden Hollow Landfill Gas | 3.20 | Jan-2007 | Jan-2027 |
| Bettencourt Dry Creek BioFactory | 2.25 | May-2010 | May-2020 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | Rock Creek Dairy | 4.00 | Aug-2012 | Aug-2027 |
| Double A Digester Project | 4.50 | Jan-2012 | Jan-2032 | Tamarack CSPP | 5.00 | Jun-1983 | Jun-2018 |
| **Total Biomass Nameplate Rating 29.45 MW** | | | | | | | |
| **Solar Projects** | | | | | | | |
| American Falls Solar II, LLC | 20.00 | Dec-2016 | Estimated | Open Range Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| American Falls Solar, LLC | 40.00 | Jan-2016 | Estimated | Orchard Ranch Solar, LLC | 20.00 | Dec-2016 | Estimated |
| Boise City Solar, LLC | 80.00 | Sep-2016 | Estimated | Pocatello Solar 1, LLC | 20.00 | Dec-2016 | Estimated |
| Grand View PV Solar Two | 10.00 | Dec-2016 | Estimated | Railroad Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Grove Solar Center, LLC | 10.00 | Dec-2016 | Estimated | Simco Solar, LLC | 20.00 | Dec-2016 | Estimated |
| Hyline Solar Center, LLC | 20.00 | Dec-2016 | Estimated | Thunderegg Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Mountain Home Solar, LLC | 20.00 | Dec-2016 | Estimated | Vale Air Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Murphy Flat Power, LLC | 20.00 | Dec-2016 | Estimated | | | | |
| **Total Solar Nameplate Rating 320 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Mainline Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Benson Creek Windfarm | 10.00 | Dec-2016 | Estimated | Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 |
| Burley Butte Wind Park | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind Park | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm LLC | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Cold Springs Windfarm | 23.00 | Dec-2012 | Dec-2032 | Prospector Windfarm | 10.00 | Dec-2016 | Estimated |
| Desert Meadow Windfarm | 23.00 | Dec-2012 | Dec-2032 | Rockland Wind Farm | 80.00 | Dec-2011 | Dec-2036 |
| Durbin Creek Windfarm | 10.00 | Dec-2016 | Estimated | Ryegrass Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Salmon Falls Wind | 22.00 | Apr-2011 | Apr-2031 |
| Golden Valley Wind Park | 12.00 | Feb-2011 | Feb-2031 | Sawtooth Wind Project | 22.00 | Nov-2011 | Nov-2031 |
| Hammett Hill Windfarm | 23.00 | Dec-2012 | Dec-2032 | Thousand Springs Wind Park | 12.00 | Jan-2011 | Jan-2031 |
| High Mesa Wind Project | 40.00 | Dec-2012 | Dec-2032 | Tuana Gulch Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind | 9.00 | Feb-2006 | Feb-2026 | Tuana Springs Expansion | 35.70 | May-2010 | May-2030 |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Two Ponds Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Jett Creek Windfarm | 10.00 | Dec-2016 | Estimated | Willow Spring Windfarm | 10.00 | Dec-2016 | Estimated |
| Lime Wind Energy | 3.00 | Dec-2011 | Dec-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| **Total Wind Nameplate Rating 626.92 MW** | | | | | | | |
| **Total Nameplate Rating 1,161.80 MW** | | | | | | | |

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of May 26, 2015. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

# Power Purchase Agreement Data

**Idaho Power Company Power Purchase Agreements Status as of April 1, 2015**

| Project | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | November 2012 | November 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

1. Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.
2. Not included in the above table is the energy exchange agreement between Idaho Power and the Clatskanie PUD. Under the exchange, Idaho Power receives energy from the 18-MW power plant at Arrowrock Dam on the Boise River and returns to Clatskanie PUD energy of an equivalent value delivered seasonally. The agreement began in January 2010 and extends through 2015. Idaho Power retains the right to renew the agreement through 2025.

# Hydro Modeling Results (PDR580)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 319.5 | 359.7 | 341.3 | 433.4 | 409.9 | 397.5 | 247.5 | 164.8 | 212.9 | 193.7 | 152.6 | 253.6 | 290.5 |
| Oxbow | HCC | 131.7 | 155.5 | 155.1 | 188.7 | 168.0 | 161.7 | 105.0 | 75.3 | 97.5 | 89.0 | 69.3 | 106.8 | 125.3 |
| Hells Canyon | HCC | 259.2 | 308.6 | 313.1 | 386.6 | 346.5 | 326.9 | 208.1 | 148.1 | 191.3 | 175.5 | 138.1 | 211.7 | 251.1 |
| 1000 Springs | ROR** | 24.4 | 25.8 | 26.0 | 58.3 | 83.0 | 89.5 | 83.9 | 64.8 | 43.1 | 16.1 | - | 17.4 | 44.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.5 | 50.4 | 44.0 | 54.2 | 48.2 | 42.0 | 35.3 | 28.3 | 37.3 | 40.0 | 38.4 | 45.8 | 42.8 |
| C .J. Strike | ROR | 64.7 | 66.1 | 58.9 | 70.6 | 60.8 | 52.2 | 36.9 | 31.4 | 44.6 | 51.0 | 50.7 | 59.9 | 54.0 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.9 | 35.5 | 29.3 | 38.4 | 34.2 | 28.3 | 23.0 | 16.1 | 23.6 | 26.0 | 24.3 | 31.5 | 28.8 |
| Milner | ROR | 41.5 | 42.1 | 26.3 | 42.5 | 34.3 | 15.4 | 6.2 | - | - | - | 4.9 | 30.8 | 20.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.0 | 22.6 | 19.9 | 17.1 | 12.9 | 11.0 | 15.0 | 16.9 | 16.8 | 19.4 | 17.7 |
| Twin Falls | ROR | 40.8 | 41.8 | 27.9 | 45.8 | 34.7 | 20.1 | 10.5 | - | - | 6.6 | 9.1 | 31.6 | 22.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.1 | 19.1 | 17.6 | 18.1 | 14.1 | 8.9 | 14.5 | 16.1 | 14.9 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.6 | 17.7 | 17.7 | 16.2 | 13.2 | 8.9 | 13.6 | 15.0 | 13.9 | 17.7 | 15.6 |
| **HCC Total** | | **710.4** | **823.8** | **809.5** | **1,008.7** | **924.3** | **886.1** | **560.6** | **388.2** | **501.7** | **458.2** | **360.0** | **572.1** | **667.0** |
| **ROR Total** | | **353.1** | **360.4** | **310.6** | **414.6** | **396.6** | **349.8** | **285.2** | **217.2** | **235.8** | **228.4** | **212.9** | **313.1** | **306.5** |
| **Total** | | **1,063.5** | **1,184.2** | **1,120.1** | **1,423.3** | **1,320.9** | **1,235.9** | **845.8** | **605.4** | **737.5** | **686.6** | **572.9** | **885.2** | **973.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 319.9 | 361.6 | 342.8 | 440.7 | 419.2 | 406.5 | 247.9 | 164.5 | 212.8 | 193.5 | 152.7 | 254.7 | 293.1 |
| Oxbow | HCC | 131.9 | 156.3 | 155.7 | 191.7 | 171.7 | 165.2 | 105.2 | 75.2 | 97.5 | 88.9 | 69.4 | 107.3 | 126.3 |
| Hells Canyon | HCC | 259.5 | 310.1 | 314.4 | 392.7 | 353.8 | 333.8 | 208.5 | 147.8 | 191.4 | 175.4 | 138.2 | 212.6 | 253.2 |
| 1000 Springs | ROR** | 24.8 | 26.5 | 26.8 | 60.7 | 84.5 | 90.9 | 83.9 | 64.9 | 42.8 | 16.1 | - | 19.3 | 45.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.4 | 50.5 | 44.2 | 55.0 | 49.1 | 42.3 | 35.2 | 28.2 | 37.2 | 40.0 | 38.0 | 47.3 | 43.0 |
| C .J. Strike | ROR | 64.6 | 66.1 | 59.6 | 70.7 | 63.4 | 53.4 | 36.7 | 31.3 | 44.5 | 51.0 | 50.6 | 60.7 | 54.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.9 | 35.7 | 29.7 | 38.9 | 35.0 | 28.9 | 23.0 | 16.0 | 23.5 | 25.9 | 24.3 | 32.5 | 29.0 |
| Milner | ROR | 42.0 | 43.0 | 26.9 | 42.5 | 36.7 | 17.3 | 6.2 | - | - | - | 4.9 | 34.6 | 21.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.3 | 22.8 | 20.4 | 17.5 | 12.9 | 11.0 | 14.9 | 16.8 | 16.7 | 19.6 | 17.8 |
| Twin Falls | ROR | 41.7 | 42.1 | 28.0 | 45.8 | 36.7 | 21.3 | 10.5 | - | - | 6.6 | 9.1 | 35.4 | 23.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 18.6 | 14.0 | 8.9 | 14.4 | 16.1 | 14.8 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.5 | 15.0 | 13.9 | 17.7 | 15.6 |
| **HCC Total** | | **711.3** | **828.0** | **812.9** | **1,025.1** | **944.7** | **905.5** | **561.6** | **387.5** | **501.6** | **457.8** | **360.3** | **574.6** | **672.6** |
| **ROR Total** | | **354.7** | **362.6** | **313.9** | **418.6** | **407.3** | **357.3** | **284.8** | **216.9** | **235.0** | **228.2** | **212.2** | **326.1** | **309.8** |
| **Total** | | **1,066.0** | **1,190.6** | **1,126.8** | **1,443.7** | **1,351.9** | **1,262.8** | **846.4** | **604.4** | **736.6** | **686.0** | **572.5** | **900.7** | **982.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 319.1 | 365.2 | 343.4 | 446.8 | 429.4 | 418.8 | 248.5 | 164.6 | 210.7 | 194.5 | 152.6 | 253.7 | 295.6 |
| Oxbow | HCC | 131.6 | 157.8 | 156.0 | 194.3 | 175.8 | 170.1 | 105.4 | 75.2 | 96.3 | 89.1 | 69.2 | 106.9 | 127.3 |
| Hells Canyon | HCC | 258.9 | 313.1 | 314.9 | 397.8 | 361.8 | 343.3 | 209.0 | 148.0 | 189.1 | 175.7 | 138.0 | 211.8 | 255.1 |
| 1000 Springs | ROR** | 25.1 | 26.6 | 27.1 | 61.1 | 85.8 | 93.3 | 84.0 | 65.0 | 43.1 | 16.6 | - | 20.9 | 45.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.2 | 50.6 | 44.2 | 55.4 | 50.2 | 43.6 | 35.4 | 28.3 | 37.2 | 40.0 | 38.1 | 48.2 | 43.4 |
| C .J. Strike | ROR | 64.8 | 66.0 | 59.4 | 70.7 | 65.1 | 53.7 | 36.8 | 31.5 | 44.5 | 51.1 | 50.1 | 61.7 | 54.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.0 | 35.4 | 29.6 | 38.9 | 35.9 | 29.3 | 23.0 | 16.1 | 23.4 | 26.0 | 23.9 | 33.0 | 29.1 |
| Milner | ROR | 41.5 | 42.3 | 27.8 | 42.9 | 39.0 | 20.9 | 6.2 | - | - | - | 3.8 | 34.8 | 21.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.3 | 22.7 | 21.1 | 17.5 | 12.9 | 11.0 | 14.9 | 16.8 | 16.4 | 19.9 | 17.9 |
| Twin Falls | ROR | 41.5 | 41.6 | 29.1 | 45.8 | 38.7 | 23.8 | 10.5 | - | - | 6.6 | 8.5 | 35.1 | 23.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.0 | 14.0 | 8.9 | 14.3 | 16.1 | 14.5 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.4 | 15.0 | 13.6 | 17.7 | 15.5 |
| **HCC Total** | | **709.6** | **836.1** | **814.3** | **1,038.9** | **967.0** | **932.2** | **562.9** | **387.8** | **496.1** | **459.3** | **359.8** | **572.4** | **678.0** |
| **ROR Total** | | **354.4** | **361.2** | **315.9** | **419.7** | **417.3** | **368.2** | **285.2** | **217.4** | **234.9** | **228.9** | **208.8** | **330.3** | **311.9** |
| **Total** | | **1,064.0** | **1,197.3** | **1,130.2** | **1,458.6** | **1,384.3** | **1,300.4** | **848.1** | **605.2** | **731.0** | **688.2** | **568.6** | **902.7** | **989.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 321.3 | 364.6 | 343.3 | 444.7 | 432.7 | 419.1 | 249.0 | 164.3 | 209.5 | 194.4 | 153.1 | 252.6 | 295.7 |
| Oxbow | HCC | 132.5 | 157.5 | 155.9 | 193.4 | 176.8 | 170.2 | 105.6 | 75.1 | 95.7 | 88.9 | 69.4 | 106.4 | 127.3 |
| Hells Canyon | HCC | 260.5 | 312.6 | 314.8 | 396.0 | 364.4 | 343.5 | 209.4 | 147.7 | 187.8 | 175.5 | 138.3 | 210.9 | 255.1 |
| 1000 Springs | ROR** | 25.7 | 28.4 | 27.0 | 61.3 | 86.8 | 95.1 | 84.0 | 65.1 | 43.1 | 17.8 | - | 20.9 | 46.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.5 | 51.1 | 43.7 | 55.4 | 50.9 | 44.7 | 35.3 | 28.2 | 37.0 | 40.0 | 38.0 | 47.3 | 43.4 |
| C .J. Strike | ROR | 65.4 | 66.4 | 58.9 | 70.7 | 66.1 | 54.6 | 36.7 | 31.4 | 44.3 | 51.0 | 50.1 | 61.3 | 54.7 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.1 | 36.2 | 29.2 | 38.9 | 36.6 | 30.2 | 22.9 | 16.0 | 23.3 | 25.9 | 23.8 | 32.7 | 29.2 |
| Milner | ROR | 41.5 | 45.0 | 26.7 | 44.9 | 40.9 | 24.5 | 6.2 | - | - | - | 3.6 | 34.3 | 22.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.4 | 19.1 | 22.7 | 21.3 | 17.8 | 12.8 | 11.0 | 14.9 | 16.8 | 16.4 | 19.8 | 17.9 |
| Twin Falls | ROR | 41.6 | 43.8 | 28.3 | 47.4 | 40.5 | 26.9 | 10.5 | - | - | 6.6 | 8.5 | 34.7 | 24.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.1 | 19.1 | 17.5 | 19.2 | 14.0 | 8.8 | 14.2 | 16.0 | 14.4 | 19.2 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.5 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.3 | 14.9 | 13.5 | 17.7 | 15.5 |
| **HCC Total** | | **714.3** | **834.7** | **814.0** | **1,034.1** | **973.9** | **932.8** | **564.0** | **387.1** | **493.0** | **458.8** | **360.8** | **569.9** | **678.1** |
| **ROR Total** | | **356.1** | **369.8** | **312.0** | **423.5** | **424.3** | **380.4** | **284.7** | **217.1** | **234.2** | **229.8** | **208.2** | **327.7** | **314.0** |
| **Total** | | **1,070.4** | **1,204.5** | **1,126.0** | **1,457.6** | **1,398.1** | **1,313.2** | **848.7** | **604.2** | **727.2** | **688.6** | **569.0** | **897.6** | **992.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 320.0 | 363.3 | 344.2 | 441.7 | 437.9 | 419.7 | 249.6 | 164.8 | 207.5 | 195.1 | 153.1 | 250.3 | 295.6 |
| Oxbow | HCC | 132.0 | 157.0 | 156.3 | 192.2 | 177.8 | 170.4 | 105.9 | 75.3 | 94.5 | 89.0 | 69.3 | 105.4 | 127.1 |
| Hells Canyon | HCC | 259.6 | 311.5 | 315.6 | 393.5 | 368.5 | 344.0 | 209.9 | 148.1 | 185.6 | 175.5 | 138.1 | 208.9 | 254.9 |
| 1000 Springs | ROR** | 25.9 | 28.4 | 27.2 | 61.0 | 87.9 | 95.5 | 84.1 | 65.1 | 43.1 | 18.2 | 5.2 | 18.1 | 46.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.7 | 51.4 | 42.4 | 54.5 | 51.5 | 45.5 | 35.5 | 28.4 | 37.1 | 40.1 | 37.2 | 46.1 | 43.3 |
| C .J. Strike | ROR | 65.8 | 67.4 | 57.6 | 70.1 | 67.0 | 55.2 | 36.8 | 31.5 | 44.3 | 51.1 | 48.8 | 58.4 | 54.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.3 | 36.6 | 28.2 | 38.9 | 37.4 | 31.7 | 23.0 | 16.1 | 23.3 | 25.9 | 23.4 | 30.5 | 29.2 |
| Milner | ROR | 41.7 | 44.9 | 22.6 | 43.7 | 42.7 | 27.2 | 6.2 | - | - | - | - | 27.8 | 21.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 21.0 | 21.5 | 18.7 | 22.5 | 21.6 | 18.0 | 12.9 | 11.1 | 14.9 | 16.9 | 16.1 | 19.0 | 17.9 |
| Twin Falls | ROR | 41.8 | 43.7 | 24.7 | 46.7 | 41.9 | 28.9 | 10.5 | - | - | 6.6 | 6.0 | 28.9 | 23.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.3 | 19.1 | 17.5 | 19.2 | 14.1 | 8.9 | 14.2 | 16.1 | 14.1 | 19.2 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.9 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.3 | 15.0 | 13.3 | 17.7 | 15.4 |
| **HCC Total** | | **711.6** | **831.8** | **816.1** | **1,027.4** | **984.2** | **934.1** | **565.4** | **388.2** | **487.6** | **459.6** | **360.5** | **564.6** | **677.6** |
| **ROR Total** | | **357.6** | **371.4** | **299.1** | **419.6** | **431.2** | **388.6** | **285.4** | **217.7** | **234.3** | **230.7** | **201.7** | **305.5** | **311.9** |
| **Total** | | **1,069.2** | **1,203.2** | **1,115.2** | **1,447.0** | **1,415.4** | **1,322.7** | **850.8** | **605.9** | **721.9** | **690.3** | **562.2** | **870.1** | **989.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 318.8 | 360.6 | 343.8 | 440.8 | 436.3 | 418.9 | 249.0 | 164.1 | 205.9 | 195.3 | 153.5 | 249.2 | 294.7 |
| Oxbow | HCC | 131.5 | 155.8 | 156.2 | 191.8 | 177.4 | 170.1 | 105.6 | 75.0 | 93.7 | 89.0 | 69.4 | 104.9 | 126.7 |
| Hells Canyon | HCC | 258.6 | 309.3 | 315.3 | 392.8 | 367.2 | 343.3 | 209.4 | 147.5 | 184.0 | 175.5 | 138.3 | 208.0 | 254.1 |
| 1000 Springs | ROR** | 25.7 | 27.1 | 26.9 | 60.7 | 87.7 | 95.1 | 84.1 | 65.1 | 42.9 | 18.5 | 5.2 | 16.9 | 46.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.4 | 51.0 | 42.2 | 54.3 | 51.3 | 45.2 | 35.4 | 28.2 | 36.8 | 39.9 | 37.0 | 45.2 | 43.0 |
| C .J. Strike | ROR | 64.7 | 65.9 | 56.8 | 69.8 | 66.7 | 54.6 | 36.6 | 31.3 | 44.0 | 50.9 | 48.6 | 57.1 | 53.9 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.1 | 35.3 | 27.8 | 38.9 | 37.2 | 31.2 | 22.9 | 15.9 | 23.0 | 25.8 | 23.2 | 29.7 | 28.8 |
| Milner | ROR | 41.4 | 43.3 | 22.1 | 43.4 | 42.3 | 27.1 | 6.2 | - | - | - | - | 25.7 | 21.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.3 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 18.5 | 22.4 | 21.5 | 17.8 | 12.9 | 11.0 | 14.8 | 16.8 | 16.0 | 18.6 | 17.7 |
| Twin Falls | ROR | 41.5 | 43.3 | 24.3 | 46.4 | 41.6 | 28.9 | 10.5 | - | - | 6.6 | 7.4 | 27.1 | 23.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.0 | 19.1 | 17.5 | 19.2 | 14.0 | 8.8 | 14.0 | 16.0 | 14.0 | 19.1 | 16.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.6 | 17.7 | 17.7 | 16.2 | 13.2 | 8.7 | 13.2 | 14.9 | 13.1 | 17.6 | 15.4 |
| **HCC Total** | | **708.9** | **825.7** | **815.3** | **1,025.4** | **980.9** | **932.3** | **564.0** | **386.6** | **483.5** | **459.8** | **361.2** | **562.1** | **675.5** |
| **ROR Total** | | **355.1** | **364.7** | **295.7** | **418.1** | **429.5** | **386.5** | **284.9** | **216.8** | **232.8** | **230.2** | **203.7** | **296.8** | **309.6** |
| **Total** | | **1,064.0** | **1,190.4** | **1,111.0** | **1,443.5** | **1,410.4** | **1,318.8** | **848.9** | **603.4** | **716.3** | **690.0** | **564.9** | **858.9** | **985.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 317.6 | 356.8 | 343.3 | 439.9 | 434.6 | 418.1 | 248.4 | 163.5 | 204.4 | 195.9 | 153.1 | 248.5 | 293.7 |
| Oxbow | HCC | 131.0 | 154.3 | 156.0 | 191.4 | 177.1 | 169.8 | 105.4 | 74.7 | 92.9 | 89.1 | 69.2 | 104.6 | 126.3 |
| Hells Canyon | HCC | 257.7 | 306.2 | 314.9 | 392.0 | 365.9 | 342.7 | 208.9 | 147.0 | 182.4 | 175.7 | 137.9 | 207.4 | 253.2 |
| 1000 Springs | ROR** | 25.5 | 26.9 | 26.4 | 60.5 | 87.5 | 95.1 | 84.1 | 65.0 | 42.4 | 18.0 | - | 15.6 | 45.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.2 | 50.7 | 41.9 | 54.0 | 51.1 | 44.8 | 35.2 | 28.0 | 36.6 | 39.7 | 36.8 | 44.3 | 42.7 |
| C .J. Strike | ROR | 64.4 | 65.0 | 56.4 | 69.4 | 66.4 | 54.3 | 36.4 | 31.1 | 43.6 | 50.6 | 48.4 | 55.7 | 53.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.7 | 34.9 | 27.6 | 38.5 | 37.0 | 30.8 | 22.8 | 15.7 | 22.8 | 25.6 | 23.0 | 29.5 | 28.6 |
| Milner | ROR | 41.1 | 42.9 | 21.4 | 43.0 | 42.0 | 26.9 | 6.2 | - | - | - | - | 24.9 | 20.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.8 | 21.1 | 18.4 | 22.3 | 21.4 | 17.7 | 12.8 | 10.9 | 14.7 | 16.7 | 16.0 | 18.2 | 17.6 |
| Twin Falls | ROR | 41.3 | 43.0 | 23.4 | 45.9 | 41.3 | 28.5 | 10.5 | - | - | 6.6 | 6.0 | 26.9 | 22.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.8 | 19.1 | 17.5 | 19.2 | 13.9 | 8.6 | 13.8 | 15.8 | 13.8 | 19.0 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.4 | 17.7 | 17.7 | 16.2 | 13.1 | 8.6 | 13.0 | 14.7 | 13.0 | 17.5 | 15.3 |
| **HCC Total** | | **706.3** | **817.3** | **814.2** | **1,023.3** | **977.5** | **930.6** | **562.7** | **385.2** | **479.6** | **460.7** | **360.2** | **560.5** | **673.2** |
| **ROR Total** | | **353.4** | **362.0** | **292.2** | **415.8** | **427.9** | **384.7** | **284.1** | **215.7** | **231.0** | **228.5** | **194.6** | **291.4** | **306.8** |
| **Total** | | **1,059.7** | **1,179.3** | **1,106.4** | **1,439.1** | **1,405.4** | **1,315.3** | **846.8** | **600.9** | **710.6** | **689.2** | **554.8** | **851.9** | **980.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 316.4 | 353.8 | 342.8 | 438.9 | 433.0 | 417.3 | 247.7 | 162.8 | 201.2 | 196.4 | 153.6 | 247.3 | 292.6 |
| Oxbow | HCC | 130.5 | 153.0 | 155.7 | 191.0 | 176.8 | 169.5 | 105.1 | 74.4 | 91.1 | 89.0 | 69.4 | 104.1 | 125.8 |
| Hells Canyon | HCC | 256.8 | 303.7 | 314.4 | 391.2 | 364.6 | 342.1 | 208.3 | 146.4 | 178.9 | 175.5 | 138.2 | 206.4 | 252.2 |
| 1000 Springs | ROR** | 24.7 | 26.5 | 26.1 | 60.3 | 87.3 | 95.1 | 84.1 | 65.0 | 42.3 | 17.5 | - | 14.3 | 45.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.9 | 50.0 | 41.4 | 53.8 | 50.9 | 44.5 | 35.0 | 27.8 | 36.4 | 39.5 | 36.6 | 43.4 | 42.4 |
| C .J. Strike | ROR | 64.0 | 65.0 | 56.0 | 69.1 | 66.1 | 54.0 | 36.2 | 30.8 | 43.3 | 50.3 | 47.8 | 54.5 | 53.1 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.4 | 34.7 | 27.3 | 38.2 | 36.8 | 30.4 | 22.6 | 15.6 | 22.6 | 25.4 | 22.8 | 29.3 | 28.3 |
| Milner | ROR | 40.6 | 42.3 | 18.8 | 42.8 | 41.7 | 26.2 | 6.2 | - | - | - | - | 24.9 | 20.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.4 | 21.0 | 18.3 | 22.2 | 21.3 | 17.6 | 12.8 | 10.8 | 14.6 | 16.4 | 15.8 | 17.9 | 17.4 |
| Twin Falls | ROR | 40.1 | 41.4 | 21.6 | 45.8 | 41.1 | 28.3 | 10.5 | - | - | 6.6 | 6.0 | 26.9 | 22.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.6 | 19.1 | 17.5 | 19.2 | 13.8 | 8.5 | 13.7 | 15.7 | 13.7 | 18.8 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.3 | 17.7 | 17.7 | 16.2 | 13.0 | 8.5 | 12.9 | 14.6 | 12.9 | 17.3 | 15.2 |
| **HCC Total** | | **703.7** | **810.5** | **812.9** | **1,021.1** | **974.4** | **928.9** | **561.1** | **383.6** | **471.2** | **460.9** | **361.2** | **557.8** | **670.6** |
| **ROR Total** | | **349.5** | **358.4** | **285.9** | **414.4** | **426.4** | **382.7** | **283.3** | **214.8** | **230.0** | **226.8** | **193.2** | **287.1** | **304.4** |
| **Total** | | **1,053.2** | **1,168.9** | **1,098.8** | **1,435.5** | **1,400.8** | **1,311.6** | **844.4** | **598.4** | **701.2** | **687.7** | **554.4** | **844.9** | **975.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 315.3 | 351.6 | 342.5 | 438.1 | 431.7 | 416.5 | 247.1 | 162.2 | 198.5 | 196.2 | 153.6 | 246.7 | 291.7 |
| Oxbow | HCC | 130.1 | 152.1 | 155.6 | 190.6 | 176.5 | 169.2 | 104.8 | 74.1 | 89.7 | 88.7 | 69.3 | 103.8 | 125.4 |
| Hells Canyon | HCC | 255.9 | 301.9 | 314.2 | 390.5 | 363.6 | 341.5 | 207.8 | 145.8 | 176.2 | 175.0 | 138.1 | 205.9 | 251.4 |
| 1000 Springs | ROR** | 24.5 | 25.6 | 25.9 | 60.0 | 87.1 | 95.1 | 84.1 | 64.9 | 42.3 | 17.4 | - | 13.8 | 45.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.7 | 48.8 | 41.3 | 53.6 | 50.7 | 44.2 | 34.9 | 27.6 | 36.2 | 39.3 | 36.4 | 42.5 | 42.0 |
| C .J. Strike | ROR | 63.6 | 64.6 | 55.9 | 68.8 | 65.8 | 53.8 | 36.0 | 30.6 | 43.0 | 50.1 | 47.6 | 53.3 | 52.8 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.2 | 34.0 | 27.1 | 37.8 | 36.6 | 30.0 | 22.5 | 15.4 | 22.4 | 25.3 | 22.6 | 28.5 | 28.0 |
| Milner | ROR | 40.3 | 40.7 | 18.5 | 42.5 | 41.4 | 25.4 | 6.2 | - | - | - | - | 23.9 | 19.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.3 | 20.9 | 18.2 | 22.1 | 21.3 | 17.6 | 12.7 | 10.7 | 14.5 | 16.4 | 15.8 | 17.5 | 17.3 |
| Twin Falls | ROR | 39.9 | 40.8 | 21.3 | 45.6 | 40.9 | 27.8 | 10.5 | - | - | 6.6 | 6.0 | 25.4 | 22.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.4 | 19.1 | 17.5 | 19.2 | 13.7 | 8.4 | 13.5 | 15.6 | 13.5 | 18.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.1 | 17.7 | 17.7 | 16.2 | 12.9 | 8.4 | 12.7 | 14.5 | 12.8 | 16.8 | 15.1 |
| **HCC Total** | | **701.3** | **805.6** | **812.3** | **1,019.2** | **971.7** | **927.2** | **559.7** | **382.1** | **464.4** | **459.9** | **361.0** | **556.4** | **668.4** |
| **ROR Total** | | **347.9** | **352.9** | **284.2** | **412.6** | **425.0** | **380.5** | **282.6** | **213.8** | **228.7** | **226.0** | **192.3** | **279.7** | **302.2** |
| **Total** | | **1,049.2** | **1,158.5** | **1,096.5** | **1,431.8** | **1,396.7** | **1,307.7** | **842.3** | **595.9** | **693.1** | **685.9** | **553.3** | **836.1** | **970.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 314.2 | 350.3 | 345.8 | 437.2 | 430.1 | 415.7 | 246.5 | 161.5 | 196.3 | 196.1 | 153.6 | 245.6 | 291.1 |
| Oxbow | HCC | 129.6 | 151.5 | 157.0 | 190.3 | 176.3 | 168.9 | 104.6 | 73.8 | 88.6 | 88.6 | 69.3 | 103.3 | 125.1 |
| Hells Canyon | HCC | 255.0 | 300.9 | 317.0 | 389.8 | 362.4 | 340.9 | 207.3 | 145.2 | 174.0 | 174.8 | 138.0 | 205.0 | 250.9 |
| 1000 Springs | ROR** | 24.3 | 25.4 | 25.6 | 59.8 | 86.9 | 95.0 | 84.1 | 64.9 | 42.1 | 17.4 | - | 13.8 | 44.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.4 | 48.4 | 41.1 | 53.4 | 50.5 | 43.8 | 34.7 | 27.4 | 35.9 | 39.0 | 36.3 | 41.7 | 41.7 |
| C .J. Strike | ROR | 63.2 | 64.2 | 55.7 | 68.5 | 65.5 | 53.5 | 35.8 | 30.3 | 42.6 | 49.6 | 47.3 | 52.5 | 52.4 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.0 | 33.7 | 26.9 | 37.5 | 36.4 | 29.6 | 22.4 | 15.2 | 22.2 | 25.1 | 22.4 | 27.6 | 27.8 |
| Milner | ROR | 40.1 | 40.4 | 18.1 | 42.2 | 41.1 | 24.9 | 6.2 | - | - | - | - | 21.7 | 19.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.2 | 20.2 | 18.1 | 22.0 | 21.2 | 17.5 | 12.6 | 10.6 | 14.4 | 16.3 | 15.7 | 17.3 | 17.2 |
| Twin Falls | ROR | 39.6 | 40.5 | 20.9 | 45.4 | 40.6 | 27.3 | 10.5 | - | - | 6.6 | 6.0 | 23.5 | 21.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.2 | 19.1 | 17.5 | 19.2 | 13.5 | 8.3 | 13.3 | 15.4 | 13.4 | 17.5 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.9 | 17.7 | 17.7 | 16.2 | 12.8 | 8.3 | 12.6 | 14.4 | 12.7 | 16.2 | 15.0 |
| **HCC Total** | | **698.8** | **802.7** | **819.8** | **1,017.3** | **968.7** | **925.5** | **558.4** | **380.5** | **458.8** | **459.5** | **360.9** | **553.9** | **667.1** |
| **ROR Total** | | **346.2** | **350.3** | **282.0** | **411.0** | **423.4** | **378.2** | **281.7** | **212.8** | **227.3** | **224.6** | **191.4** | **271.6** | **300.0** |
| **Total** | | **1,045.0** | **1,153.0** | **1,101.8** | **1,428.3** | **1,392.1** | **1,303.7** | **840.1** | **593.3** | **686.1** | **684.1** | **552.3** | **825.5** | **967.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 313.2 | 349.2 | 344.9 | 436.5 | 429.4 | 415.0 | 245.9 | 160.9 | 194.4 | 196.1 | 153.8 | 244.7 | 290.3 |
| Oxbow | HCC | 129.2 | 151.1 | 156.7 | 190.0 | 175.8 | 168.6 | 104.3 | 73.5 | 87.6 | 88.5 | 69.4 | 103.0 | 124.8 |
| Hells Canyon | HCC | 254.2 | 300.0 | 316.2 | 389.2 | 361.8 | 340.3 | 206.8 | 144.7 | 172.1 | 174.6 | 138.2 | 204.3 | 250.2 |
| 1000 Springs | ROR** | 23.9 | 25.2 | 25.4 | 59.5 | 86.7 | 94.7 | 84.1 | 64.9 | 42.0 | 17.3 | - | 13.4 | 44.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.1 | 48.1 | 40.9 | 53.2 | 50.3 | 43.5 | 34.5 | 27.2 | 35.7 | 38.9 | 36.0 | 41.0 | 41.5 |
| C .J. Strike | ROR | 62.9 | 63.8 | 55.3 | 68.2 | 65.3 | 53.3 | 35.6 | 30.1 | 42.3 | 49.4 | 47.1 | 51.4 | 52.1 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.6 | 33.5 | 26.7 | 37.2 | 36.2 | 29.3 | 22.2 | 15.1 | 21.9 | 24.9 | 22.3 | 26.9 | 27.5 |
| Milner | ROR | 39.5 | 40.3 | 17.8 | 42.0 | 40.8 | 24.6 | 6.2 | - | - | - | - | 20.0 | 19.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.1 | 20.0 | 18.0 | 21.9 | 21.1 | 17.4 | 12.6 | 10.6 | 14.3 | 16.2 | 15.6 | 17.0 | 17.1 |
| Twin Falls | ROR | 39.1 | 40.3 | 20.6 | 45.2 | 40.4 | 27.0 | 10.5 | - | - | 6.6 | 6.0 | 22.0 | 21.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.1 | 19.1 | 17.5 | 18.9 | 13.4 | 8.1 | 13.1 | 15.3 | 13.3 | 16.9 | 15.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.8 | 17.7 | 17.7 | 16.2 | 12.7 | 8.2 | 12.4 | 14.3 | 12.6 | 15.7 | 14.9 |
| **HCC Total** | | **696.6** | **800.3** | **817.8** | **1,015.7** | **967.0** | **923.9** | **557.0** | **379.1** | **454.0** | **459.2** | **361.4** | **552.0** | **665.3** |
| **ROR Total** | | **343.6** | **348.7** | **280.1** | **409.4** | **422.0** | **376.1** | **280.9** | **212.0** | **225.9** | **223.7** | **190.5** | **264.1** | **298.1** |
| **Total** | | **1,040.2** | **1,149.0** | **1,097.9** | **1,425.1** | **1,389.0** | **1,300.0** | **837.9** | **591.1** | **679.9** | **682.9** | **551.9** | **816.1** | **963.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 312.2 | 348.2 | 343.9 | 435.7 | 429.4 | 414.2 | 245.3 | 160.3 | 192.5 | 196.0 | 153.8 | 244.5 | 289.7 |
| Oxbow | HCC | 128.8 | 150.6 | 156.2 | 189.6 | 175.8 | 168.2 | 104.0 | 73.2 | 86.6 | 88.3 | 69.3 | 102.9 | 124.5 |
| Hells Canyon | HCC | 253.4 | 299.1 | 315.4 | 388.5 | 361.8 | 339.7 | 206.3 | 144.1 | 170.2 | 174.2 | 138.1 | 204.1 | 249.6 |
| 1000 Springs | ROR** | 23.7 | 25.0 | 25.1 | 59.3 | 86.6 | 94.4 | 84.0 | 64.8 | 42.0 | 17.9 | - | 12.4 | 44.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.6 | 47.9 | 40.6 | 53.0 | 50.1 | 43.2 | 34.5 | 27.0 | 35.4 | 38.7 | 35.9 | 40.3 | 41.2 |
| C .J. Strike | ROR | 62.6 | 63.0 | 54.7 | 67.9 | 64.3 | 52.9 | 35.3 | 29.9 | 42.0 | 49.1 | 46.6 | 50.4 | 51.6 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.2 | 33.3 | 26.5 | 36.9 | 36.0 | 29.2 | 22.1 | 14.9 | 21.7 | 24.7 | 22.1 | 26.2 | 27.2 |
| Milner | ROR | 39.3 | 40.1 | 17.5 | 41.7 | 40.6 | 24.2 | 6.2 | - | - | - | - | 18.0 | 19.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.0 | 19.9 | 17.9 | 21.8 | 20.9 | 17.3 | 12.5 | 10.5 | 14.2 | 16.2 | 15.5 | 16.7 | 17.0 |
| Twin Falls | ROR | 38.9 | 40.1 | 20.3 | 45.0 | 40.2 | 26.7 | 10.5 | - | - | 6.6 | 6.0 | 20.5 | 21.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 16.9 | 19.1 | 17.5 | 18.9 | 13.3 | 8.0 | 13.0 | 15.1 | 13.1 | 16.4 | 15.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.7 | 17.7 | 17.7 | 16.2 | 12.6 | 8.1 | 12.3 | 14.2 | 12.4 | 15.2 | 14.8 |
| **HCC Total** | | **694.4** | **797.9** | **815.5** | **1,013.8** | **967.0** | **922.1** | **555.6** | **377.6** | **449.3** | **458.5** | **361.2** | **551.5** | **663.7** |
| **ROR Total** | | **341.7** | **346.8** | **277.7** | **407.8** | **419.9** | **374.2** | **280.1** | **211.0** | **224.7** | **223.3** | **189.2** | **255.9** | **296.0** |
| **Total** | | **1,036.1** | **1,144.7** | **1,093.2** | **1,421.6** | **1,386.8** | **1,296.3** | **835.7** | **588.6** | **674.0** | **681.8** | **550.4** | **807.4** | **959.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 311.1 | 347.2 | 343.1 | 434.9 | 429.0 | 413.4 | 244.6 | 159.7 | 190.0 | 196.6 | 154.2 | 242.7 | 288.9 |
| Oxbow | HCC | 128.4 | 150.2 | 155.9 | 189.3 | 175.6 | 167.9 | 103.8 | 72.9 | 85.3 | 88.4 | 69.5 | 102.1 | 124.1 |
| Hells Canyon | HCC | 252.6 | 298.3 | 314.7 | 387.9 | 361.5 | 339.1 | 205.7 | 143.5 | 167.7 | 174.4 | 138.4 | 202.6 | 248.9 |
| 1000 Springs | ROR** | 23.6 | 24.8 | 24.9 | 59.1 | 86.4 | 94.2 | 84.0 | 64.8 | 41.9 | 17.3 | - | 11.4 | 44.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.4 | 47.6 | 40.4 | 52.1 | 49.9 | 42.9 | 34.4 | 26.8 | 35.2 | 38.4 | 35.9 | 39.6 | 40.9 |
| C .J. Strike | ROR | 62.0 | 61.5 | 54.0 | 67.6 | 63.9 | 52.5 | 35.1 | 29.6 | 41.7 | 48.9 | 46.3 | 49.2 | 51.0 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.0 | 33.0 | 26.0 | 36.6 | 35.8 | 29.1 | 22.0 | 14.8 | 21.5 | 24.5 | 21.9 | 25.4 | 27.0 |
| Milner | ROR | 39.1 | 39.8 | 17.2 | 40.9 | 40.3 | 23.9 | 6.2 | - | - | - | - | 16.0 | 18.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.9 | 19.8 | 17.7 | 21.8 | 20.7 | 17.2 | 12.4 | 10.4 | 14.1 | 16.1 | 15.4 | 16.2 | 16.8 |
| Twin Falls | ROR | 38.7 | 39.8 | 20.0 | 43.8 | 40.0 | 26.4 | 10.5 | - | - | 6.6 | 6.0 | 18.9 | 20.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.6 | 19.1 | 17.6 | 18.7 | 13.2 | 7.9 | 12.8 | 15.0 | 13.0 | 15.8 | 15.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.4 | 17.7 | 17.7 | 16.2 | 12.5 | 8.0 | 12.2 | 14.0 | 12.3 | 14.7 | 14.7 |
| **HCC Total** | | **692.1** | **795.7** | **813.7** | **1,012.1** | **966.1** | **920.4** | **554.1** | **376.1** | **443.0** | **459.4** | **362.1** | **547.4** | **661.9** |
| **ROR Total** | | **340.2** | **343.8** | **274.7** | **404.1** | **418.3** | **372.3** | **279.4** | **210.1** | **223.6** | **221.6** | **188.4** | **247.0** | **293.6** |
| **Total** | | **1,032.3** | **1,139.5** | **1,088.4** | **1,416.2** | **1,384.4** | **1,292.7** | **833.5** | **586.2** | **666.6** | **681.0** | **550.5** | **794.4** | **955.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 310.1 | 346.1 | 340.1 | 434.1 | 427.8 | 412.6 | 244.0 | 159.0 | 188.1 | 196.7 | 153.9 | 242.1 | 287.9 |
| Oxbow | HCC | 128.0 | 149.8 | 154.6 | 189.0 | 175.1 | 167.6 | 103.5 | 72.6 | 84.3 | 88.4 | 69.3 | 101.8 | 123.7 |
| Hells Canyon | HCC | 251.8 | 297.4 | 312.2 | 387.2 | 360.6 | 338.5 | 205.3 | 143.0 | 165.8 | 174.3 | 138.0 | 202.1 | 248.0 |
| 1000 Springs | ROR** | 23.5 | 24.6 | 23.9 | 58.2 | 86.3 | 94.0 | 84.0 | 64.7 | 41.9 | 17.0 | - | 10.4 | 44.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.1 | 47.3 | 39.8 | 51.8 | 49.7 | 42.6 | 34.3 | 26.7 | 34.9 | 38.2 | 35.7 | 38.9 | 40.6 |
| C .J. Strike | ROR | 61.3 | 61.1 | 53.0 | 67.3 | 63.5 | 52.1 | 34.9 | 29.4 | 41.3 | 48.5 | 46.1 | 48.1 | 50.6 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.7 | 32.8 | 25.5 | 36.4 | 35.4 | 28.8 | 21.8 | 14.6 | 21.3 | 24.4 | 21.8 | 24.7 | 26.7 |
| Milner | ROR | 38.9 | 39.5 | 16.2 | 43.5 | 40.2 | 23.6 | 6.2 | - | - | - | - | 14.4 | 18.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.7 | 19.7 | 17.5 | 21.7 | 20.4 | 17.1 | 12.4 | 10.3 | 14.2 | 16.0 | 15.3 | 15.9 | 16.7 |
| Twin Falls | ROR | 38.5 | 39.6 | 18.7 | 42.3 | 39.8 | 26.2 | 10.5 | - | - | 6.6 | 5.9 | 17.3 | 20.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 16.1 | 19.1 | 17.6 | 18.5 | 13.1 | 7.8 | 12.6 | 14.9 | 12.9 | 15.2 | 15.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.0 | 17.7 | 17.7 | 16.2 | 12.4 | 7.9 | 12.0 | 13.9 | 12.2 | 14.2 | 14.6 |
| **HCC Total** | | **689.9** | **793.3** | **806.9** | **1,010.3** | **963.5** | **918.7** | **552.8** | **374.6** | **438.1** | **459.4** | **361.2** | **546.0** | **659.6** |
| **ROR Total** | | **338.2** | **342.2** | **268.2** | **403.4** | **416.6** | **370.3** | **278.7** | **209.2** | **222.3** | **220.3** | **187.4** | **238.9** | **291.3** |
| **Total** | | **1,028.1** | **1,135.5** | **1,075.1** | **1,413.7** | **1,380.0** | **1,289.0** | **831.5** | **583.8** | **660.4** | **679.7** | **548.6** | **784.9** | **950.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 309.1 | 345.1 | 339.7 | 433.4 | 427.0 | 411.9 | 243.5 | 158.4 | 185.8 | 197.0 | 154.2 | 241.1 | 287.2 |
| Oxbow | HCC | 127.6 | 149.3 | 154.4 | 188.7 | 174.8 | 167.3 | 103.3 | 72.3 | 83.2 | 88.3 | 69.4 | 101.4 | 123.3 |
| Hells Canyon | HCC | 251.0 | 296.6 | 311.8 | 386.6 | 359.9 | 337.9 | 204.8 | 142.5 | 163.6 | 174.3 | 138.2 | 201.2 | 247.4 |
| 1000 Springs | ROR** | 23.3 | 24.5 | 23.7 | 58.0 | 85.8 | 93.8 | 84.0 | 64.7 | 41.8 | 17.3 | - | 9.4 | 43.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.9 | 47.1 | 39.5 | 51.6 | 49.5 | 42.3 | 34.1 | 26.5 | 34.7 | 38.1 | 35.4 | 38.2 | 40.3 |
| C .J. Strike | ROR | 61.0 | 60.8 | 52.6 | 66.5 | 63.2 | 51.7 | 34.7 | 29.2 | 41.0 | 48.2 | 45.8 | 47.1 | 50.2 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.5 | 32.5 | 25.0 | 36.1 | 34.2 | 28.5 | 21.7 | 14.4 | 21.1 | 24.2 | 21.5 | 24.0 | 26.3 |
| Milner | ROR | 38.6 | 39.3 | 14.5 | 42.9 | 36.4 | 23.3 | 6.2 | - | - | - | - | 12.5 | 17.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.6 | 19.6 | 17.3 | 21.4 | 20.3 | 17.0 | 12.3 | 10.3 | 14.1 | 15.9 | 15.2 | 15.6 | 16.6 |
| Twin Falls | ROR | 38.3 | 39.4 | 18.4 | 41.8 | 36.5 | 25.9 | 10.5 | - | - | 6.6 | 5.9 | 15.8 | 19.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.7 | 19.1 | 17.6 | 18.3 | 13.0 | 7.7 | 12.5 | 14.8 | 12.7 | 14.7 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 17.7 | 17.7 | 16.2 | 12.3 | 7.8 | 11.9 | 13.8 | 12.1 | 13.8 | 14.5 |
| **HCC Total** | | **687.7** | **791.0** | **805.9** | **1,008.7** | **961.7** | **917.1** | **551.6** | **373.2** | **432.6** | **459.6** | **361.8** | **543.7** | **657.9** |
| **ROR Total** | | **336.7** | **340.8** | **263.9** | **400.5** | **407.2** | **368.2** | **277.9** | **208.4** | **221.2** | **219.7** | **186.1** | **230.9** | **288.5** |
| **Total** | | **1,024.4** | **1,131.8** | **1,069.8** | **1,409.2** | **1,368.9** | **1,285.3** | **829.5** | **581.6** | **653.8** | **679.3** | **547.9** | **774.6** | **946.3** |

*HCC=HellsCanyonComplex,**ROR=RunofRiver

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 308.1 | 344.0 | 339.3 | 432.6 | 426.2 | 411.0 | 242.8 | 157.8 | 184.7 | 197.1 | 153.9 | 240.3 | 286.5 |
| Oxbow | HCC | 127.1 | 148.9 | 154.2 | 188.3 | 174.5 | 167.0 | 103.0 | 72.0 | 82.6 | 88.3 | 69.2 | 101.0 | 123.0 |
| Hells Canyon | HCC | 250.2 | 295.7 | 311.5 | 385.9 | 359.3 | 337.3 | 204.3 | 141.9 | 162.4 | 174.2 | 137.9 | 200.5 | 246.8 |
| 1000 Springs | ROR** | 23.1 | 24.3 | 23.4 | 57.8 | 85.8 | 93.7 | 84.0 | 64.7 | 41.7 | 17.2 | - | 8.4 | 43.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.7 | 46.8 | 38.9 | 51.4 | 49.3 | 42.0 | 34.0 | 26.3 | 34.4 | 38.0 | 35.4 | 37.5 | 40.1 |
| C .J. Strike | ROR | 60.7 | 60.4 | 52.3 | 66.1 | 62.9 | 51.3 | 34.5 | 28.9 | 40.7 | 48.0 | 45.5 | 46.7 | 49.8 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.3 | 32.1 | 25.0 | 35.8 | 34.0 | 28.3 | 21.6 | 14.3 | 20.8 | 24.1 | 21.3 | 23.7 | 26.1 |
| Milner | ROR | 38.4 | 39.0 | 13.5 | 42.6 | 36.2 | 23.0 | 6.2 | - | - | - | - | 11.4 | 17.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.5 | 19.5 | 17.2 | 21.3 | 20.2 | 16.9 | 12.2 | 10.2 | 14.0 | 15.9 | 15.4 | 15.6 | 16.5 |
| Twin Falls | ROR | 38.1 | 39.1 | 17.2 | 41.4 | 36.2 | 25.6 | 10.5 | - | - | 6.6 | 5.9 | 14.2 | 19.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.7 | 19.1 | 17.6 | 18.1 | 12.9 | 7.5 | 12.3 | 14.6 | 12.5 | 14.5 | 15.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 17.7 | 17.7 | 16.2 | 12.3 | 7.7 | 11.7 | 13.7 | 11.9 | 13.6 | 14.4 |
| **HCC Total** | | **685.4** | **788.6** | **805.0** | **1,006.8** | **959.9** | **915.3** | **550.1** | **371.7** | **429.7** | **459.6** | **361.0** | **541.8** | **656.2** |
| **ROR Total** | | **335.3** | **338.8** | **260.4** | **398.6** | **405.9** | **366.3** | **277.3** | **207.4** | **219.7** | **218.9** | **185.4** | **225.4** | **286.6** |
| **Total** | | **1,020.7** | **1,127.4** | **1,065.4** | **1,405.4** | **1,365.8** | **1,281.6** | **827.4** | **579.1** | **649.4** | **678.5** | **546.4** | **767.2** | **942.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 307.1 | 343.0 | 338.8 | 431.9 | 425.3 | 410.3 | 242.3 | 157.2 | 179.2 | 197.0 | 154.4 | 239.4 | 285.5 |
| Oxbow | HCC | 126.7 | 148.5 | 154.0 | 188.0 | 174.2 | 166.7 | 102.8 | 71.7 | 81.7 | 88.1 | 69.4 | 100.7 | 122.7 |
| Hells Canyon | HCC | 249.4 | 294.8 | 311.0 | 385.3 | 358.6 | 336.8 | 203.8 | 141.3 | 160.4 | 173.8 | 138.3 | 199.8 | 246.1 |
| 1000 Springs | ROR** | 23.0 | 23.8 | 22.6 | 57.0 | 85.8 | 93.5 | 84.0 | 64.6 | 41.7 | 17.3 | - | 7.4 | 43.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.4 | 46.5 | 38.6 | 51.2 | 49.1 | 42.0 | 33.8 | 26.1 | 34.2 | 37.8 | 35.3 | 36.8 | 39.8 |
| C .J. Strike | ROR | 60.3 | 60.0 | 52.0 | 65.2 | 62.7 | 50.9 | 34.3 | 28.7 | 40.5 | 47.7 | 45.3 | 46.5 | 49.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.1 | 31.9 | 24.9 | 35.5 | 33.8 | 28.0 | 21.4 | 14.1 | 20.6 | 23.9 | 21.2 | 23.7 | 25.9 |
| Milner | ROR | 38.2 | 38.5 | 13.5 | 42.0 | 35.9 | 22.6 | 6.2 | - | - | - | - | 9.8 | 17.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.4 | 19.4 | 17.1 | 21.1 | 20.1 | 16.7 | 12.2 | 10.1 | 13.9 | 15.8 | 15.3 | 15.6 | 16.4 |
| Twin Falls | ROR | 38.0 | 38.2 | 16.8 | 40.9 | 36.0 | 25.3 | 10.5 | - | - | 6.6 | 5.9 | 12.6 | 19.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.6 | 19.1 | 17.6 | 17.9 | 12.8 | 7.4 | 12.1 | 14.5 | 12.4 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 17.7 | 17.7 | 16.2 | 12.2 | 7.6 | 11.6 | 13.6 | 11.8 | 13.6 | 14.3 |
| **HCC Total** | | **683.2** | **786.3** | **803.8** | **1,005.2** | **958.1** | **913.8** | **548.9** | **370.2** | **421.2** | **458.9** | **362.1** | **539.9** | **654.3** |
| **ROR Total** | | **333.9** | **335.9** | **258.2** | **395.1** | **404.7** | **364.3** | **276.5** | **206.4** | **218.7** | **218.0** | **184.7** | **220.3** | **284.7** |
| **Total** | | **1,017.1** | **1,122.2** | **1,062.0** | **1,400.3** | **1,362.7** | **1,278.1** | **825.4** | **576.6** | **639.9** | **676.9** | **546.8** | **760.2** | **939.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 306.1 | 342.0 | 338.4 | 431.1 | 424.6 | 409.3 | 241.7 | 156.5 | 177.0 | 197.3 | 154.3 | 238.7 | 284.7 |
| Oxbow | HCC | 126.3 | 148.0 | 153.8 | 187.7 | 173.9 | 166.3 | 102.5 | 71.4 | 80.5 | 88.1 | 69.3 | 100.4 | 122.3 |
| Hells Canyon | HCC | 248.6 | 294.0 | 310.7 | 384.7 | 358.0 | 335.9 | 203.4 | 140.8 | 158.1 | 173.8 | 138.1 | 199.2 | 245.4 |
| 1000 Springs | ROR** | 22.9 | 23.7 | 21.7 | 56.8 | 85.6 | 93.3 | 84.0 | 64.6 | 41.6 | 17.2 | - | 6.4 | 43.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.2 | 46.3 | 38.5 | 51.1 | 48.9 | 42.0 | 33.7 | 25.9 | 33.9 | 37.7 | 35.1 | 36.5 | 39.7 |
| C .J. Strike | ROR | 60.0 | 59.7 | 51.7 | 64.9 | 62.4 | 50.5 | 34.1 | 28.4 | 40.2 | 47.6 | 45.1 | 46.2 | 49.2 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.9 | 31.7 | 24.7 | 35.0 | 33.7 | 27.7 | 21.3 | 14.0 | 20.4 | 23.8 | 21.0 | 23.7 | 25.7 |
| Milner | ROR | 38.0 | 38.2 | 12.5 | 40.8 | 35.7 | 22.3 | 6.2 | - | - | - | - | 8.2 | 16.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.4 | 19.3 | 17.0 | 21.0 | 20.1 | 16.5 | 12.1 | 10.0 | 13.8 | 15.7 | 15.3 | 15.6 | 16.3 |
| Twin Falls | ROR | 37.8 | 38.0 | 16.0 | 39.9 | 35.8 | 25.0 | 10.5 | - | - | 6.6 | 5.9 | 11.0 | 18.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.5 | 19.1 | 17.6 | 17.7 | 12.7 | 7.3 | 12.0 | 14.4 | 12.3 | 14.5 | 15.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.5 | 17.7 | 17.7 | 16.2 | 12.1 | 7.5 | 11.4 | 13.5 | 11.7 | 13.6 | 14.3 |
| **HCC Total** | | **681.0** | **784.0** | **802.9** | **1,003.5** | **956.4** | **911.5** | **547.6** | **368.7** | **415.6** | **459.2** | **361.7** | **538.3** | **652.5** |
| **ROR Total** | | **332.7** | **334.5** | **254.6** | **391.7** | **403.5** | **362.4** | **275.8** | **205.5** | **217.4** | **217.3** | **183.9** | **215.5** | **282.9** |
| **Total** | | **1,013.7** | **1,118.5** | **1,057.5** | **1,395.2** | **1,359.9** | **1,273.9** | **823.4** | **574.2** | **633.0** | **676.5** | **545.6** | **753.8** | **935.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 305.2 | 340.9 | 337.8 | 430.3 | 423.7 | 408.0 | 241.1 | 155.9 | 174.7 | 197.8 | 154.3 | 237.6 | 283.9 |
| Oxbow | HCC | 126.0 | 147.6 | 153.5 | 187.4 | 173.5 | 165.8 | 102.3 | 71.1 | 79.4 | 88.2 | 69.3 | 99.9 | 122.0 |
| Hells Canyon | HCC | 247.9 | 293.2 | 310.2 | 384.0 | 357.3 | 334.9 | 202.9 | 140.2 | 155.9 | 174.0 | 138.0 | 198.3 | 244.7 |
| 1000 Springs | ROR** | 22.7 | 23.5 | 20.8 | 56.6 | 85.4 | 93.1 | 83.9 | 64.5 | 41.5 | 16.9 | - | 5.4 | 42.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.0 | 46.0 | 38.2 | 50.9 | 48.7 | 42.0 | 33.5 | 25.7 | 33.7 | 37.4 | 34.9 | 36.5 | 39.5 |
| C .J. Strike | ROR | 59.7 | 59.3 | 51.3 | 64.6 | 62.1 | 50.2 | 33.9 | 28.2 | 39.9 | 47.4 | 44.8 | 46.0 | 49.0 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.7 | 31.5 | 23.7 | 34.5 | 33.5 | 27.5 | 21.2 | 13.8 | 20.2 | 23.6 | 20.9 | 23.7 | 25.5 |
| Milner | ROR | 37.7 | 37.9 | 11.9 | 38.0 | 35.4 | 22.0 | 6.2 | - | - | - | - | 6.4 | 16.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.3 | 19.2 | 16.9 | 21.0 | 20.0 | 16.4 | 12.0 | 9.9 | 13.7 | 15.6 | 15.2 | 15.6 | 16.2 |
| Twin Falls | ROR | 37.6 | 37.8 | 14.6 | 37.4 | 35.6 | 24.8 | 10.5 | - | - | 6.6 | 5.9 | 9.6 | 18.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 14.7 | 19.1 | 17.6 | 17.5 | 12.6 | 7.2 | 11.8 | 14.3 | 12.2 | 14.5 | 15.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 13.8 | 17.7 | 17.7 | 16.2 | 12.0 | 7.4 | 11.3 | 13.4 | 11.7 | 13.6 | 14.2 |
| **HCC Total** | | **679.1** | **781.7** | **801.5** | **1,001.7** | **954.4** | **908.7** | **546.3** | **367.2** | **410.0** | **460.0** | **361.6** | **535.8** | **650.7** |
| **ROR Total** | | **331.2** | **332.8** | **248.4** | **385.2** | **402.0** | **360.9** | **274.9** | **204.5** | **216.2** | **216.0** | **183.1** | **211.1** | **280.5** |
| **Total** | | **1,010.3** | **1,114.5** | **1,049.9** | **1,386.9** | **1,356.4** | **1,269.6** | **821.2** | **571.7** | **626.2** | **676.0** | **544.7** | **746.9** | **931.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 304.1 | 339.2 | 337.0 | 429.6 | 422.9 | 406.7 | 240.5 | 155.3 | 172.7 | 197.7 | 154.7 | 236.6 | 283.1 |
| Oxbow | HCC | 125.5 | 146.9 | 153.2 | 187.1 | 173.2 | 165.3 | 102.0 | 70.8 | 78.4 | 88.0 | 69.4 | 99.5 | 121.6 |
| Hells Canyon | HCC | 247.1 | 291.7 | 309.4 | 383.4 | 356.7 | 333.9 | 202.4 | 139.6 | 154.0 | 173.7 | 138.3 | 197.5 | 244.0 |
| 1000 Springs | ROR** | 22.4 | 23.3 | 19.9 | 56.4 | 85.3 | 92.9 | 83.9 | 64.5 | 41.5 | 16.5 | - | - | 42.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.7 | 45.7 | 38.0 | 50.7 | 48.5 | 41.8 | 33.3 | 25.5 | 33.4 | 37.2 | 34.7 | 36.5 | 39.3 |
| C .J. Strike | ROR | 59.4 | 58.9 | 51.0 | 64.3 | 61.8 | 50.0 | 33.7 | 28.0 | 39.5 | 47.1 | 44.7 | 45.8 | 48.7 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.5 | 31.2 | 23.5 | 34.3 | 33.3 | 27.2 | 21.0 | 13.6 | 20.0 | 23.4 | 20.7 | 23.7 | 25.3 |
| Milner | ROR | 37.3 | 37.6 | 11.6 | 36.7 | 35.2 | 21.7 | 6.2 | - | - | - | - | 6.2 | 16.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.1 | 19.1 | 16.8 | 20.9 | 19.9 | 16.3 | 12.0 | 9.9 | 13.6 | 15.6 | 15.2 | 15.6 | 16.2 |
| Twin Falls | ROR | 37.2 | 37.5 | 14.3 | 36.3 | 35.4 | 24.5 | 10.5 | - | - | 6.6 | 5.9 | 9.5 | 18.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 14.6 | 19.1 | 17.6 | 17.3 | 12.5 | 7.0 | 11.6 | 14.1 | 12.0 | 14.5 | 14.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 13.7 | 17.7 | 17.7 | 16.0 | 11.9 | 7.3 | 11.2 | 13.3 | 11.5 | 13.6 | 14.1 |
| **HCC Total** | | **676.7** | **777.8** | **799.6** | **1,000.1** | **952.7** | **905.9** | **544.9** | **365.7** | **405.0** | **459.4** | **362.4** | **533.6** | **648.6** |
| **ROR Total** | | **329.1** | **330.9** | **245.9** | **381.8** | **400.7** | **358.9** | **274.1** | **203.6** | **214.9** | **214.6** | **182.2** | **205.2** | **278.5** |
| **Total** | | **1,005.8** | **1,108.7** | **1,045.5** | **1,381.9** | **1,353.3** | **1,264.8** | **819.0** | **569.3** | **619.9** | **674.0** | **544.6** | **738.8** | **927.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 252.2 | 312.3 | 252.5 | 317.5 | 387.2 | 263.4 | 232.9 | 157.0 | 191.8 | 173.5 | 146.5 | 214.8 | 241.8 |
| Oxbow | HCC | 106.2 | 131.2 | 111.4 | 133.2 | 160.2 | 110.8 | 98.5 | 71.6 | 88.8 | 78.5 | 65.6 | 90.0 | 103.8 |
| Hells Canyon | HCC | 210.3 | 258.9 | 227.3 | 269.4 | 325.3 | 226.7 | 194.3 | 140.7 | 174.0 | 154.8 | 130.6 | 178.3 | 207.5 |
| 1000 Springs | ROR** | - | 15.4 | 14.2 | 36.1 | 71.6 | 88.4 | 84.3 | 62.0 | 36.3 | 12.7 | - | - | 35.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 38.1 | 42.4 | 38.5 | 38.9 | 41.0 | 39.2 | 34.7 | 27.7 | 36.5 | 38.9 | 36.9 | 37.0 | 37.5 |
| C .J. Strike | ROR | 49.7 | 55.1 | 50.5 | 51.0 | 48.1 | 45.2 | 35.4 | 30.5 | 43.5 | 49.3 | 47.9 | 48.1 | 46.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.1 | 29.1 | 24.2 | 25.3 | 27.3 | 27.1 | 22.5 | 15.7 | 23.1 | 25.2 | 23.6 | 23.5 | 24.2 |
| Milner | ROR | 8.9 | 26.6 | 10.1 | 10.4 | 15.4 | 15.4 | 6.2 | - | - | - | 3.0 | 6.2 | 8.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.8 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.2 | 17.9 | 16.5 | 17.3 | 16.1 | 15.2 | 12.6 | 10.7 | 14.7 | 16.2 | 15.8 | 15.8 | 15.4 |
| Twin Falls | ROR | 11.9 | 27.8 | 12.5 | 12.5 | 18.2 | 18.4 | 10.5 | - | - | 6.6 | 7.8 | 9.5 | 11.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.8 | 18.9 | 15.1 | 16.0 | 17.6 | 17.2 | 13.6 | 8.6 | 14.1 | 15.5 | 14.3 | 14.3 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.9 | 17.4 | 14.1 | 14.9 | 16.2 | 15.9 | 12.9 | 8.6 | 13.2 | 14.5 | 13.4 | 13.5 | 14.0 |
| **HCC Total** | | **568.7** | **702.4** | **591.2** | **720.1** | **872.6** | **600.9** | **525.7** | **369.3** | **454.5** | **406.8** | **342.7** | **483.1** | **553.2** |
| **ROR Total** | | **217.2** | **291.1** | **236.7** | **263.1** | **314.2** | **328.2** | **279.0** | **210.4** | **224.0** | **219.2** | **202.3** | **207.7** | **249.4** |
| **Total** | | **785.9** | **993.5** | **827.9** | **983.2** | **1,186.8** | **929.1** | **804.7** | **579.7** | **678.5** | **626.0** | **545.0** | **690.8** | **802.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 252.7 | 316.9 | 254.5 | 321.2 | 391.9 | 265.6 | 232.6 | 156.8 | 190.9 | 173.3 | 146.8 | 214.6 | 243.1 |
| Oxbow | HCC | 106.4 | 133.1 | 112.3 | 134.7 | 162.1 | 111.8 | 98.4 | 71.5 | 88.4 | 78.4 | 65.8 | 89.9 | 104.4 |
| Hells Canyon | HCC | 210.6 | 262.6 | 229.0 | 272.3 | 329.0 | 228.6 | 194.1 | 140.6 | 173.3 | 154.7 | 130.9 | 178.1 | 208.6 |
| 1000 Springs | ROR** | - | 18.0 | 14.1 | 36.7 | 71.6 | 88.5 | 84.5 | 62.4 | 37.1 | 12.9 | - | - | 35.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 38.0 | 43.1 | 38.8 | 39.0 | 41.4 | 39.2 | 34.6 | 27.6 | 36.4 | 38.8 | 36.7 | 36.9 | 37.5 |
| C .J. Strike | ROR | 49.8 | 57.3 | 50.8 | 51.2 | 48.8 | 45.1 | 35.4 | 30.4 | 43.3 | 49.2 | 47.8 | 48.1 | 46.4 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.2 | 30.9 | 24.8 | 25.3 | 27.4 | 26.9 | 22.4 | 15.6 | 23.0 | 25.1 | 23.5 | 23.5 | 24.4 |
| Milner | ROR | 8.9 | 30.6 | 11.9 | 10.8 | 15.4 | 15.4 | 6.2 | - | - | - | 3.0 | 6.2 | 9.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.8 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.2 | 18.1 | 16.8 | 17.5 | 16.1 | 15.3 | 12.6 | 10.7 | 14.6 | 16.2 | 15.8 | 15.8 | 15.5 |
| Twin Falls | ROR | 12.2 | 31.2 | 14.6 | 13.2 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 7.8 | 9.5 | 11.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.9 | 19.2 | 15.6 | 16.1 | 17.6 | 17.1 | 13.6 | 8.6 | 13.9 | 15.4 | 14.2 | 14.3 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.9 | 17.7 | 14.5 | 14.9 | 16.3 | 15.8 | 12.8 | 8.5 | 13.1 | 14.4 | 13.4 | 13.4 | 14.1 |
| **HCC Total** | | **569.7** | **712.6** | **595.8** | **728.2** | **882.9** | **606.0** | **525.1** | **368.9** | **452.5** | **406.4** | **343.5** | **482.6** | **556.2** |
| **ROR Total** | | **217.7** | **306.6** | **242.9** | **265.4** | **315.6** | **328.3** | **278.9** | **210.4** | **224.0** | **218.9** | **201.8** | **207.5** | **251.5** |
| **Total** | | **787.4** | **1,019.2** | **838.7** | **993.6** | **1,198.5** | **934.3** | **804.0** | **579.3** | **676.5** | **625.3** | **545.3** | **690.1** | **807.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 251.4 | 315.8 | 256.8 | 322.5 | 397.3 | 269.0 | 232.8 | 157.2 | 189.6 | 174.0 | 146.8 | 216.3 | 244.1 |
| Oxbow | HCC | 105.9 | 132.6 | 113.3 | 135.2 | 164.3 | 113.2 | 98.5 | 71.7 | 87.6 | 78.5 | 65.7 | 90.6 | 104.8 |
| Hells Canyon | HCC | 209.6 | 261.7 | 230.9 | 273.4 | 333.3 | 231.3 | 194.2 | 140.9 | 171.8 | 154.9 | 130.7 | 179.5 | 209.3 |
| 1000 Springs | ROR** | - | 19.2 | 14.2 | 38.7 | 71.6 | 88.5 | 84.5 | 62.9 | 37.5 | 13.0 | - | - | 35.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.7 | 44.0 | 38.5 | 38.9 | 41.9 | 39.4 | 34.6 | 27.6 | 36.3 | 38.8 | 36.1 | 36.4 | 37.5 |
| C .J. Strike | ROR | 49.9 | 57.3 | 50.2 | 52.3 | 49.9 | 45.5 | 35.5 | 30.4 | 43.2 | 49.2 | 47.0 | 47.6 | 46.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.0 | 31.3 | 24.8 | 25.3 | 27.6 | 27.0 | 22.5 | 15.7 | 22.9 | 25.1 | 23.2 | 23.1 | 24.4 |
| Milner | ROR | 8.2 | 31.5 | 11.1 | 10.6 | 15.4 | 15.4 | 6.2 | - | - | - | - | 4.5 | 8.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.9 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 18.5 | 16.4 | 17.6 | 16.5 | 15.4 | 12.6 | 10.7 | 14.6 | 16.2 | 15.5 | 15.7 | 15.5 |
| Twin Falls | ROR | 11.2 | 32.1 | 13.7 | 13.0 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 6.2 | 8.5 | 11.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.7 | 19.2 | 15.6 | 16.1 | 17.7 | 17.1 | 13.6 | 8.6 | 13.9 | 15.4 | 13.9 | 14.0 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 14.5 | 14.9 | 16.4 | 15.8 | 12.9 | 8.6 | 13.1 | 14.4 | 13.1 | 13.1 | 14.0 |
| **HCC Total** | | **566.9** | **710.1** | **601.0** | **731.1** | **894.8** | **613.5** | **525.5** | **369.8** | **448.9** | **407.4** | **343.2** | **486.4** | **558.2** |
| **ROR Total** | | **215.3** | **311.3** | **240.0** | **268.1** | **318.0** | **329.5** | **279.2** | **211.1** | **224.2** | **219.0** | **192.7** | **202.7** | **250.9** |
| **Total** | | **782.2** | **1,021.4** | **841.0** | **999.2** | **1,212.8** | **943.0** | **804.7** | **580.9** | **673.1** | **626.4** | **535.9** | **689.1** | **809.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 251.4 | 315.7 | 256.4 | 323.3 | 399.7 | 268.5 | 232.5 | 156.9 | 189.0 | 174.4 | 146.6 | 215.6 | 244.2 |
| Oxbow | HCC | 105.9 | 132.6 | 113.1 | 135.5 | 165.2 | 113.0 | 98.3 | 71.6 | 87.3 | 78.7 | 65.6 | 90.3 | 104.8 |
| Hells Canyon | HCC | 209.6 | 261.7 | 230.6 | 274.0 | 335.1 | 230.9 | 194.0 | 140.6 | 171.1 | 155.2 | 130.5 | 178.9 | 209.3 |
| 1000 Springs | ROR** | - | 19.1 | 14.0 | 39.4 | 72.1 | 88.6 | 84.6 | 63.1 | 37.8 | 14.2 | - | - | 36.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.6 | 43.0 | 38.4 | 39.5 | 42.4 | 39.4 | 34.5 | 27.5 | 36.2 | 38.7 | 36.1 | 36.1 | 37.5 |
| C .J. Strike | ROR | 49.9 | 57.0 | 49.5 | 52.4 | 49.9 | 45.4 | 35.4 | 30.3 | 43.0 | 49.1 | 46.9 | 47.2 | 46.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.0 | 31.2 | 24.1 | 25.4 | 27.5 | 26.9 | 22.4 | 15.6 | 22.8 | 25.0 | 23.1 | 22.8 | 24.2 |
| Milner | ROR | 8.2 | 31.3 | 9.6 | 10.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 3.8 | 8.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.9 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 18.2 | 16.2 | 17.7 | 16.5 | 15.2 | 12.6 | 10.6 | 14.5 | 16.1 | 15.5 | 15.6 | 15.4 |
| Twin Falls | ROR | 11.6 | 31.8 | 12.2 | 13.5 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 6.2 | 8.1 | 11.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.8 | 19.2 | 15.1 | 16.1 | 17.7 | 17.0 | 13.6 | 8.5 | 13.8 | 15.4 | 13.9 | 13.8 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 14.1 | 15.0 | 16.4 | 15.8 | 12.8 | 8.5 | 13.0 | 14.3 | 13.1 | 13.0 | 14.0 |
| **HCC Total** | | **566.9** | **710.0** | **600.1** | **732.8** | **900.0** | **612.4** | **524.8** | **369.1** | **447.4** | **408.3** | **342.7** | **484.8** | **558.3** |
| **ROR Total** | | **215.7** | **309.0** | **234.2** | **270.4** | **318.9** | **329.1** | **278.9** | **210.7** | **223.8** | **219.7** | **192.5** | **200.2** | **250.3** |
| **Total** | | **782.6** | **1,019.0** | **834.3** | **1,003.2** | **1,218.8** | **941.5** | **803.7** | **579.8** | **671.1** | **628.0** | **535.2** | **685.0** | **808.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 252.1 | 316.1 | 256.3 | 324.2 | 402.8 | 270.3 | 233.2 | 157.3 | 187.0 | 174.9 | 147.1 | 212.8 | 244.5 |
| Oxbow | HCC | 106.2 | 132.7 | 113.1 | 135.9 | 166.4 | 113.7 | 98.6 | 71.8 | 86.2 | 78.6 | 65.7 | 89.2 | 104.8 |
| Hells Canyon | HCC | 210.2 | 262.0 | 230.5 | 274.7 | 337.5 | 232.3 | 194.6 | 141.0 | 169.0 | 155.2 | 130.8 | 176.6 | 209.5 |
| 1000 Springs | ROR** | - | 17.6 | 14.1 | 39.7 | 72.8 | 88.6 | 84.6 | 63.3 | 37.7 | 15.0 | - | - | 36.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.9 | 42.8 | 36.9 | 39.3 | 42.7 | 39.5 | 34.7 | 27.7 | 36.1 | 38.8 | 35.8 | 35.6 | 37.3 |
| C .J. Strike | ROR | 49.9 | 56.8 | 47.8 | 52.3 | 50.3 | 45.7 | 35.7 | 30.3 | 42.9 | 49.1 | 46.0 | 46.4 | 46.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.9 | 30.3 | 22.9 | 24.6 | 27.7 | 27.0 | 22.5 | 15.6 | 22.8 | 25.1 | 22.5 | 22.3 | 23.9 |
| Milner | ROR | 8.0 | 29.0 | 5.8 | 8.1 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 7.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.7 | 10.6 |
| Swan Falls | ROR | 16.1 | 17.8 | 15.8 | 17.7 | 16.7 | 15.4 | 12.6 | 10.6 | 14.5 | 16.1 | 15.4 | 15.4 | 15.3 |
| Twin Falls | ROR | 11.3 | 29.8 | 9.1 | 10.9 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.8 | 10.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.7 | 19.2 | 14.1 | 15.5 | 17.7 | 17.1 | 13.7 | 8.6 | 13.8 | 15.4 | 13.4 | 13.4 | 14.7 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 13.3 | 14.4 | 16.5 | 15.9 | 12.9 | 8.6 | 13.0 | 14.4 | 12.7 | 12.6 | 13.8 |
| **HCC Total** | | **568.5** | **710.8** | **599.9** | **734.8** | **906.6** | **616.3** | **526.4** | **370.1** | **442.1** | **408.7** | **343.6** | **478.6** | **558.9** |
| **ROR Total** | | **215.2** | **301.5** | **220.8** | **263.2** | **320.8** | **330.0** | **279.7** | **211.3** | **223.5** | **220.8** | **186.3** | **192.7** | **247.2** |
| **Total** | | **783.7** | **1,012.3** | **820.7** | **998.0** | **1,227.4** | **946.3** | **806.1** | **581.4** | **665.6** | **629.5** | **529.9** | **671.3** | **806.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 251.1 | 315.3 | 256.2 | 323.3 | 401.8 | 269.0 | 232.6 | 156.7 | 184.5 | 175.0 | 147.2 | 210.1 | 243.6 |
| Oxbow | HCC | 105.7 | 132.4 | 113.0 | 135.5 | 166.1 | 113.2 | 98.4 | 71.4 | 84.9 | 78.5 | 65.7 | 88.0 | 104.4 |
| Hells Canyon | HCC | 209.3 | 261.3 | 230.4 | 274.0 | 336.8 | 231.3 | 194.1 | 140.4 | 166.6 | 155.0 | 130.7 | 174.3 | 208.7 |
| 1000 Springs | ROR** | - | 15.6 | 14.0 | 39.5 | 72.7 | 88.6 | 84.6 | 63.2 | 37.7 | 15.0 | - | - | 35.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.5 | 42.1 | 36.7 | 39.1 | 42.5 | 39.3 | 34.6 | 27.5 | 35.9 | 38.6 | 35.5 | 35.5 | 37.1 |
| C .J. Strike | ROR | 49.1 | 54.6 | 47.5 | 52.1 | 50.1 | 45.4 | 35.4 | 30.1 | 42.6 | 48.8 | 45.7 | 46.2 | 45.6 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.5 | 29.3 | 22.6 | 24.4 | 27.6 | 26.9 | 22.4 | 15.5 | 22.5 | 24.9 | 22.5 | 22.2 | 23.7 |
| Milner | ROR | 7.7 | 26.8 | 5.2 | 7.8 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 7.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.6 |
| Swan Falls | ROR | 16.1 | 17.5 | 15.7 | 17.6 | 16.5 | 15.3 | 12.6 | 10.6 | 14.4 | 16.0 | 15.3 | 15.3 | 15.2 |
| Twin Falls | ROR | 11.1 | 27.9 | 8.6 | 10.6 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.4 | 19.0 | 13.9 | 15.3 | 17.7 | 17.0 | 13.6 | 8.4 | 13.6 | 15.3 | 13.4 | 13.3 | 14.6 |
| Upper Salmon 3&4 | ROR | 13.5 | 17.5 | 13.1 | 14.3 | 16.4 | 15.8 | 12.8 | 8.4 | 12.8 | 14.3 | 12.7 | 12.6 | 13.7 |
| **HCC Total** | | **566.1** | **709.0** | **599.6** | **732.8** | **904.6** | **613.5** | **525.1** | **368.5** | **436.0** | **408.5** | **343.6** | **472.4** | **556.6** |
| **ROR Total** | | **212.5** | **290.8** | **218.3** | **261.4** | **319.8** | **329.1** | **279.0** | **210.3** | **222.2** | **219.8** | **185.6** | **192.7** | **245.1** |
| **Total** | | **778.6** | **999.8** | **817.9** | **994.2** | **1,224.4** | **942.6** | **804.1** | **578.8** | **658.1** | **628.3** | **529.2** | **665.1** | **801.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 250.0 | 314.4 | 251.5 | 322.3 | 400.9 | 267.8 | 232.0 | 156.0 | 182.3 | 175.2 | 147.5 | 208.5 | 242.4 |
| Oxbow | HCC | 105.3 | 132.0 | 110.9 | 135.1 | 165.7 | 112.7 | 98.1 | 71.1 | 83.8 | 78.5 | 65.8 | 87.3 | 103.9 |
| Hells Canyon | HCC | 208.5 | 260.6 | 226.4 | 273.1 | 336.1 | 230.3 | 193.6 | 139.9 | 164.4 | 154.8 | 130.9 | 173.1 | 207.6 |
| 1000 Springs | ROR** | - | 15.2 | 14.0 | 39.3 | 72.5 | 88.6 | 84.7 | 63.0 | 37.6 | 15.0 | - | - | 35.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.2 | 40.6 | 35.7 | 38.8 | 42.4 | 39.1 | 34.4 | 27.3 | 35.6 | 38.4 | 35.3 | 35.4 | 36.7 |
| C .J. Strike | ROR | 48.9 | 53.2 | 47.3 | 51.9 | 49.9 | 45.1 | 35.2 | 29.8 | 42.2 | 48.5 | 45.5 | 45.9 | 45.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.4 | 29.0 | 21.6 | 24.1 | 27.5 | 26.7 | 22.3 | 15.3 | 22.3 | 24.7 | 22.3 | 22.1 | 23.4 |
| Milner | ROR | 7.7 | 26.0 | 2.4 | 7.4 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.5 |
| Swan Falls | ROR | 16.0 | 17.4 | 15.7 | 17.5 | 16.4 | 15.2 | 12.5 | 10.5 | 14.3 | 16.0 | 15.2 | 15.3 | 15.2 |
| Twin Falls | ROR | 10.4 | 27.3 | 6.4 | 10.2 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.3 | 18.8 | 13.1 | 15.1 | 17.7 | 16.9 | 13.5 | 8.3 | 13.4 | 15.1 | 13.3 | 13.2 | 14.4 |
| Upper Salmon 3&4 | ROR | 13.4 | 17.3 | 12.4 | 14.2 | 16.4 | 15.6 | 12.7 | 8.3 | 12.7 | 14.1 | 12.6 | 12.5 | 13.5 |
| **HCC Total** | | **563.8** | **707.0** | **588.8** | **730.5** | **902.6** | **610.8** | **523.7** | **367.0** | **430.4** | **408.5** | **344.2** | **468.9** | **553.9** |
| **ROR Total** | | **210.9** | **285.3** | **207.8** | **259.2** | **319.1** | **328.0** | **278.3** | **209.1** | **220.8** | **218.7** | **184.7** | **192.0** | **242.8** |
| **Total** | | **774.7** | **992.3** | **796.6** | **989.7** | **1,221.7** | **938.8** | **802.0** | **576.1** | **651.2** | **627.2** | **528.9** | **660.9** | **796.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 249.1 | 313.6 | 250.6 | 321.3 | 400.0 | 266.6 | 231.3 | 155.4 | 180.2 | 175.6 | 147.2 | 207.6 | 241.5 |
| Oxbow | HCC | 104.9 | 131.7 | 110.5 | 134.7 | 165.3 | 112.2 | 97.8 | 70.8 | 82.6 | 78.5 | 65.6 | 86.9 | 103.5 |
| Hells Canyon | HCC | 207.7 | 260.0 | 225.6 | 272.3 | 335.3 | 229.3 | 193.0 | 139.3 | 162.2 | 155.0 | 130.5 | 172.2 | 206.9 |
| 1000 Springs | ROR** | - | 15.4 | 13.6 | 39.0 | 72.3 | 88.6 | 84.6 | 62.8 | 37.5 | 15.0 | - | - | 35.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.1 | 40.7 | 35.7 | 38.6 | 41.9 | 38.9 | 34.4 | 27.1 | 35.4 | 38.2 | 35.3 | 35.2 | 36.5 |
| C .J. Strike | ROR | 48.6 | 53.3 | 47.1 | 51.7 | 49.7 | 44.9 | 35.0 | 29.6 | 41.9 | 48.3 | 45.5 | 45.7 | 45.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.1 | 29.1 | 21.5 | 23.9 | 27.4 | 26.5 | 22.1 | 15.2 | 22.1 | 24.5 | 22.1 | 21.9 | 23.3 |
| Milner | ROR | 7.7 | 25.8 | - | 7.0 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.4 |
| Swan Falls | ROR | 15.9 | 17.5 | 15.6 | 17.4 | 16.4 | 15.2 | 12.4 | 10.4 | 14.2 | 15.9 | 15.4 | 15.4 | 15.1 |
| Twin Falls | ROR | 10.4 | 27.4 | 5.8 | 9.9 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.0 | 18.8 | 13.1 | 15.0 | 17.6 | 16.7 | 13.4 | 8.2 | 13.3 | 15.0 | 13.1 | 13.1 | 14.3 |
| Upper Salmon 3&4 | ROR | 13.2 | 17.3 | 12.4 | 14.0 | 16.3 | 15.5 | 12.6 | 8.2 | 12.6 | 14.0 | 12.4 | 12.4 | 13.4 |
| **HCC Total** | | **561.7** | **705.3** | **586.7** | **728.3** | **900.6** | **608.1** | **522.1** | **365.5** | **424.9** | **409.1** | **343.3** | **466.7** | **551.9** |
| **ROR Total** | | **209.6** | **285.8** | **203.3** | **257.2** | **318.0** | **327.1** | **277.5** | **208.1** | **219.7** | **217.8** | **184.3** | **191.3** | **241.6** |
| **Total** | | **771.3** | **991.1** | **790.0** | **985.5** | **1,218.5** | **935.2** | **799.6** | **573.6** | **644.6** | **626.9** | **527.6** | **658.0** | **793.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 247.9 | 312.3 | 250.1 | 320.3 | 399.2 | 265.3 | 230.7 | 154.8 | 177.7 | 175.8 | 147.5 | 204.3 | 240.5 |
| Oxbow | HCC | 104.4 | 131.2 | 110.4 | 134.3 | 165.0 | 111.6 | 97.6 | 70.5 | 81.4 | 78.5 | 65.7 | 85.5 | 103.0 |
| Hells Canyon | HCC | 206.8 | 259.0 | 225.3 | 271.6 | 334.7 | 228.3 | 192.5 | 138.7 | 159.7 | 154.9 | 130.7 | 169.5 | 206.0 |
| 1000 Springs | ROR** | - | 12.7 | 13.5 | 38.8 | 72.0 | 88.6 | 84.7 | 62.7 | 36.9 | 14.8 | - | - | 35.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.9 | 37.9 | 35.7 | 38.3 | 41.8 | 38.7 | 34.2 | 26.9 | 35.1 | 38.0 | 35.2 | 35.0 | 36.1 |
| C .J. Strike | ROR | 48.3 | 52.6 | 46.9 | 51.6 | 49.1 | 44.6 | 34.8 | 29.4 | 41.6 | 48.0 | 45.3 | 45.1 | 44.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.7 | 27.4 | 21.4 | 23.7 | 27.2 | 26.4 | 22.0 | 15.0 | 21.9 | 24.4 | 21.9 | 21.7 | 23.0 |
| Milner | ROR | 7.7 | 21.2 | - | 6.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.4 |
| Swan Falls | ROR | 15.8 | 17.0 | 15.6 | 17.4 | 16.3 | 15.2 | 12.4 | 10.3 | 14.1 | 15.8 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 10.4 | 23.3 | 5.8 | 9.8 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 9.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.8 | 17.5 | 13.0 | 14.8 | 17.5 | 16.6 | 13.3 | 8.1 | 13.1 | 14.9 | 13.0 | 12.9 | 14.0 |
| Upper Salmon 3&4 | ROR | 13.0 | 16.2 | 12.3 | 13.9 | 16.2 | 15.4 | 12.5 | 8.1 | 12.4 | 13.9 | 12.3 | 12.3 | 13.2 |
| **HCC Total** | | **559.1** | **702.5** | **585.8** | **726.2** | **898.8** | **605.2** | **520.8** | **364.0** | **418.7** | **409.2** | **343.9** | **459.3** | **549.5** |
| **ROR Total** | | **208.2** | **266.3** | **202.7** | **255.7** | **316.4** | **326.3** | **276.9** | **207.1** | **217.8** | **216.7** | **183.5** | **189.9** | **239.0** |
| **Total** | | **767.3** | **968.8** | **788.5** | **981.9** | **1,215.2** | **931.5** | **797.7** | **571.1** | **636.5** | **625.9** | **527.4** | **649.2** | **788.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 246.6 | 309.4 | 249.7 | 319.4 | 398.3 | 263.9 | 230.1 | 154.1 | 174.9 | 176.2 | 147.5 | 200.3 | 239.2 |
| Oxbow | HCC | 103.8 | 130.0 | 110.2 | 133.9 | 164.6 | 111.0 | 97.3 | 70.2 | 79.9 | 78.4 | 65.5 | 83.8 | 102.4 |
| Hells Canyon | HCC | 205.7 | 256.6 | 224.9 | 270.8 | 334.0 | 227.2 | 192.0 | 138.1 | 156.9 | 154.8 | 130.4 | 166.2 | 204.8 |
| 1000 Springs | ROR** | - | 10.3 | 13.0 | 37.1 | 71.9 | 88.6 | 84.7 | 62.5 | 36.9 | 14.7 | - | - | 35.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.7 | 37.7 | 35.7 | 38.1 | 41.6 | 38.5 | 34.0 | 26.7 | 34.9 | 37.8 | 35.0 | 34.8 | 36.0 |
| C .J. Strike | ROR | 48.0 | 52.7 | 46.7 | 51.3 | 48.9 | 44.3 | 34.6 | 29.1 | 41.2 | 47.8 | 45.1 | 44.9 | 44.6 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.7 | 26.0 | 21.3 | 23.5 | 27.2 | 26.2 | 21.8 | 14.8 | 21.7 | 24.2 | 21.8 | 21.6 | 22.7 |
| Milner | ROR | 7.7 | 17.2 | 2.0 | 6.2 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.7 | 10.4 |
| Swan Falls | ROR | 15.7 | 17.1 | 15.5 | 17.2 | 16.3 | 15.2 | 12.3 | 10.2 | 14.1 | 15.8 | 15.2 | 15.2 | 15.0 |
| Twin Falls | ROR | 10.4 | 20.2 | 6.0 | 9.5 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.8 | 9.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.7 | 16.5 | 12.9 | 14.7 | 17.5 | 16.5 | 13.1 | 8.0 | 12.9 | 14.8 | 12.9 | 12.8 | 13.9 |
| Upper Salmon 3&4 | ROR | 13.0 | 15.3 | 12.2 | 13.8 | 16.1 | 15.3 | 12.4 | 8.0 | 12.3 | 13.8 | 12.2 | 12.2 | 13.1 |
| **HCC Total** | | **556.1** | **696.0** | **584.8** | **724.1** | **896.8** | **602.1** | **519.4** | **362.4** | **411.7** | **409.4** | **343.4** | **450.3** | **546.4** |
| **ROR Total** | | **207.5** | **253.5** | **204.0** | **252.1** | **315.9** | **325.4** | **275.9** | **205.9** | **216.7** | **215.8** | **182.7** | **188.7** | **237.0** |
| **Total** | | **763.6** | **949.5** | **788.8** | **976.2** | **1,212.7** | **927.5** | **795.3** | **568.3** | **628.3** | **625.2** | **526.1** | **639.0** | **783.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 246.0 | 308.4 | 249.3 | 318.5 | 397.5 | 262.2 | 229.5 | 153.5 | 173.2 | 168.8 | 147.9 | 198.8 | 237.8 |
| Oxbow | HCC | 103.6 | 129.6 | 110.0 | 133.6 | 164.3 | 110.3 | 97.1 | 69.9 | 79.1 | 78.2 | 65.7 | 83.1 | 102.0 |
| Hells Canyon | HCC | 205.2 | 255.9 | 224.5 | 270.2 | 333.4 | 225.8 | 191.5 | 137.6 | 155.3 | 154.0 | 130.7 | 164.9 | 204.1 |
| 1000 Springs | ROR** | - | 9.0 | 11.9 | 37.0 | 71.8 | 88.6 | 84.6 | 62.2 | 36.3 | 14.6 | - | - | 34.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.6 | 37.6 | 35.2 | 37.9 | 41.5 | 38.3 | 33.9 | 26.5 | 34.6 | 37.7 | 34.8 | 34.5 | 35.8 |
| C .J. Strike | ROR | 47.4 | 50.7 | 46.5 | 51.1 | 48.7 | 44.1 | 34.4 | 28.9 | 40.9 | 47.6 | 44.7 | 44.9 | 44.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.6 | 25.1 | 21.3 | 23.4 | 27.1 | 26.0 | 21.7 | 14.7 | 21.4 | 24.1 | 21.6 | 21.4 | 22.5 |
| Milner | ROR | 7.7 | 14.8 | 2.1 | 5.9 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 5.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.5 | 10.4 |
| Swan Falls | ROR | 15.6 | 16.1 | 15.4 | 17.2 | 16.2 | 15.1 | 12.2 | 10.2 | 14.1 | 15.7 | 15.2 | 15.2 | 14.9 |
| Twin Falls | ROR | 10.4 | 18.2 | 6.1 | 9.3 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.6 | 9.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.7 | 15.8 | 12.9 | 14.6 | 17.4 | 16.4 | 13.0 | 7.8 | 12.8 | 14.6 | 12.8 | 12.7 | 13.7 |
| Upper Salmon 3&4 | ROR | 12.9 | 14.7 | 12.2 | 13.7 | 16.1 | 15.2 | 12.4 | 7.9 | 12.1 | 13.7 | 12.1 | 12.0 | 12.9 |
| **HCC Total** | | **554.8** | **693.9** | **583.8** | **722.3** | **895.1** | **598.3** | **518.1** | **361.0** | **407.5** | **401.0** | **344.3** | **446.8** | **543.9** |
| **ROR Total** | | **206.5** | **242.5** | **202.4** | **250.8** | **315.1** | **324.5** | **275.2** | **204.8** | **214.9** | **214.9** | **181.7** | **187.3** | **235.1** |
| **Total** | | **761.3** | **936.4** | **786.2** | **973.1** | **1,210.2** | **922.8** | **793.3** | **565.8** | **622.4** | **615.9** | **526.0** | **634.1** | **779.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 245.3 | 306.0 | 248.8 | 317.7 | 396.7 | 261.4 | 228.9 | 152.8 | 171.5 | 168.8 | 147.9 | 198.4 | 237.0 |
| Oxbow | HCC | 103.3 | 128.6 | 109.8 | 133.2 | 164.0 | 110.0 | 96.8 | 69.6 | 78.2 | 78.2 | 65.6 | 83.0 | 101.7 |
| Hells Canyon | HCC | 204.6 | 253.9 | 224.1 | 269.5 | 332.8 | 225.1 | 191.0 | 137.0 | 153.6 | 153.9 | 130.6 | 164.6 | 203.4 |
| 1000 Springs | ROR** | - | 7.4 | 11.2 | 35.9 | 71.7 | 88.6 | 84.6 | 62.0 | 35.9 | 14.5 | - | - | 34.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.4 | 37.2 | 34.6 | 37.7 | 41.4 | 38.1 | 33.7 | 26.3 | 34.4 | 37.5 | 34.6 | 34.2 | 35.5 |
| C .J. Strike | ROR | 47.2 | 49.3 | 46.3 | 50.9 | 48.2 | 43.7 | 34.2 | 28.6 | 40.7 | 47.4 | 44.6 | 44.6 | 43.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.5 | 22.7 | 21.1 | 22.5 | 27.0 | 25.8 | 21.6 | 14.5 | 21.2 | 23.9 | 21.5 | 21.3 | 22.1 |
| Milner | ROR | 7.7 | 10.7 | 2.0 | 5.2 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.8 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.5 | 10.4 |
| Swan Falls | ROR | 15.6 | 16.0 | 15.3 | 17.1 | 16.0 | 14.9 | 12.1 | 10.1 | 14.0 | 15.6 | 15.1 | 15.1 | 14.7 |
| Twin Falls | ROR | 10.4 | 12.6 | 6.0 | 8.5 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.7 | 8.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.7 | 13.9 | 17.3 | 16.2 | 12.9 | 7.7 | 12.6 | 14.5 | 12.6 | 12.6 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.1 | 12.1 | 13.1 | 16.0 | 15.1 | 12.3 | 7.8 | 12.0 | 13.6 | 12.0 | 11.9 | 12.7 |
| **HCC Total** | | **553.2** | **688.5** | **582.7** | **720.4** | **893.5** | **596.5** | **516.7** | **359.4** | **403.2** | **400.9** | **344.1** | **446.0** | **542.1** |
| **ROR Total** | | **205.8** | **223.4** | **200.0** | **245.5** | **313.9** | **322.8** | **274.4** | **203.6** | **213.5** | **213.9** | **180.9** | **186.5** | **232.0** |
| **Total** | | **759.0** | **911.9** | **782.7** | **965.9** | **1,207.4** | **919.3** | **791.1** | **563.0** | **616.7** | **614.8** | **525.0** | **632.5** | **774.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 244.3 | 301.9 | 248.3 | 316.9 | 395.9 | 260.6 | 228.3 | 152.2 | 169.6 | 169.1 | 147.9 | 197.8 | 236.1 |
| Oxbow | HCC | 102.9 | 126.9 | 109.5 | 132.9 | 163.7 | 109.7 | 96.6 | 69.3 | 77.2 | 78.2 | 65.6 | 82.7 | 101.3 |
| Hells Canyon | HCC | 203.8 | 250.6 | 223.7 | 268.9 | 332.2 | 224.5 | 190.5 | 136.4 | 151.7 | 153.9 | 130.6 | 164.1 | 202.6 |
| 1000 Springs | ROR** | - | - | 11.1 | 34.8 | 71.7 | 88.6 | 84.7 | 61.8 | 35.2 | 14.3 | - | - | 33.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 37.5 | 41.2 | 37.9 | 33.6 | 26.1 | 34.1 | 37.4 | 34.2 | 34.0 | 35.3 |
| C .J. Strike | ROR | 47.0 | 48.6 | 45.8 | 50.7 | 48.1 | 43.6 | 34.0 | 28.4 | 40.3 | 47.1 | 44.4 | 44.5 | 43.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.4 | 22.7 | 20.9 | 22.5 | 26.9 | 25.7 | 21.4 | 14.4 | 21.0 | 23.8 | 21.3 | 21.1 | 22.0 |
| Milner | ROR | 7.7 | 8.2 | 1.7 | 4.9 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 5.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.4 | 10.4 |
| Swan Falls | ROR | 15.5 | 15.8 | 15.4 | 17.0 | 16.0 | 14.8 | 12.1 | 10.0 | 13.9 | 15.5 | 15.0 | 15.0 | 14.7 |
| Twin Falls | ROR | 10.4 | 11.6 | 6.0 | 8.5 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.6 | 8.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.5 | 13.9 | 12.6 | 13.8 | 17.2 | 16.1 | 12.8 | 7.6 | 12.4 | 14.4 | 12.5 | 12.4 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 12.0 | 13.0 | 16.0 | 15.0 | 12.2 | 7.7 | 11.8 | 13.6 | 11.9 | 11.8 | 12.6 |
| **HCC Total** | | **551.0** | **679.4** | **581.5** | **718.7** | **891.8** | **594.8** | **515.4** | **357.9** | **398.4** | **401.2** | **344.1** | **444.6** | **539.9** |
| **ROR Total** | | **205.1** | **211.4** | **198.7** | **243.4** | **313.4** | **322.1** | **273.8** | **202.6** | **211.4** | **213.0** | **179.8** | **185.3** | **230.0** |
| **Total** | | **756.1** | **890.8** | **780.2** | **962.1** | **1,205.2** | **916.9** | **789.2** | **560.5** | **609.8** | **614.2** | **523.9** | **629.9** | **769.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 243.3 | 299.7 | 247.9 | 316.0 | 395.2 | 259.9 | 227.7 | 151.6 | 167.3 | 169.6 | 148.0 | 196.7 | 235.2 |
| Oxbow | HCC | 102.4 | 126.0 | 109.4 | 132.5 | 163.4 | 109.4 | 96.3 | 69.0 | 76.1 | 78.3 | 65.6 | 82.3 | 100.9 |
| Hells Canyon | HCC | 202.9 | 248.8 | 223.3 | 268.2 | 331.6 | 223.9 | 190.0 | 135.9 | 149.4 | 154.1 | 130.6 | 163.2 | 201.8 |
| 1000 Springs | ROR** | - | - | 11.0 | 36.0 | 71.7 | 88.6 | 84.7 | 61.5 | 34.9 | 14.2 | - | - | 33.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.2 | 36.7 | 34.3 | 37.3 | 41.0 | 37.7 | 33.4 | 26.0 | 33.9 | 37.2 | 34.0 | 34.0 | 35.1 |
| C .J. Strike | ROR | 46.8 | 48.4 | 45.4 | 50.6 | 47.9 | 43.5 | 33.8 | 28.1 | 40.0 | 46.9 | 44.2 | 44.3 | 43.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.3 | 22.5 | 20.8 | 22.4 | 26.8 | 25.5 | 21.3 | 14.2 | 20.8 | 23.7 | 20.9 | 20.9 | 21.8 |
| Milner | ROR | 7.6 | 8.2 | - | 4.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 4.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.1 | 10.3 |
| Swan Falls | ROR | 15.4 | 15.7 | 15.4 | 16.9 | 16.0 | 14.8 | 12.0 | 9.9 | 13.8 | 15.5 | 15.0 | 15.0 | 14.6 |
| Twin Falls | ROR | 10.4 | 11.6 | 5.2 | 8.4 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.3 | 8.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.7 | 12.5 | 13.8 | 17.2 | 16.0 | 12.7 | 7.5 | 12.3 | 14.3 | 12.2 | 12.3 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.7 | 12.9 | 11.9 | 13.0 | 15.9 | 14.9 | 12.1 | 7.6 | 11.7 | 13.4 | 11.7 | 11.7 | 12.5 |
| **HCC Total** | | **548.6** | **674.5** | **580.6** | **716.7** | **890.1** | **593.2** | **514.0** | **356.5** | **392.7** | **402.0** | **344.2** | **442.2** | **537.9** |
| **ROR Total** | | **204.4** | **210.2** | **194.3** | **243.8** | **312.8** | **321.4** | **273.0** | **201.4** | **210.1** | **212.1** | **178.5** | **184.1** | **228.8** |
| **Total** | | **753.0** | **884.7** | **774.9** | **960.5** | **1,202.9** | **914.6** | **787.0** | **557.9** | **602.8** | **614.1** | **522.7** | **626.3** | **766.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 242.7 | 298.5 | 247.5 | 315.1 | 394.4 | 259.1 | 227.1 | 151.1 | 161.7 | 169.4 | 148.1 | 196.1 | 234.2 |
| Oxbow | HCC | 102.2 | 125.5 | 109.2 | 132.2 | 163.1 | 109.0 | 96.1 | 68.8 | 75.1 | 78.1 | 65.6 | 82.0 | 100.6 |
| Hells Canyon | HCC | 202.5 | 247.9 | 223.0 | 267.5 | 331.0 | 223.3 | 189.6 | 135.5 | 147.4 | 153.7 | 130.6 | 162.7 | 201.2 |
| 1000 Springs | ROR** | - | - | 10.7 | 34.9 | 71.7 | 88.6 | 84.7 | 61.4 | 34.8 | 14.1 | - | - | 33.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.1 | 36.1 | 34.2 | 36.6 | 40.9 | 37.5 | 33.3 | 25.8 | 33.6 | 37.0 | 33.8 | 33.8 | 34.9 |
| C .J. Strike | ROR | 46.6 | 48.2 | 45.3 | 50.4 | 47.8 | 43.2 | 33.6 | 27.8 | 39.7 | 46.6 | 44.0 | 44.0 | 43.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.0 | 20.7 | 21.7 | 26.7 | 25.3 | 21.2 | 14.0 | 20.6 | 23.5 | 20.8 | 20.7 | 21.6 |
| Milner | ROR | 7.6 | 8.0 | - | 4.5 | 15.4 | 15.3 | 6.2 | - | - | - | - | 1.6 | 4.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.2 |
| Swan Falls | ROR | 15.3 | 15.6 | 15.3 | 16.8 | 16.0 | 14.7 | 11.9 | 9.8 | 13.7 | 15.5 | 14.9 | 14.9 | 14.5 |
| Twin Falls | ROR | 10.4 | 11.3 | 5.2 | 8.4 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.4 | 12.4 | 13.2 | 17.1 | 15.8 | 12.6 | 7.3 | 12.1 | 14.2 | 12.1 | 12.1 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.6 | 11.8 | 12.5 | 15.8 | 14.7 | 12.0 | 7.5 | 11.6 | 13.3 | 11.5 | 11.6 | 12.3 |
| **HCC Total** | | **547.4** | **671.9** | **579.7** | **714.8** | **888.4** | **591.4** | **512.8** | **355.4** | **384.1** | **401.2** | **344.3** | **440.8** | **536.0** |
| **ROR Total** | | **203.6** | **207.7** | **193.4** | **239.7** | **312.3** | **320.1** | **272.3** | **200.2** | **208.8** | **211.1** | **177.6** | **182.2** | **227.4** |
| **Total** | | **751.0** | **879.6** | **773.1** | **954.5** | **1,200.7** | **911.5** | **785.1** | **555.6** | **592.9** | **612.3** | **521.9** | **623.0** | **763.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 242.1 | 297.7 | 247.0 | 314.3 | 393.6 | 258.4 | 226.5 | 151.0 | 159.8 | 169.5 | 148.2 | 195.0 | 233.6 |
| Oxbow | HCC | 101.9 | 125.2 | 109.0 | 131.9 | 162.8 | 108.7 | 95.8 | 68.8 | 74.1 | 78.1 | 65.6 | 81.5 | 100.3 |
| Hells Canyon | HCC | 202.0 | 247.2 | 222.6 | 266.8 | 330.4 | 222.7 | 189.0 | 135.4 | 145.5 | 153.7 | 130.7 | 161.8 | 200.6 |
| 1000 Springs | ROR** | - | - | 10.4 | 34.7 | 71.6 | 88.5 | 84.7 | 61.4 | 34.8 | 14.2 | - | - | 33.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.8 | 35.9 | 34.1 | 35.7 | 40.8 | 37.3 | 33.1 | 25.6 | 33.4 | 36.8 | 33.6 | 33.5 | 34.6 |
| C .J. Strike | ROR | 46.2 | 47.9 | 45.1 | 49.0 | 47.6 | 42.9 | 33.3 | 27.6 | 39.4 | 46.4 | 43.7 | 43.9 | 42.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.0 | 21.9 | 20.6 | 21.3 | 26.6 | 25.1 | 21.0 | 13.9 | 20.4 | 23.3 | 20.7 | 20.6 | 21.5 |
| Milner | ROR | 7.3 | 8.0 | - | 3.1 | 15.4 | 15.0 | 6.2 | - | - | - | - | 1.6 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 11.3 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.2 |
| Swan Falls | ROR | 15.2 | 15.6 | 15.3 | 16.5 | 15.9 | 14.6 | 11.9 | 9.8 | 13.6 | 15.4 | 14.9 | 14.8 | 14.5 |
| Twin Falls | ROR | 10.3 | 11.3 | 5.8 | 7.3 | 18.1 | 18.6 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.3 | 12.4 | 12.9 | 17.0 | 15.7 | 12.5 | 7.2 | 11.9 | 14.1 | 12.0 | 12.0 | 12.9 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.5 | 11.8 | 12.3 | 15.8 | 14.6 | 11.9 | 7.4 | 11.4 | 13.2 | 11.5 | 11.5 | 12.2 |
| **HCC Total** | | **546.0** | **670.1** | **578.6** | **713.0** | **886.8** | **589.8** | **511.3** | **355.2** | **379.3** | **401.3** | **344.5** | **438.3** | **534.5** |
| **ROR Total** | | **202.1** | **206.9** | **194.0** | **232.8** | **311.6** | **318.5** | **271.4** | **199.5** | **207.6** | **210.3** | **176.9** | **181.4** | **226.1** |
| **Total** | | **748.1** | **877.0** | **772.6** | **945.8** | **1,198.3** | **908.3** | **782.7** | **554.7** | **586.9** | **611.6** | **521.4** | **619.7** | **760.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 241.3 | 297.0 | 246.6 | 313.4 | 392.9 | 257.7 | 225.9 | 150.7 | 157.7 | 169.7 | 148.2 | 193.7 | 232.9 |
| Oxbow | HCC | 101.6 | 124.9 | 108.8 | 131.5 | 162.5 | 108.4 | 95.5 | 68.7 | 72.9 | 78.0 | 65.6 | 81.0 | 99.9 |
| Hells Canyon | HCC | 201.3 | 246.7 | 222.3 | 266.1 | 329.7 | 222.1 | 188.5 | 135.2 | 143.3 | 153.6 | 130.6 | 160.7 | 200.0 |
| 1000 Springs | ROR** | - | - | 10.2 | 33.2 | 71.6 | 88.5 | 84.7 | 61.4 | 34.6 | 14.1 | - | - | 33.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.6 | 35.6 | 34.0 | 35.6 | 40.7 | 37.1 | 33.0 | 25.4 | 33.1 | 36.6 | 33.6 | 33.4 | 34.5 |
| C .J. Strike | ROR | 46.0 | 47.6 | 44.9 | 47.8 | 47.5 | 42.5 | 33.2 | 27.4 | 39.1 | 46.1 | 43.5 | 43.6 | 42.4 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.8 | 21.7 | 20.5 | 21.1 | 26.5 | 24.9 | 20.9 | 13.7 | 20.2 | 23.2 | 20.5 | 20.4 | 21.3 |
| Milner | ROR | 7.3 | 8.0 | - | 2.0 | 15.3 | 14.8 | 6.2 | - | - | - | - | 1.6 | 4.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.2 | 10.2 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.1 |
| Swan Falls | ROR | 15.4 | 15.5 | 15.2 | 16.4 | 15.9 | 14.5 | 11.8 | 9.7 | 13.5 | 15.3 | 14.8 | 14.8 | 14.4 |
| Twin Falls | ROR | 10.3 | 10.7 | 5.5 | 6.4 | 17.9 | 18.6 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.1 | 12.3 | 12.8 | 16.9 | 15.5 | 12.4 | 7.1 | 11.8 | 13.9 | 11.9 | 11.9 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.4 | 11.7 | 12.1 | 15.7 | 14.4 | 11.8 | 7.3 | 11.3 | 13.1 | 11.4 | 11.4 | 12.1 |
| **HCC Total** | | **544.2** | **668.6** | **577.7** | **711.0** | **885.0** | **588.2** | **509.9** | **354.6** | **373.9** | **401.3** | **344.4** | **435.4** | **532.8** |
| **ROR Total** | | **201.5** | **205.1** | **192.5** | **226.3** | **310.8** | **317.0** | **270.8** | **198.6** | **206.3** | **209.2** | **176.2** | **180.6** | **224.6** |
| **Total** | | **745.7** | **873.7** | **770.2** | **937.3** | **1,195.8** | **905.2** | **780.7** | **553.2** | **580.1** | **610.5** | **520.6** | **616.0** | **757.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 240.7 | 296.2 | 245.9 | 312.6 | 392.1 | 256.8 | 225.3 | 150.1 | 155.7 | 169.9 | 148.2 | 193.1 | 232.2 |
| Oxbow | HCC | 101.3 | 124.6 | 108.5 | 131.2 | 162.2 | 108.1 | 95.3 | 68.4 | 71.9 | 78.0 | 65.6 | 80.7 | 99.6 |
| Hells Canyon | HCC | 200.8 | 246.1 | 221.6 | 265.5 | 329.2 | 221.4 | 188.0 | 134.6 | 141.4 | 153.5 | 130.5 | 160.2 | 199.4 |
| 1000 Springs | ROR** | - | - | 9.9 | 33.1 | 71.6 | 88.5 | 84.6 | 61.4 | 34.5 | 14.1 | - | - | 33.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.4 | 35.4 | 33.9 | 35.5 | 40.6 | 36.9 | 32.9 | 25.2 | 32.9 | 36.4 | 33.4 | 33.2 | 34.3 |
| C .J. Strike | ROR | 45.7 | 47.1 | 44.6 | 47.6 | 47.4 | 42.4 | 33.0 | 27.1 | 38.8 | 45.9 | 43.3 | 43.2 | 42.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.7 | 21.6 | 20.4 | 20.9 | 26.4 | 24.7 | 20.8 | 13.6 | 19.9 | 23.0 | 20.3 | 20.3 | 21.1 |
| Milner | ROR | 7.3 | 7.8 | - | - | 15.0 | 14.5 | 6.2 | - | - | - | - | 1.6 | 4.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.9 | 9.4 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 10.0 |
| Swan Falls | ROR | 15.3 | 15.4 | 15.2 | 16.3 | 15.9 | 14.5 | 11.8 | 9.7 | 13.4 | 15.2 | 14.7 | 14.7 | 14.3 |
| Twin Falls | ROR | 10.3 | 10.6 | 5.3 | 5.7 | 17.9 | 18.3 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 8.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.0 | 12.2 | 12.6 | 16.8 | 15.3 | 12.3 | 7.0 | 11.6 | 13.8 | 11.8 | 11.8 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.3 | 11.6 | 12.0 | 15.6 | 14.3 | 11.7 | 7.2 | 11.1 | 13.0 | 11.3 | 11.3 | 12.0 |
| **HCC Total** | | **542.8** | **666.9** | **576.0** | **709.3** | **883.4** | **586.3** | **508.6** | **353.1** | **369.0** | **401.4** | **344.3** | **434.0** | **531.3** |
| **ROR Total** | | **200.5** | **203.7** | **191.0** | **221.8** | **309.9** | **315.6** | **270.1** | **197.8** | **204.9** | **208.3** | **175.3** | **179.4** | **223.2** |
| **Total** | | **743.3** | **870.6** | **767.0** | **931.1** | **1,193.3** | **901.9** | **778.7** | **550.9** | **573.8** | **609.7** | **519.6** | **613.4** | **754.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 240.1 | 295.5 | 243.7 | 311.7 | 391.6 | 256.0 | 224.7 | 149.5 | 153.8 | 169.7 | 148.7 | 192.4 | 231.4 |
| Oxbow | HCC | 101.1 | 124.3 | 107.6 | 130.8 | 162.0 | 107.7 | 95.0 | 68.1 | 70.9 | 77.8 | 65.7 | 80.4 | 99.3 |
| Hells Canyon | HCC | 200.3 | 245.5 | 219.8 | 264.8 | 328.7 | 220.7 | 187.5 | 134.1 | 139.5 | 153.2 | 130.8 | 159.6 | 198.7 |
| 1000 Springs | ROR** | - | - | 9.0 | 33.1 | 71.6 | 88.5 | 84.7 | 61.4 | 34.5 | 14.0 | - | - | 33.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.3 | 35.2 | 33.8 | 35.3 | 40.5 | 36.7 | 32.8 | 25.0 | 32.6 | 36.2 | 33.2 | 33.0 | 34.1 |
| C .J. Strike | ROR | 45.0 | 46.6 | 44.4 | 47.4 | 47.2 | 42.3 | 32.8 | 26.9 | 38.5 | 45.7 | 43.2 | 42.6 | 41.9 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.6 | 21.5 | 20.3 | 20.7 | 26.3 | 24.5 | 20.6 | 13.4 | 19.7 | 22.8 | 20.2 | 20.1 | 21.0 |
| Milner | ROR | 7.3 | 7.8 | - | - | 14.3 | 14.2 | 6.2 | - | - | - | - | 1.6 | 4.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 8.8 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 9.9 |
| Swan Falls | ROR | 15.2 | 15.3 | 15.1 | 16.3 | 15.8 | 14.4 | 11.7 | 9.6 | 13.3 | 15.4 | 14.6 | 14.5 | 14.3 |
| Twin Falls | ROR | 10.3 | 10.6 | 4.8 | 5.2 | 17.7 | 18.2 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 7.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.8 | 12.9 | 12.1 | 12.5 | 16.8 | 15.2 | 12.2 | 6.9 | 11.4 | 13.7 | 11.6 | 11.7 | 12.5 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.2 | 11.6 | 11.9 | 15.6 | 14.2 | 11.6 | 7.1 | 11.0 | 12.9 | 11.2 | 11.2 | 11.9 |
| **HCC Total** | | **541.5** | **665.3** | **571.1** | **707.3** | **882.2** | **584.4** | **507.2** | **351.7** | **364.2** | **400.7** | **345.2** | **432.4** | **529.4** |
| **ROR Total** | | **199.3** | **202.6** | **188.7** | **219.9** | **308.5** | **314.4** | **269.4** | **196.9** | **203.7** | **207.6** | **174.5** | **178.0** | **222.0** |
| **Total** | | **740.8** | **867.9** | **759.8** | **927.2** | **1,190.7** | **898.8** | **776.6** | **548.6** | **567.8** | **608.3** | **519.7** | **610.4** | **751.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 240.1 | 294.7 | 242.8 | 310.9 | 391.1 | 255.1 | 224.1 | 148.9 | 151.9 | 169.8 | 148.4 | 192.2 | 230.8 |
| Oxbow | HCC | 101.1 | 123.9 | 107.1 | 130.5 | 161.8 | 107.3 | 94.8 | 67.8 | 69.9 | 77.8 | 65.6 | 80.3 | 99.0 |
| Hells Canyon | HCC | 200.3 | 244.9 | 219.0 | 264.1 | 328.3 | 220.0 | 187.1 | 133.5 | 137.6 | 153.1 | 130.5 | 159.4 | 198.1 |
| 1000 Springs | ROR** | - | - | 8.6 | 33.1 | 71.6 | 88.3 | 84.6 | 61.3 | 34.5 | 14.0 | - | - | 33.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.9 | 35.0 | 33.6 | 35.2 | 40.4 | 36.5 | 32.6 | 24.8 | 32.4 | 36.0 | 32.8 | 32.8 | 33.9 |
| C .J. Strike | ROR | 44.1 | 45.2 | 44.2 | 47.2 | 47.1 | 42.0 | 32.6 | 26.7 | 38.2 | 45.5 | 43.0 | 42.2 | 41.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.4 | 21.3 | 20.1 | 20.5 | 26.2 | 24.3 | 20.5 | 13.2 | 19.5 | 22.7 | 19.9 | 19.9 | 20.8 |
| Milner | ROR | 7.3 | 7.5 | - | - | 14.3 | 14.2 | 6.2 | - | - | - | - | 1.6 | 4.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 8.6 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 9.9 |
| Swan Falls | ROR | 15.0 | 15.3 | 15.0 | 16.2 | 15.7 | 14.4 | 11.6 | 9.5 | 13.2 | 15.3 | 14.6 | 14.4 | 14.2 |
| Twin Falls | ROR | 10.3 | 10.5 | 4.7 | 4.8 | 17.7 | 18.2 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 7.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.7 | 12.8 | 12.0 | 12.3 | 16.7 | 15.0 | 12.1 | 6.7 | 11.3 | 13.5 | 11.4 | 11.5 | 12.3 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.1 | 11.5 | 11.8 | 15.5 | 14.1 | 11.5 | 7.0 | 10.8 | 12.8 | 11.0 | 11.0 | 11.8 |
| **HCC Total** | | **541.5** | **663.5** | **568.9** | **705.5** | **881.1** | **582.4** | **506.0** | **350.2** | **359.4** | **400.7** | **344.5** | **431.9** | **528.0** |
| **ROR Total** | | **197.4** | **200.2** | **187.2** | **218.4** | **307.9** | **313.2** | **268.5** | **195.8** | **202.6** | **206.7** | **173.2** | **176.7** | **220.7** |
| **Total** | | **738.9** | **863.7** | **756.1** | **923.9** | **1,189.0** | **895.6** | **774.5** | **546.0** | **561.9** | **607.4** | **517.7** | **608.6** | **748.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 211.6 | 197.2 | 238.9 | 253.6 | 272.2 | 204.3 | 218.2 | 144.1 | 157.4 | 153.8 | 149.0 | 191.1 | 199.3 |
| Oxbow | HCC | 88.6 | 82.8 | 99.9 | 105.6 | 112.7 | 84.2 | 91.9 | 65.5 | 73.1 | 70.5 | 65.7 | 79.6 | 85.0 |
| Hells Canyon | HCC | 175.1 | 164.8 | 202.4 | 214.2 | 231.3 | 169.8 | 180.6 | 128.8 | 143.1 | 139.2 | 130.4 | 157.4 | 169.8 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.8 | 70.5 | 86.4 | 85.4 | 56.2 | 28.0 | 9.4 | 0.0 | 0.0 | 30.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.7 | 35.0 | 33.4 | 32.5 | 38.0 | 36.7 | 33.5 | 26.6 | 35.2 | 37.7 | 35.6 | 35.4 | 34.5 |
| C .J. Strike | ROR | 44.1 | 43.7 | 43.5 | 41.2 | 42.5 | 39.4 | 31.3 | 29.0 | 39.0 | 44.9 | 44.5 | 44.0 | 40.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.3 | 22.6 | 20.6 | 20.0 | 25.5 | 24.4 | 21.8 | 15.0 | 22.0 | 24.1 | 22.9 | 22.7 | 22.0 |
| Milner | ROR | 6.0 | 6.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.6 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.2 | 10.7 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.9 | 14.8 | 14.8 | 14.2 | 14.7 | 14.0 | 11.4 | 10.2 | 13.8 | 15.2 | 15.2 | 15.0 | 14.0 |
| Twin Falls | ROR | 9.3 | 9.3 | 4.0 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.5 | 6.8 | 8.9 | 7.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.8 | 12.3 | 11.9 | 16.1 | 15.1 | 13.1 | 8.1 | 13.2 | 14.7 | 13.8 | 13.7 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.0 | 11.7 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.5 | 13.7 | 13.0 | 12.9 | 12.5 |
| **HCC Total** | | **475.3** | **444.8** | **541.2** | **573.4** | **616.1** | **458.3** | **490.7** | **338.4** | **373.6** | **363.5** | **345.1** | **428.1** | **454.0** |
| **ROR Total** | | **196.9** | **198.8** | **176.9** | **194.3** | **293.2** | **302.6** | **271.1** | **197.6** | **205.2** | **204.1** | **190.3** | **197.2** | **219.0** |
| **Total** | | **672.2** | **643.6** | **718.1** | **767.7** | **909.3** | **760.9** | **761.8** | **536.0** | **578.8** | **567.6** | **535.4** | **625.3** | **673.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 211.3 | 200.1 | 238.7 | 253.8 | 275.8 | 203.8 | 218.0 | 143.7 | 156.5 | 154.1 | 149.1 | 190.8 | 199.6 |
| Oxbow | HCC | 88.4 | 84.1 | 99.8 | 105.7 | 114.2 | 84.0 | 91.8 | 65.3 | 72.7 | 70.7 | 65.7 | 79.5 | 85.2 |
| Hells Canyon | HCC | 174.8 | 167.2 | 202.3 | 214.4 | 234.2 | 169.5 | 180.4 | 128.4 | 142.3 | 139.4 | 130.5 | 157.1 | 170.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.7 | 70.5 | 86.7 | 85.6 | 56.9 | 28.9 | 9.3 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.7 | 35.0 | 33.4 | 32.8 | 38.0 | 36.6 | 33.4 | 26.5 | 35.0 | 37.7 | 35.4 | 35.3 | 34.5 |
| C .J. Strike | ROR | 44.0 | 43.5 | 43.5 | 41.1 | 42.5 | 39.3 | 31.2 | 28.9 | 38.8 | 44.9 | 44.4 | 43.9 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.2 | 22.5 | 20.5 | 19.9 | 25.4 | 24.3 | 21.8 | 14.9 | 21.9 | 24.1 | 22.8 | 22.6 | 21.9 |
| Milner | ROR | 6.1 | 7.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 4.9 | 4.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.6 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.8 | 11.1 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.9 | 14.8 | 14.8 | 14.2 | 14.8 | 14.0 | 11.4 | 10.2 | 13.8 | 15.2 | 15.2 | 15.0 | 14.0 |
| Twin Falls | ROR | 9.3 | 9.9 | 4.0 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.0 | 7.2 | 8.9 | 7.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.7 | 12.3 | 11.9 | 16.1 | 15.0 | 13.1 | 8.0 | 13.1 | 14.6 | 13.7 | 13.6 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.6 | 13.0 | 11.7 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.4 | 13.7 | 12.9 | 12.9 | 12.5 |
| **HCC Total** | | **474.5** | **451.4** | **540.8** | **573.9** | **624.1** | **457.3** | **490.2** | **337.4** | **371.4** | **364.2** | **345.3** | **427.4** | **454.8** |
| **ROR Total** | | **196.6** | **200.0** | **176.8** | **194.3** | **293.2** | **302.5** | **271.1** | **197.9** | **205.4** | **205.0** | **190.5** | **196.8** | **219.2** |
| **Total** | | **671.1** | **651.4** | **717.6** | **768.2** | **917.3** | **759.8** | **761.3** | **535.3** | **576.7** | **569.2** | **535.8** | **624.2** | **674.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 210.7 | 201.0 | 236.8 | 257.8 | 280.9 | 204.0 | 218.4 | 143.7 | 155.6 | 154.3 | 149.6 | 189.2 | 200.2 |
| Oxbow | HCC | 88.2 | 84.4 | 99.0 | 107.3 | 114.6 | 84.1 | 92.0 | 65.3 | 72.2 | 70.6 | 65.9 | 78.8 | 85.2 |
| Hells Canyon | HCC | 174.3 | 167.9 | 200.7 | 217.6 | 234.1 | 169.6 | 180.7 | 128.4 | 141.3 | 139.3 | 130.8 | 155.9 | 170.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.9 | 70.7 | 86.7 | 85.7 | 57.1 | 30.1 | 9.4 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.3 | 34.7 | 33.2 | 33.2 | 38.3 | 36.6 | 33.4 | 26.5 | 34.9 | 37.6 | 34.8 | 34.7 | 34.4 |
| C .J. Strike | ROR | 43.7 | 43.3 | 43.5 | 41.4 | 43.5 | 39.6 | 31.4 | 29.0 | 38.8 | 44.9 | 44.1 | 43.2 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.3 | 20.4 | 20.0 | 25.5 | 24.3 | 21.8 | 14.9 | 21.9 | 24.1 | 22.3 | 22.1 | 21.8 |
| Milner | ROR | 5.0 | 7.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3.8 | 4.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 9.8 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.2 | 15.1 | 14.1 | 11.5 | 10.2 | 13.8 | 15.2 | 15.0 | 14.8 | 14.0 |
| Twin Falls | ROR | 8.7 | 9.8 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 6.1 | 8.3 | 7.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.2 | 11.9 | 16.2 | 15.0 | 13.1 | 8.0 | 13.1 | 14.6 | 13.3 | 13.2 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.8 | 11.6 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.4 | 13.7 | 12.5 | 12.5 | 12.4 |
| **HCC Total** | | **473.2** | **453.3** | **536.5** | **582.7** | **629.5** | **457.7** | **491.1** | **337.4** | **369.0** | **364.2** | **346.3** | **423.9** | **455.4** |
| **ROR Total** | | **193.8** | **198.6** | **175.8** | **195.3** | **295.2** | **302.9** | **271.5** | **198.2** | **206.5** | **205.4** | **185.7** | **192.3** | **218.4** |
| **Total** | | **667.0** | **651.9** | **712.3** | **778.0** | **924.7** | **760.6** | **762.6** | **535.6** | **575.5** | **569.6** | **532.0** | **616.2** | **673.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 209.6 | 202.7 | 236.0 | 258.1 | 281.9 | 203.7 | 218.1 | 143.4 | 154.5 | 154.1 | 149.5 | 188.5 | 200.0 |
| Oxbow | HCC | 87.7 | 85.2 | 98.7 | 107.4 | 115.0 | 84.0 | 91.9 | 65.1 | 71.6 | 70.5 | 65.8 | 78.5 | 85.1 |
| Hells Canyon | HCC | 173.4 | 169.3 | 200.0 | 217.8 | 234.9 | 169.4 | 180.5 | 128.1 | 140.3 | 139.1 | 130.7 | 155.3 | 169.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.8 | 70.8 | 86.8 | 85.7 | 57.2 | 30.4 | 10.3 | 0.0 | 0.0 | 30.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.2 | 34.6 | 33.3 | 33.0 | 38.3 | 36.5 | 33.4 | 26.4 | 34.8 | 37.6 | 34.8 | 34.5 | 34.3 |
| C .J. Strike | ROR | 43.6 | 43.2 | 43.5 | 41.1 | 43.6 | 39.6 | 31.3 | 28.9 | 38.6 | 44.8 | 44.0 | 42.8 | 40.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.2 | 20.4 | 20.0 | 25.5 | 24.3 | 21.7 | 14.8 | 21.7 | 24.0 | 22.2 | 21.8 | 21.7 |
| Milner | ROR | 5.0 | 7.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 | 3.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 9.8 | 11.8 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.4 | 15.1 | 14.0 | 11.4 | 10.1 | 13.7 | 15.1 | 15.0 | 14.7 | 14.0 |
| Twin Falls | ROR | 8.7 | 9.8 | 3.8 | 0.0 | 16.0 | 16.8 | 10.1 | 0.0 | 0.0 | 6.2 | 6.1 | 7.8 | 7.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.5 | 12.2 | 11.9 | 16.2 | 15.0 | 13.0 | 8.0 | 13.0 | 14.6 | 13.2 | 13.0 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.6 | 11.4 | 15.0 | 14.0 | 12.4 | 8.0 | 12.3 | 13.7 | 12.5 | 12.3 | 12.4 |
| **HCC Total** | | **470.7** | **457.2** | **534.7** | **583.3** | **631.8** | **457.1** | **490.5** | **336.6** | **366.3** | **363.7** | **346.0** | **422.3** | **455.0** |
| **ROR Total** | | **193.7** | **198.2** | **175.9** | **194.9** | **295.5** | **303.1** | **271.1** | **197.8** | **206.0** | **206.0** | **185.4** | **189.6** | **218.1** |
| **Total** | | **664.4** | **655.4** | **710.6** | **778.2** | **927.2** | **760.2** | **761.6** | **534.4** | **572.3** | **569.7** | **531.4** | **611.9** | **673.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 209.6 | 205.5 | 232.5 | 257.6 | 283.9 | 204.5 | 218.9 | 143.3 | 153.6 | 154.6 | 149.9 | 180.0 | 199.5 |
| Oxbow | HCC | 87.7 | 86.4 | 97.2 | 107.2 | 115.8 | 84.2 | 92.2 | 65.1 | 71.1 | 70.6 | 65.9 | 78.0 | 85.1 |
| Hells Canyon | HCC | 173.4 | 171.6 | 197.2 | 217.4 | 236.5 | 170.0 | 181.1 | 128.0 | 139.3 | 139.3 | 130.9 | 153.8 | 169.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.9 | 85.6 | 57.3 | 30.6 | 11.2 | 0.0 | 0.0 | 31.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.1 | 34.6 | 33.4 | 32.8 | 38.6 | 36.7 | 33.3 | 26.5 | 34.7 | 37.6 | 34.4 | 33.9 | 34.2 |
| C .J. Strike | ROR | 43.4 | 43.2 | 43.8 | 41.2 | 43.9 | 39.8 | 31.6 | 28.9 | 38.6 | 44.9 | 43.6 | 42.2 | 40.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.2 | 20.5 | 20.1 | 25.7 | 24.4 | 21.7 | 14.9 | 21.5 | 24.1 | 21.5 | 21.3 | 21.7 |
| Milner | ROR | 5.0 | 6.8 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.9 | 14.3 | 15.2 | 14.1 | 11.5 | 10.2 | 13.7 | 15.2 | 14.8 | 14.4 | 14.0 |
| Twin Falls | ROR | 8.6 | 9.6 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 4.5 | 5.9 | 6.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.3 | 12.0 | 16.3 | 15.1 | 13.0 | 8.0 | 12.8 | 14.6 | 12.7 | 12.6 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.7 | 11.5 | 15.2 | 14.1 | 12.4 | 8.1 | 12.2 | 13.7 | 12.0 | 12.0 | 12.3 |
| **HCC Total** | | **470.7** | **463.5** | **526.9** | **582.2** | **636.2** | **458.7** | **492.2** | **336.4** | **364.0** | **364.5** | **346.7** | **411.8** | **454.5** |
| **ROR Total** | | **193.2** | **197.8** | **184.7** | **194.3** | **296.4** | **303.6** | **271.3** | **198.3** | **205.6** | **207.2** | **179.5** | **179.6** | **217.6** |
| **Total** | | **663.9** | **661.3** | **711.6** | **776.5** | **932.6** | **762.3** | **763.5** | **534.7** | **569.6** | **571.7** | **526.2** | **591.4** | **672.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 208.9 | 200.8 | 232.5 | 256.6 | 283.2 | 203.7 | 218.3 | 142.6 | 151.9 | 154.7 | 149.4 | 180.0 | 198.6 |
| Oxbow | HCC | 87.4 | 84.4 | 97.2 | 106.8 | 115.6 | 83.9 | 92.0 | 64.8 | 70.2 | 70.6 | 65.7 | 77.9 | 84.7 |
| Hells Canyon | HCC | 172.8 | 167.8 | 197.2 | 216.7 | 235.9 | 169.4 | 180.6 | 127.4 | 137.6 | 139.2 | 130.4 | 153.8 | 169.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.8 | 85.6 | 57.0 | 30.2 | 11.0 | 0.0 | 0.0 | 31.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.9 | 34.4 | 33.4 | 32.6 | 38.4 | 36.5 | 33.1 | 26.3 | 34.4 | 37.4 | 34.3 | 33.8 | 34.0 |
| C .J. Strike | ROR | 43.2 | 43.2 | 43.6 | 41.1 | 43.2 | 39.5 | 31.4 | 28.7 | 38.4 | 44.8 | 43.4 | 42.3 | 40.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.0 | 22.1 | 20.4 | 20.0 | 25.6 | 24.2 | 21.6 | 14.8 | 21.2 | 23.9 | 21.4 | 21.3 | 21.5 |
| Milner | ROR | 5.0 | 6.8 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.8 | 14.3 | 14.9 | 14.0 | 11.5 | 10.1 | 13.7 | 15.1 | 14.8 | 14.5 | 13.9 |
| Twin Falls | ROR | 8.6 | 9.6 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 4.5 | 5.9 | 6.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.4 | 12.2 | 11.9 | 16.2 | 14.9 | 12.9 | 7.9 | 12.6 | 14.5 | 12.6 | 12.6 | 12.9 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.7 | 11.4 | 15.1 | 14.0 | 12.3 | 8.0 | 12.0 | 13.6 | 12.0 | 11.9 | 12.3 |
| **HCC Total** | | **469.1** | **453.0** | **526.9** | **580.1** | **634.6** | **457.0** | **490.9** | **334.8** | **359.7** | **364.5** | **345.5** | **411.7** | **452.3** |
| **ROR Total** | | **192.6** | **197.4** | **184.2** | **193.7** | **294.9** | **302.4** | **270.6** | **197.2** | **204.0** | **206.2** | **179.0** | **179.6** | **216.8** |
| **Total** | | **661.7** | **650.4** | **711.1** | **773.8** | **929.5** | **759.4** | **761.5** | **532.0** | **563.6** | **570.7** | **524.5** | **591.3** | **669.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 208.3 | 196.1 | 230.3 | 256.2 | 282.5 | 202.9 | 217.6 | 141.9 | 149.7 | 154.7 | 149.5 | 179.7 | 197.4 |
| Oxbow | HCC | 87.1 | 82.4 | 96.3 | 106.6 | 115.3 | 83.6 | 91.7 | 64.4 | 69.0 | 70.4 | 65.7 | 77.8 | 84.2 |
| Hells Canyon | HCC | 172.3 | 163.9 | 195.5 | 216.3 | 235.3 | 168.8 | 180.1 | 126.8 | 135.4 | 139.0 | 130.4 | 153.5 | 168.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.6 | 85.5 | 56.9 | 29.8 | 10.9 | 0.0 | 0.0 | 31.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.8 | 34.3 | 33.2 | 32.5 | 38.3 | 36.3 | 33.0 | 26.1 | 34.2 | 37.2 | 34.2 | 33.6 | 33.9 |
| C .J. Strike | ROR | 42.8 | 42.8 | 43.5 | 41.0 | 43.0 | 39.2 | 31.1 | 28.5 | 38.3 | 44.6 | 43.3 | 42.0 | 40.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.6 | 21.9 | 20.3 | 19.9 | 25.5 | 24.0 | 21.5 | 14.6 | 21.0 | 23.8 | 21.2 | 21.1 | 21.4 |
| Milner | ROR | 5.0 | 6.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.8 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.7 | 14.6 | 14.8 | 14.2 | 14.9 | 13.9 | 11.4 | 10.0 | 13.6 | 15.1 | 14.7 | 14.4 | 13.9 |
| Twin Falls | ROR | 8.6 | 9.4 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.0 | 4.5 | 5.9 | 6.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.2 | 12.1 | 11.9 | 16.2 | 14.8 | 12.9 | 7.8 | 12.4 | 14.4 | 12.5 | 12.4 | 12.8 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.5 | 11.6 | 11.3 | 15.0 | 13.9 | 12.2 | 7.9 | 11.8 | 13.5 | 11.9 | 11.8 | 12.1 |
| **HCC Total** | | **467.7** | **442.4** | **522.1** | **579.1** | **633.0** | **455.3** | **489.4** | **333.1** | **354.0** | **364.1** | **345.6** | **411.0** | **449.7** |
| **ROR Total** | | **191.1** | **195.3** | **183.6** | **193.2** | **294.4** | **301.2** | **269.8** | **196.2** | **202.6** | **205.0** | **178.3** | **178.5** | **215.8** |
| **Total** | | **658.8** | **637.7** | **705.7** | **772.3** | **927.4** | **756.5** | **759.2** | **529.3** | **556.6** | **569.1** | **523.9** | **589.5** | **665.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 207.6 | 194.1 | 229.4 | 255.7 | 281.8 | 202.5 | 217.0 | 141.2 | 147.4 | 154.8 | 149.6 | 179.3 | 196.7 |
| Oxbow | HCC | 86.9 | 81.5 | 95.9 | 106.4 | 115.0 | 83.4 | 91.4 | 64.1 | 67.9 | 70.4 | 65.7 | 77.6 | 83.8 |
| Hells Canyon | HCC | 171.8 | 162.3 | 194.7 | 215.9 | 234.8 | 168.4 | 179.5 | 126.2 | 133.2 | 138.8 | 130.5 | 153.2 | 167.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.5 | 70.6 | 86.5 | 85.5 | 56.5 | 29.6 | 10.9 | 0.0 | 0.0 | 31.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.6 | 34.1 | 33.0 | 32.5 | 38.2 | 36.1 | 32.9 | 25.9 | 33.9 | 37.0 | 34.0 | 33.4 | 33.7 |
| C .J. Strike | ROR | 42.5 | 42.5 | 42.5 | 40.9 | 42.8 | 38.9 | 30.9 | 28.2 | 38.1 | 44.3 | 43.1 | 41.8 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.4 | 21.7 | 20.2 | 19.8 | 25.4 | 23.9 | 21.4 | 14.4 | 20.8 | 23.7 | 21.1 | 20.9 | 21.2 |
| Milner | ROR | 5.0 | 5.9 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.6 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.6 | 14.5 | 14.5 | 14.1 | 14.8 | 13.8 | 11.2 | 9.9 | 13.6 | 15.0 | 14.6 | 14.3 | 13.7 |
| Twin Falls | ROR | 8.6 | 9.3 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.8 | 4.5 | 5.9 | 6.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.7 | 13.1 | 12.1 | 11.8 | 16.1 | 14.7 | 12.8 | 7.6 | 12.2 | 14.3 | 12.3 | 12.3 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.4 | 11.5 | 11.3 | 15.0 | 13.8 | 12.1 | 7.8 | 11.7 | 13.4 | 11.8 | 11.7 | 12.1 |
| **HCC Total** | | **466.3** | **437.9** | **520.0** | **578.0** | **631.5** | **454.3** | **487.9** | **331.5** | **348.4** | **364.0** | **345.8** | **410.1** | **448.0** |
| **ROR Total** | | **190.0** | **194.0** | **181.9** | **192.6** | **293.8** | **300.2** | **269.0** | **194.7** | **201.4** | **203.7** | **177.4** | **177.6** | **214.7** |
| **Total** | | **656.3** | **631.9** | **701.9** | **770.6** | **925.3** | **754.5** | **756.9** | **526.2** | **549.8** | **567.7** | **523.2** | **587.7** | **662.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 206.9 | 193.5 | 228.5 | 255.3 | 281.2 | 202.0 | 216.4 | 140.6 | 145.3 | 154.5 | 149.9 | 178.7 | 196.1 |
| Oxbow | HCC | 86.6 | 81.3 | 95.6 | 106.3 | 114.7 | 83.2 | 91.1 | 63.8 | 66.7 | 70.1 | 65.8 | 77.3 | 83.5 |
| Hells Canyon | HCC | 171.2 | 161.8 | 194.0 | 215.6 | 234.3 | 168.0 | 179.0 | 125.6 | 131.0 | 138.4 | 130.7 | 152.6 | 166.8 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.5 | 86.5 | 85.5 | 56.2 | 29.0 | 10.6 | 0.0 | 0.0 | 31.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.4 | 33.9 | 32.9 | 32.4 | 38.1 | 35.9 | 32.8 | 25.7 | 33.7 | 36.8 | 33.8 | 33.2 | 33.6 |
| C .J. Strike | ROR | 42.3 | 42.3 | 42.2 | 40.9 | 42.7 | 38.5 | 30.7 | 28.0 | 38.0 | 44.1 | 42.8 | 41.5 | 39.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.3 | 21.5 | 20.1 | 19.7 | 25.3 | 23.7 | 21.2 | 14.3 | 20.6 | 23.4 | 20.9 | 20.8 | 21.1 |
| Milner | ROR | 5.0 | 5.4 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.5 | 14.4 | 14.4 | 14.1 | 14.8 | 13.7 | 11.2 | 9.9 | 13.5 | 14.9 | 14.5 | 14.2 | 13.7 |
| Twin Falls | ROR | 8.6 | 8.9 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.6 | 13.0 | 12.0 | 11.7 | 16.0 | 14.6 | 12.6 | 7.5 | 12.1 | 14.1 | 12.2 | 12.2 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.0 | 12.3 | 11.5 | 11.2 | 14.9 | 13.7 | 12.0 | 7.7 | 11.5 | 13.3 | 11.6 | 11.6 | 11.9 |
| **HCC Total** | | **464.7** | **436.6** | **518.1** | **577.2** | **630.1** | **453.2** | **486.5** | **330.0** | **342.9** | **363.0** | **346.4** | **408.6** | **446.4** |
| **ROR Total** | | **189.2** | **192.2** | **181.2** | **192.3** | **293.2** | **299.1** | **268.2** | **193.7** | **199.9** | **200.9** | **176.3** | **176.7** | **213.6** |
| **Total** | | **653.9** | **628.8** | **699.3** | **769.5** | **923.3** | **752.3** | **754.7** | **523.7** | **542.8** | **563.9** | **522.7** | **585.3** | **660.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 206.3 | 192.8 | 227.9 | 254.8 | 280.4 | 201.6 | 215.5 | 139.9 | 143.7 | 154.5 | 149.7 | 179.1 | 195.5 |
| Oxbow | HCC | 86.3 | 81.0 | 95.3 | 106.1 | 114.4 | 83.1 | 90.8 | 63.5 | 65.9 | 70.1 | 65.7 | 77.5 | 83.3 |
| Hells Canyon | HCC | 170.7 | 161.2 | 193.5 | 215.2 | 233.7 | 167.7 | 178.4 | 125.0 | 129.5 | 138.4 | 130.5 | 153.0 | 166.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.2 | 86.5 | 85.6 | 56.2 | 28.5 | 10.3 | 0.0 | 0.0 | 31.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.3 | 33.8 | 32.8 | 32.4 | 37.9 | 35.7 | 32.6 | 25.5 | 33.4 | 36.5 | 33.6 | 33.0 | 33.4 |
| C .J. Strike | ROR | 42.0 | 41.9 | 42.0 | 40.7 | 42.5 | 38.3 | 30.5 | 27.7 | 37.7 | 43.8 | 42.5 | 41.2 | 39.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.1 | 21.3 | 20.1 | 19.6 | 25.1 | 23.5 | 21.0 | 14.1 | 20.3 | 23.2 | 20.7 | 20.5 | 20.9 |
| Milner | ROR | 4.9 | 6.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.4 | 14.4 | 14.3 | 14.0 | 14.8 | 13.6 | 11.1 | 9.8 | 13.4 | 14.8 | 14.4 | 14.1 | 13.6 |
| Twin Falls | ROR | 8.6 | 9.2 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 12.0 | 11.6 | 15.9 | 14.4 | 12.5 | 7.4 | 11.9 | 13.9 | 12.1 | 12.0 | 12.4 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.4 | 11.1 | 14.8 | 13.5 | 11.9 | 7.6 | 11.4 | 13.1 | 11.5 | 11.5 | 11.8 |
| **HCC Total** | | **463.3** | **435.0** | **516.7** | **576.1** | **628.5** | **452.4** | **484.7** | **328.4** | **339.0** | **363.0** | **345.9** | **409.6** | **445.2** |
| **ROR Total** | | **188.2** | **192.1** | **180.7** | **191.7** | **292.1** | **298.0** | **267.4** | **192.7** | **198.1** | **199.3** | **175.3** | **175.5** | **212.6** |
| **Total** | | **651.5** | **627.1** | **697.4** | **767.8** | **920.6** | **750.4** | **752.1** | **521.1** | **537.1** | **562.3** | **521.2** | **585.1** | **657.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 204.8 | 192.1 | 227.4 | 254.4 | 275.8 | 201.3 | 215.0 | 139.3 | 142.1 | 154.1 | 150.2 | 178.5 | 194.6 |
| Oxbow | HCC | 85.7 | 80.7 | 95.1 | 105.9 | 114.2 | 82.9 | 90.6 | 63.2 | 65.1 | 69.8 | 65.9 | 77.3 | 83.0 |
| Hells Canyon | HCC | 169.5 | 160.6 | 193.1 | 214.8 | 234.2 | 167.5 | 177.9 | 124.4 | 127.9 | 137.8 | 130.9 | 152.5 | 165.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.5 | 69.8 | 85.9 | 85.6 | 56.2 | 28.3 | 10.5 | 0.0 | 0.0 | 31.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.2 | 33.7 | 32.7 | 32.3 | 37.3 | 35.4 | 32.4 | 25.3 | 33.1 | 36.4 | 33.4 | 32.8 | 33.2 |
| C .J. Strike | ROR | 41.7 | 41.8 | 42.0 | 40.6 | 42.0 | 37.3 | 30.4 | 27.5 | 37.4 | 43.5 | 42.3 | 41.0 | 39.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.0 | 21.2 | 20.0 | 19.5 | 24.9 | 23.3 | 20.9 | 13.9 | 20.1 | 23.0 | 20.5 | 20.4 | 20.7 |
| Milner | ROR | 4.8 | 6.0 | 0.0 | 0.0 | 11.3 | 11.2 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.4 | 14.3 | 14.3 | 14.0 | 14.7 | 13.3 | 11.0 | 9.7 | 13.3 | 14.8 | 14.4 | 14.1 | 13.5 |
| Twin Falls | ROR | 8.5 | 9.2 | 3.8 | 0.0 | 14.0 | 15.0 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.4 | 12.7 | 11.9 | 11.5 | 15.7 | 14.2 | 12.4 | 7.3 | 11.7 | 13.8 | 11.9 | 11.9 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.8 | 12.1 | 11.4 | 11.1 | 14.6 | 13.4 | 11.8 | 7.5 | 11.2 | 13.0 | 11.4 | 11.4 | 11.7 |
| **HCC Total** | | **460.0** | **433.4** | **515.6** | **575.1** | **624.1** | **451.7** | **483.5** | **326.9** | **335.0** | **361.7** | **347.0** | **408.3** | **443.5** |
| **ROR Total** | | **187.3** | **191.5** | **180.4** | **191.2** | **286.5** | **292.4** | **266.7** | **191.8** | **196.6** | **198.7** | **174.4** | **174.8** | **211.0** |
| **Total** | | **647.3** | **624.9** | **696.0** | **766.3** | **910.5** | **744.1** | **750.2** | **518.7** | **531.6** | **560.4** | **521.4** | **583.1** | **654.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 203.8 | 191.5 | 226.9 | 254.0 | 275.2 | 201.0 | 214.3 | 138.5 | 140.0 | 154.2 | 150.2 | 177.9 | 194.0 |
| Oxbow | HCC | 85.3 | 80.4 | 94.9 | 105.7 | 113.9 | 82.8 | 90.3 | 62.9 | 64.1 | 69.8 | 65.9 | 77.0 | 82.7 |
| Hells Canyon | HCC | 168.7 | 160.1 | 192.6 | 214.5 | 233.7 | 167.2 | 177.4 | 123.8 | 125.9 | 137.8 | 130.8 | 152.0 | 165.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.6 | 85.5 | 85.5 | 56.2 | 28.2 | 10.4 | 0.0 | 0.0 | 31.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.1 | 33.5 | 32.6 | 32.3 | 37.1 | 35.1 | 32.3 | 25.1 | 32.8 | 36.2 | 33.2 | 32.8 | 33.0 |
| C .J. Strike | ROR | 41.5 | 41.7 | 41.8 | 40.4 | 41.8 | 36.5 | 30.4 | 27.3 | 37.1 | 43.3 | 42.0 | 40.8 | 38.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.8 | 21.0 | 19.9 | 19.3 | 24.3 | 23.1 | 20.7 | 13.8 | 19.9 | 22.9 | 20.4 | 20.2 | 20.5 |
| Milner | ROR | 5.0 | 6.0 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.3 | 14.3 | 13.9 | 14.7 | 13.1 | 11.0 | 9.7 | 13.2 | 14.8 | 14.3 | 14.1 | 13.5 |
| Twin Falls | ROR | 8.6 | 9.2 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.3 | 12.6 | 11.8 | 11.4 | 15.3 | 14.1 | 12.3 | 7.2 | 11.5 | 13.7 | 11.8 | 11.8 | 12.2 |
| Upper Salmon 3&4 | ROR | 11.7 | 12.0 | 11.3 | 11.0 | 14.3 | 13.3 | 11.7 | 7.4 | 11.1 | 12.9 | 11.3 | 11.3 | 11.6 |
| **HCC Total** | | **457.8** | **432.0** | **514.4** | **574.2** | **622.7** | **451.0** | **482.0** | **325.2** | **330.0** | **361.8** | **346.9** | **406.9** | **442.1** |
| **ROR Total** | | **186.7** | **190.8** | **179.7** | **190.4** | **283.1** | **288.8** | **266.1** | **191.1** | **195.3** | **197.9** | **173.5** | **174.2** | **209.8** |
| **Total** | | **644.5** | **622.8** | **694.1** | **764.6** | **905.8** | **739.8** | **748.1** | **516.3** | **525.2** | **559.7** | **520.4** | **581.1** | **651.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 203.1 | 190.1 | 225.7 | 253.5 | 274.6 | 200.7 | 213.7 | 137.8 | 138.1 | 154.3 | 149.9 | 177.6 | 193.3 |
| Oxbow | HCC | 85.0 | 79.9 | 94.4 | 105.5 | 113.7 | 82.7 | 90.0 | 62.5 | 63.0 | 69.7 | 65.7 | 76.8 | 82.4 |
| Hells Canyon | HCC | 168.1 | 159.0 | 191.7 | 214.1 | 233.2 | 167.0 | 176.9 | 123.1 | 124.0 | 137.7 | 130.5 | 151.7 | 164.7 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.4 | 85.6 | 85.5 | 56.2 | 27.8 | 10.2 | 0.0 | 0.0 | 31.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.0 | 33.3 | 32.5 | 32.2 | 37.0 | 34.8 | 32.0 | 24.9 | 32.5 | 36.0 | 33.1 | 32.6 | 32.8 |
| C .J. Strike | ROR | 41.2 | 41.3 | 42.0 | 40.2 | 41.7 | 36.2 | 30.3 | 27.0 | 36.8 | 43.1 | 41.7 | 40.4 | 38.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.7 | 20.8 | 19.9 | 19.2 | 24.2 | 23.1 | 20.5 | 13.6 | 19.6 | 22.7 | 20.2 | 20.1 | 20.4 |
| Milner | ROR | 5.0 | 5.1 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.1 | 14.3 | 13.8 | 14.7 | 13.0 | 10.9 | 9.6 | 13.1 | 14.8 | 14.2 | 14.0 | 13.4 |
| Twin Falls | ROR | 8.6 | 8.5 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.2 | 12.4 | 11.8 | 11.3 | 15.2 | 14.1 | 12.1 | 7.0 | 11.4 | 13.6 | 11.7 | 11.7 | 12.0 |
| Upper Salmon 3&4 | ROR | 11.6 | 11.8 | 11.3 | 10.9 | 14.2 | 13.2 | 11.6 | 7.2 | 10.9 | 12.8 | 11.2 | 11.2 | 11.5 |
| **HCC Total** | | **456.2** | **429.0** | **511.8** | **573.1** | **621.5** | **450.4** | **480.6** | **323.4** | **325.0** | **361.7** | **346.1** | **406.1** | **440.4** |
| **ROR Total** | | **186.0** | **187.8** | **179.8** | **189.7** | **282.4** | **288.1** | **265.1** | **189.9** | **193.6** | **196.9** | **172.6** | **173.2** | **208.8** |
| **Total** | | **642.2** | **616.8** | **691.6** | **762.8** | **903.9** | **738.5** | **745.7** | **513.3** | **518.6** | **558.6** | **518.7** | **579.3** | **649.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 202.5 | 190.4 | 224.7 | 253.1 | 274.0 | 200.4 | 213.3 | 137.2 | 135.5 | 154.2 | 150.4 | 176.4 | 192.7 |
| Oxbow | HCC | 84.7 | 80.0 | 94.0 | 105.3 | 113.4 | 82.6 | 89.8 | 62.2 | 61.7 | 69.6 | 65.9 | 76.3 | 82.1 |
| Hells Canyon | HCC | 167.6 | 159.3 | 190.9 | 213.8 | 232.7 | 166.7 | 176.5 | 122.6 | 121.5 | 137.3 | 130.9 | 150.7 | 164.2 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.5 | 85.6 | 85.6 | 56.2 | 27.3 | 10.4 | 0.0 | 0.0 | 31.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 33.0 | 32.4 | 32.1 | 37.0 | 34.6 | 31.8 | 24.8 | 32.2 | 35.8 | 32.6 | 32.4 | 32.6 |
| C .J. Strike | ROR | 40.9 | 41.1 | 41.8 | 40.0 | 41.6 | 36.0 | 30.2 | 26.8 | 36.4 | 43.0 | 41.5 | 40.2 | 38.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.5 | 20.7 | 19.7 | 19.1 | 24.1 | 23.0 | 20.4 | 13.5 | 19.4 | 22.5 | 20.0 | 20.0 | 20.2 |
| Milner | ROR | 5.0 | 5.2 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.1 | 14.3 | 13.8 | 14.7 | 12.9 | 10.8 | 9.5 | 13.0 | 14.7 | 14.1 | 14.0 | 13.3 |
| Twin Falls | ROR | 8.5 | 8.5 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 6.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.1 | 12.3 | 11.6 | 11.2 | 15.1 | 14.0 | 12.0 | 6.9 | 11.2 | 13.4 | 11.5 | 11.6 | 11.9 |
| Upper Salmon 3&4 | ROR | 11.5 | 11.8 | 11.2 | 10.8 | 14.1 | 13.2 | 11.5 | 7.1 | 10.8 | 12.7 | 11.1 | 11.1 | 11.4 |
| **HCC Total** | | **454.8** | **429.7** | **509.6** | **572.2** | **620.1** | **449.7** | **479.6** | **322.0** | **318.7** | **361.1** | **347.2** | **403.4** | **439.0** |
| **ROR Total** | | **185.1** | **187.2** | **179.0** | **189.1** | **282.1** | **287.4** | **264.5** | **189.2** | **191.8** | **195.7** | **171.3** | **171.7** | **207.8** |
| **Total** | | **639.9** | **616.9** | **688.6** | **761.3** | **902.2** | **737.1** | **744.1** | **511.2** | **510.4** | **556.8** | **518.5** | **575.1** | **646.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 201.9 | 189.8 | 223.8 | 252.7 | 273.4 | 200.1 | 212.7 | 136.6 | 133.5 | 154.3 | 150.2 | 175.6 | 192.0 |
| Oxbow | HCC | 84.5 | 79.7 | 93.6 | 105.2 | 113.2 | 82.4 | 89.6 | 62.0 | 60.7 | 69.5 | 65.7 | 75.9 | 81.8 |
| Hells Canyon | HCC | 167.1 | 158.7 | 190.2 | 213.5 | 232.3 | 166.5 | 176.0 | 122.0 | 119.5 | 137.3 | 130.6 | 150.0 | 163.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.8 | 29.4 | 69.1 | 84.8 | 85.5 | 56.1 | 26.6 | 10.3 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 32.7 | 32.3 | 32.0 | 36.2 | 34.0 | 31.7 | 24.6 | 32.0 | 35.6 | 32.5 | 32.1 | 32.4 |
| C .J. Strike | ROR | 40.9 | 40.9 | 41.8 | 39.8 | 41.4 | 35.5 | 30.1 | 26.5 | 36.1 | 42.9 | 41.2 | 40.0 | 38.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.4 | 20.6 | 19.6 | 19.0 | 23.6 | 22.6 | 20.3 | 13.3 | 19.2 | 22.3 | 19.9 | 19.7 | 20.0 |
| Milner | ROR | 5.0 | 5.0 | 0.0 | 0.0 | 9.7 | 9.6 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.3 | 13.7 | 14.6 | 12.5 | 10.8 | 9.4 | 12.9 | 14.7 | 14.1 | 13.9 | 13.3 |
| Twin Falls | ROR | 8.5 | 8.1 | 3.8 | 0.0 | 12.4 | 13.1 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 5.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.0 | 12.2 | 11.6 | 11.2 | 14.7 | 13.7 | 11.9 | 6.8 | 11.0 | 13.3 | 11.4 | 11.3 | 11.8 |
| Upper Salmon 3&4 | ROR | 11.4 | 11.7 | 11.1 | 10.8 | 13.8 | 12.9 | 11.4 | 7.0 | 10.6 | 12.6 | 10.9 | 10.9 | 11.3 |
| **HCC Total** | | **453.5** | **428.2** | **507.6** | **571.4** | **618.8** | **449.0** | **478.3** | **320.6** | **313.7** | **361.1** | **346.5** | **401.5** | **437.5** |
| **ROR Total** | | **184.7** | **185.8** | **178.6** | **188.6** | **277.7** | **282.1** | **263.9** | **188.1** | **189.9** | **194.9** | **170.5** | **170.3** | **206.3** |
| **Total** | | **638.2** | **614.0** | **686.2** | **760.0** | **896.5** | **731.1** | **742.2** | **508.7** | **503.5** | **556.0** | **517.0** | **571.8** | **643.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 201.5 | 189.1 | 223.1 | 252.2 | 272.8 | 199.8 | 212.1 | 135.8 | 131.5 | 154.5 | 150.2 | 175.4 | 191.5 |
| Oxbow | HCC | 84.3 | 79.4 | 93.3 | 105.0 | 112.9 | 82.3 | 89.3 | 61.6 | 59.7 | 69.5 | 65.7 | 75.9 | 81.6 |
| Hells Canyon | HCC | 166.8 | 158.2 | 189.5 | 213.1 | 231.8 | 166.3 | 175.5 | 121.4 | 117.6 | 137.3 | 130.5 | 149.8 | 163.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.4 | 85.0 | 85.5 | 56.1 | 26.5 | 10.2 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.7 | 32.5 | 32.2 | 31.9 | 36.4 | 34.2 | 31.5 | 24.4 | 31.7 | 35.4 | 32.4 | 32.0 | 32.3 |
| C .J. Strike | ROR | 40.6 | 40.6 | 41.5 | 39.5 | 41.3 | 35.2 | 29.9 | 26.3 | 35.8 | 42.8 | 41.0 | 39.7 | 37.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.3 | 20.3 | 19.5 | 18.9 | 23.6 | 22.5 | 20.1 | 13.1 | 19.0 | 22.2 | 19.7 | 19.7 | 19.9 |
| Milner | ROR | 5.0 | 4.7 | 0.0 | 0.0 | 9.6 | 9.5 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.0 | 14.2 | 13.6 | 14.5 | 12.8 | 10.7 | 9.3 | 12.8 | 14.6 | 14.1 | 13.8 | 13.2 |
| Twin Falls | ROR | 8.5 | 8.0 | 3.8 | 0.0 | 12.3 | 13.0 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 5.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.8 | 12.0 | 11.5 | 11.1 | 14.7 | 13.6 | 11.8 | 6.7 | 10.8 | 13.2 | 11.3 | 11.3 | 11.7 |
| Upper Salmon 3&4 | ROR | 11.3 | 11.5 | 11.0 | 10.7 | 13.8 | 12.8 | 11.3 | 6.9 | 10.5 | 12.5 | 10.9 | 10.9 | 11.2 |
| **HCC Total** | | **452.6** | **426.7** | **505.9** | **570.3** | **617.4** | **448.4** | **476.9** | **318.8** | **308.7** | **361.3** | **346.4** | **401.1** | **436.2** |
| **ROR Total** | | **183.9** | **184.1** | **177.9** | **187.8** | **277.8** | **282.0** | **263.0** | **187.2** | **188.6** | **194.1** | **169.9** | **169.8** | **205.5** |
| **Total** | | **636.5** | **610.8** | **683.8** | **758.1** | **895.2** | **730.4** | **739.9** | **506.0** | **497.3** | **555.4** | **516.3** | **570.9** | **641.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 201.2 | 188.2 | 222.3 | 251.8 | 272.4 | 199.5 | 211.4 | 135.3 | 129.4 | 154.1 | 150.6 | 174.8 | 190.9 |
| Oxbow | HCC | 84.2 | 79.0 | 93.0 | 104.8 | 112.8 | 82.2 | 89.1 | 61.4 | 58.6 | 69.2 | 65.9 | 75.6 | 81.3 |
| Hells Canyon | HCC | 166.5 | 157.4 | 188.9 | 212.8 | 231.4 | 166.0 | 175.0 | 120.9 | 115.6 | 136.7 | 130.8 | 149.3 | 162.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.2 | 85.0 | 85.6 | 56.1 | 26.4 | 9.4 | 0.0 | 0.0 | 30.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.5 | 32.4 | 32.1 | 31.8 | 36.1 | 33.7 | 31.3 | 24.2 | 31.4 | 35.2 | 32.2 | 31.7 | 32.1 |
| C .J. Strike | ROR | 40.4 | 40.3 | 41.3 | 39.2 | 41.1 | 34.9 | 29.7 | 26.1 | 35.4 | 42.7 | 40.7 | 39.2 | 37.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.1 | 20.1 | 19.4 | 18.8 | 23.5 | 22.3 | 19.9 | 13.0 | 18.7 | 22.0 | 19.6 | 19.3 | 19.7 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 9.6 | 9.5 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.2 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.1 | 14.0 | 14.2 | 13.6 | 14.5 | 12.6 | 10.7 | 9.3 | 12.8 | 14.5 | 14.0 | 13.7 | 13.2 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 12.3 | 13.0 | 10.1 | 0.0 | 0.0 | 4.6 | 4.5 | 5.3 | 5.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.7 | 11.9 | 11.4 | 11.0 | 14.6 | 13.5 | 11.7 | 6.5 | 10.7 | 13.0 | 11.2 | 11.1 | 11.5 |
| Upper Salmon 3&4 | ROR | 11.2 | 11.4 | 11.0 | 10.6 | 13.7 | 12.7 | 11.2 | 6.8 | 10.3 | 12.3 | 10.8 | 10.7 | 11.1 |
| **HCC Total** | | **451.9** | **424.6** | **504.2** | **569.4** | **616.5** | **447.7** | **475.5** | **317.6** | **303.6** | **360.0** | **347.3** | **399.7** | **434.8** |
| **ROR Total** | | **182.6** | **183.1** | **177.4** | **187.1** | **276.8** | **280.6** | **262.3** | **186.4** | **187.2** | **191.8** | **169.0** | **167.6** | **204.3** |
| **Total** | | **634.5** | **607.7** | **681.6** | **756.5** | **893.3** | **728.3** | **737.8** | **504.0** | **490.8** | **551.8** | **516.3** | **567.3** | **639.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 200.9 | 187.5 | 221.6 | 251.4 | 272.0 | 199.2 | 210.9 | 134.7 | 127.3 | 154.2 | 150.7 | 174.1 | 190.4 |
| Oxbow | HCC | 84.0 | 78.8 | 92.7 | 104.6 | 112.6 | 82.1 | 88.8 | 61.1 | 57.6 | 69.2 | 65.9 | 75.3 | 81.1 |
| Hells Canyon | HCC | 166.2 | 156.9 | 188.3 | 212.4 | 231.1 | 165.8 | 174.5 | 120.3 | 113.6 | 136.6 | 130.8 | 148.8 | 162.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.6 | 68.6 | 84.8 | 85.6 | 55.7 | 26.3 | 9.4 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.4 | 32.2 | 32.0 | 31.7 | 35.7 | 33.3 | 31.2 | 24.0 | 31.1 | 35.0 | 32.0 | 31.5 | 31.8 |
| C .J. Strike | ROR | 40.2 | 40.1 | 41.2 | 38.9 | 41.0 | 34.6 | 29.5 | 25.8 | 35.1 | 42.6 | 40.4 | 38.8 | 37.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.0 | 20.0 | 19.3 | 18.6 | 23.3 | 22.1 | 19.8 | 12.8 | 18.5 | 21.8 | 19.4 | 19.0 | 19.6 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 9.5 | 9.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.0 | 13.9 | 14.1 | 13.5 | 14.5 | 12.4 | 10.6 | 9.2 | 12.6 | 14.4 | 14.0 | 13.6 | 13.1 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 12.2 | 12.9 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.6 | 11.8 | 11.4 | 10.9 | 14.5 | 13.3 | 11.5 | 6.4 | 10.5 | 12.9 | 11.0 | 10.8 | 11.4 |
| Upper Salmon 3&4 | ROR | 11.2 | 11.3 | 10.9 | 10.5 | 13.6 | 12.6 | 11.1 | 6.7 | 10.2 | 12.2 | 10.6 | 10.5 | 11.0 |
| **HCC Total** | | **451.1** | **423.2** | **502.6** | **568.4** | **615.6** | **447.1** | **474.2** | **316.1** | **298.4** | **360.0** | **347.4** | **398.2** | **433.5** |
| **ROR Total** | | **182.0** | **182.3** | **176.7** | **186.4** | **275.1** | **278.8** | **261.5** | **185.0** | **185.8** | **191.0** | **167.7** | **166.1** | **203.2** |
| **Total** | | **633.1** | **605.5** | **679.3** | **754.8** | **890.7** | **725.9** | **735.7** | **501.1** | **484.2** | **551.0** | **515.1** | **564.3** | **636.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 200.5 | 179.7 | 220.9 | 250.9 | 271.5 | 198.9 | 210.2 | 134.0 | 125.2 | 154.3 | 150.4 | 174.0 | 189.2 |
| Oxbow | HCC | 83.9 | 78.5 | 92.4 | 104.5 | 112.4 | 81.9 | 88.5 | 60.8 | 56.5 | 69.2 | 65.7 | 75.2 | 80.8 |
| Hells Canyon | HCC | 165.9 | 156.0 | 187.8 | 212.1 | 230.7 | 165.5 | 174.0 | 119.7 | 111.6 | 136.6 | 130.5 | 148.6 | 161.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.6 | 68.5 | 84.4 | 85.7 | 55.6 | 26.2 | 9.4 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.2 | 32.0 | 31.9 | 31.6 | 35.5 | 33.1 | 31.0 | 23.8 | 30.9 | 34.8 | 31.8 | 31.3 | 31.7 |
| C .J. Strike | ROR | 40.0 | 40.0 | 41.1 | 38.7 | 40.6 | 34.4 | 29.2 | 25.6 | 34.8 | 42.4 | 40.1 | 38.5 | 37.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 19.9 | 19.8 | 19.2 | 18.5 | 23.2 | 21.7 | 19.6 | 12.7 | 18.3 | 21.7 | 19.2 | 18.9 | 19.4 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 8.7 | 8.6 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.7 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.0 | 13.8 | 14.1 | 13.4 | 14.4 | 12.0 | 10.5 | 9.1 | 12.5 | 14.3 | 13.9 | 13.6 | 13.0 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 11.4 | 12.3 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.5 | 11.6 | 11.3 | 10.8 | 14.4 | 13.0 | 11.4 | 6.3 | 10.3 | 12.8 | 10.9 | 10.7 | 11.3 |
| Upper Salmon 3&4 | ROR | 11.1 | 11.2 | 10.9 | 10.5 | 13.5 | 12.3 | 11.0 | 6.6 | 10.0 | 12.1 | 10.5 | 10.4 | 10.8 |
| **HCC Total** | | **450.3** | **414.2** | **501.1** | **567.5** | **614.6** | **446.3** | **472.7** | **314.5** | **293.3** | **360.1** | **346.6** | **397.8** | **431.6** |
| **ROR Total** | | **181.3** | **181.4** | **176.3** | **185.8** | **272.4** | **275.2** | **260.6** | **184.1** | **184.5** | **190.2** | **166.7** | **165.3** | **202.0** |
| **Total** | | **631.6** | **595.6** | **677.4** | **753.3** | **887.0** | **721.5** | **733.3** | **498.6** | **477.8** | **550.3** | **513.3** | **563.1** | **633.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 200.1 | 177.6 | 220.2 | 250.5 | 271.1 | 198.6 | 209.7 | 133.3 | 123.7 | 154.2 | 150.5 | 173.4 | 188.6 |
| Oxbow | HCC | 83.7 | 77.5 | 92.1 | 104.3 | 112.2 | 81.8 | 88.3 | 60.4 | 55.8 | 69.0 | 65.7 | 74.9 | 80.5 |
| Hells Canyon | HCC | 165.6 | 154.2 | 187.2 | 211.7 | 230.4 | 165.3 | 173.5 | 119.1 | 110.2 | 136.3 | 130.5 | 148.1 | 161.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.4 | 66.9 | 84.1 | 85.7 | 55.6 | 26.2 | 9.8 | 0.0 | 0.0 | 30.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| C .J. Strike | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Cascade | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Clear Lake | ROR | 8.4 | 7.8 | 3.8 | 0.0 | 11.1 | 12.1 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.6 |
| Lower Malad | ROR | 12.0 | 11.8 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Lower Salmon | ROR | 11.0 | 10.9 | 10.8 | 10.4 | 13.4 | 12.1 | 10.9 | 6.5 | 9.9 | 12.0 | 10.4 | 10.3 | 10.7 |
| Milner | ROR | 11.4 | 11.4 | 11.2 | 10.8 | 14.2 | 12.8 | 11.3 | 6.2 | 10.2 | 12.6 | 10.7 | 10.6 | 11.1 |
| Shoshone Falls | ROR | 19.7 | 19.4 | 19.1 | 18.5 | 23.0 | 21.4 | 19.5 | 12.5 | 18.1 | 21.5 | 19.0 | 18.7 | 19.2 |
| Swan Falls | ROR | 32.1 | 31.9 | 31.8 | 31.5 | 35.1 | 33.0 | 30.9 | 23.6 | 30.7 | 34.6 | 31.6 | 31.2 | 31.5 |
| Twin Falls | ROR | 39.8 | 39.9 | 40.9 | 38.4 | 39.5 | 34.1 | 29.0 | 25.4 | 34.5 | 42.2 | 39.9 | 38.3 | 36.8 |
| Upper Malad | ROR | 13.9 | 13.8 | 14.1 | 13.3 | 13.9 | 11.9 | 10.5 | 9.0 | 12.4 | 14.3 | 13.7 | 13.4 | 12.9 |
| Upper Salmon 1&2 | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Upper Salmon 3&4 | ROR | 4.6 | 4.1 | 0.0 | 0.0 | 8.3 | 8.2 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.6 |
| **HCC Total** | | **449.4** | **409.3** | **499.5** | **566.5** | **613.6** | **445.7** | **471.5** | **312.8** | **289.7** | **359.5** | **346.7** | **396.4** | **430.1** |
| **ROR Total** | | **180.4** | **179.5** | **175.7** | **185.0** | **267.6** | **273.1** | **260.0** | **183.2** | **183.5** | **189.7** | **165.6** | **164.4** | **200.7** |
| **Total** | | **629.8** | **588.8** | **675.2** | **751.5** | **881.2** | **718.8** | **731.5** | **496.0** | **473.2** | **549.2** | **512.3** | **560.8** | **630.7** |

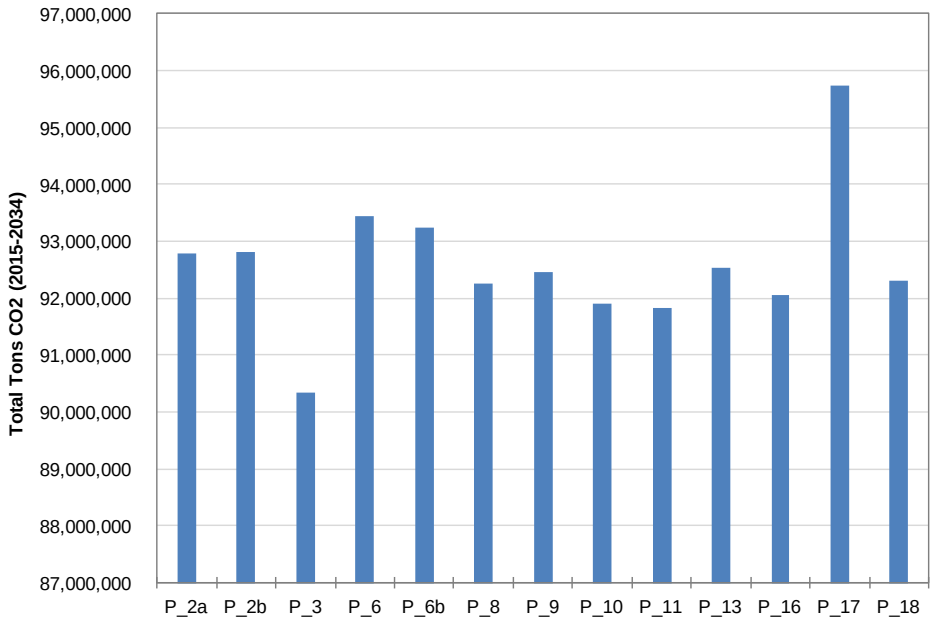
*HCC=Hells Canyon Complex,**ROR= Run of River

# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

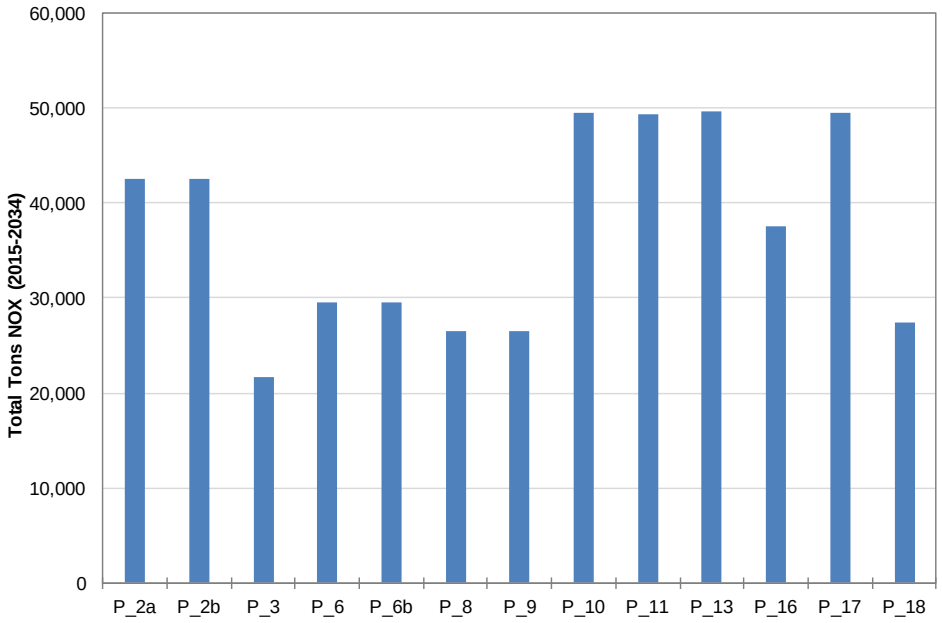
## Portfolio Emissions

### *IPC Systems*

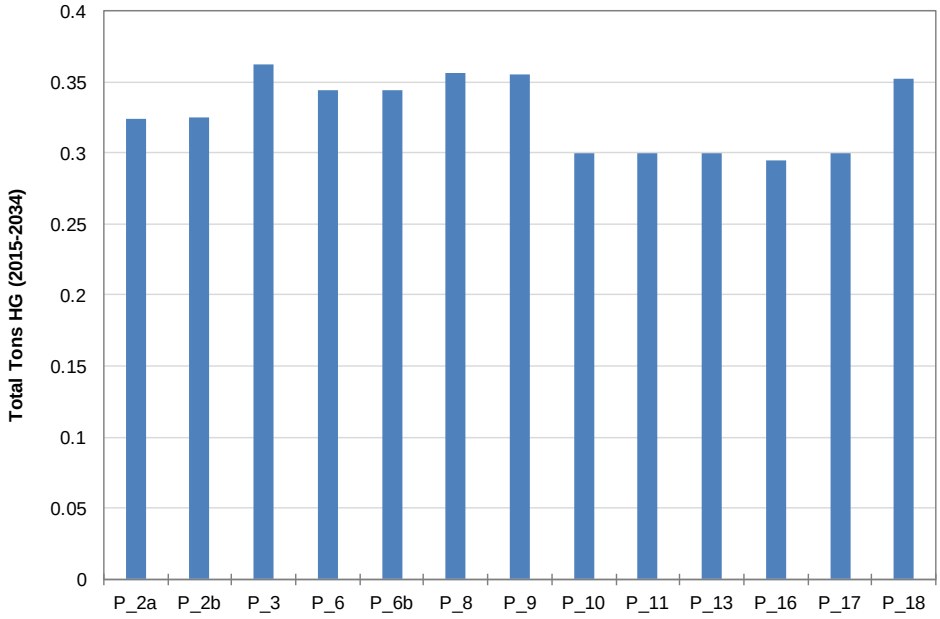
#### $CO_2$ Emission



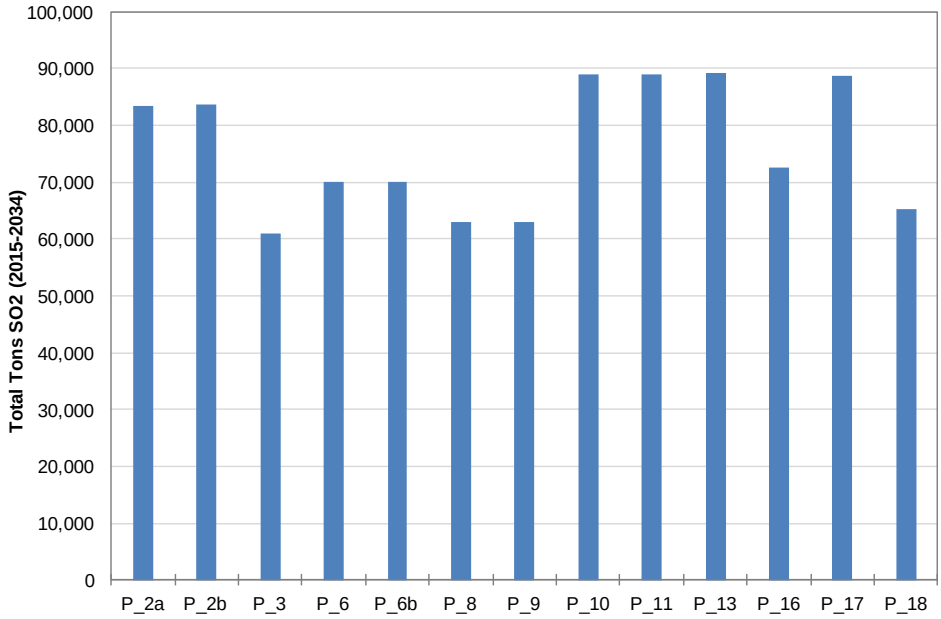

#### NOx Emission



## HG Emission




## $SO_2$ Emission



# Loss of Load Expectation Analysis

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 2a**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 3**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.93 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 1.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.43 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.32 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.47 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 2.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 2.48 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.56 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 2.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 3.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 3.08 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 6b**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 1.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 8**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.81 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.81 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.80 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.19 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.47 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 9**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.72 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 10**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 11**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.52 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 13**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 16**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 1.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.75 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.52 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 2.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.76 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 1.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.99 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.95 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 2.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.66 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 2.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 17**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.58 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 1.81 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.79 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 1.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 2.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.06 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 2.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 2.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.23 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 18**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.39 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.56 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.72 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

# STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Integrated Resource Planning. | )<br>)<br>)<br>)<br>)<br>)<br>) | ERRATA ORDER |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 0 9 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

*c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

*a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

*b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

*c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

*d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

*e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

*f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# Compliance with State of Oregon IRP Guidelines

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| **Guideline 1: Substantive Requirements**<br>a. All resources must be evaluated on a consistent and comparable basis.<br>• All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response.<br>• Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.<br>• Consistent assumptions and methods should be used for evaluation of all resources.<br>• The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.<br>b. Risk and uncertainty must be considered.<br>• At a minimum, utilities should address the following sources of risk and uncertainty:<br>1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.<br>2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.<br>• Utilities should identify in their plans any additional sources of risk and uncertainty.<br>c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.<br>• The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.<br>• Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.<br>• To address risk, the plan should include, at a minimum:<br>1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.<br>2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.<br>• The utility should explain in its plan how its resource choices appropriately balance cost and risk.<br>d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3 (Idaho Power Today), section *Existing Supply-Side Resources*, pages 27–38. Demand-side options for meeting the utility's load are discussed in Chapter 4 (Demand-Side Resources). Chapter 6 (Transmission Planning) discusses transmission resources for meeting the utility's load.<br>a-2) New resource options are described in Chapters 4 through 7. Chapter 4 (Demand-Side Resources) describes demand-side resource options for IRP resource portfolios. Chapter 5 (Supply-Side Generation and Storage Resources) describes generating resources and energy storage resources to be considered for IRP resource portfolios. Chapter 6 (Transmission Planning) describes transmission resources considered for IRP resource portfolios. Chapter 7 (Planning Period Forecasts) provides resource cost information.<br>a-3) The consistent modeling method for evaluating new resource options is described in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. The consistent modeling method for evaluating all resource portfolios is explained in Chapter 9 (Modeling Analysis and Results), pages 113–114.<br>a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9 (Modeling Analysis and Results), in Table 9.1 Financial Assumptions, on page 114.<br>b-1) Electric utility risk and uncertainty factors (load, NG and water conditions) for resource portfolios are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis*, pages 121–124. (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). Sensitivity analysis for CAA Section 111(d) performed to address costs to comply with greenhouse gas regulations is discussed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114.<br>Note: Plant forced outages for resource options and resource portfolios are not discussed in the IRP document or *2015 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis.<br>b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2 (Political, Regulatory, and Operational Issues) in the following sections: *FERC Relicensing*, page 14; *Idaho Water Issues*, page 15; *Northwest Power Pool Energy Imbalance Market*, page 19; and *Federal Energy Legislation CAA Section 111(d)*, page 21.<br>Further discussion of risks is included in Chapter 9 (Modeling Analysis and Results), in section *Qualitative Risk Analysis*, beginning on page 125. Uncertainty factoring into the selection of the preferred portfolio is expressed in Chapter 1 (Summary) on pages 8-10.<br>c-1) The IRP methodology and the planning horizon of 20 years are discussed in Chapter 1 (Summary), section *IRP Methodology,* page 3.<br>c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the NPV accounting for total portfolio costs is provided in Chapter 9 (Modeling Analysis and Results), pages 113-114. |

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| | c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121–124. A discussion of extreme outcomes, including extreme bad outcomes, is provided in the *Stochastic Risk Analysis* section in the third paragraph of page 123.<br>c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1 (Summary), in the last paragraph of section *Introduction*, on page 2. Idaho Power explains how its preferred portfolio appropriately balances cost and risk in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130. The accounting for qualitative risks and uncertainty in the preferred portfolio selection is discussed in Chapter 1 (Summary), section *Portfolio Analysis Summary*, beginning on page 8. Further discussion of the preferred portfolio's appropriate balancing of cost and risk is included in Chapter 10 (Preferred Portfolio and Action Plan), section *Preferred Portfolio (2015-2034)*, page 141.<br>d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2 (Political, Regulatory, and Operational Issues). Additional discussion relevant to this requirement is in Chapter 1 (Summary), section *Public Advisory Process*, pages 2–3. |
| **Guideline 2: Procedural Requirements.**<br>a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.<br>b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.<br>c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. | As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011, 2013, and 2015 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the IRPs. The IRP Advisory Council meetings are open to the public. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan.<br>As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2015 IRP, the 2015 Load and Sales Forecast and in the 2015 Technical Appendix.<br>As set forth in Guideline 2, part c., Idaho Power posted online a draft 2015 IRP for public review on Thursday, June 4, 2015. The company requested for comments to be provided no later than Friday, June 12, 2015. |

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| **Guideline 3: Plan Filing, Review, and Updates.**<br>a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.<br>b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.<br>c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.<br>d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.<br>e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.<br>f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.<br>g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:<br>• Describes what actions the utility has taken to implement the plan;<br>• Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and<br>• Justifies any deviations from the acknowledged action plan. | a. The OPUC acknowledged Idaho Power's 2013 IRP on July 8, 2014 in Order 14-253. Idaho Power plans to file the 2015 IRP by June 30, 2015.<br>b. Idaho Power will schedule a public meeting at the OPUC after the 2015 IRP has been filed.<br>c. No action needed.<br>d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan.<br>e. In Order No. 12-013, the OPUC provided direction on IRP flexible resource guidelines. In Order No. 14-253, the OPUC provided its resolution of fourteen components of the 2013 IRP. Idaho Power has addressed these action items in the 2015 IRP.<br>f. In Order No. 14-253, the OPUC waived for Idaho Power the requirement to file an annual update to the 2013 IRP, the most recently acknowledged IRP.<br>g. No action needed. |

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| **Guideline 4: Plan Components.**<br>At a minimum, the plan must include the following elements:<br>a. An explanation of how the utility met each of the substantive and procedural requirements;<br>b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;<br>c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;<br>d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;<br>e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;<br>f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;<br>g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;<br>h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;<br>i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;<br>j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;<br>k. Analysis of the uncertainties associated with each portfolio evaluated;<br>l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;<br>m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and<br>n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff.<br>b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 7 (Planning Period Forecasts), section *Load Forecast,* beginning on page 73.. High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in Chapter 7, Figures 7.1 and 7.2 and Tables 7.1 and 7.2. High- and low-growth scenarios analyzed for the stochastic load risk analysis are discussed in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121-124.<br>c. Peaking capacity and energy capability for each year of the plan for existing resources are discussed in Chapter 7 (Planning Period Forecasts), section *Generation Forecast for Existing Resources,* beginning on page 80. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios,* beginning on page 71.<br>d. Not applicable.<br>e. Supply-side resources considered are identified and described in Chapter 5 (Supply-Side Generation and Storage Resources). Resource costs are discussed and provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Demand-side resources and their levelized costs and technologies are covered in Chapter 4 (Demand-Side Resources).<br>f. Resource reliability is covered in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation (LOLE),* beginning on page 139.<br>g. Natural gas price forecasts are discussed in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, page 84-85. Chapter 7 also includes key assumptions about future load in section *Load Forecast* and generation in section *Generation Forecast for Existing Resources*. Costs for environmental compliance with proposed $CO_2$ regulations are addressed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114. Compliance alternatives to SCR installation at Jim Bridger Units 1 and 2 are addressed by portfolios considering early retirement of Jim Bridger Units 1 and 2. Environmental compliance costs for SCR installation at Jim Bridger units 3 and 4 are addressed in the *Appendix C—Technical Appendix* in the section *Jim Bridger Units 3 and 4 Selective Catalytic Reduction Analysis*.<br>h. Resource portfolios considered for the 2015 IRP are described in Chapter 8 (Portfolio Selection). Resource portfolios were developed using resources from the resource stack provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Resource portfolios were developed with consult from the IRP Advisory Council and public participants.<br>i. The resource portfolios are evaluated against various risks in Chapter 9, Modeling Analysis and Results, section *Stochastic Risk Analysis,* pages 121–124.<br>j. Portfolio cost and risk results, with interpretations, are provided in Chapter 9 (Modeling Analysis and Results).<br>k. The uncertainties associated with each portfolio are evaluated in Chapter 9 (Modeling Analysis and Results), sections *Stochastic Risk Analysis* and *Qualitative Risk Analysis*.<br>l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130.<br>m. No inconsistencies were identified.<br>n. An action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10. |

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| **Guideline 5: Transmission.**<br>Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. | The transmission required for each resource being considered is described in the 2015 IRP *Technical Appendix*, section *Transmission Cost Assumptions*. Transmission assumptions for supply-side resources considered are included in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios*, pages 71–72. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. For natural gas-fired resources, the Idaho Citygate price reflects the cost of transport to a power plant. The Idaho Citygate price is described in Chapter 7 (Planning Period Forecasts), section Natural Gas Price Forecast, pages 84-85. Forecasts for Idaho Citygate price are provided in the 2015 IRP *Technical Appendix*, section *Fuel Price Forecasts*. |
| **Guideline 6: Conservation.**<br>a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.<br>b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.<br>c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:<br>• Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and<br>• Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | a. The potential study conducted by Applied Energy Group (AEG) for the 2015 IRP is described in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, beginning on page 43.<br>b. The 2015 IRP action plan expresses Idaho Power's intent to continue pursuit of cost-effective energy efficiency. A forecast for energy efficiency effects in five-year blocks is provided in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, Table 4.2. Detailed year-by-year forecast values are included in the 2015 IRP *Technical Appendix,* section *Monthly average energy load and resource balance*.<br>c. Treatment of third party market transformation savings provided by the Northwest Energy Efficiency Alliance (NEEA) in the 2015 IRP is discussed in Chapter 4 (Demand-Side Resource), pages 40-41. Idaho Power has changed how market transformation savings provided by NEEA are treated in the IRP. NEEA savings are now included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study. |
| **Guideline 7: Demand Response.**<br>Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). | Demand response resources are detailed in Chapter 4 (Demand-Side Resources), section *Demand Response Performance,* page 42. Additional demand response above baseline levels is considered in select portfolios, including the preferred portfolio. The additional demand response is discussed in Chapter 4 (Demand-Side Resources), section *Additional Demand Response*, page 47. |
| **Guideline 8: Environmental Costs.**<br>Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO^2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable. | It is noted in Chapter 9 (Modeling Analysis and Results), section *Portfolio Emissions*, page 125, that with the exception of portfolios retiring Jim Bridger Units 1 and 2 without installation of NOx-controlling retrofits, all portfolios are designed to comply with environmental regulations. CAA Section 111(d) is modeled to reflect future carbon dioxide regulations. Portfolio costs provided for the considered CAA Section 111(d) sensitivities as provided in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) sensitivity analysis – results*, Table 9.4, page 119. |
| **Guideline 9: Direct Access Loads.**<br>An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2015 IRP 20-year planning period. |
| **Guideline 10: Multi-state Utilities.**<br>Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers. | Idaho Power intends to file the 2015 IRP in both the Idaho and Oregon jurisdictions. |
| **Guideline 11: Reliability.**<br>Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives. | Idaho Power discussed the capacity planning margin in Chapter 9 (Modeling Analysis and Results), section *Capacity Planning Margin*, beginning on page 131, and the loss of load probability in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation,* beginning on page 139. |

| Oregon Order 07-047 Action Items | 2015 IRP |
|---|---|
| **Guideline 12: Distributed Generation.**<br>Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation. | Idaho Power evaluated distributed solar PV as a resource option in portfolio 18. Portfolio 18 is described in Chapter 8 (Portfolio Selection), page 110. Distributed storage (ice-based thermal and V redox flow battery) resources were evaluated in multiple portfolios. Portfolios are described in Chapter 8 (Portfolio Selection), beginning on page 97. Distributed resources, generating and storage, were credited to account for avoided transmission line losses. |
| **Guideline 13: Resource Acquisition.**<br>a. An electric utility should, in its IRP:<br>• Identify its proposed acquisition strategy for each resource in its action plan.<br>• Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.<br>• Identify any Benchmark Resources it plans to consider in competitive bidding.<br>b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment. | Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order No. 14-149 issued on April 30, 2014.<br>Idaho Power discusses asset ownership in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, page 143.<br>Idaho Power's action plan includes ongoing permitting, planning studies, and regulatory filings associated with the Boardman to Hemingway transmission line. Construction of the Boardman to Hemingway transmission line will be managed to be consistent with resource acquisition and competitive bidding processes provided in guidelines established by Oregon in Order No. 14-149. |

# STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1461

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation of matters related to Electric Vehicle Charging. | ORDER |

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

## I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

*2. Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

**D. Integrated Resource Planning Flexible Resources Guidelines**

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

*1. Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

### 2. *Resolution*

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

ORDER NO. 12 013

2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

# Compliance with EV Guidelines

| Oregon Order 12-013 Guideline | 2015 IRP |
|---|---|
| **Guideline 1: Forecast the Demand for Flexible Capacity.**<br>Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;<br>**Guideline 2: Forecast the Supply for Flexible Capacity.**<br>Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;<br>**Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis**<br>In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis. | A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section Flexible Resource Needs Assessment, pages 135–139. Figure 9.4 on page 135 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136–138. |

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2013 IRP

ORDER NO. 12 253

ENTERED JUL 0 8 2014

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

LC 58

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|---|---|
| In the Matter of<br>IDAHO POWER COMPANY,<br>2013 Integrated Resource Plan | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED IN PART AND AS REVISED

## I. INTRODUCTION

Idaho Power Company is a public utility operating in Oregon and is subject to the Commission's jurisdiction and requirements regarding integrated resource planning. Idaho Power's 2011 Integrated Resource Plan (IRP) was acknowledged with exceptions and guidance for its next IRP in Order No. 12-177. Idaho Power now seeks acknowledgment of its 2013 IRP.

We require each regulated energy utility to prepare and file an IRP within two years of acknowledgment of the utility's last plan. In the IRP, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[1]

Once a utility completes a plan, we review for adherence to the procedural and substantive requirements outlined in Order No. 89-507. We generally acknowledge the plan—that is, find it reasonable based on the information available at that time—or return it to the utility with comments.[2] We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers.

We reaffirm our long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding. Acknowledgment of an IRP, however, is relevant to subsequent examination of whether a

[1] Order No. 07-002.
[2] *Id.* at 2.

utility's resource investment is prudent and should be recovered from ratepayers. As we have previously stated:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment.[3]

Just as acknowledgment does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of imprudence. The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in a subsequent rate case proceeding.

## II. DISCUSSION

We conclude Idaho Power satisfies all the procedural guidelines and all but one of the substantive guidelines for IRP planning. Idaho Power did not comply with the IRP Guideline regarding flexible capacity adopted in Order No 12-013.

We acknowledge the short-term action items in Idaho Power's Action Plan, except for the investment in selective catalytic reduction emissions technology at Jim Bridger Units 3 and 4.[4] In addition, we acknowledge two additional action items recommended by Staff that relate to energy efficiency. We do not acknowledge the remaining action items, which are for the most part outside the two-to-four year action plan period.[5]

## III. IDAHO POWER'S IRP

During the 20-year planning period, Idaho Power expects that the number of its customers will increase by about 8,400 each year, from approximately 500,000 in 2012 to 670,000 in 2032. Idaho Power's expected-case load forecast predicts that summer-peaking hour load requirements will grow at about 55 MW per year, and that the average-energy requirements will grow at 21 aMW per year. Idaho Power's load and resource balance analysis, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases, shows no energy deficits through the planning period. Idaho Power's analysis shows a capacity deficit starting in 2016 and monthly peak-hour deficit positions growing steadily in magnitude and the number of months affected. By July 2032, the capacity deficits are approximately 870 MW.

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[3] *Id.* at 24, *quoting* Order No. 89-507 at 7.
[4] *See* Appendix A.
[5] *See* Guideline 4(n).

Idaho Power identifies as its major resource addition the Boardman to Hemingway transmission line (B2H) with market purchases. The company's preferred portfolio also includes demand response, continued operations at the Jim Bridger and North Valmy coal facilities after investment in emission-control technology, and the continued operation of Idaho Power's other existing supply-side resources.

Guideline 4(n) requires the utility to include an action plan with resource activities the utility intends to undertake over the next two to four years. Idaho Power includes the following activities in its Action Plan:

| Year | Resource – Action |
|---|---|
| 2013-2018 | Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | Gateway West – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology |
| 2013 | Jim Bridger Units 3&4 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2016-2017 | Demand response – Have demand response capacity available to satisfy deficiencies up to approximately 150 MW |
| 2018 | Boardman to Hemingway – Transmission line complete and in service |
| 2019 | Shoshone Falls – Upgrade complete and in service |
| 2019 | Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2020 | Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2020 | Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020 |
| 2024-2032 | Demand response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW |

## IV. DISCUSSION

In this order, we first address Idaho Power's Action Plan, discussing the comments filed by participants[6] and specific IRP Guidelines as appropriate. We then address issues raised by the participants or that we identify related to Idaho Power's compliance with the IRP Guidelines and our order regarding Idaho Power's 2011 IRP that are not discussed in connection with our review of the Action Plan.

[6] Renewable Northwest (RNW), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE), and Staff of the Public Utility Commission (Staff) filed opening and reply comments regarding Idaho Power's IRP, and Idaho Power filed two rounds of comments in response. In addition, a resident of Idaho, John Weber, forwarded comments to Staff, which Staff forwarded to the Administrative Hearings Division for inclusion in the record.

ORDER NO. 14 253

## A. Transmission

### *1. Boardman to Hemingway*

Currently, the Boardman to Hemingway transmission project (B2H) is envisioned as a single-circuit 500 kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. Idaho Power states that it has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting the project, under which Idaho Power is the permitting project manager.

Idaho Power proposes the following actions for the Boardman to Hemingway transmission project:

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|---|---|
| *2013-2018* | *Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings* |
| *2018* | *Boardman to Hemingway – Transmission line complete and in service* |

#### *a. Participants' Comments*

RNW supports investment in B2H because it would provide Idaho Power not only with transmission to a liquid market, enabling the company to access low-cost resources to meet capacity and energy needs, but to also generate revenue by selling energy to other regional utilities. RNW also contends B2H will provide environmental benefits by enabling Idaho Power to reach renewable energy resource zones, thereby facilitating renewable energy resources.

Staff recommends acknowledgement of ongoing permitting, planning studies, and regulatory filings for B2H. Staff notes that B2H is included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolios" include B2H. Staff finds that the IRP analysis regarding B2H supports acknowledgment of ongoing permitting, planning studies, and regulatory filings.

Staff recommends, however, that we decline to acknowledge B2H "Transmission line complete and in-service" in 2018. Staff reports that the estimated in-service date for B2H has moved from 2018 (the year noted in Idaho Power's IRP) to 2020 (the year reported in the company's reply comments). Staff concludes this action item is now well beyond the two-to-four year period prescribed in the IRP Guidelines.

With respect to Idaho Power's activities that occur between the our order in this docket and Idaho Power's 2015 IRP, Staff asks to be apprised of any (1) updated project plan incorporating changes related to Bureau of Land Management delays and Energy Facilities Siting Council developments; (2) final agreement regarding allocation of construction costs between project participants; and (3) significant regulatory decisions that impact the project schedule or costs. Staff also asks that the company to further explore whether B2H would significantly impact wind generation curtailment during

periods of low demand as well as the impact of B2H on resource integration costs in general.

In its first round of comments, Idaho Power asserts that Staff's recommendation to acknowledge only the permitting activities of B2H and not the construction phase of the project is inconsistent with the our past acknowledgment of B2H and is unnecessary to ensure continued analysis of this project. In its final comments, Idaho Power states that it is only requesting acknowledgment of specific action items scheduled to occur within the next four years (which excludes the construction of B2H), but does ask that we acknowledge the 2013 IRP in its entirety, which includes B2H in its preferred portfolio.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H.

We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (*e.g.*, permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

***2. Gateway West***

Gateway West is a multi-segment, multi-year, joint transmission project of Idaho Power and PacifiCorp/Rocky Mountain Power to build and operate approximately 1000 miles of new transmission lines from Wyoming to the Hemingway Substation near Melba, Idaho. The project timeline indicates line segments in service between 2019 and 2023. Idaho Power has a one-third interest in some, but not all, of the segments to be located in Idaho and sole interest in one segment.

Idaho Power asks for acknowledgment of the following action item related to Gateway West:

*2013* *Gateway West – Ongoing permitting, planning studies, and regulatory filings*

Idaho Power reports that the Gateway West and B2H projects are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to a population center in Utah. Idaho Power states that Gateway West will benefit customers by (1) relieving transmission constraints on certain transmission paths allowing Idaho Power to move additional energy between the east and west sides of the system; (2) providing the option

to locate future generation resources east of the Treasure Valley load center; and (3) providing future load service to the Magic Valley from the Cedar Hill Substation. Idaho Power does not request acknowledgment of Gateway West as a supply side resource. Instead, the company asserts that Gateway West is reasonable to address transmission system constraints and provide for future least cost resource development.

*a. Participants' Comments*

RNW supports investment in Gateway West because it will provide the same benefits that B2H will provide—that is, access to low-cost resources, access to regions where renewable resources could be sited, and reliability.

CUB recommends that we not acknowledge Gateway West as presented. CUB notes that Gateway West is a large project composed of a number of segments that can be analyzed individually. CUB asserts that Idaho Power should narrow its request and seek acknowledgment only of the segments of Gateway West that it can demonstrate are cost effective for Idaho Power's customers.

Staff concludes that, although there is insufficient information to support acknowledgment of the construction of Gateway West, we should acknowledge the permitting-related activities that must occur prior to construction. For purposes of Idaho Power's next IRP, however, Staff recommends that the company include an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest in order to demonstrate the need and specific constraint-related benefits.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

**B. Pollution Control Investments in Coal Resources**

***1. Idaho Power's Analysis***

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present $CO_2$ level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures in its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the $CO_2$ emission cost adder level

that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

*a. Participants' Comments*

RNW asserts that Idaho Power's analysis of its coal resources failed to meet IRP Guideline 8 because the company did not (1) model natural gas conversions of the Jim Bridger Units 3 and 4 boilers; (2) model a range of pollution control costs; and (3) account for recent direction from President Obama's Administration that may reduce the cost competitiveness of existing coal resources. RNW asserts that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

CUB also criticizes Idaho Power's analysis, and contends the company failed to consider all possible scenarios. CUB proposes a four-part, Boardman-style analysis that (1) allows potential pollution controls under different scenarios; (2) compares the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigates whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) analyzes whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff voices a concern similar to CUB's regarding Idaho Power's failure to consider a range of early shutdown scenarios. Staff notes that Idaho Power compared the cost of early shutdown and no controls against other alternatives, but did not model a range of early shut-down scenarios, *e.g.*, smaller pollution control investment in exchange for shutdowns at different points in time, which Staff expected would be done. Like CUB, Staff recommends that future coal analysis consider alternative dates for pollution control equipment, shut down, or other alternatives such as gas conversion.

Staff concludes that Idaho Power's analysis is sufficient to comply with the IRP Guidelines, as well as our direction, provided in 2012, to evaluate whether there is flexibility in the emerging environmental regulations that would allow the company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives.

Idaho Power responds that its modeling complies with Guideline 8. Idaho Power notes that it modeled three levels of carbon adders to evaluate the potential impact of carbon emissions regulations in its coal study and in the IRP. In addition, Idaho Power explains it created an alternate portfolio in which the North Valmy units are converted to a gas-fired plant and Jim Bridger Units 3 and 4 are replaced with combined cycle combustion turbines (CCCTs). Idaho Power points out that President Obama's announcement regarding $CO_2$ regulation was issued the same month Idaho Power filed its IRP and that Idaho Power could not account for the announcement without delaying the filing of the 2013 IRP. And, Idaho Power asserts the June 2013 Presidential Memorandum concerned regulations for new power plants and none are included in the company's IRP.

*b. Commission Resolution*

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger Units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger Units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger Units 3 and 4 are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenarios analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of §111(d) of the Clean Air Act.

***2. North Valmy Unit 1***

North Valmy is a coal-fired plant consisting of two generating units located in Nevada. Idaho Power is a 50 percent owner of North Valmy. After adjusting for routine scheduled maintenance and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 220 aMW. Idaho Power plans on the continued operation of North Valmy Unit 1 throughout the 20-year planning period of the 2013 IRP and both units of North Valmy are included in Idaho Power's preferred portfolio.

Idaho Power proposes the following action for North Valmy Unit 1 to comply with federal Mercury Air Toxics Standards (MATS):

*2013* *North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology*

*a. Participants' Comments*

CUB is concerned because Idaho Power's preferred portfolio includes North Valmy with an end-of-life date that CUB fears is too far in the future. CUB notes that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio but that the co-owner of North Valmy, Nevada Energy, has announced plans to close the plant in 2025.

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

Staff recommends acknowledgment of DSI installation. Staff finds that because the cost of the investment is so small, there is no tipping point in the modeled scenarios at which it is more cost-effective to shut down North Valmy rather than invest in DSI.

*b. Commission Resolution*

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***3. Jim Bridger Units 3 and 4***

Jim Bridger is a coal-fired plant consisting of four generating units located in Wyoming. Idaho Power owns one-third of the plant, or 771 MW. The Environmental Protection Agency (EPA) submitted a final rule on January 10, 2014, requiring the installation of selective catalytic reduction emission-control technology (SCR) at Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. Idaho Power's application to the Idaho Public Utilities Commission (IPUC) for a Certificate of Public Convenience

and Necessity states that Idaho Power's cost before AFUDC is estimated to be approximately $118 million.

Idaho Power proposes the following action for Jim Bridger Units 3 and 4:

*2013* *Jim Bridger Units 3 and 4 – Commit to the installation of selective catalytic reduction emission-control technology*

*a. Participants' Comments*

CUB and RNW recommend that we not acknowledge pollution control investments at Jim Bridger Units 3 and 4, contending additional analysis is needed. Specifically, CUB asserts that Idaho Power should analyze the effect that different early retirement dates would have on the need for pollution controls at Bridger Units 3 and 4 to inform whether the currently planned investment is cost-effective. CUB notes that a shorter life may reduce the controls needed (and therefore costs), making early retirement of coal plants more cost-effective than other options. RNW adds that Idaho Power did not adequately analyze conversion to natural gas or a sufficient range of future $CO_2$ compliance costs. Also, RNW believes that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

Idaho Power disagrees with RNW's and CUB's conclusions regarding its analysis for Bridger Units 3 and 4, noting that it examined a range of options including early shutdown and conversion to natural gas, and that its analysis shows that installation of SCR at Bridger Units 3 and 4 is the least cost option for the majority of the alternate carbon and natural gas scenarios it modeled.

Staff recommends we acknowledge installation of SCR at Bridger Units 3 and 4. Staff concludes that Idaho Power's coal study demonstrates that the SCR investments are the lowest cost compared to the alternatives analyzed under planning case assumptions and in the majority of the carbon and gas sensitivities. In addition to reviewing the coal study, Staff constructed an independent spreadsheet analysis of the impact of a range of gas and carbon prices on the economics of the SCR investments, which confirmed the coal study results.

*b. Commission Resolution*

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger Units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger Units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger Units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp,

the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger Units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

**C. Demand Response**

Idaho Power proposes the following near-term action related to demand response:

*2016-2017* *Have demand response capacity available to satisfy deficiencies up to approximately 150 MW*

*a. Participants' Comments*

Staff notes that both the Oregon and Idaho commissions recently issued orders approving stipulations regarding the redesign of Idaho Power's demand response programs for 2014 and beyond. Those stipulations provide that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW. Therefore, Staff recommends changing this action item to read: "Have demand response capacity available to satisfy deficiencies up to approximately ~~150 MW~~ 170 MW beginning in 2014, and increasing as needed through 2017."

Staff also recommends that the company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors by the end of 2014. In addition, Staff recommends that the Energy Efficiency Advisory Group review any revisions to the resource assessment, along with other relevant factors.

RNW supports Idaho Power's continuation of its demand response program to meet the company's capacity needs.

*b. Commission Resolution*

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

ORDER NO. 14 253

**D. Long-term Action Items**

Idaho Power's Action Plan includes the following long-term activities:

| | |
|---|---|
| *2019* | *Shoshone Falls – Upgrade complete and in service* |
| *2019* | *Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology* |
| *2020* | *Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology* |
| *2020* | *Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end* |
| *2024-2032* | *Demand Response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW* |

*a. Participants' Comments*

Both Staff and CUB note, and Idaho Power acknowledges, that Idaho Power's Action Plan includes long-term action items in addition to the short-term action items typically presented in an IRP action plan. Staff and CUB recommend that we not acknowledge action items occurring beyond a two-to-four year period. In response, Idaho Power states that it does not seek acknowledgment of the long-term items.

*b. Commission Resolution*

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs.[7] We generally do not acknowledge action items planned to occur more than four years in the future.[8]

**D. Analysis of IRP**

***1. Wind Resources***

*a. Participants' Comments*

Several participants raise concerns related to wind resources. RNW asserts that Idaho Power's IRP underestimates the capacity factor of modern wind turbines and includes an unsupported and unreasonably high wind integration rate.

Staff and RNW raise concerns about Idaho Power's wind integration study (WIS), and the company's use of the technical review committee (TRC) we recommended the

[7] *See* Order No. 12-177.
[8] *Id.*

company form to improve such studies.[9] Staff notes that it anticipated more involvement of the TRC and recommends that Idaho Power engage with the TRC for future IRPs. RNW adds that Idaho Power's WIS based the size of the required balancing reserve on the difference between the day-ahead forecast and actual generation, which increased the assumed balancing reserves and costs. RNW notes that the TRC we required in Order No. 12-177 flagged this methodological assumption as a significant concern. Staff shares RNW's concern, and has reservations about using the study results in future filings.

In response to RNW's concern regarding overstated costs, Idaho Power notes the cost difference between the National Renewable Energy Laboratory (NREL) report and its costs comes from the conversion of 2009 dollars to 2013 dollars, the common base for the IRP's comparison of resource costs. In response to RNW's concern regarding the size of the balancing reserves, Idaho Power states that it chose to base the assumption on the day-ahead forecast because balancing reserves based on the hour-ahead forecast "would too often translate to a risky reliance on the wholesale energy market."

In response to RNW's concern regarding the average capacity factor, Idaho Power asserts that the NREL reports that Class 3 resources have an average capacity factor of 33 percent—a percentage Idaho Power adjusted downward to account for lower capacity factors of Class 2 resources. Idaho Power also asserts that its actual observations support the 26 percent average capacity factor used in the WIS and IRP.

In response to Staff's and RNW's concern regarding the role of the TRC, Idaho Power notes that we directed the company to form the committee in February 2012, nearly a year after the company had begun work on the WIS. Idaho Power announced the formation of the committee at an April 2012 workshop, but by this time the study was complete and the company was presenting preliminary study results.

*b. Commission Resolution*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a

[9] *Id.* at Appendix A at 3.

future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

***2. Capacity Contribution of Solar and Other Resources***

*a. Participants' Comments*

ODOE recommends certain changes to how Idaho Power examines capacity credits for solar, wind, and hydro resources, and how the company models orientation of flat-plate solar PV systems.

Idaho Power disagrees with ODOE's specific recommendation regarding the capacity contribution, but recognizes that solar resources are unique and that its analysis must address numerous considerations such as tracking systems, resource orientation, and materials. Idaho Power states it seeks to attribute the proper capacity credit to distributed solar PV and has initiated an IRP Advisory Council distributed solar PV workgroup to address the cost and capacity credit of distributed solar PV in the 2015 IRP. Idaho Power states that it anticipates the workgroup will address topics such as panel orientation and tracking systems. Idaho Power also states that it is analyzing integration of large-scale solar PV projects and working on this topic with members of its Solar Integration Study Technical Review Committee.

*b. Commission Resolution*

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

***3. Gas Price Forecasts***

*a. Participants' Comments*

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

*b. Commission Resolution*

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

### 4. *Flexibility Guideline*

In our investigation of matters related to electric vehicle charging, we adopted our Staff's recommendation to add an IRP guideline to require utilities to incorporate planning for flexible capacity in IRPs.[10] Utilities must forecast the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation over the 20-year planning period and to forecast the availability of balancing reserves at different time intervals. In planning to fill any gap between the demand and supply of flexible capacity, utilities must also evaluate all resource options on a consistent and comparable basis.

#### *a. Participants' Comments*

RNP asserts that Idaho Power's IRP does not comply with the IRP Guidelines because it does not forecast the demand for and supply of flexible capacity, or evaluate flexible resources on a consistent and comparable basis. RNW suggests that future IRPs should quantify the existing supply of flexible resources across multiple time scales, quantify the amount of reserves associated with each supply-side resource, and expand types of demand for flexible resources, *e.g.*, need to meet hourly ramps of load and other variable resources.

Idaho Power responds that its 2013 IRP did, in fact, include much of the flexibility analysis that RNW asserts is lacking. Idaho Power notes that a pumped storage hydro project was modeled as a resource alternative and as a tool to assist in the integration of wind resources. Idaho Power asserts that this modeling captured the flexibility and peaking capacity of the pumped storage hydro project and helped to integrate the variable wind generation into the system, and captured market arbitrage opportunities.

Staff recognizes that the company provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNW that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

#### *b. Commission Resolution*

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

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[10] Order No. 12-013 at16-18.

ORDER NO. 14 255

### 5. *Conservation Voltage Reduction*

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.[11]

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP.

In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report.[12] Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

### 6. *Energy Efficiency*

Although Idaho Power's IRP contains specific energy efficiency targets as part of its plan, the company does not include those amounts in the Action Plan. Staff proposes two action items to address energy efficiency:

| | | |
|---|---|---|
| *2013-2017* | *Energy Efficiency* | *The forecast reduction for 2013 to 2017 programs will be 69 aMW* |
| *2013-2017* | *Energy Efficiency* | *The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW* |

We adopt Staff's proposed additions to the Action Plan.

### 7. *NEEA*

Idaho Power plans to curtail funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Idaho Power explains that it has asked NEEA to operate under an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of activities that Idaho Power believes are most valuable to its customers. Idaho Power supports the concept of optional programs in NEEA's 2015-2019 Business Plan in which funders could choose to participate and fund certain programs or opt out of them altogether.

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[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

ORDER NO. 14 257

*a. Participants' Comments*

CUB and Staff are concerned with Idaho Power's proposal to curtail funding to NEAA. Staff believes that NEAA is one of Idaho Power's most cost effective energy investments. Staff notes that NEEA is a compact between over 100 Northwest utilities and efficiency organizations that creates value for its supporters by broad market intervention and energy efficiency market development. NEEA's activities have resulted in the development of an energy efficiency products and practices pipeline to the region that benefits Idaho Power's and the region's ratepayers.

*b. Commission Resolution:*

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

**D. Recommendations For Idaho Power's 2015 IRP**

In Order No. 12-177, we reminded Idaho Power that IRP Guideline 4(n) requires utilities to include in an IRP action plan the resource activities the utility plans to undertake over the next two to four years to acquire the identified resources. We also recommended that Idaho Power's future IRPs include a "concise listing of action items for all resources and resource related activities, with each action item numbered."[13]

Idaho Power did include an action plan with resource activities it plans to take in the next two to four years, but the plan also includes longer-term actions. We clarify that, in future IRPs, Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years. Idaho Power may compile other lists of activities planned for an extended period, as it has done in this IRP, but we recommend the company create and identify the action plan activities for which it requests specific acknowledgment. Again, we recommend that the company number each of these action items to facilitate our review.

**E. IRP Update**

Staff sought delays in these proceedings to facilitate our review of resource action items presented for acknowledgment in both PacifiCorp's IRP and Idaho Power's IRP.

[13] Order No. 12-177 at 8.

ORDER NO. 14 255

As a result of this delay, Idaho Power's annual update to its 2013 IRP, which is due no later than 12 months after acknowledgment. However, Idaho Power must file its 2015 IRP with the Idaho Public Utilities Commission no later than June 2015. Idaho Power intends to file an IRP in Oregon at the same time it files in Idaho.

Given that Idaho Power will file its next IRP with the Idaho commission by June 2015, we waive the requirement that Idaho Power file an annual update to this IRP. This waiver addresses only a routine IRP update, and we expect Idaho Power to file an IRP update if it anticipates a significant deviation from its acknowledged 2013 IRP in the manner required by IRP Guideline 3(f).

## V. ORDER

IT IS ORDERED that the 2013 Integrated Resource Plan filed by Idaho Power Company is acknowledged in part consistent with the terms of this order.

Made, entered, and effective JUL 08 2014.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

ORDER NO. 14 253

# Appendix A

**Acknowledged Action Plan Items**

| Year | Resource - Action |
|---|---|
| 2013- 2018 | Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | Gateway West – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology |
| 2016-2017 | Have demand response capacity available to satisfy deficiencies up to approximately 170 MW beginning in 2014, and increasing as needed through 2017 |
| 2013-2017 | Energy efficiency – The forecast reduction for 2013 to 2017 programs will be 69 aMW |
| 2013-2017 | The incremental energy efficiency savings for 2013-2017 will reduce energy loads by 38 aMW |
| 2013-2015 | CVR – Include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in service area and an action item related to this resource in the next IRP. Incorporate the planned energy savings and reduced peak demand into load-resource balance forecasts. |

APPENDIX A
Page 1 of 1

# Compliance with State of Oregon IRP Guidelines

## A. Transmission

### 1. Boardman to Hemingway

***Commission Resolution (Order No. 14-253):***

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H. We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (e.g., permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

***Idaho Power Response (2015 IRP):***

Discussion specific to B2H is found in Chapter 6 (Transmission Planning), section Boardman to Hemingway, pages 71-72. Portfolio design for the 2015 IRP provides a comparison of portfolios having B2H as a resource to portfolios not having B2H. A tabulation of resource portfolios with respect to B2H inclusion is provided in Chapter 8 (Portfolio Selection), section *Portfolio Design Summary*, page 111.

### 2. Gateway West

***Commission Resolution (Order No. 14-253):***

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

***Idaho Power Response (2015 IRP):***

Discussion specific to Gateway West is found in Chapter 6 (Transmission Planning), pages 69–71. The results of a "need" analysis are provided in the section Gateway West Need Analysis, pages 70–71.

## B. Pollution Control Investments in Coal Resources

### 1. Idaho Power's Analysis

Commission Resolution (Order No. 14-253):

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger units 3 and 4

are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenario analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of Section 111(d) of the Clean Air Act.

***Idaho Power Response (2015 IRP):***

The 2015 IRP considers multiple early retirement scenarios as described in Chapter 8 (Portfolio Selection), pages 97–111. These early retirement scenarios were developed with input from the IRP Advisory Council and public participants of the IRP process, including input received at a portfolio design workshop held on January 28, 2015.

CAA Section 111(d) was discussed frequently during IRP Advisory Council meetings. A discussion led by IRP Advisory Council member John Chatburn (Idaho Office of Energy Resources) was held as part of the December 4, 2014 IRP Advisory Council meeting. Multiple sensitivities for CAA Section 111(d) were analyzed for the IRP. These sensitivities are described in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, pages 114–120.

## 2. North Valmy Unit 1

***Commission Resolution (Order No. 14-253):***

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***Idaho Power Response (2015 IRP):***

No action required.

### 3. Jim Bridger Units 3 and 4

***Commission Resolution (Order No. 14-253):***

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp, the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

***Idaho Power Response (2015 IRP):***

A section titled Jim Bridger units 3 and 4 SCR Analysis is included in *Appendix C—Technical Appendix*.

## *C. Demand Response*

### Commission Resolution (Order No. 14-253):

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

### Idaho Power Response (2015 IRP):

The performance of demand response programs in 2014 is provided in Chapter 4 (Demand-Side Resources), section *Demand Response Performance*, pages 42–43. Chapter 4 also notes that demand response is forecast to provide 390 MW of peak reduction during July throughout the planning period (section *Committed Demand Response*, page 46).

## D. Long-Term Action Items

### Commission Resolution (Order No. 14-253):

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs. We generally do not acknowledge action items planned to occur more than four years in the future.

### Idaho Power Response (2015 IRP):

The action plan provided in the 2015 IRP is focused on resource actions for the four-year period 2015-2018. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

## E. Analysis of IRP

### 1. Wind Resources

#### *Commission Resolution (Order No. 14-253):*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

#### *Idaho Power Response (2015 IRP):*

No action required.While no IRP-related action is required, Idaho Power notes the use of a technical review committee from the outset of its first solar integration study, completed in June 2014. A technical review committee has also been in place since the January 2015 start of Idaho Power's second solar integration study.

## 2. Capacity Contribution of Solar and Other Resources

***Commission Resolution (Order No. 14-253):***

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

***Idaho Power Response (2015 IRP):***

Idaho Power convened public working group meetings to address solar-related issues, including capacity contribution, on August 6, 2014 and September 3, 2014. The results of the solar capacity contribution analysis conducted as part of the working group meetings are provided in Chapter 5 (Supply-Side Generation and Storage Resources), section *Solar Capacity Credit*, pages 50–51.

## 3. Gas Price Forecasts

***Commission Resolution (Order No. 14-253):***

We anticipate these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

***Idaho Power Response (2015 IRP):***

The natural gas price forecast is provided in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, pages 84–85. As noted in this section, Idaho Power uses EIA published nominal forecast prices. Also noted is the use of the EIA high resource case for the low case natural gas price forecast, and similarly use of the EIA low resource case for the high case natural gas price forecast. Finally, part of AURORA model calibration conducted for the IRP is verification that future power market (i.e., Mid-C) prices derived by the AURORA model maintain their historic relationship to natural gas market prices. The ratio of these prices, power market and natural gas market, is called the implied market heat rate. Idaho Power verified that future implied market heat rate values (ratio of AURORA-derived power market price to input natural gas market price) reasonably approximate historic values for this ratio. The implied market heat rate analysis was presented to the IRP Advisory Council and public participants at the February 5, 2015 IRP Advisory Council meeting.

## 4. Flexibility Guideline

***Commission Resolution (Order No. 14-253):***

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

***Idaho Power Response (2015 IRP):***

A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section *Flexible Resource Needs Assessment*, pages 135–139. Figure 9.4 on page 143 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136-138.

## 5. Conservation Voltage Reduction

***Commission Resolution (Order No. 14-253):***

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP. In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report. Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

***Idaho Power Response (2015 IRP):***

CVR is discussed in Chapter 4 (Demand-Side Resources), section *Conservation Voltage Reduction*, page 48. The 2015 IRP's treatment of CVR was communicated to OPUC staff in a conference call on August 22, 2014.

## 6. Energy Efficiency

***Commission Resolution (Order No. 14-253):***

We adopt Staff's proposed additions to the Action Plan. [Staff proposed the addition of action plan items specifying IRP energy efficiency targets.]

***Idaho Power Response (2015 IRP):***

The action plan provided in the 2015 IRP includes an action item related to the pursuit of cost-effective energy efficiency, and expresses energy efficiency targets in a manner similar to that proposed by Staff. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, pages 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

## 7. NEEA

***Commission Resolution (Order No. 14-253):***

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

***Idaho Power Response (2015 IRP):***

Idaho Power continues its commitment to NEEA as a participant in NEEA's 2015-2019 funding cycle. On September 30, 2014 Idaho Power and NEEA executed a contract to participate in the 2015-2019 funding cycle. For complete details on Idaho Power's involvement in NEEA activities please see pages 9, 141-145 of the Company's Demand-Side Management 2014 Annual Report – Appendix B.

# ATTACHMENT N-5
# ORDER NO. 10-392 IN DOCKET LC 50

ORDER NO. 10-392
ENTERED 10/11/10

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 50

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>2009 Integrated Resource Plan. | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

## I. INTRODUCTION

Idaho Power Company (Idaho Power or Company) seeks acknowledgement of its 2009 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047,[1] which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning.

We acknowledge Idaho Power's 2009 IRP and its preferred portfolio as presenting the best combination of expected costs and associated risks and uncertainties for the Company and its customers, and as satisfying the procedural and substantive requirements of this Commission. At the same time, we recognize that the assumptions for several key factors remain uncertain. For this reason, we require that Idaho Power perform further analyses in its 2011 IRP consistent with our discussion below.[2]

### A. Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their planning process prior to resource decision-making.

Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process to select a portfolio of resources with the best combination of

[1] The Commission originally adopted least-cost planning in Docket No. UM 180, *See* Order No. 89-507 (Apr 20, 1989). The Commission updated the least-cost planning process in 2007 in Docket No. UM 1056. *See* Order No. 07-002 (Jan 8, 2007).

[2] The original due date for the filing of the Company's 2009 IRP was June 2009. That date was extended by Commission order to December 2009. The Company will file its 2011 IRP in June 2011.

expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in state and federal energy policies.[3]

**B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions**

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[4] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[5]

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> The establishment of Least-Cost Planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.
>
> * * * * *
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.[6]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken in accordance with Idaho Power's 2009 IRP. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged integrated

[3] *See* Order No. 07-002.
[4] *See id.* at 25.
[5] *See id.* at 16.
[6] *See* Order No. 89-507 at 6, 11. The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

resource plans. A utility is also expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

## C. Idaho Power's 2009 IRP

The Commission's IRP Guidelines state that a utility must file its IRP two years from the date of acknowledgement of the previous plan. Idaho Power received acknowledgement of its 2006 IRP on September 12, 2007.[7] Due to substantial changes in economic conditions and permitting delays for the Boardman to Hemingway 500 kV transmission project (B2H Project or Boardman to Hemingway), the Company requested a delay in its September 12, 2009 filing deadline. On May 26, 2009, the Commission approved Idaho Power's motion to delay its filing of the 2009 IRP until December 2009.[8] On December 30, 2009, Idaho Power filed its 2009 IRP.

This is Idaho Power's first plan under the Commission's newly adopted Guidelines.[9] In developing its 2009 plan, Idaho Power worked with an IRP advisory group comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, Commission representatives, and others.

Idaho Power's 2009 IRP analyses the potential cost of carbon emissions in two ways: cap-and-trade and carbon tax adders. While Idaho Power modeled both a cap-and-trade system and carbon tax adders in future scenarios, the Company primarily focuses on cap-and trade as the most likely regulatory outcome. The Company's analysis uses the Waxman-Markey Bill[10] as the basis for its assumptions on emission targets and allowances.

Idaho Power uses the AURORAxmp (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio cost for the twenty-year IRP. Using the AURORA model, the Company performed a quantitative risk analysis of the following variables: third-party transmission subscription; renewable energy credit prices; natural gas prices; carbon emission costs; load growth; and conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting.

For the first time, Idaho Power bifurcated the required twenty-year planning period into two ten-year planning periods—2010 through 2019 and 2020 through 2029. The Company believes that this approach prevents near-term decision making from being unduly influenced by resource decisions in the second ten-year planning period.

In the first ten-year planning period (2010 through 2019), Idaho Power examines four resource portfolios, classified as Solar, Gas Peaker, Gas Peaker and B2H,

[7] *See* Order No. 07-394 (Docket No. LC 41).
[8] *See* Order No. 09-183 (Docket No. UM 1428).
[9] *See* Order No. 07-002.
[10] The Waxman-Markey Bill, named after its authors, Representatives Henry A. Waxman of California and Edward J. Markey of Massachusetts, was introduced as an energy bill in the 111th United States Congress. The bill was approved by the House of Representatives on June 26, 2009.

and B2H. The labeling of these portfolios defines the type of supply-side resource that would be used to meet Idaho Power's forecasted energy and capacity deficits. Originally evaluated in the Company's 2006 IRP, and common to all resource portfolios as "committed" resources, are (1) the Langley Gulch combined-cycle combustion turbine (CCCT), (2) up to 150 megawatts (MW) of wind generation, and (3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

In the second ten-year planning period (2020 through 2029), Idaho Power examines five resource portfolios. Idaho Power uses its preferred portfolio for the first ten-year planning period as the basis for designing the second period portfolios. The load forecast for the second planning period is relatively flat. The primary driver for new resources in the second period is carbon emission reductions due to coal curtailment, as identified in the Waxman-Markey Bill.

New energy efficiency programs included in the 2009 IRP are forecast to reduce annual load by 127 average MW (MWa) by the year 2029. This reduction represents a 53 percent increase over the measures included in the Company's 2006 IRP. New and expanded demand response programs are expected to reduce peak summer load by 323 MW by the year 2012, once the programs mature. This reduction represents significant growth over the 2006 IRP when demand response programs were estimated to provide only 78 MW of peak reduction by 2026. All estimated reductions in load due to energy efficiency and demand response programs are included in Idaho Power's 2009 load forecast.

Using an August 2009 load forecast, Idaho Power projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load is forecasted to grow by 13 MWa or 0.64 percent on an average annual basis over the twenty-year planning period. Idaho Power projects that its system will become short on capacity in 2013 and, on an energy basis, the system begins to experience a short position by 2014.[11]

Based on its analysis, Idaho Power selected "Portfolio 1-4 Boardman to Hemingway" as its preferred portfolio for the 2010-2019 planning period and "Portfolio 2-4 Wind and Peakers" as its preferred portfolio for the 2020-2029 planning period. The selection of these portfolios as the Preferred Portfolio for the twenty-year study is based on the Company's conclusion that the portfolios present the best combination of expected cost and associated risks.

The Company requests acknowledgement of an Action Plan to implement its Preferred Portfolio. The Action Plan includes the following items:

2010 Irrigation Peak Rewards program increases to 220 MW
FlexPeak Management program increases to 40 MW

[11] Idaho Power uses a 70th percentile water conditions and 70th percentile average load conditions for energy planning purposes. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load.

2011 Irrigation Peak Rewards program increases to 250 MW
FlexPeak Management program increases to 45 MW

2012 Wind project on-line 150 MW
Langley Gulch CCCT on-line 300 MW
Geothermal Project on-line 20 MW

2013 Boardman to Hemingway construction begins
Shoshone Falls Upgrade Project construction begins

2015 Shoshone Falls Upgrade Project on-line 49 MW
Boardman to Hemingway completed for market purchases of 250 MW

2016 Geothermal Project on-line 20 MW

2017 Boardman to Hemingway capacity for market purchases of 175 MW

Finally, Idaho Power believes that the flexibility to adjust to changes during the present period of uncertainty regarding carbon regulation is very important.

## II. DISCUSSION

### A. Load Forecast

*1. Parties' Positions*

During a public comment hearing in Ontario, Oregon, on April 20, 2010, many commentators argued that the load forecast in Idaho Power's 2009 IRP is too high. Some of the reasons cited for this conclusion are: (1) the Company should not have included new large load customers; (2) the Company did not consider more recent load information in its forecast; and (3) based on historical housing start data, a more protracted economic recovery will occur than assumed by Idaho Power. Commentators believe that the Company over-projected its short-term load growth, making the Boardman to Hemingway transmission line appear necessary when, in fact, it is not needed in the time period specified by the Company.

In its reply comments, Idaho Power refutes all of the commentators' claims regarding its load forecast. The Company states that its forecast contains the most recent information available at the time the filing was prepared and, compared to the Northwest Power and Conservation Council (NPCC) forecast, Idaho Power's forecast is conservatively low. According to Commission Staff's comments, the NPCC's Sixth Power Plan average load forecast grows at an annual average rate of 1.96 percent, while Idaho Power's forecast grows at 1.4 percent over the twenty-year planning period. For peak-hour load, the NPCC forecast grows at an annual average rate of 2.13 percent, while Idaho Power forecasts its peak-hour load to grow at 2.02 percent.

Regarding the inclusion of large load customers in its forecast, Idaho Power states that large loads are developed through direct input from each of the Company's large load customers. These forecasted customer loads reflect the recession and other operational impacts on future energy use.

In its final comments, Staff agrees with the Company. After reviewing Idaho Power's analyses, Staff believes that the Company has conservatively forecasted its average-energy and peak-hour load, taking into consideration the recent economic downturn. But Staff notes that for the 2019 through 2029 planning period, Idaho Power forecasts average energy to grow at a rate of only 0.1 percent per annum, and peak-hour load growth of only 0.9 percent per annum. Staff is concerned that these growth rates may be too low, especially when the rate of growth in demand-side management (DSM) is projected to slow over this time period.

The inclusion of a customer response to potential price increases due to proposed carbon legislation is a contributing factor to relatively flat growth rates in the second ten-year planning period. Staff finds the customer response to projected price increases associated with carbon regulation to be an interesting change in the Company's forecasting methodology. Staff recommends that the Company provide further description of this analysis in future IRP planning cycles, including the regression coefficients and estimated price responsiveness of each customer class. In its final comments, Idaho Power supports Staff's recommendation.

In its final comments, the Oregon Department of Energy (ODOE) supports Idaho Power's load forecast estimates in its 2009 IRP. ODOE also supports the Staff comments associated with Idaho Power's load forecast and reiterates Staff's concerns about the load growth forecast beyond 2019.

*2. Resolution*

We agree with Staff's conclusion that Idaho Power's first ten-year load forecast is reasonable. We agree with Staff and ODOE that the projected load growth for the second ten-year period seems low. We adopt Staff's recommendation and require Idaho Power to justify its load forecast for the second ten-year period in future IRPs.

We also adopt Staff's recommendation that Idaho Power provide estimates of the price sensitivity for each of its customer classes and document the analyses underpinning those estimates in its next IRP planning cycle.

## B. Preferred Portfolio for the First Ten-Year Planning Period and the Boardman to Hemingway Transmission Project

*1. Parties' Positions*

Idaho Power selected Portfolio 1-4 (Boardman to Hemingway) as its preferred portfolio for the 2010-2019 planning period. In comments on the IRP, Staff and intervening

parties primarily focus on the selection of Portfolio 1-4 as the preferred portfolio versus the other portfolios and, more specifically, the inclusion of the Boardman to Hemingway transmission project. In its analysis, Staff examined the portfolio assumptions associated with the B2H Project, such as capital cost assumptions and third-party subscriptions. Staff evaluated the Company's approach to these variables and their robustness under changing circumstances (for example, higher construction costs or lower third-party subscription rates).

Staff notes that very few interstate transmission projects have been constructed in the region over the last 30 years. It is only recently that utilities in the west have proposed and started to build these large transmission projects, such as Gateway West, the Southwest Intertie, and others. Due to the more recent interest by utilities and consortiums in building these projects, Staff was unable to obtain a reliable set of benchmark data to compare to Idaho Power's cost assumptions and subscription rates. In addition, Staff notes that the cost components of an interstate transmission project can vary widely depending on the type of terrain and right-of-way costs. Thus, rather than attempting to compare these components side-by-side to another project, Staff examined how much these assumptions would have to change in order to make the Portfolio 1-4 no longer the best combination of cost and risk. Idaho Power refers to this analysis as the "tipping point."

Staff discusses at length the Company's analysis of a break-even point, or tipping point, with Portfolio 1-2 (Gas Peaker)—the next best alternative to Portfolio 1-4—to understand the sensitivity of the change in cost within the first ten-year planning period. This analysis demonstrates that Portfolio 1-4 is so robust that capital cost could vary by up to 40 percent and subscription rates could change by 15 percent before the portfolio hits the break-even point with the next best alternative.

In support of its subscription rate assumptions, Idaho Power states that there is significant demand for transmission capacity on its Idaho-Northwest transmission path. Idaho Power states that it is aware of over 4,000 MW of transmission requests on the existing transmission path, with only 133 MW of those requests being granted through 2007 due to limited transmission capacity. The Company claims that it is currently reviewing active transmission requests for the B2H Project. The Company states in its reply comments that it has entered into an agreement with PacifiCorp to negotiate the joint ownership and development of the B2H Project.

Even with a change in cost, Staff states that the Company's analysis also includes additional quantitative and qualitative risk measures that must be taken into consideration. According to Staff, Portfolio 1-4 scored higher than all the alternative portfolios in the Company's risk analyses. The different types of risk modeled in Idaho Power's 2009 IRP are renewable energy credit prices, natural gas prices, carbon emission costs, load growth, and lower conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting. Therefore, the Boardman to Hemingway capital costs and subscription estimates would have to vary by more than 40 percent and 15 percent respectively to change

the selection of the Portfolio 1-4 as the preferred portfolio for the 2010 through 2019 planning period.

In conclusion, Staff recommends that the Company continue to evaluate the B2H Project in its 2011 IRP. This on-going analysis of the B2H Project should include updated estimates of construction costs, documentation of progress the Company has made towards securing equity partners, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. Staff additionally recommends that the Commission require that Idaho Power provide third-party documentation in support of the Company's construction cost estimates.

Staff's recommendation for further analysis of third-party subscription and the associated wheeling revenues is based on a concern that the active transmission requests referred to by Idaho Power in its 2009 IRP may not materialize, leaving Idaho Power customers liable for paying for an unused transmission line. Given these concerns, Staff initially recommended that the Commission's acknowledgement of the Boardman to Hemingway action item be conditioned on Idaho Power providing further analysis of these issues in its annual IRP update and next IRP.

In their final comments, ODOE and Idaho Power support Staff's recommendation for further information and analyses on the B2H Project in future IRP planning cycles. Idaho Power also agreed with Staff that if there are significant deviations from the IRP assumptions on issues such as construction costs, equity ownership, and subscription rates, then the Company must explain these deviations in its 2011 IRP. But given that Staff found the Company's estimates to be reasonable at this time, Idaho Power argues that conditional acknowledgment is not necessary. The Company agreed to provide additional analyses of the B2H Project, as prescribed in the eight conditions of Staff's proposed final order.

At the Commission public meeting on September 7, 2010, Staff revised its original recommendation for conditional acknowledgement and agreed with Idaho Power that, with the Company's commitment to continue to analyze and assess the B2H Project as an uncommitted resource, acknowledgement with requirements is a reasonable recommendation that meets the goals of Staff's proposed final order.

Finally, Staff discussed the future ratemaking treatment of the B2H Project. Staff reaffirmed that the Company will be required to compare its actual results with its IRP estimates. If the comparison shows significant deviations from its IRP assumptions, then the Company must provide an adequate explanation for why this project was the right resource as compared to an alternative.

In its opening comments, Renewable Northwest Project (RNP) urges the Commission to acknowledge Portfolio 1-3 (Gas Peaker and B2H) as the preferred portfolio for the first ten-year planning period. RNP states that it believes that the Company's commitment to 150 MW of wind energy and 40 MW of geothermal, coupled with the Boardman to Hemingway transmission line, will foster the growth of new renewable energy

resources in the Northwest. Staff agrees with the latter half of RNP's statement, but points out that Idaho Power's preferred portfolio, Portfolio 1-4, also includes the Company's commitment to 150 MW of wind energy and 40 MW of geothermal. Therefore, Staff believes that Portfolio 1-4 meets RNP's goals.

In reply comments, RNP supported Staff's conclusions associated with Portfolio 1-3, and agreed with Staff that the Company's Portfolio 1-4 will also foster the growth of new renewable resources in the Northwest.

Commentators at the April 20, 2010 public comment hearing focused on the need for the B2H Project. Specifically, commentators believe that building a natural gas plant and additional purchased power are preferable to the Boardman to Hemingway transmission line, and that the line should not be built to accommodate third-party wheeling requests.

Idaho Power refutes each of these claims. First, Idaho Power notes the robustness of Portfolio 1-4 as compared to the other portfolios. Second, Idaho Power refutes the possibility of additional purchased power due to its limited transmission capacity during peaking time on existing transmission paths. Third, Idaho Power states that all wheeling requests on the proposed B2H Project will offset costs associated with building the project, which in turn will reduce its customers' rates. In addition, Idaho Power states that it is bound by federal law to provide wheeling services on a non-discriminatory basis, which requires the Company to construct a transmission system that will ensure reliable and economic service to transmission customers.

*2. Resolution*

As Staff notes, the dearth of recent transmission development and the case-specific nature of any transmission project make it difficult to vet key assumptions that will determine the cost to Idaho Power's retail customers of the B2H Project. But our concern about this uncertainty is tempered by risk analyses showing that the "B2H portfolio" (Portfolio 1-4) is the best portfolio for customers over a range of capital costs and third-party subscription levels. Accordingly, we consider it reasonable to proceed with the B2H Project based on the information available now and acknowledge it as part of the Company's 2009 IRP.

We also adopt Staff's recommendation that Idaho Power be required to update its B2H Project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) in its 2011 IRP. We always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages at the time of an IRP acknowledgement. We make this updating requirement explicit for the B2H Project because of current uncertainty about underlying assumptions. We expect the Company to provide a thorough update of its B2H Project assumptions and its risk analysis in the 2011 IRP, with the understanding that the Commission's acknowledgment of the 2011 IRP will depend on the outcome of that updated analysis.

Finally, we reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. Given the inherent risk associated with a transmission facility and the possibility of escalating costs and delays in permitting, the Company will need to address any significant changes in construction cost, equity partnership, or expected third-party subscription and how these factors influenced the Company's decision to continue with the project.

## C. Preferred Portfolio for the Second Ten-Year Planning Period and the Consolidated Preferred Portfolio

### *1. Parties' Positions*

Idaho Power chose Portfolio 2-4 (Wind and Peakers) for the second ten-year planning period. Portfolio 2-4 consists of five single cycle combustion turbine (SCCT) gas resources with a combined capacity of 1,400 MW, two wind facilities with a combined capacity of 200 MW, and 100 MW of market purchases on PacifiCorp's proposed Gateway West transmission project. Idaho Power states that these resources represent a strategy of adding wind resources sufficient to provide energy and renewable energy credits (REC) along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation.

In its final comments, Staff noted that the load forecast for the second ten-year planning period is relatively flat. The Company stated that the primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey Bill. In its comments, RNP lauded Idaho Power for developing a resource portfolio that allows for considerable curtailment of the Company's coal-fired generation. RNP believes that Idaho Power's IRP strategy appropriately accounts for the costs, risks, and environmental concerns associated with future limits on greenhouse gas emissions.

Staff agrees with RNP and believes that Idaho Power complied with Guideline 8 of the Commission's IRP guidelines by modeling the carbon emission future that it believed was most likely to occur. But Staff cites the need for additional analysis, including the end-effects and costs of the retirement of a coal facility. Staff recommends that the Commission require that Idaho Power examine coal curtailment and the costs associated with coal plant retirement.

In its opening comments, RNP expressed concern that the portfolios rely too heavily on natural gas-fired resources. Staff agrees that Portfolio 2-4 relies too heavily on gas in the second ten-year planning period. Staff's primary concern, however, was not the concentration of gas in the second planning period, but the type of gas resource modeled. Because the primary reason for additional resources in the second ten-year planning period was due to modeled coal curtailment, Staff believes it is unreasonable for the Company to choose multiple SCCTs versus one or two CCCTs.

Staff and RNP believe that the Company needs to consider expanding the number of portfolios it considers in the second ten-year planning period. Staff notes that an IRP is designed to take into consideration a broad array of portfolio options. For the second ten-year planning period and the consolidated Preferred Portfolio, Staff discussed the design of Idaho Power's five alternative portfolios. Staff notes that the Company designed the five portfolios for the second ten-year planning period based on the selection of Portfolio 1-4 for the first ten-year planning period, which limits the resource options considered by Idaho Power.

Staff believes that building portfolios is a learning process examining multiple futures, and this learning process should not be overlooked. Staff believes that more than five portfolios should be developed for the second ten-year planning period. Staff therefore recommends that the Commission require Idaho Power to develop significantly more portfolios for the second ten-year planning period for its next IRP. In addition, Staff recommends that Idaho Power be required to provide a review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit. In its final comments, Idaho Power supported Staff's recommendation.

In its final comments, ODOE also recognized the need for Idaho Power to develop more portfolios and suggested that the Company should consider uncertainty in its future analyses.

As part of the carbon cost evaluation, Staff recommends that Idaho Power be required to look at the likelihood of Environmental Protection Agency (EPA) regulations on air quality, fly ash, and water for all of its generation facilities. Staff believes the Company needs to include the operational impacts of these possible regulations for future consideration. In its final comments, Idaho Power supported Staff's recommendation.

*2. Resolution*

We support Idaho Power's selection of Portfolio 2-4 for the second ten-year planning period and the overall selection of the Preferred Portfolio. While we recognize the speculative nature of the second half of the planning period, we agree with Staff's conclusion that much can be learned from analyzing more portfolios and resource options. We therefore adopt Staff's recommendation and direct the Company to consider more portfolios, including those needed to evaluate the benefits of a CCCT versus a SCCT, in its next IRP cycle. We also direct the Company to include an analysis of potential EPA or other federal and state environmental policies that may affect Idaho Power's generation portfolio.

**D. Demand-Side Management and Energy Efficiency Programs.**

*1. Parties' Positions*

Several commentators at the April 20, 2010 public comment hearing argued that Idaho Power has been deficient in seeking energy savings. Commentators suggested that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan. They further asserted that the Company could supplant the need for the Boardman to Hemingway transmission line with increased DSM efforts.

Idaho Power responded to these remarks in its reply comments by explaining how they treat DSM in the planning process and by comparing the Company's efforts to the goals set by the NPCC. Idaho Power explains that prior to evaluating the need for traditional resources, the Company includes all cost-effective energy efficiency from existing and new programs in its load and resource balance. In other words, the Idaho Power gives first priority to obtaining cost-effective conservation. The Company then compares its efforts to the goals set by the NPCC. According to Idaho Power, in 2009 it exceeded the goals in NPCC's Fifth Power Plan by approximately 30 percent. Idaho Power also states that it is working aggressively to meet the goals set in the Sixth Power Plan.

In its final comments, Staff echoed the sentiments of Idaho Power and believes that the Company has explored and included all cost-effective DSM and energy efficiency programs in its 2009 IRP. In addition, Staff states that the Company has made great strides with its energy efficiency and DSM measures as compared to the Company's 2006 IRP.

*2. Resolution*

Idaho Power's existing and new energy efficiency programs are forecasted to reduce average annual system loads by 189 MWa by the year 2019 and 383 MWa by 2029. We agree with Staff that Idaho Power is running a reasonable set of programs to capture all cost-effective conservation. We also support the Company in its efforts to refine and improve upon its programs.

We find that Idaho Power cannot rely on additional cost-effective conservation in lieu of a supply-side resource to meet its summer capacity needs and maintain a reliable system. On a monthly basis, after counting energy efficiency savings, the Company forecasts a resource deficit of 155 MWa during July 2019. On a peak hour basis, after counting savings from existing and new energy efficiency programs and new demand response programs, the Company forecasts summertime capacity deficits as large as 471 MW during 2019. We concur with Staff and Idaho Power that a supply-side resource is required to meet these forecasted capacity deficits.

## E. Policy Issues

### *1. Parties' Positions*

In its opening comments, RNP did not agree with Idaho Power's recommendation to sell its RECs from its renewable energy projects until the Company is required to use the RECs to comply with a federal Renewable Energy Standard (RES). RNP believes Idaho Power should be retaining RECs in preparation for compliance with a future federal RES.

In its final comments, Staff notes that the Idaho Public Utilities Commission accepted Idaho Power's REC management plan filing on June 11, 2010.[12] This REC management plan is consistent with Idaho Power's IRP. In its reply comments, Idaho Power explained that its REC management strategy will benefit customers of Idaho Power in two ways. First, customers' rates will be reduced due to REC sales revenue. Second, the Company plans to continue to acquire and hold long-term contract rights to own RECs to meet future federal RES.

In addition, RNP supported the development of a solar pilot project in Idaho Power's service territory. RNP stated that it would like to participate in a stakeholder workshop with Idaho Power to explore options for a solar pilot project. In response to Staff final comments, RNP generally supported Staff's conclusions.

### *2. Resolution*

We agree with Idaho Power's conclusion that its REC management strategy is in the best interest of customers, will reduce rates, and will provide the ability to meet future RES standards.

More recently, Idaho Power has participated in the pilot project for a solar feed-in tariff in Oregon. We believe Idaho Power's participation and introduction of the solar feed-in tariff fulfills RNP's request to develop a solar pilot project in Idaho Power's service territory.[13]

## F. General Issues

### *1. Parties' Positions*

In final comments, Staff noted several deficiencies in Idaho Power's narrative description of its 2009 IRP. Staff believes that Idaho Power should provide a more thorough explanation of the Company's selection of the Preferred Portfolio. Staff believes that Idaho Power failed to provide an adequate narrative of how the Preferred Portfolio performed in the risk analysis individually and comparatively to the other portfolios. Staff therefore recommended that the Commission require Idaho Power to devote specific chapters in its next IRP explaining the selection of its Preferred Portfolio in greater detail and as compared

[12] *See* Idaho Public Utilities Commission Case No. IPC-E-08-24, Order No. 32002.
[13] *See* Docket No. UM 1452.

to an alternative portfolio. Staff believes this narrative should include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Finally, Staff recommended that Idaho Power should be required to provide an explanation of how each portfolio performed with regard to the qualitative measures the Company considered in its selection process.

Staff also pointed out that Idaho Power's risk analysis consisted of modeling risk variables, such as load growth, in only one direction—high. In its Technical Appendix the Company did not model low load growth scenarios, low subscription rates, or low natural gas prices. Staff recommends the Company model the full range of possible futures for its risk variables, including both the high and low side, in the next IRP. In response to Staff's final comments, Idaho Power agrees with Staff's recommendations.

*2. Resolution*

We support Staff's recommendation regarding Idaho Power's next IRP cycle. As stated in Order No. 07-002, the Commission guidelines incorporate what we minimally expect from an IRP.[14] We always urge the utility to provide more, rather than less, information, especially given the increasing complexity of the planning process.

## III. CONCLUSION

Idaho Power Company's 2009 Integrated Resource Plan, as highlighted in this order, reasonably adheres to the principles of resource planning established in Order No. 07-002 and is acknowledged with the following requirements:

1. Idaho Power Company will file its next integrated resource plan no later than June 30, 2011.

2. In its 2011 Integrated Resource Plan, Idaho Power Company will treat the Boardman to Hemingway transmission project as an uncommitted resource and will update its project analysis, including progress the Company has made towards securing equity partners, updated estimates of construction costs, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. In addition, Idaho Power Company will provide third-party documentation in support of its construction cost estimates.

3. In its next planning cycle, Idaho Power Company will analyze coal curtailment and the costs associated with coal plant retirement.

[14] *See* Order 07-002 at 12.

4. In its next planning cycle, Idaho Power Company will develop significantly more portfolios for the second ten-year planning period, including portfolios designed to evaluate the benefits of a combined cycle combustion turbine gas resource versus multiple single cycle combustion turbine gas resources.

5. In its next planning cycle, Idaho Power Company, will analyze any potential Environmental Protection Agency, state, and other federal agency regulations associated with air quality, fly ash, and water that may affect the Company's generation facilities. These results will be included in the Company's 2011 Integrated Resource Plan.

6. In its 2011 Integrated Resource Plan, Idaho Power Company will provide a more robust justification for its load forecast for the second ten-year planning period. In addition, Idaho Power will provide additional analysis and a description of its estimated price response related to future carbon regulation for each customer class in its next IRP planning cycle.

7. In its 2011 Integrated Resource Plan, Idaho Power Company will devote specific chapters in the Plan to explaining the selection of the Preferred Portfolio in greater detail and as compared to an alternative portfolio. This narrative will include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Idaho Power Company will provide an explanation of how each portfolio performed using the qualitative measures the Company considered in its selection process.

8. In the 2011 Integrated Resource Plan, Idaho Power Company will model the full range of possible futures for its updated risk variables. Idaho Power Company will model both a high and low future for each variable.

At the Commission's September 7, 2010 public meeting, Idaho Power Company agreed to perform all of the above analyses in its 2011 Integrated Resource Plan and understood that the Commission's acknowledgement of Idaho Power's 2011 Integrated Resource Plan will be based upon the results of the updated analyses.[15]

[15] For further details regarding Idaho Power's adherence to the Commission's Guidelines in Order No. 07-002, *see* Staff Final Comments, Appendix A: Adherence of the Plan to Integrated Resource Planning Guidelines (July 9, 2010).

## IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Idaho Power Company on December 30, 2009, is acknowledged with the requirements set forth in this order.

2. Idaho Power Company will file its next Integrated Resource Plan no later than June 30, 2011.

Made, entered, and effective OCT 11 2010.

**Ray Baum**
Chairman

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

# ATTACHMENT N-6
# ORDER NO. 12-177 IN DOCKET LC 53

ORDER NO. 12 177

ENTERED MAY 21 2012

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 53

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>2011 Integrated Resource Plan. | ORDER |

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

## I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

## II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be

[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

## III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a public meeting. A technical workshop was held for parties on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

## IV. DISCUSSION

### A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

## B. Objections to Idaho Power's 2011 IRP

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

### *1. Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)*

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as

well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

*Resolution*

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

### *2. Boardman to Hemingway Transmission (Action Item 7)*

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

*Resolution*

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

### *3. Conservation Voltage Reduction (Action Item 4)*

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

*Resolution*

We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:

> Action Item 4 – Conservation Voltage Reduction – The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

### *4. Demand Response (Action Item 3)*

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

*Resolution*

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

### *5. Energy Efficiency (Action Items 1 and 2)*

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

*Resolution*

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

### *6. Alternative Portfolio (Action Items 8 and 9)*

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

*Resolution*

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

### *7. Long Term Action Items (Action Item 12)*

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

*Resolution*

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

### *8. Load Forecast*

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

*Resolution*

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

### *9 Risk Analysis*

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

*Resolution*

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

### *10. Wind Integration Study*

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

*Resolution*

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

### *11. Solar Photovoltaic Analysis*

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

*Resolution*

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

### *12. Adherence of Plan to Integrated Resource Planning Guidelines*

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

*Resolution*

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

[4] IRP Guideline 1(c) prescribes the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future enviromnental compliance costs.

## IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 21 day of May, 2012, at Salem, Oregon.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

# Appendix A
# Adopted Action Items and Recommendations for Future IRPs

Idaho Power 2011 Integrated Resource Plan (IRP)

Action Items:

Near-Term Action Plan (2011-2020)

Demand-Side Resource Action Items

Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.

Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

Supply-Side Resource Action Items (Preferred Portfolio)

Action Item 5 - Solar - Issue a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. Evaluate proposals by mid-2012, and if a successful bidder is identified, file a request with the IPUC for a CPCN. If approved, have the facility on line as early as the end of 2012.

This solar resource will satisfy the State of Oregon's Solar PV Pilot Program requirement to build a 500-kilovolt (kV) solar PV project. Continue working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP.

Action Item 6 - Power Purchase Agreements - Complete 83 MW in market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016.

Action Item 7 - Transmission – Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.

As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

~~Supply-Side Resource Action Items (Alternative Portfolio)~~

~~Action Item 8 - Solar – as described for preferred portfolio Action Item 5.~~

~~Action Item 9 - Simple Cycle Combustion Turbine – 170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Other Action Items

Action Item 10 - Renewable Energy Certificate Management - As detailed in the REC Management Plan, continue selling RECs in the near term until they are needed to meet a federal RES.

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

~~Long-Term Action Plan (2021-2030)~~

~~Action Item 12 – Long-Term Action Items – as outlined in IRP Table 10.2~~

Recommendations for future Idaho Power IRPs:

1. During preparation of the 2013 IRP, there be an Integrated Resource Plan Advisory Council (IRPAC) meeting specifically focused on demand response. Staff will participate in that meeting, and work with the Company and parties to develop a demand response approach that is in the best interest of ratepayers.

2. Base the 2011 IRP Update and the 2013 IRP on an updated load forecast that, as accurately as possible, reflects current conditions.

3. Related to the new large load issue, include an allowance for new large loads in the load forecast only if there is a signed energy service agreement. Further, include an allowance for new large loads in the load and resource balance, but the new large load must be based on specific supporting documentation.

4. Toward the goal of working collaboratively to improve of the stochastic risk analysis, at least one 2013 IRP IRPAC meeting should be set aside to focus on this subject. Further, the 2013 IRP risk analysis should include hydroelectric generation variability. In the risk analysis focused IRPAC meeting, the Company should vet its approach to including hydroelectric generation variability in the 2013 IRP risk analysis.

5. Form a wind integration study technical review committee as soon as possible. The committee is recommended to be fully engaged to review and offer suggestions for improvement of the Company's proposals for analytical methods and data used in the study. In addition, establish as soon as possible, a schedule for workshops providing full opportunity for stakeholder involvement and progress reviews. Finally, in the Company's next wind integration study look for ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources.

6. Include in future IRPs an explanation of how the utility met each substantive and procedural requirement, as required by Guideline 4(a).

7. Include in future IRPs an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, as required by IRP Guideline 4(n).

8. Include in future IRPs a concise listing of action items for all resources and resource related activities, with each action item numbered.

# ATTACHMENT N-7
# ORDER NO. 14-253 IN DOCKET LC 58

ORDER NO. 14 253

ENTERED JUL 08 2014

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 58

| | |
|---|---|
| In the Matter of<br>IDAHO POWER COMPANY,<br>2013 Integrated Resource Plan | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED IN PART AND AS REVISED

## I. INTRODUCTION

Idaho Power Company is a public utility operating in Oregon and is subject to the Commission's jurisdiction and requirements regarding integrated resource planning. Idaho Power's 2011 Integrated Resource Plan (IRP) was acknowledged with exceptions and guidance for its next IRP in Order No. 12-177. Idaho Power now seeks acknowledgment of its 2013 IRP.

We require each regulated energy utility to prepare and file an IRP within two years of acknowledgment of the utility's last plan. In the IRP, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[1]

Once a utility completes a plan, we review for adherence to the procedural and substantive requirements outlined in Order No. 89-507. We generally acknowledge the plan—that is, find it reasonable based on the information available at that time—or return it to the utility with comments.[2] We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers.

We reaffirm our long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding. Acknowledgment of an IRP, however, is relevant to subsequent examination of whether a

[1] Order No. 07-002.
[2] *Id.* at 2.

utility's resource investment is prudent and should be recovered from ratepayers. As we have previously stated:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment.[3]

Just as acknowledgment does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of imprudence. The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in a subsequent rate case proceeding.

## II. DISCUSSION

We conclude Idaho Power satisfies all the procedural guidelines and all but one of the substantive guidelines for IRP planning. Idaho Power did not comply with the IRP Guideline regarding flexible capacity adopted in Order No 12-013.

We acknowledge the short-term action items in Idaho Power's Action Plan, except for the investment in selective catalytic reduction emissions technology at Jim Bridger Units 3 and 4.[4] In addition, we acknowledge two additional action items recommended by Staff that relate to energy efficiency. We do not acknowledge the remaining action items, which are for the most part outside the two-to-four year action plan period.[5]

## III. IDAHO POWER'S IRP

During the 20-year planning period, Idaho Power expects that the number of its customers will increase by about 8,400 each year, from approximately 500,000 in 2012 to 670,000 in 2032. Idaho Power's expected-case load forecast predicts that summer-peaking hour load requirements will grow at about 55 MW per year, and that the average-energy requirements will grow at 21 aMW per year. Idaho Power's load and resource balance analysis, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases, shows no energy deficits through the planning period. Idaho Power's analysis shows a capacity deficit starting in 2016 and monthly peak-hour deficit positions growing steadily in magnitude and the number of months affected. By July 2032, the capacity deficits are approximately 870 MW.

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[3] *Id.* at 24, *quoting* Order No. 89-507 at 7.
[4] *See* Appendix A.
[5] *See* Guideline 4(n).

Idaho Power identifies as its major resource addition the Boardman to Hemingway transmission line (B2H) with market purchases. The company's preferred portfolio also includes demand response, continued operations at the Jim Bridger and North Valmy coal facilities after investment in emission-control technology, and the continued operation of Idaho Power's other existing supply-side resources.

Guideline 4(n) requires the utility to include an action plan with resource activities the utility intends to undertake over the next two to four years. Idaho Power includes the following activities in its Action Plan:

| Year | Resource – Action |
|---|---|
| 2013-2018 | Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | Gateway West – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology |
| 2013 | Jim Bridger Units 3&4 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2016-2017 | Demand response – Have demand response capacity available to satisfy deficiencies up to approximately 150 MW |
| 2018 | Boardman to Hemingway – Transmission line complete and in service |
| 2019 | Shoshone Falls – Upgrade complete and in service |
| 2019 | Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2020 | Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology |
| 2020 | Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020 |
| 2024-2032 | Demand response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW |

## IV. DISCUSSION

In this order, we first address Idaho Power's Action Plan, discussing the comments filed by participants[6] and specific IRP Guidelines as appropriate. We then address issues raised by the participants or that we identify related to Idaho Power's compliance with the IRP Guidelines and our order regarding Idaho Power's 2011 IRP that are not discussed in connection with our review of the Action Plan.

[6] Renewable Northwest (RNW), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE), and Staff of the Public Utility Commission (Staff) filed opening and reply comments regarding Idaho Power's IRP, and Idaho Power filed two rounds of comments in response. In addition, a resident of Idaho, John Weber, forwarded comments to Staff, which Staff forwarded to the Administrative Hearings Division for inclusion in the record.

## A. Transmission

### *1. Boardman to Hemingway*

Currently, the Boardman to Hemingway transmission project (B2H) is envisioned as a single-circuit 500 kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. Idaho Power states that it has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting the project, under which Idaho Power is the permitting project manager.

Idaho Power proposes the following actions for the Boardman to Hemingway transmission project:

| | |
|---|---|
| *2013-2018* | *Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings* |
| *2018* | *Boardman to Hemingway – Transmission line complete and in service* |

#### *a. Participants' Comments*

RNW supports investment in B2H because it would provide Idaho Power not only with transmission to a liquid market, enabling the company to access low-cost resources to meet capacity and energy needs, but to also generate revenue by selling energy to other regional utilities. RNW also contends B2H will provide environmental benefits by enabling Idaho Power to reach renewable energy resource zones, thereby facilitating renewable energy resources.

Staff recommends acknowledgement of ongoing permitting, planning studies, and regulatory filings for B2H. Staff notes that B2H is included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolios" include B2H. Staff finds that the IRP analysis regarding B2H supports acknowledgment of ongoing permitting, planning studies, and regulatory filings.

Staff recommends, however, that we decline to acknowledge B2H "Transmission line complete and in-service" in 2018. Staff reports that the estimated in-service date for B2H has moved from 2018 (the year noted in Idaho Power's IRP) to 2020 (the year reported in the company's reply comments). Staff concludes this action item is now well beyond the two-to-four year period prescribed in the IRP Guidelines.

With respect to Idaho Power's activities that occur between the our order in this docket and Idaho Power's 2015 IRP, Staff asks to be apprised of any (1) updated project plan incorporating changes related to Bureau of Land Management delays and Energy Facilities Siting Council developments; (2) final agreement regarding allocation of construction costs between project participants; and (3) significant regulatory decisions that impact the project schedule or costs. Staff also asks that the company to further explore whether B2H would significantly impact wind generation curtailment during

periods of low demand as well as the impact of B2H on resource integration costs in general.

In its first round of comments, Idaho Power asserts that Staff's recommendation to acknowledge only the permitting activities of B2H and not the construction phase of the project is inconsistent with the our past acknowledgment of B2H and is unnecessary to ensure continued analysis of this project. In its final comments, Idaho Power states that it is only requesting acknowledgment of specific action items scheduled to occur within the next four years (which excludes the construction of B2H), but does ask that we acknowledge the 2013 IRP in its entirety, which includes B2H in its preferred portfolio.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H.

We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (*e.g.*, permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

*2. Gateway West*

Gateway West is a multi-segment, multi-year, joint transmission project of Idaho Power and PacifiCorp/Rocky Mountain Power to build and operate approximately 1000 miles of new transmission lines from Wyoming to the Hemingway Substation near Melba, Idaho. The project timeline indicates line segments in service between 2019 and 2023. Idaho Power has a one-third interest in some, but not all, of the segments to be located in Idaho and sole interest in one segment.

Idaho Power asks for acknowledgment of the following action item related to Gateway West:

*2013* *Gateway West – Ongoing permitting, planning studies, and regulatory filings*

Idaho Power reports that the Gateway West and B2H projects are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to a population center in Utah. Idaho Power states that Gateway West will benefit customers by (1) relieving transmission constraints on certain transmission paths allowing Idaho Power to move additional energy between the east and west sides of the system; (2) providing the option

to locate future generation resources east of the Treasure Valley load center; and (3) providing future load service to the Magic Valley from the Cedar Hill Substation. Idaho Power does not request acknowledgment of Gateway West as a supply side resource. Instead, the company asserts that Gateway West is reasonable to address transmission system constraints and provide for future least cost resource development.

*a. Participants' Comments*

RNW supports investment in Gateway West because it will provide the same benefits that B2H will provide—that is, access to low-cost resources, access to regions where renewable resources could be sited, and reliability.

CUB recommends that we not acknowledge Gateway West as presented. CUB notes that Gateway West is a large project composed of a number of segments that can be analyzed individually. CUB asserts that Idaho Power should narrow its request and seek acknowledgment only of the segments of Gateway West that it can demonstrate are cost effective for Idaho Power's customers.

Staff concludes that, although there is insufficient information to support acknowledgment of the construction of Gateway West, we should acknowledge the permitting-related activities that must occur prior to construction. For purposes of Idaho Power's next IRP, however, Staff recommends that the company include an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest in order to demonstrate the need and specific constraint-related benefits.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

## B. Pollution Control Investments in Coal Resources

### *1. Idaho Power's Analysis*

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present $CO_2$ level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures in its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the $CO_2$ emission cost adder level

that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

*a. Participants' Comments*

RNW asserts that Idaho Power's analysis of its coal resources failed to meet IRP Guideline 8 because the company did not (1) model natural gas conversions of the Jim Bridger Units 3 and 4 boilers; (2) model a range of pollution control costs; and (3) account for recent direction from President Obama's Administration that may reduce the cost competitiveness of existing coal resources. RNW asserts that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

CUB also criticizes Idaho Power's analysis, and contends the company failed to consider all possible scenarios. CUB proposes a four-part, Boardman-style analysis that (1) allows potential pollution controls under different scenarios; (2) compares the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigates whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) analyzes whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff voices a concern similar to CUB's regarding Idaho Power's failure to consider a range of early shutdown scenarios. Staff notes that Idaho Power compared the cost of early shutdown and no controls against other alternatives, but did not model a range of early shut-down scenarios, *e.g.*, smaller pollution control investment in exchange for shutdowns at different points in time, which Staff expected would be done. Like CUB, Staff recommends that future coal analysis consider alternative dates for pollution control equipment, shut down, or other alternatives such as gas conversion.

Staff concludes that Idaho Power's analysis is sufficient to comply with the IRP Guidelines, as well as our direction, provided in 2012, to evaluate whether there is flexibility in the emerging environmental regulations that would allow the company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives.

Idaho Power responds that its modeling complies with Guideline 8. Idaho Power notes that it modeled three levels of carbon adders to evaluate the potential impact of carbon emissions regulations in its coal study and in the IRP. In addition, Idaho Power explains it created an alternate portfolio in which the North Valmy units are converted to a gas-fired plant and Jim Bridger Units 3 and 4 are replaced with combined cycle combustion turbines (CCCTs). Idaho Power points out that President Obama's announcement regarding $CO_2$ regulation was issued the same month Idaho Power filed its IRP and that Idaho Power could not account for the announcement without delaying the filing of the 2013 IRP. And, Idaho Power asserts the June 2013 Presidential Memorandum concerned regulations for new power plants and none are included in the company's IRP.

*b. Commission Resolution*

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger Units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger Units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger Units 3 and 4 are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenarios analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of §111(d) of the Clean Air Act.

***2. North Valmy Unit 1***

North Valmy is a coal-fired plant consisting of two generating units located in Nevada. Idaho Power is a 50 percent owner of North Valmy. After adjusting for routine scheduled maintenance and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 220 aMW. Idaho Power plans on the continued operation of North Valmy Unit 1 throughout the 20-year planning period of the 2013 IRP and both units of North Valmy are included in Idaho Power's preferred portfolio.

Idaho Power proposes the following action for North Valmy Unit 1 to comply with federal Mercury Air Toxics Standards (MATS):

*2013* *North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology*

*a. Participants' Comments*

CUB is concerned because Idaho Power's preferred portfolio includes North Valmy with an end-of-life date that CUB fears is too far in the future. CUB notes that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio but that the co-owner of North Valmy, Nevada Energy, has announced plans to close the plant in 2025.

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

Staff recommends acknowledgment of DSI installation. Staff finds that because the cost of the investment is so small, there is no tipping point in the modeled scenarios at which it is more cost-effective to shut down North Valmy rather than invest in DSI.

*b. Commission Resolution*

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***3. Jim Bridger Units 3 and 4***

Jim Bridger is a coal-fired plant consisting of four generating units located in Wyoming. Idaho Power owns one-third of the plant, or 771 MW. The Environmental Protection Agency (EPA) submitted a final rule on January 10, 2014, requiring the installation of selective catalytic reduction emission-control technology (SCR) at Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. Idaho Power's application to the Idaho Public Utilities Commission (IPUC) for a Certificate of Public Convenience

and Necessity states that Idaho Power's cost before AFUDC is estimated to be approximately $118 million.

Idaho Power proposes the following action for Jim Bridger Units 3 and 4:

*2013* — *Jim Bridger Units 3 and 4 – Commit to the installation of selective catalytic reduction emission-control technology*

*a. Participants' Comments*

CUB and RNW recommend that we not acknowledge pollution control investments at Jim Bridger Units 3 and 4, contending additional analysis is needed. Specifically, CUB asserts that Idaho Power should analyze the effect that different early retirement dates would have on the need for pollution controls at Bridger Units 3 and 4 to inform whether the currently planned investment is cost-effective. CUB notes that a shorter life may reduce the controls needed (and therefore costs), making early retirement of coal plants more cost-effective than other options. RNW adds that Idaho Power did not adequately analyze conversion to natural gas or a sufficient range of future $CO_2$ compliance costs. Also, RNW believes that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

Idaho Power disagrees with RNW's and CUB's conclusions regarding its analysis for Bridger Units 3 and 4, noting that it examined a range of options including early shutdown and conversion to natural gas, and that its analysis shows that installation of SCR at Bridger Units 3 and 4 is the least cost option for the majority of the alternate carbon and natural gas scenarios it modeled.

Staff recommends we acknowledge installation of SCR at Bridger Units 3 and 4. Staff concludes that Idaho Power's coal study demonstrates that the SCR investments are the lowest cost compared to the alternatives analyzed under planning case assumptions and in the majority of the carbon and gas sensitivities. In addition to reviewing the coal study, Staff constructed an independent spreadsheet analysis of the impact of a range of gas and carbon prices on the economics of the SCR investments, which confirmed the coal study results.

*b. Commission Resolution*

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger Units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger Units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger Units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp,

the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger Units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

## C. Demand Response

Idaho Power proposes the following near-term action related to demand response:

*2016-2017* *Have demand response capacity available to satisfy deficiencies up to approximately 150 MW*

### *a. Participants' Comments*

Staff notes that both the Oregon and Idaho commissions recently issued orders approving stipulations regarding the redesign of Idaho Power's demand response programs for 2014 and beyond. Those stipulations provide that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW. Therefore, Staff recommends changing this action item to read: "Have demand response capacity available to satisfy deficiencies up to approximately ~~150 MW~~ 170 MW beginning in 2014, and increasing as needed through 2017."

Staff also recommends that the company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors by the end of 2014. In addition, Staff recommends that the Energy Efficiency Advisory Group review any revisions to the resource assessment, along with other relevant factors.

RNW supports Idaho Power's continuation of its demand response program to meet the company's capacity needs.

### *b. Commission Resolution*

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

## D. Long-term Action Items

Idaho Power's Action Plan includes the following long-term activities:

| | |
|---|---|
| *2019* | *Shoshone Falls – Upgrade complete and in service* |
| *2019* | *Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology* |
| *2020* | *Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology* |
| *2020* | *Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end* |
| *2024-2032* | *Demand Response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW* |

### *a. Participants' Comments*

Both Staff and CUB note, and Idaho Power acknowledges, that Idaho Power's Action Plan includes long-term action items in addition to the short-term action items typically presented in an IRP action plan. Staff and CUB recommend that we not acknowledge action items occurring beyond a two-to-four year period. In response, Idaho Power states that it does not seek acknowledgment of the long-term items.

### *b. Commission Resolution*

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs.[7] We generally do not acknowledge action items planned to occur more than four years in the future.[8]

## D. Analysis of IRP

### *1. Wind Resources*

#### *a. Participants' Comments*

Several participants raise concerns related to wind resources. RNW asserts that Idaho Power's IRP underestimates the capacity factor of modern wind turbines and includes an unsupported and unreasonably high wind integration rate.

Staff and RNW raise concerns about Idaho Power's wind integration study (WIS), and the company's use of the technical review committee (TRC) we recommended the

[7] *See* Order No. 12-177.
[8] *Id.*

company form to improve such studies.[9] Staff notes that it anticipated more involvement of the TRC and recommends that Idaho Power engage with the TRC for future IRPs. RNW adds that Idaho Power's WIS based the size of the required balancing reserve on the difference between the day-ahead forecast and actual generation, which increased the assumed balancing reserves and costs. RNW notes that the TRC we required in Order No. 12-177 flagged this methodological assumption as a significant concern. Staff shares RNW's concern, and has reservations about using the study results in future filings.

In response to RNW's concern regarding overstated costs, Idaho Power notes the cost difference between the National Renewable Energy Laboratory (NREL) report and its costs comes from the conversion of 2009 dollars to 2013 dollars, the common base for the IRP's comparison of resource costs. In response to RNW's concern regarding the size of the balancing reserves, Idaho Power states that it chose to base the assumption on the day-ahead forecast because balancing reserves based on the hour-ahead forecast "would too often translate to a risky reliance on the wholesale energy market."

In response to RNW's concern regarding the average capacity factor, Idaho Power asserts that the NREL reports that Class 3 resources have an average capacity factor of 33 percent—a percentage Idaho Power adjusted downward to account for lower capacity factors of Class 2 resources. Idaho Power also asserts that its actual observations support the 26 percent average capacity factor used in the WIS and IRP.

In response to Staff's and RNW's concern regarding the role of the TRC, Idaho Power notes that we directed the company to form the committee in February 2012, nearly a year after the company had begun work on the WIS. Idaho Power announced the formation of the committee at an April 2012 workshop, but by this time the study was complete and the company was presenting preliminary study results.

*b. Commission Resolution*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a

[9] *Id.* at Appendix A at 3.

future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

### 2. *Capacity Contribution of Solar and Other Resources*

#### a. *Participants' Comments*

ODOE recommends certain changes to how Idaho Power examines capacity credits for solar, wind, and hydro resources, and how the company models orientation of flat-plate solar PV systems.

Idaho Power disagrees with ODOE's specific recommendation regarding the capacity contribution, but recognizes that solar resources are unique and that its analysis must address numerous considerations such as tracking systems, resource orientation, and materials. Idaho Power states it seeks to attribute the proper capacity credit to distributed solar PV and has initiated an IRP Advisory Council distributed solar PV workgroup to address the cost and capacity credit of distributed solar PV in the 2015 IRP. Idaho Power states that it anticipates the workgroup will address topics such as panel orientation and tracking systems. Idaho Power also states that it is analyzing integration of large-scale solar PV projects and working on this topic with members of its Solar Integration Study Technical Review Committee.

#### b. *Commission Resolution*

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

### 3. *Gas Price Forecasts*

#### a. *Participants' Comments*

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

#### b. *Commission Resolution*

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

### 4. *Flexibility Guideline*

In our investigation of matters related to electric vehicle charging, we adopted our Staff's recommendation to add an IRP guideline to require utilities to incorporate planning for flexible capacity in IRPs.[10] Utilities must forecast the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation over the 20-year planning period and to forecast the availability of balancing reserves at different time intervals. In planning to fill any gap between the demand and supply of flexible capacity, utilities must also evaluate all resource options on a consistent and comparable basis.

#### *a. Participants' Comments*

RNP asserts that Idaho Power's IRP does not comply with the IRP Guidelines because it does not forecast the demand for and supply of flexible capacity, or evaluate flexible resources on a consistent and comparable basis. RNW suggests that future IRPs should quantify the existing supply of flexible resources across multiple time scales, quantify the amount of reserves associated with each supply-side resource, and expand types of demand for flexible resources, *e.g.*, need to meet hourly ramps of load and other variable resources.

Idaho Power responds that its 2013 IRP did, in fact, include much of the flexibility analysis that RNW asserts is lacking. Idaho Power notes that a pumped storage hydro project was modeled as a resource alternative and as a tool to assist in the integration of wind resources. Idaho Power asserts that this modeling captured the flexibility and peaking capacity of the pumped storage hydro project and helped to integrate the variable wind generation into the system, and captured market arbitrage opportunities.

Staff recognizes that the company provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNW that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

#### *b. Commission Resolution*

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

[10] Order No. 12-013 at16-18.

### 5. *Conservation Voltage Reduction*

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.[11]

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP.

In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report.[12] Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

### 6. *Energy Efficiency*

Although Idaho Power's IRP contains specific energy efficiency targets as part of its plan, the company does not include those amounts in the Action Plan. Staff proposes two action items to address energy efficiency:

| | | |
|---|---|---|
| *2013-2017* | *Energy Efficiency* | *The forecast reduction for 2013 to 2017 programs will be 69 aMW* |
| *2013-2017* | *Energy Efficiency* | *The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW* |

We adopt Staff's proposed additions to the Action Plan.

### 7. *NEEA*

Idaho Power plans to curtail funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Idaho Power explains that it has asked NEEA to operate under an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of activities that Idaho Power believes are most valuable to its customers. Idaho Power supports the concept of optional programs in NEEA's 2015-2019 Business Plan in which funders could choose to participate and fund certain programs or opt out of them altogether.

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[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

*a. Participants' Comments*

CUB and Staff are concerned with Idaho Power's proposal to curtail funding to NEAA. Staff believes that NEAA is one of Idaho Power's most cost effective energy investments. Staff notes that NEEA is a compact between over 100 Northwest utilities and efficiency organizations that creates value for its supporters by broad market intervention and energy efficiency market development. NEEA's activities have resulted in the development of an energy efficiency products and practices pipeline to the region that benefits Idaho Power's and the region's ratepayers.

*b. Commission Resolution:*

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

## D. Recommendations For Idaho Power's 2015 IRP

In Order No. 12-177, we reminded Idaho Power that IRP Guideline 4(n) requires utilities to include in an IRP action plan the resource activities the utility plans to undertake over the next two to four years to acquire the identified resources. We also recommended that Idaho Power's future IRPs include a "concise listing of action items for all resources and resource related activities, with each action item numbered."[13]

Idaho Power did include an action plan with resource activities it plans to take in the next two to four years, but the plan also includes longer-term actions. We clarify that, in future IRPs, Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years. Idaho Power may compile other lists of activities planned for an extended period, as it has done in this IRP, but we recommend the company create and identify the action plan activities for which it requests specific acknowledgment. Again, we recommend that the company number each of these action items to facilitate our review.

## E. IRP Update

Staff sought delays in these proceedings to facilitate our review of resource action items presented for acknowledgment in both PacifiCorp's IRP and Idaho Power's IRP.

[13] Order No. 12-177 at 8.

As a result of this delay, Idaho Power's annual update to its 2013 IRP, which is due no later than 12 months after acknowledgment. However, Idaho Power must file its 2015 IRP with the Idaho Public Utilities Commission no later than June 2015. Idaho Power intends to file an IRP in Oregon at the same time it files in Idaho.

Given that Idaho Power will file its next IRP with the Idaho commission by June 2015, we waive the requirement that Idaho Power file an annual update to this IRP. This waiver addresses only a routine IRP update, and we expect Idaho Power to file an IRP update if it anticipates a significant deviation from its acknowledged 2013 IRP in the manner required by IRP Guideline 3(f).

## V. ORDER

IT IS ORDERED that the 2013 Integrated Resource Plan filed by Idaho Power Company is acknowledged in part consistent with the terms of this order.

Made, entered, and effective JUL 08 2014.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

# Appendix A

**Acknowledged Action Plan Items**

| Year | Resource - Action |
|---|---|
| 2013- 2018 | Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | Gateway West – Ongoing permitting, planning studies, and regulatory filings |
| 2013 | North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology |
| 2016-2017 | Have demand response capacity available to satisfy deficiencies up to approximately 170 MW beginning in 2014, and increasing as needed through 2017 |
| 2013-2017 | Energy efficiency – The forecast reduction for 2013 to 2017 programs will be 69 aMW |
| 2013-2017 | The incremental energy efficiency savings for 2013-2017 will reduce energy loads by 38 aMW |
| 2013-2015 | CVR – Include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in service area and an action item related to this resource in the next IRP. Incorporate the planned energy savings and reduced peak demand into load-resource balance forecasts. |

# ATTACHMENT N-8
# ORDER NO. 16-160 IN DOCKET LC 63

ORDER NO. 16 160

ENTERED: APR 28 2016

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 63

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY,<br><br>2015 Integrated Resource Plan. | ORDER |

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED AS REVISED

This order memorializes our decision made at the March 24, 2016 Special Public Meeting regarding Idaho Power Company's 2015 Integrated Resource Plan (IRP). At the meeting, we adopted Commission Staff's recommendation to acknowledge Idaho Power's 2015 IRP, as revised by Staff's presentation during the meeting. As we stated at the close of the meeting, our decision to not acknowledge certain action items was based on procedural reasons rather than the merits of the action items.

The Staff Report with its initial recommendation is attached as Appendix A. During the public meeting, Staff made the following revisions to this initial recommendation:

*Action Items 5, 7, 10, and 12* – Staff recommends that we not acknowledge these items. Staff explains that these actions are better suited for evaluation in a general rate case as they relate to a facility upgrade that no longer is forecast to meet any resource need.

*Action Items 6 and 8* – Staff recommends that we not acknowledge these items. Staff recommends that we wait and review these actions in a general rate case as they relate to installation of emission-control technology that is already completed or is significantly underway.

*Action Item 11* – Staff recommends that we not acknowledge this item. Staff reasons that the act of evaluating installing emission-control technology is outside the usual scope of IRP acknowledgement and suggests we wait and address the outcome of the evaluation (rather than the decision itself to evaluate).

For the convenience of the parties, we attach, as Appendix B, a list summarizing all of the action items and our decision as to each item.

## ORDER

IT IS ORDERED that the 2015 Integrated Resource Plan, filed by Idaho Power Company, is acknowledged consistent with the terms of this order and the attached Appendices A & B.

Dated this 28 day of April, 2016, at Salem, Oregon.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

ORDER NO. 16 160

**ITEM NO.1**

**PUBLIC UTILITY COMMISSION OF OREGON**
**STAFF REPORT**
**PUBLIC MEETING DATE: March 24, 2016**

**REGULAR** X **CONSENT** ____ **EFFECTIVE DATE** **Upon Commission's Approval**

**DATE:** March 8, 2016

**TO:** Public Utility Commission

**FROM:** Michael Breish MB

**THROUGH:** Jason Eisdorfer and Aster Adams

**SUBJECT:** IDAHO POWER COMPANY: (Docket No. LC 63) Acknowledgement of the 2015 Integrated Resource Plan.

**STAFF RECOMMENDATION:**

Staff recommends the Commission acknowledge Idaho Power Company's (Idaho Power or Company) 2015 Integrated Resource Plan (IRP) with certain recommendations.

**DISCUSSION:**

**Procedural History**

Idaho Power filed its 2015 IRP on June 30, 2015. The Company's filing included the IRP and three appendices.[1] Gail Carbiener, a member of the public, filed initial comments on October 22, 2015. Commission Staff (Staff) and the Citizen's Utility Board (CUB) filed initial comments on November 25, 2015. Idaho Power filed reply comments on December 30, 2015. Mr. Carbiener filed his final comments on January 8, 2016, and CUB and Staff filed final comments on January 22, 2016. Idaho Power filed final reply comments on February 19, 2016.

Idaho Power held 12 IRP Advisory Council (IRPAC) meetings leading up to the submission of the 2015 IRP. IRPAC members represent various public agencies, public and private enterprises, and advocacy groups. The IRPAC covers aspects of the IRP development, particularly on the resource stack, resource portfolio considerations and

[1] The appendices are the "Sales and Load Forecast," the "DSM Annual Report," and the "Technical Report."

risk analyses. The IRPAC played an integral role this year in discussing matters related to the Environmental Protection Agency Clean Power Plan (CPP), promulgated pursuant to the Clean Air Act, Section 111(d) (Section 111(d)), as well as distributed energy resource integration. Staff appreciated the open and involved stakeholder process that Idaho Power dedicates time and energy into in order to fulfill the public input component of the Company's IRP process.

Staff discusses the comments by the parties and the Company, referencing the near-term action plan, long-term planning aspects of the preferred portfolio, and other IRP issues. The original IRP action plan is set forth in Attachment A to this memo.

**General Description of the IRP**

Idaho Power's IRP presents an analysis that considers costs, risks, and uncertainties of various resource portfolios designed to sufficiently satisfy system load, reliability, and flexibility needs over the next 20 years. Idaho Power analyzed 23 resource portfolios under seven different CPP scenarios as well as three variables in a stochastic analysis.[2] Not only was this a significant increase in the number of portfolios provided with previous IRPs, but the diversity of resource considerations within those portfolios increased as well.

Of critical importance in the 2015 IRP are the fates of Idaho Power's two remaining coal-fired generating plants, North Valmy located in Nevada and Jim Bridger located in Wyoming. Because Idaho Power's 2015 IRP was published at the time of only the draft Section 111(d) rules, Idaho Power's analysis reflects the Company's best assumption of what the final Section 111(d) rule may be. Staff addresses final Section 111(d) considerations later in this report.

With a peak-hour capacity deficit first occurring in 2025 under the Company's preferred portfolio, the 2015 IRP action plan features no additional planned generation. Beyond the ongoing processes related to the Boardman-to-Hemingway (B2H) and Gateway West transmission lines, the only significant actions in the 2015 IRP Action Plan relate to completion and consideration of emissions technology on Jim Bridger units and an upgrade of the Shoshone Falls generation station.

**Compliance with Commission IRP Guidelines**

In its Final Comments, Staff asserted that Idaho Power was not compliant with IRP Guidelines 1 and 12 due to aspects of the Company's residential and commercial solar photovoltaic (PV) resource consideration and calculation. Staff believed that Idaho

[2] These three variables were natural gas prices, customer load, and hydroelectric variability.

Power's inclusion of the fixed costs of a customer-owned and financed resource in the Company's supply-side resource stack was inconsistent with Guideline 1. Guideline 1, part 1, states that "all resources must be evaluated on a consistent and comparable basis." Staff found that since the fixed costs of a residential or commercial solar PV system are not directly borne by the Company unlike other supply-side resources, the results "are inherently inconsistent and incomparable and do not reflect the realities of customer-owned resources."[3] Because of this inconsistency in fixed costs burden, Staff concluded that Idaho Power did not comply with Guideline 12, which states that "electric utilities should evaluate distributed generation technologies on par with other supply-side resources...." Staff further concluded in its Final Comments that it "does not want to punish but rather create an opportunity to determine a more realistic analysis of this new class of supply-side resource."[4]

In its Final Comments, the Company disagreed with Staff's assertions, building on its response made in its Reply Comments. There, Idaho Power argued that "the inclusion of capital costs associated with resource construction is consistent with the treatment for other resources considered in the IRP, thus allowing meaningful cost comparisons between resources."[5] Additionally, Idaho Power stated that excluding a supply-side resource's fixed costs would "lead to uneconomic resource procurement and inefficient deployment of capital on the part of Idaho Power and its customers."[6]

Idaho Power expanded on these points in its Final Comments. There the Company explained that its methodology is predicated on the flow of both costs and benefits to all customers. Idaho Power believes this approach to be reasonable, in part because, though the Company does not directly incur the fixed costs, the customer who owns the PV system will eventually recover its fixed cost investment. Furthermore, the analysis of distributed solar PV's total resource cost, which the Company utilizes for all resources including energy efficiency, enables reasonable comparisons of resources' respective values. Therefore, the Company's approach is consistent with the treatment of other resources.

Staff appreciates Idaho Power's effort in addressing its concerns regarding the consideration of distributed solar PV systems. Idaho Power indicates it is open to exploring the possibility of modeling refinements in its 2017 IRP.[7] Staff appreciates this because additional opportunities for incorporating distributed PV solar system benefits exist. Staff believes that once the resource value of solar is established in

[3] Staff's Final Comments, at page 1, Docket No. LC 63, January 22, 2016.
[4] Ibid., at page 2.
[5] Idaho Power's Reply Comments, at page 19, Docket No. LC 63, December 30, 2015.
[6] Ibid.
[7] Idaho Power's Final Comments, at page 7, Docket No. LC 63, February 19, 2016.

Docket No. UM 1716, the conversation regarding different approaches to modeling distributed solar PV resources at the IRPAC will be appropriate.

Staff also asserted in its Final Comments that Idaho Power was noncompliant with Guideline 4, part I, which states that a utility's IRP must select "a portfolio that represents the best combination of cost and risk for the utility and its customers."[8] Idaho Power's selection of preferred portfolio P6(b) is neither least-cost nor least-risk. However, the Company states that consideration of qualitative risks results in the Company selecting P6(b) as the preferred portfolio.

As Staff discusses later in this memo, without a comprehensive and balanced assessment of every portfolio's qualitative risks, Staff cannot make an informed determination on whether a particular portfolio is least-cost, least-risk when qualitative risks are a deciding factor. Though Idaho Power is correct in pointing out that the Commission only acknowledges a utility's Action Plan, Staff notes that a short-term Action Plan is ultimately derived from a resource plan that achieves long-run cost-risk optimality.[9] Therefore, concerns regarding mid-term and long-term action items should not be dismissed.

| Staff is satisfied that the Company has adequately met the IRP guidelines. |
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**Compliance with Previous IRP Order No. 14-253**

In issuing Order No. 14-253, the Commission accepted Idaho Power's 2013 IRP with several directives and recommendations. These are listed below along with Staff's conclusions about Idaho Power's respective compliance.

Pollution Control Investments in Coal Resources

The Commission directed Idaho Power "to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements §111(d) of the Clean Air Act."[10] Staff finds that Idaho Power satisfied the first component of this directive by holding an inclusive and engaging stakeholder process (i.e. the IRP Advisory Council). Idaho Power presented the considerations and analyses of the Company's Coal Study Working Group at the

[8] Commission Order No. 07-002, Appendix A, at page 5, Docket No. UM 10, January 8, 2007.
[9] Commission Order No. 14-253, at page 12, Docket No. LC 58, July 8, 2014.
[10] Ibid., at page 8.

September 2014 IRPAC meeting. Additionally, Idaho Power welcomed and incorporated coal plant retirement date suggestions from IRPAC members.

Staff also finds that Idaho Power satisfied the second component of this directive. To address uncertainty surrounding Section 111(d) and the joint ownership of Idaho Power's coal plants, Idaho Power analyzed 23 portfolios that contain various retirement dates for those facilities. Additionally, Idaho Power conducted a Section 111(d) sensitivity on the 23 resource portfolios that consisted of seven different scenarios split into mass-based or rate-based. However, these analyses were conducted prior to the finalization of Section 111(d) rules. Due to this temporal issue, Staff will recommend additional analyses in Idaho Power's 2015 IRP update.

Gas Price Forecasts

Though not an explicit directive, Staff mentions the Commission's expectation that Idaho Power would address stakeholders' concerns regarding three aspects of the Company's natural gas price forecast.[11] Staff finds that Idaho Power sufficiently addressed the concerns by utilizing Energy Information Administration data for high and low cases as well as the nominal forecast prices. The Company also verified that the implied heat rate, which verifies the relationship between natural gas prices and wholesale electricity prices, aligns with the historical correlation.[12]

Conservation Voltage Reduction (CVR)

Idaho Power was directed to include a CVR assessment in the 2015 IRP after failing to do so in the 2013 IRP. CVR efforts currently progressing at Idaho Power under the "CVR Enhancements Project" should be completed by 2016. Through its *2014 and 2015 Smart Grid Reports*, the Company has kept Staff and the Commission abreast of the renewed evaluation and possible integration of CVR into distribution system operations.

Idaho Power did not include a CVR assessment due to the ongoing nature of the project, but did include a description of the current project on page 48 of the IRP. Staff recommends the Commission delay action on CVR until Staff has been able to review the Company's analysis in the CVR Enhancements Project report to be filed September 1, 2016.

[11] The three issues were " the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration's reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. "*See* Commission Order No. 14-253, at page 14, Docket No. LC 58, July 8, 2014.
[12] Idaho Power's 2015 IRP, Appendix C, at page 215, Docket No. LC 63, June 30, 2015.

Action Plan Limits

The Commission stated that Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years as well as enumerate them for ease of analysis. Idaho Power has done so.

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| Staff is satisfied that the Company has adequately addressed all of the Commission's directives set forth in Order 14-253. |

**Action Item Discussion**

The Company offered the following Action Items for the time period 2015-2019.

Action Item #1 – B2H Transmission Line

*Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.*

Mr. Carbiener expressed concerns about the increasing costs of the B2H line as well as the Company's presentation of the viability of portfolios that do not contain B2H. Additionally, Mr. Carbiener discussed how a tipping point analysis of the costs of B2H would be helpful in considering alternative resources.

Staff notes that the Commission acknowledged the same actions for B2H in Order No. 14-253.[13]

The only major development to occur since the 2014 IRP is the Bureau of Land Management's (BLM) issuance of the draft Environmental Impact Statement (EIS), which includes the agency's initial analysis on the proposed and alternate routes of the B2H line.[14] Idaho Power expects the BLM to issue a final EIS in 2016.

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| Staff recommends acknowledgment of Action Item #1. |

[13] Ibid., at page 5.
[14] BLM's *Draft Environmental Impact Statement and Land Use Plan Amendments for the Boardman to Hemingway Transmission Line Project, DOI-BLM-OR-V000-2012-016-EIS,* December 19, 2014.

Action Item #2 – Gateway West Transmission Line

*Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.*

No parties commented on this Action Item.

Staff notes that the Commission acknowledged the same actions for B2H in Order No. 14-253.[15]

Staff recommends acknowledgment of Action Item #2.

Action Item #3 – Energy Efficiency

*Idaho Power will continue the pursuit of cost-effective energy efficiency – the forecast reduction for the 2015-2019 programs is 84 average megawatts (MW) for energy demand and 126 MW for peak demand*

CUB expressed concern that Idaho Power is underestimating the forecasted achievable energy efficiency potential that the Company can acquire. At the core of CUB's concern was Idaho Power's pursuit of achievable, cost-effective energy efficiency, which the Company historically has exceeded annually. CUB believes opportunities exist for Idaho Power to meet more of its projected load growth through energy efficiency, including offering more programs, increasing the Company's energy efficiency marketing, and implementing a "more aggressive (energy efficiency) policy."[16] Staff highlights the fact that Idaho Power's energy efficiency target for the five year period from 2015 to 2019 is 22 percent higher than the five-year window in the 2013 IRP.

Staff recommends acknowledgment of Action Item #3.

Action Item #4 – Section 111(d)

*Idaho Power will coordinate with government agencies on implementation planning for Section 111(d).*

[15] Ibid., at page 6.
[16] CUB's Initial Comments, at page 7, Docket No. LC 63, November 25' 2015.

Staff analyzed and discussed the results of Idaho Power's Section 111(d) sensitivity analyses in its Initial and Reply Comments. Because the 2015 IRP was published prior to the release of the final Section 111(d) rules, Staff expects Idaho Power will continue to work with the co-owners of the North Valmy and Jim Bridger Coal-fired generation stations as states develop Section 111(d) compliance plans.

Staff recommends acknowledgment of Action Item #4, and proposes the following additional recommendations:

- Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path.
- Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.

Action Item #5 – Shoshone Falls License Amendment

*Idaho Power will file to amend the FERC license regarding the 50-MW expansion.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #5.

Action Item #6 – Jim Bridger Unit 3

*Idaho Power will complete the installation of selective catalytic reduction (SCR) emission-control technology.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #6.

Action Item #7 – Shoshone Falls Upgrades Study

*Idaho Power will study options for smaller upgrades ranging in size up to approximately 4 MW.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #7.

Action Item #8 – Jim Bridger Unit 4

*Idaho Power will complete installation of SCR emission-control technology.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #8.

Action Item #9 – North Valmy Units 1 and 2

*Idaho Power will continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations.*

Mr. Carbiener suggested Idaho Power include additional portfolios that mirror Nevada Power's 2013 IRP 2021 modeled shut down date for North Valmy.

Staff raised concerns regarding the forecasted shut down dates of the North Valmy plant in the Company's preferred portfolio compared to other portfolios that have lower cost and risk. However, all shut down dates considered in Idaho Power's resource portfolios occur beyond the four-year window of the 2015 IRP, so Staff discusses this matter further below.

Staff recommends acknowledgment of Action Item #9.

Action Item #10 – Shoshone Falls 2017 Upgrade

*Idaho Power will commence construction of a smaller upgrade.*

Idaho Power in its Final Comments provided clarifying and additional information regarding the planned upgrades and maintenance of the Shoshone Falls facility that

enables Staff to retract its initial recommendation of non-acknowledgement. The upgrade of the Shoshone Falls facility is necessary for continued reliable operations.[17]

| Staff recommends acknowledgment of Action Item #10. |
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Action Item #11 – Jim Bridger Units 1 and 2

*Idaho Power will evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP.*

Staff noted in its Final Comments that when Idaho Power models Section 111(d) compliance paths, it should fully consider Jim Bridger scenarios that are informed by considerations and possible decisions of the co-owner PacifiCorp. Staff addresses matters related to Jim Bridger in recommendations made under Action Item #4.

| Staff recommends acknowledgment of Action Item #11. |
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Action Item # 12 – Shoshone Falls 2019 On-Line Date

*Idaho Power will place the smaller upgrade on-line.*

Similar to Action Item #10, Staff initially recommended non-acknowledgement of this Action Item in its Final Comments. However, Idaho Power provided clarifying information that led Staff to retract that recommendation.

| Staff recommends acknowledgment of Action Item #12. |
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**Other Issues**

Selection of Preferred Portfolio

Staff and CUB challenged Idaho Power's selection of portfolio P6(b) as the Company's preferred portfolio due to the its higher cost, higher risk, and higher Section 111(d) compliance cost compared to alternative resource portfolios. The Company responded

[17] Idaho Power's Final Comments, at page 7, Docket No. LC 63, February 19, 2016.

that in addition to the relatively small differences in cost for the portfolios that Staff and CUB contended were quantitatively supported, portfolio P6(b) minimized qualitative risks.

Idaho Power also correctly identified that the Commission in its review of a utility's IRP will only consider items set forth in the utility's short-term Action Plan.[18] The portfolios that Staff and CUB argued were more appropriate choices share the same four-year Action Plan as the Company's preferred portfolio. From this, the Company argues the Commission should acknowledge the Company's IRP.

Staff reiterates its observation made in its Final Comments: an Action Plan is only justified by the long-term resource plan. Despite similar or even identical Action Plans, they are otherwise irrelevant if not considered in the broader context of a cost-risk optimal long-term resource plan.

Staff agrees with Idaho Power's position that the Commission should acknowledge Idaho Power's 2015 IRP Action Plan.

Qualitative Risk Analysis

Both CUB and Staff raised concerns over the Company's reliance on qualitative risks to support the selection of portfolio P6(b) as the preferred portfolio despite four lower-cost, lower-risk alternatives. In particular, Staff raised concerns regarding the Section 111(d), "regulatory" resource commitment, PURPA, and DSM implementation qualitative risks. Though Idaho Power further clarified some of Staff's concerns in its Reply Comments, Staff believes that some of these lower-cost, lower-risk portfolios also afford the same qualitative risk benefits the Company attributes to preferred portfolio P6(b). Because of the lack of comprehensive evaluation of qualitative risks of all other portfolios besides the preferred portfolio, Staff recommends Idaho Power pursue a systematic evaluation of all portfolios' qualitative risks. This evaluation must be balanced and consistent in its comparisons in order to support future preferred portfolios. Despite this concern, Staff appreciates Idaho Power's broader assessment in assessing qualitative risks.

| Staff recommends Idaho Power include a more systematic evaluation of the qualitative benefits of the resource portfolios in the 2017 IRP. |
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[18] Commission Order No. 14-253, at page 12, Docket No. LC 58, July 8, 2014.

2015 IRP Update Waiver

In its final comments, Staff recommended that Idaho Power provide updated Section 111(d) and existing coal unit considerations in the 2015 IRP Update. Idaho Power replied in its Final Comments that, though it plans to comply with Staff's recommendations regarding additional analyses, doing so in the 2015 IRP Update would be inefficient. The Company notes that the 2017 IRP is due only three months after the planned 2015 IRP Update filing. Because the analyses requested by Staff are substantial and therefore more suited for a complete IRP cycle rather than an IRP Update, Idaho Power recommends the Commission waive its obligation to file a 2015 IRP Update.

| |
|---|
| Staff agrees and recommends the Commission waive Idaho Power's obligation to file a 2015 IRP Update. |

**PROPOSED COMMISSION MOTION:**

Idaho Power's 2015 IRP be acknowledged with the following recommendations by Staff as contained in this report and summarized in Attachment A to this report.

## ATTACHMENT A

| Action Item | Description | Staff Recommendation |
|---|---|---|
| 1 | B2H – ongoing permitting, planning studies, and regulatory filings | Acknowledge |
| 2 | Gateway West – ongoing permitting, planning studies, and regulatory filings | Acknowledge |
| 3 | Pursuit of cost-effective energy efficiency | Acknowledge |
| 4 | Implementation planning for Section 111(d) | Acknowledge with Recommendations |
| 5 | Shoshone Falls license amendment | Acknowledge |
| 6 | Jim Bridger 3 – Complete SCR installation | Acknowledge |
| 7 | Shoshone Falls upgrade study | Acknowledge |
| 8 | Jim Bridger 4 – Complete SCR installation | Acknowledge |
| 9 | North Valmy – NV Energy collaboration | Acknowledge |
| 10 | Shoshone Falls 2017 upgrade | Acknowledge |
| 11 | Jim Bridger 1 & 2 – SCR evaluation | Acknowledge |
| 12 | Shoshone Falls 2019 on-line date | Acknowledge |

**Recommendations**

In addition to acknowledgement of the Action Plan items, Staff recommends that the Commission direct the Company to:

- Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path in the 2017 IRP.
- Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.
- Include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyzes in the 2017 IRP.

APPENDIX B

## 1. Action Items

| Action Item | Resource | Description | Disposition |
|---|---|---|---|
| 1 | B2H Transmission | Ongoing permitting, planning studies, and regulatory filings | ***Acknowledged*** |
| 2 | Gateway West Transmission | Ongoing permitting, planning studies, and regulatory filings | ***Acknowledged*** |
| 3 | Energy Efficiency | Continue the pursuit of cost-effective energy efficiency | ***Acknowledged*** |
| 4 | N/A | Coordinate with government agencies on implementation planning for Clean Air Act Section 111(d) | ***Acknowledged*** |
| 5 | Shoshone Falls Hydro | File to amend FERC license regarding 50-MW expansion | Not Acknowledged |
| 6 | Jim Bridger Unit 3 | Complete installation of selective catalytic reduction (SCR) emission-control technology | Not Acknowledged |
| 7 | Shoshone Falls Hydro | Study options for a smaller upgrade ranging in size up to approximately 4 MW | Not Acknowledged |
| 8 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | Not Acknowledged |
| 9 | North Valmy Units 1 & 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | ***Acknowledged*** |
| 10 | Shoshone Falls Hydro | Commence construction of smaller upgrade | Not Acknowledged |
| 11 | Jim Bridger Units 1 & 2 | Evaluate the installation of SCR technology in the 2017 IRP | Not Acknowledged |
| 12 | Shoshone Falls Hydro | On-line date for smaller upgrade during first quarter of 2019 | Not Acknowledged |

## 2. Recommendations

a. Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path in the 2017 IRP.
b. Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.
c. Include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyzes in the company's 2017 IRP.

# ATTACHMENT N-9
# ANNUAL CAPACITY FACTORS

Exhibit N 3.3.6 Table
Idaho Power - Power Supply
T Noll May 2012

**Annual Capacity Factors**

| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|---|---|
| Hydro Nameplate Capacity (MW)[1] | 1,709 | 1,709 | 1,709 | 1,709 | 1,709 | 1,709 | 1,758 |
| Annual Hydro Forecast (aMW) at 50th Percentile Water | 982.3 | 982.1 | 981.3 | 977.4 | 974.9 | 972.0 | 987.2 |
| Hydro Annual Capacity factor at 90th Percentile Water | **0.57** | **0.57** | **0.57** | **0.57** | **0.57** | **0.57** | **0.56** |
| Annual Hydro Forecast (aMW) at 70th Percentile Water | 807.8 | 806.7 | 805.8 | 800.2 | 795.4 | 792.3 | 793.9 |
| Hydro Annual Capacity factor at 70th Percentile Water | **0.47** | **0.47** | **0.47** | **0.47** | **0.47** | **0.46** | **0.45** |
| Annual Hydro Forecast (aMW) at 90th Percentile Water | 681.9 | 681.2 | 680.4 | 676.9 | 673.3 | 665.0 | 661.9 |
| Hydro Annual Capacity factor at 90th Percentile Water | **0.40** | **0.40** | **0.40** | **0.40** | **0.39** | **0.39** | **0.38** |
| Total Coal Annual Forecast (aMW) | 879.3 | 891.6 | 867.0 | 879.5 | 870.3 | 900.6 | 908.0 |
| Total Coal Nameplate Capacity (MW) [2] [3] | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 |
| Coal Annual Capacity Factor | **0.79** | **0.80** | **0.78** | **0.79** | **0.78** | **0.81** | **0.81** |
| Total CCCT Annual Forecast (aMW) | 0.0 | 125.5 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 |
| Total CCCT Nameplate Capacity (MW) [4],[5] | 0.0 | 150.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 |
| CCCT Annual Capacity Factor | **0.00** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** |
| Total SCCT Annual Forecast (aMW) | 96.8 | 96.1 | 96.8 | 96.8 | 97.6 | 96.8 | 96.1 |
| Total SCCT Nameplate Capacity (MW) [6] | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 |
| SCCT Annual Capacity Factor | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** |

[1] Shoshone Falls upgrade assumed to be operational in 2017

[2] Boardman coal plant assumed to be decommissioned after 2020

[3] Coal nameplate capacity assumes Idaho Power share

[4] Langley Gulch nameplate capacity assumed to be 300 MW

[5] Additional 300 MW CCCT assumed to be operational in 2025

[6] Two additional 170 MW SCCT units assumed to be operational, one in 2022 and the second in 2029

Construction Notes (not for publication)

Existing Nameplate Capacity from 2011 IRP page 27

Hydro forecast values from 2011 IRP Technical Appendix, pages 96 through 125

Coal, CCCT, SCCT forrecast values from 2011 IRP Technical Appendix

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 |
| 982.6 | 979.0 | 976.6 | 975.1 | 973.9 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 |
| **0.56** | **0.56** | **0.56** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** |
| 788.8 | 784.8 | 781.5 | 778.9 | 777.6 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 |
| **0.45** | **0.45** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** |
| 657.9 | 655.1 | 653.2 | 651.8 | 650.3 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 |
| **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** |
| 913.7 | 917.0 | 918.6 | 867.1 | 863.0 | 866.4 | 867.8 | 867.1 | 863.0 | 866.4 | 867.8 | 867.1 | 863.0 |
| 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 |
| **0.82** | **0.82** | **0.82** | **0.78** | **0.81** | **0.82** | **0.82** | **0.82** | **0.81** | **0.82** | **0.82** | **0.82** | **0.81** |
| 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 397.4 | 502.0 | 502.0 | 502.0 | 502.0 | 502.0 |
| 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 600.0 | 600.0 | 600.0 | 600.0 | 600.0 | 600.0 |
| **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.66** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** |
| 96.8 | 96.8 | 97.6 | 97.6 | 121.6 | 120.9 | 120.8 | 120.8 | 121.6 | 121.6 | 120.1 | 144.9 | 144.9 |
| 443.7 | 443.7 | 443.7 | 443.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 783.7 | 783.7 |
| **0.22** | **0.22** | **0.22** | **0.22** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.18** | **0.18** |

Data from 2011 06 01 Load and resource Balance for Appendix C.xlsx

| Year | Month | Date | Coal | Langley | NewCCCT | CCCT | Peakers | NewSCCT1 | NewSCCT2 | SCCT |
|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | 1 | 1/1/2011 | 933.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2011 | 2 | 2/1/2011 | 933.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 3 | 3/1/2011 | 863.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 4 | 4/1/2011 | 669.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 5 | 5/1/2011 | 646.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 6 | 6/1/2011 | 913.7 | 0.0 | 0.0 | 0.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2011 | 7 | 7/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2011 | 8 | 8/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2011 | 9 | 9/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 10 | 10/1/2011 | 931.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 11 | 11/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 12 | 12/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2012 | 1 | 1/1/2012 | 932.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2012 | 2 | 2/1/2012 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 3 | 3/1/2012 | 885.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 4 | 4/1/2012 | 775.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 5 | 5/1/2012 | 734.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 6 | 6/1/2012 | 851.4 | 0.0 | 0.0 | 0.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2012 | 7 | 7/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2012 | 8 | 8/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2012 | 9 | 9/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 10 | 10/1/2012 | 930.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 11 | 11/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 12 | 12/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2013 | 1 | 1/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2013 | 2 | 2/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 3 | 3/1/2013 | 852.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 4 | 4/1/2013 | 558.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 5 | 5/1/2013 | 612.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 6 | 6/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 7 | 7/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2013 | 8 | 8/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2013 | 9 | 9/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 10 | 10/1/2013 | 930.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 11 | 11/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 12 | 12/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2014 | 1 | 1/1/2014 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 2 | 2/1/2014 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 3 | 3/1/2014 | 879.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 4 | 4/1/2014 | 584.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 5 | 5/1/2014 | 721.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 6 | 6/1/2014 | 920.5 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |
| 2014 | 7 | 7/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 8 | 8/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 9 | 9/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 10 | 10/1/2014 | 929.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 11 | 11/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 12 | 12/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 1 | 1/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 2 | 2/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 3 | 3/1/2015 | 834.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 4 | 4/1/2015 | 634.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 5 | 5/1/2015 | 714.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 6 | 6/1/2015 | 814.4 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2015 | 7 | 7/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 8 | 8/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 9 | 9/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 10 | 10/1/2015 | 929.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 11 | 11/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 12 | 12/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2016 | 1 | 1/1/2016 | 931.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2016 | 2 | 2/1/2016 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 3 | 3/1/2016 | 898.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 4 | 4/1/2016 | 823.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | 5 | 5/1/2016 | 715.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 6 | 6/1/2016 | 887.8 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2016 | 7 | 7/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2016 | 8 | 8/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2016 | 9 | 9/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 10 | 10/1/2016 | 935.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 11 | 11/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 12 | 12/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2017 | 1 | 1/1/2017 | 937.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2017 | 2 | 2/1/2017 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 3 | 3/1/2017 | 904.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 4 | 4/1/2017 | 840.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 5 | 5/1/2017 | 704.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 6 | 6/1/2017 | 915.6 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2017 | 7 | 7/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2017 | 8 | 8/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2017 | 9 | 9/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 10 | 10/1/2017 | 941.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 11 | 11/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 12 | 12/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2018 | 1 | 1/1/2018 | 943.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2018 | 2 | 2/1/2018 | 947.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 3 | 3/1/2018 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 4 | 4/1/2018 | 841.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 5 | 5/1/2018 | 726.3 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 6 | 6/1/2018 | 899.6 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2018 | 7 | 7/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2018 | 8 | 8/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2018 | 9 | 9/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 10 | 10/1/2018 | 942.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 11 | 11/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 12 | 12/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2019 | 1 | 1/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2019 | 2 | 2/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2019 | 3 | 3/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 4 | 4/1/2019 | 842.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 5 | 5/1/2019 | 727.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 6 | 6/1/2019 | 900.8 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |
| 2019 | 7 | 7/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2019 | 8 | 8/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2019 | 9 | 9/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 10 | 10/1/2019 | 948.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 11 | 11/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 12 | 12/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2020 | 1 | 1/1/2020 | 944.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 2 | 2/1/2020 | 946.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 3 | 3/1/2020 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 4 | 4/1/2020 | 838.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 5 | 5/1/2020 | 729.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 6 | 6/1/2020 | 896.2 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2020 | 7 | 7/1/2020 | 954.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 8 | 8/1/2020 | 955.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 9 | 9/1/2020 | 948.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 10 | 10/1/2020 | 956.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 11 | 11/1/2020 | 950.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 12 | 12/1/2020 | 959.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2021 | 1 | 1/1/2021 | 888.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2021 | 2 | 2/1/2021 | 880.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 3 | 3/1/2021 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 4 | 4/1/2021 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 5 | 5/1/2021 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 6 | 6/1/2021 | 840.7 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2021 | 7 | 7/1/2021 | 898.7 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2021 | 8 | 8/1/2021 | 899.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2021 | 9 | 9/1/2021 | 893.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 10 | 10/1/2021 | 900.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 11 | 11/1/2021 | 895.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 12 | 12/1/2021 | 903.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 1 | 1/1/2022 | 887.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2022 | 2 | 2/1/2022 | 891.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 3 | 3/1/2022 | 887.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 4 | 4/1/2022 | 791.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 5 | 5/1/2022 | 724.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 6 | 6/1/2022 | 843.7 | 251.0 | 0.0 | 251.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2022 | 7 | 7/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2022 | 8 | 8/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2022 | 9 | 9/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 10 | 10/1/2022 | 887.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 11 | 11/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 12 | 12/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2023 | 1 | 1/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2023 | 2 | 2/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 3 | 3/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 4 | 4/1/2023 | 792.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 5 | 5/1/2023 | 725.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 6 | 6/1/2023 | 845.2 | 251.0 | 0.0 | 251.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2023 | 7 | 7/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2023 | 8 | 8/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2023 | 9 | 9/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 10 | 10/1/2023 | 893.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 11 | 11/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 12 | 12/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2024 | 1 | 1/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2024 | 2 | 2/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 3 | 3/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 4 | 4/1/2024 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 5 | 5/1/2024 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 6 | 6/1/2024 | 840.7 | 251.0 | 0.0 | 251.0 | 231.1 | 98.1 | 0.0 | 329.2 |
| 2024 | 7 | 7/1/2024 | 898.7 | 251.0 | 0.0 | 251.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2024 | 8 | 8/1/2024 | 899.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2024 | 9 | 9/1/2024 | 893.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 10 | 10/1/2024 | 900.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | 11 | 11/1/2024 | 895.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 12 | 12/1/2024 | 903.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2025 | 1 | 1/1/2025 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2025 | 2 | 2/1/2025 | 880.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 3 | 3/1/2025 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 4 | 4/1/2025 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 5 | 5/1/2025 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 6 | 6/1/2025 | 840.7 | 251.0 | 251.0 | 502.0 | 231.1 | 98.1 | 0.0 | 329.2 |
| 2025 | 7 | 7/1/2025 | 898.7 | 251.0 | 251.0 | 502.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2025 | 8 | 8/1/2025 | 899.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |
| 2025 | 9 | 9/1/2025 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 10 | 10/1/2025 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 11 | 11/1/2025 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 12 | 12/1/2025 | 903.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2026 | 1 | 1/1/2026 | 887.2 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2026 | 2 | 2/1/2026 | 891.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 3 | 3/1/2026 | 887.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 4 | 4/1/2026 | 791.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 5 | 5/1/2026 | 724.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 6 | 6/1/2026 | 843.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2026 | 7 | 7/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2026 | 8 | 8/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |
| 2026 | 9 | 9/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 10 | 10/1/2026 | 887.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 11 | 11/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 12 | 12/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2027 | 1 | 1/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2027 | 2 | 2/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 3 | 3/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 4 | 4/1/2027 | 792.6 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 5 | 5/1/2027 | 725.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 6 | 6/1/2027 | 845.2 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2027 | 7 | 7/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 241.5 | 91.5 | 0.0 | 333.1 |
| 2027 | 8 | 8/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2027 | 9 | 9/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 10 | 10/1/2027 | 893.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 11 | 11/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 12 | 12/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2028 | 1 | 1/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2028 | 2 | 2/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 3 | 3/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 4 | 4/1/2028 | 788.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 5 | 5/1/2028 | 727.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 6 | 6/1/2028 | 840.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2028 | 7 | 7/1/2028 | 898.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2028 | 8 | 8/1/2028 | 899.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2028 | 9 | 9/1/2028 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 10 | 10/1/2028 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 11 | 11/1/2028 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 12 | 12/1/2028 | 903.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2029 | 1 | 1/1/2029 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2029 | 2 | 2/1/2029 | 880.6 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 3 | 3/1/2029 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 4 | 4/1/2029 | 788.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 5 | 5/1/2029 | 727.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 6 | 6/1/2029 | 840.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 98.1 | 436.5 |
| 2029 | 7 | 7/1/2029 | 898.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 91.5 | 406.7 |
| 2029 | 8 | 8/1/2029 | 899.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 98.9 | 439.3 |
| 2029 | 9 | 9/1/2029 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 10 | 10/1/2029 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 11 | 11/1/2029 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 12 | 12/1/2029 | 903.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2030 | 1 | 1/1/2030 | 887.2 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2030 | 2 | 2/1/2030 | 891.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 3 | 3/1/2030 | 887.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 4 | 4/1/2030 | 791.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 5 | 5/1/2030 | 724.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 6 | 6/1/2030 | 843.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 98.1 | 436.5 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2030 | 7 | 7/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 91.5 | 406.7 |
| 2030 | 8 | 8/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 98.9 | 439.3 |
| 2030 | 9 | 9/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 10 | 10/1/2030 | 887.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 11 | 11/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 12 | 12/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |

Data from 2011IRPAvgGen.accdb
AnnualGenDataQ

| Year | Coal MWa | CCCT MWa | SCCT MWa |
|---|---|---|---|
| 2011 | 879.3 | 0 | 96.8 |
| 2012 | 891.6 | 125.5 | 96.1 |
| 2013 | 867 | 251 | 96.8 |
| 2014 | 879.5 | 251 | 96.8 |
| 2015 | 870.3 | 251 | 97.6 |
| 2016 | 900.6 | 251 | 96.8 |
| 2017 | 908 | 251 | 96.1 |
| 2018 | 913.7 | 251 | 96.8 |
| 2019 | 917 | 251 | 96.8 |
| 2020 | 918.6 | 251 | 97.6 |
| 2021 | 867.1 | 251 | 97.6 |
| 2022 | 863 | 251 | 121.6 |
| 2023 | 866.4 | 251 | 120.9 |
| 2024 | 867.8 | 251 | 120.8 |
| 2025 | 867.1 | 397.4 | 120.8 |
| 2026 | 863 | 502 | 121.6 |
| 2027 | 866.4 | 502 | 121.6 |
| 2028 | 867.8 | 502 | 120.1 |
| 2029 | 867.1 | 502 | 144.9 |
| 2030 | 863 | 502 | 144.9 |