ATTACHMENT N-2
IDAHO POWER COMPANY'S 2011 INTEGRATED RESOURCE PLAN (DOCKET LC 53)

2011 Integrated Resource Plan

June 2011

IDAHO POWER.
An IDACORP Company

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Acknowledgement

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

Idaho Power invited outside participation to help develop the 2011 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the IRP Advisory Council, and the comments provided by other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The IRP team is comprised of individuals that represent many different departments within the company. IRP team members are responsible for preparing forecasts, working with the IRP Advisory Council (IRPAC) and the public, and performing all the analyses necessary to prepare the resource plan.

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

Safe Harbor Statement

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1. SUMMARY

Introduction

Idaho Power's IRP is updated every two years.

The *2011 Integrated Resource Plan* (IRP) is Idaho Power's 10th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2011 IRP assumes that during the planning period (2011–2030), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and that the company will continue to operate as a vertically integrated electric utility. In developing this plan, Idaho Power has worked with the IRP Advisory Council (IRPAC), which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. There are four primary goals of Idaho Power's planning process.

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

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

Highlights

- The 2011 IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent) and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year planning period.
- In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.

customers[1] and the company's retail customers.[2] The 2011 IRP evaluates only the need for additional transmission capacity necessary to serve retail customers. The total capacity of proposed transmission line projects may be larger than identified in the IRP in order to accommodate third-party requests and network customer obligations for capacity on the same transmission path.

The number of customers in Idaho Power's service area is expected to increase from approximately 492,000 in 2010 to over 650,000 by the end of the planning period in 2030. Even with the recent recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base.

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

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Prior Idaho Power IRPs used a 10-year planning horizon, but with the increased need for resources with long construction lead times, the need for a 20-year resource plan to support *Public Utility Regulatory Policies Act of 1978* (PURPA) contract negotiations, and support from the IRPAC, Idaho Power decided to extend the planning horizon of the 2006 and future resource plans to 20 years.

Planning for the future is necessary to meet the needs of Idaho Power's customers today and tomorrow. While the 2011 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term in accordance with the *Energy Risk Management Policy and Standards* that were collaboratively developed in 2002 between Idaho Power, the IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). While the IRP has a planning horizon of 20 years and is updated every two years, the *Energy Risk Management Policy and Standards* focuses on an 18-month period and is updated every month.

Public Advisory Process

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRPAC. The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2011 IRP, Idaho Power hosted a field trip covering wind, hydroelectric, and natural gas resources, two portfolio-design workshops, and nine monthly IRPAC meetings. The IRPAC meetings served as an open forum for discussions related to the development of the IRP. The IRPAC members and the public have made significant contributions to this plan. A list of the 2011 IRPAC members can be found in *Appendix C—Technical Appendix*.

Idaho Power believes working with members of the IRPAC and the public is a rewarding process, and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are

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

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

made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2011 IRP and the planning process in general.

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

IRP Methodology

The preparation of Idaho Power's 2011 IRP begins with updating the forecast of future customer demand. Existing resources, the ability to import electricity, and the performance of existing demand-side management (DSM) programs are then accounted for in the load and resource balance. The next step involves evaluating new DSM programs and the expansion of existing programs. Finally, Idaho Power evaluates portfolios of supply-side resources designed to eliminate any remaining deficits.

Idaho Power primarily uses a financial analysis to compare various resource portfolios to determine the preferred portfolio. Idaho Power attempts to financially value the costs and benefits of each resource type. Traditional resources have fixed and variable costs and a market value for the delivered energy, and Idaho Power includes both the costs and the value when evaluating resources. The cost of any necessary transmission upgrades and the value of renewable energy certificates (REC) are also accounted for in the analysis.

Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP—1) the 300-megawatt (MW) Langley Gulch combined-cycle combustion turbine (CCCT) that is expected to be available in the summer of 2012, and 2) a 49-MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

For the 2011 IRP, the 20-year planning period was divided into two, 10-year segments. Dividing the planning period into these two segments prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years.

In the first 10-year period (2011–2020), nine resource portfolios were examined. Each resource portfolio was designed to substantially meet the energy and capacity deficits identified in the load and resource balance.

For the second 10-year period (2021–2030), the preferred resource portfolio from the first 10-year period was coupled with each of the 10 portfolios analyzed for the second period. Using the preferred portfolio from the first 10-year period ensures all the portfolios in the second 10-year period are analyzed consistently.

Demand-Side Management

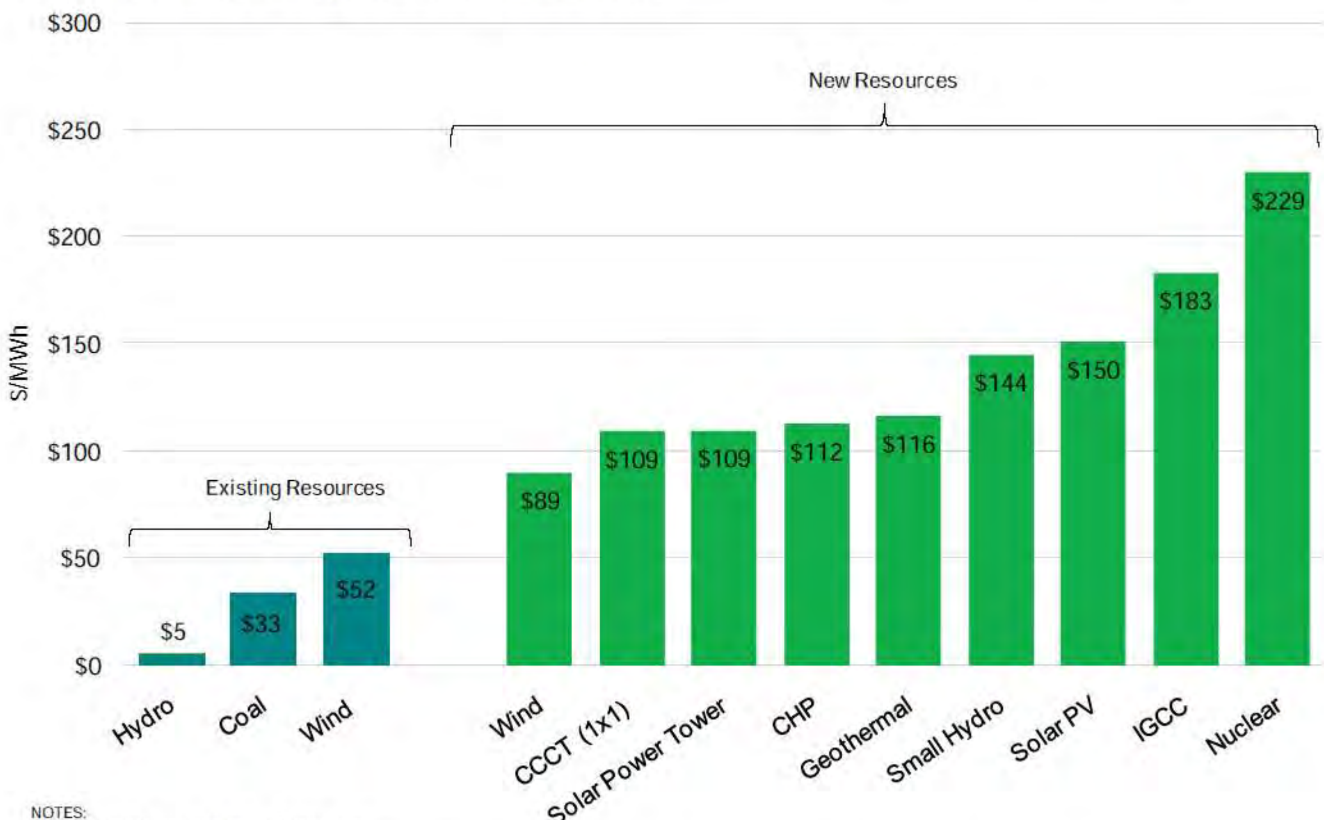
Energy efficiency programs from both the existing portfolio and new program opportunities included in the 2011 IRP are forecast to reduce average load by 233 average megawatts (aMW) by 2030. New energy efficiency opportunities come from a combination of new measures and program expansions. The cost to acquire energy efficiency will vary between an average of 3.6 cents per kilowatt hour (kWh) for existing programs to 5.1 cents per kWh for new program activities and measures for the 2011 IRP.

Demand response programs for the 2011 IRP are targeted to reduce peak summer load by 351 MW by summer 2016. Demand response resources have an average levelized cost of $48 per kilowatt (kW) over the IRP planning period. Demand response programs as peaking resources have grown dramatically in the past few years. The large increase comes from the introduction of the FlexPeak Management program, which targets commercial and industrial customers, and the transition of the Irrigation Peak Rewards program into a dispatchable, direct load-control program as part of the 2011 IRP.

Details on Idaho Power's existing and proposed DSM programs can be found in Chapter 4 and in *Appendix B–2010 Demand-Side Management Annual Report*. An explanation of the methodologies used to incorporate prior and forecast energy efficiency impacts into the load forecast can be found in *Appendix A–Sales and Load Forecast.*

Supply-Side Resource Costs

The 2011 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future needs of customers. Recent cost increases have significantly impacted the cost of new supply-side resources, especially when compared to the cost of the existing resources in Idaho Power's generation portfolio. Figure 1.1 shows the 2010 costs in dollars per megawatt hour (MWh) for Idaho Power's existing hydroelectric resources, coal generation facilities, and power purchased from the Elkhorn Valley Wind Project. In addition, Figure 1.1 shows the estimated cost of energy from new resources considered in the 2011 IRP. Existing resource costs are based on 2010 actual costs of capital, fuel, and non-fuel operating and maintenance (O&M). New resource costs are 30-year levelized estimates (based on expected annual generation), which include capital, fuel, non-fuel O&M, and the expected-case carbon adder.



NOTES:
1) Cost of existing resources based on 2010 costs
2) Cost of new resources based on 30-year levelized cost estimates
3) Cost of existing wind is for the Elkhorn Wind Project only (Elkhorn produced approximately 80% of the wind generation purchased by Idaho Power during 2010).

Figure 1.1 Cost of existing and new supply-side resources

While it is important to evaluate the costs presented in Figure 1.1, these figures represent only a part of the total resource cost. In preparing the IRP, Idaho Power must also consider the value that each type of resource provides in conjunction with the other resources in the company's generation portfolio. Supply-side resources have different operating characteristics, making some better suited for meeting capacity needs while others are better for providing energy. The low capital cost and dispatch capability of a simple-cycle combustion turbine (SCCT) resource makes it a good choice for meeting capacity needs, as long as it is needed for only short durations to meet peak-hour load. A geothermal resource typically provides maximum generation during peak load periods, but because it is non-dispatchable and generally provides constant generation year round (baseload), it is considered a better energy resource. Wind is also a good source of energy; however, it provides almost no peak-hour capacity due to the variable and intermittent nature of the generation.

Figure 1.2 shows the 30-year levelized capital cost in dollars per MW of peak-hour capacity for many of the supply-side resources evaluated in the 2011 IRP. This metric provides useful information on the value of each resource type in terms of providing peak-hour capacity. Idaho Power's peak loads typically occur between 3:00 p.m. and 7:00 p.m. on hot summer days; the expected capacity factor for each resource type during this time period is also shown in Figure 1.2.

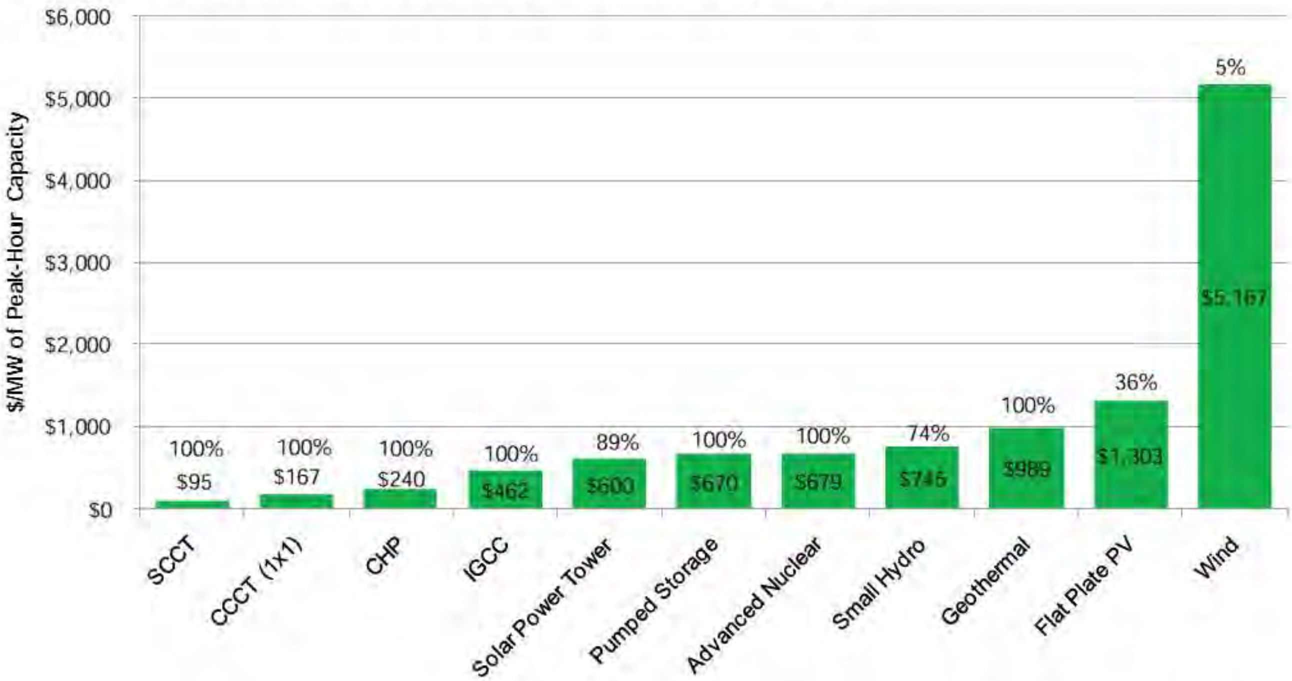


Figure 1.2 30-year levelized capital cost of peak-hour capacity

Resources capable of providing 100 percent of nameplate capacity during peak load periods have an obvious cost advantage when compared to resources with lower peak-hour capacity factors, such as wind. Because wind can be counted only to provide 5 percent of nameplate capacity during the peak-hour, 20 MW of nameplate wind would need to be built to get one MW of peak-hour capacity. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2011 IRP is presented in Chapter 6, and details of the calculations used to prepare Figure 1.2 are presented in *Appendix C–Technical Appendix*.

Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 2 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide (CO_2) emissions levels have historically been well below the national average for the 100 largest electric utilities in the United States, both in terms of total CO_2 emissions (tons) and CO_2 emissions intensity (pounds [lbs] per MWh), based on the report of 2008 CO_2 emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, released in June 2010 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and Portland Gas & Electric (PG&E) Corporation.

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

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

At present, generation and emissions from company-owned resources are included in the CO_2 intensity calculation. The company's progress toward achieving this intensity reduction goal, as well as additional information on Idaho Power's CO_2 emissions, is currently reported on the company's website at www.idahopower.com/NewsCommunity/OurEnvironment/co2Intensity.cfm. Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at www.cdproject.net.

Idaho Power's annual CO_2 emissions intensity for 2009 and 2010 were 1,003 lbs per MWh and 1,065 lbs per MWh respectively, both below the 2005 CO_2 emissions intensity level. Idaho Power's average CO_2 intensity for the goal period-to-date, January 2010–April 2011, is 949 lbs of CO_2 per MWh. This reduction in intensity relative to the 2010 level reflects an increase in hydroelectric generation, as a result of the current water conditions, and reduced coal-fired generation. For the 2010–2013 time period, Idaho Power fully expects to achieve its goal of reducing its CO_2 emissions intensity from company-owned resources (relative to the 2005 level of 1,194 lbs CO_2 per MWh) by more than 15 percent.

The guidelines are intended to reduce Idaho Power's near-term CO_2 emissions intensity levels in a manner that minimizes the cost of the reductions on the company's customers. The 2011 IRP attempts to quantify the cost and longer term impacts of carbon regulations by including a carbon adder that is applied to all resources that emit CO_2. Additional details regarding the assumptions and analysis are presented in Chapter 6 and Chapter 9 of the 2011 IRP.

Preferred Resource Portfolio

The preferred portfolio for the 2011 IRP presented in Table 1.1 was constructed by combining the preferred portfolio for the first 10 years of the planning horizon (2011–2020) with the preferred portfolio for the second 10-year period (2021–2030). In addition to the committed resources (Langley Gulch and the Shoshone Falls upgrade) the preferred resource portfolio includes 450 MW of market purchases beginning in 2016 with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW.

The preferred portfolio for the second 10-year period (2021–2030) represents a balanced strategy of adding a mixture of renewable resources along with natural gas-fired baseload and peaking resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

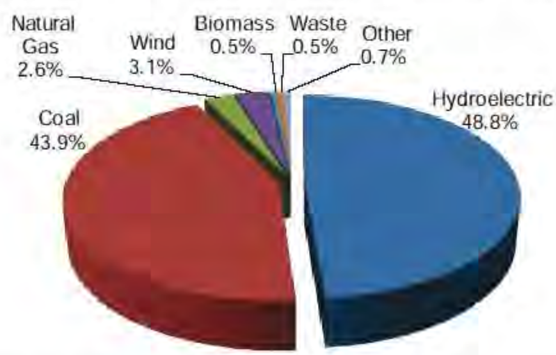
Table 1.1 Preferred portfolios

1–3 Boardman to Hemingway (2011–2020)			2–6 Balanced 1 (2021–2030)		
Year	Resource	MW	Year	Resource	MW
2011			2021	Geothermal	52
2012	CCCT (Langley Gulch)*	300	2022	SCCT	170
2013	Solar Demonstration Project		2023		
2014			2024	Solar Power Tower	50
2015	Shoshone Falls Upgrade*	49	2025	CCCT	300
2016	Boardman to Hemingway	450	2026		
2017			2027		
2018			2028	Small Hydro	60
2019			2029	SCCT	170
2020			2030		

*Committed resource

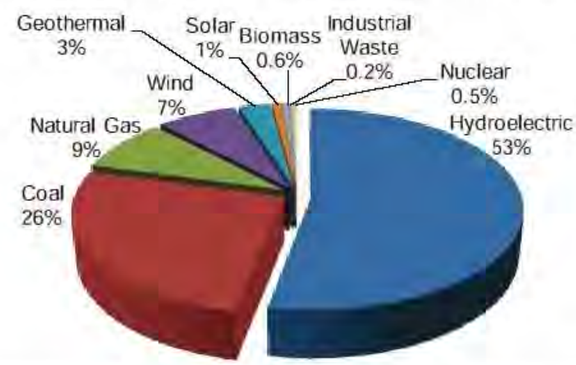
Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities along with purchased power to supply the energy needed to serve customers. Because Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River, the percentage of each energy source also changes year-to-year.

Figure 1.3 shows Idaho Power's "fuel mix" by resource type for 2010, and Figure 1.4 estimates the company's fuel mix in 2030 based on the implementation of the preferred portfolio. In 2030, Idaho Power's hydroelectric resources are the predominate resource and provide over 50 percent of the mix. Generation from coal-fired resources becomes a smaller part of the mix, being replaced by natural gas and a mixture of renewable resources. In preparing Figures 1.3 and 1.4, market purchases were assumed to be comprised of the estimated Pacific Northwest energy market fuel mix for 2010 and 2030.



NOTE: 2010 Market Purchases are 6% of Idaho Power's energy sources, and the fuel mix is modeled in this graph using the Northwest Power Pool (NWPP) system mix for 2010.

Figure 1.3 2010 fuel mix



NOTE: 2030 Market Purchases are 13% of Idaho Power's energy sources, and the fuel mix is modeled in this chart using the AURORA Washington system mix for 2030.

Figure 1.4 2030 fuel mix

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2013 IRP and subsequent plans as more certainty regarding carbon regulations and a federal renewable electricity standard (RES) become available. Future uncertainty requires alternate portfolios be considered in the resource planning process. Further details regarding the preferred portfolio and the alternate portfolios can be found in Chapter 10.

Near-Term Action Plan

The Langley Gulch CCCT is currently under construction and is expected to be completed by summer 2012. Idaho Power also anticipates beginning preliminary design work for the Shoshone Falls Upgrade

Project in 2012, which is expected to be completed in 2015. Idaho Power is also continuing to work with federal and state agencies, FERC, other transmission providers, and the public on the Boardman to Hemingway and Gateway West transmission projects. Major milestones associated with these resources and programs are presented in Table 1.2.

Table 1.2 Near-term action plan milestones

Year	Action
2011	Langley Gulch CCCT construction continues File 2011 IRP with regulatory commissions Demand response programs expected to provide 330 MW of load reduction Continue the Boardman to Hemingway permitting process Continue the Gateway West NEPA permitting process Prepare and issue an RFP for the Solar Demonstration Project
2012	Langley Gulch CCCT on line (300 MW) Evaluate responses to the Solar Demonstration Project and file a Certificate of Public Convenience and Necessity (CPCN) Complete design work on the Shoshone Falls Upgrade Project and issue RFP Continue Boardman to Hemingway permitting process Continue the Gateway West NEPA permitting process Solar Demonstration Project on line in late 2012/early 2013
2013	Issue RFP for Boardman to Hemingway construction Shoshone Falls Upgrade Project construction begins File 2013 IRP with regulatory commissions Continue the Gateway West NEPA permitting process
2014	Shoshone Falls Upgrade Project construction continues Boardman to Hemingway construction begins Secure 83 MW PPA for summer 2015 from the east side
2015	Shoshone Falls Upgrade Project on line (49 MW) File 2015 IRP with regulatory commissions
2016	Boardman to Hemingway construction completed (450 MW)
2017	File 2017 IRP with regulatory commissions
2018	
2019	File 2019 IRP with regulatory commissions
2020	

Public Policy Issues

The 2011 IRP was completed using computer modeling and other analytical methods. However, certain public policy questions exist that cannot be directly examined through analytical methods. Idaho Power has presented these issues to the IRPAC for discussion, but the nature of issues typically precludes a strong majority opinion from IRPAC members. The public policy issues presented to the IRPAC are discussed in the following sections.

New Large Loads

Locally, Idaho Power and its customers face internal conflicts created by traditional rate determination and the cost difference between existing resources and future resources. New customers that connect to Idaho Power's system benefit from energy rates based on the low-cost of existing resources that are embedded in current rates. However, Idaho Power's existing resources and transmission system are fully used, and new customers require the addition of generation, transmission, and distribution resources. Because new resources are more expensive than Idaho Power's existing portfolio, each new customer dilutes the existing resource base and increases the cost to all customers. Accordingly, for a number of years, Idaho Power has attempted to balance the impact on both the new customer and existing customers through an intermediate period by using blocked contracts that provide for an element of marginal-cost pricing.

In addition, Idaho Power's ability to serve new large loads is limited as growth in summertime peak demand continues to drive the need for additional resources. New businesses are attracted to southern Idaho due in part to Idaho Power's low rates, which have consistently been some of the lowest in the nation. When a new large customer makes a request for service, Idaho Power must include restrictions in the contract limiting the customer's usage during peak summer months. These restrictions typically last for several years until new resources can be planned for and built, and many new large customers are unable or unwilling to accept these terms.

For the 2011 IRP, an analysis was performed to determine the cost of building additional natural gas-fired peaking capacity that could be used to serve new large loads. The analysis assumes 80 MW of capacity from a SCCT is added to Idaho Power's resource portfolio in 2014. The analysis also assumes the additional capacity is built and no new large load materializes.

The results show the net present value of the revenue requirement associated with the fixed and variable cost of adding the additional 80 MW of capacity would be $60 million. In addition to positioning the company to serve new large loads, which will promote local economic development and create jobs, this additional capacity will be able to assist with integrating wind generation and, when opportunities exist, make profitable surplus sales to help offset the fixed costs of ownership. *Appendix C–Technical Appendix* contains additional details regarding the analysis.

Idaho Power recognizes the ability to serve new large loads has an impact on Idaho's economy. Because of this, and the results of the analysis mentioned above, Idaho Power is proposing an additional 80 MW of peak-hour load be added to Idaho Power's load and resource balance beginning with the 2013 IRP. By adding this additional peak-hour load to the load and resource balance, the additional capacity will come from a diverse set of resources identified in the IRP process, perhaps at a lower cost, and not specifically from the construction of a single new resource.

Asset Ownership

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

Emissions Offsets

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

Uncertainty in the future regulation of carbon is evidenced in the recent collapse of the Chicago Climate Exchange (CCX). CCX was established in 2003 as the sole voluntary GHG reduction and offset trading platform for North America and Brazil. In December 2010, CCX ceased trading due to the complete market free-fall of their carbon emissions product. However, CCX continues generation of their carbon financial instrument (CFI) product as a strictly voluntary GHG emissions offset system.

Idaho Power plans to continue to follow developments related to carbon offsets and options in the event either becomes a viable alternative. The company could potentially reduce the large financial exposure of possible carbon regulation for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emissions offset options as well as the cost of any emissions offsets purchased.

Technology Risk and Joint Development

In the 2011 IRP, several resource options dependent on developing technology have been evaluated in various portfolios. Carbon capture and sequestration, integrated gasification combined-cycle (IGCC), advanced nuclear, and numerous storage technologies are not yet commercially available; however, the technology may become available during the 20-year planning horizon evaluated in the IRP. This raises the question of whether Idaho Power should participate in development efforts related to any of these technologies prior to them becoming commercially available.

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

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

Solar Demonstration Project

While solar technology continues to be more expensive than other alternatives, the cost of solar resources continues to decrease while the cost of most other resource options has increased. In addition to providing RECs, solar resources typically deliver energy during the time of day when Idaho Power's customer demand is high.

Idaho Power's 2009 IRP discussed the advantages and disadvantages of several solar demonstration project options, including a utility-scale project located near an existing substation and a distributed rooftop program. During the preparation of the 2009 IRP, a substantial amount of support was expressed by IRPAC members and the public for some type of a local project.

Idaho Power has continued to evaluate the benefits of developing a solar photovoltaic (PV) demonstration project and the topic was again discussed with the IRPAC as part of preparing the 2011 IRP. Several IRPAC members expressed support for the project to include a research and development component as well as continued support for developing a solar rooftop program.

As the cost continues to decline, Idaho Power believes solar PV resources will become more prevalent in the future, and it will be important for the company to have operating experience and be able to determine what specific type of PV technology provides the most value for Idaho Power customers.

With that in mind, Idaho Power intends to make a more detailed proposal that would allow the company to invest in a small-scale solar PV resource.

Idaho Power anticipates issuing a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. A portion of the facility would be devoted to testing new PV panel technologies, inverters, and other mounting and tracking systems. Idaho Power would also offer to collaborate with the Center for Advanced Energy Studies (CAES) on relevant research into solar technologies.

Proposals would be evaluated by mid-2012, and if a successful bidder is identified, the company would then file a request with the IPUC for a CPCN. If approved, it is anticipated the facility could be on line as early as the end of 2012.

Based on the 2011 IRP cost estimate for a solar PV resource of $3,750 per kW, the expected cost of the project could be $2–$4 million and would require approximately 5–10 acres of land. While the proposed size of this project is small relative to what might be considered a utility-scale project, Idaho Power believes it will provide useful data and give the company experience owning and operating this type of resource. It will also allow the company to better evaluate the advantages and disadvantages of utility-scale solar PV projects and distributed rooftop programs.

Idaho Power views this proposal as a demonstration project because of its small size and its primary purpose being to collect information on how solar PV resources integrate with the company's other system resources. In addition to providing valuable information on solar integration, the demonstration project will provide an opportunity for Idaho Power to expand green power program options for customers.

Idaho Power's REC Management Plan details the company's intent to continue selling RECs in the near term until they are needed to meet a federal RES. In general, a majority of Idaho Power's customers support this policy, as 95 percent of the revenue from the sale of RECs is returned to customers to keep rates low. However, there is a growing segment of customers who desire, and are willing, to pay a premium for, green energy. Idaho Power believes it is important to provide additional options for these customers, and the solar demonstration project presents an opportunity to expand the available offerings.

In addition to the benefits already identified, Idaho Power is required to build a 500-kilovolt (kV) solar PV project within the next several years under the State of Oregon's Solar PV Pilot Program. The company is currently working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP. Additional details on the Oregon Solar PV Pilot Program can be found in Chapter 3.

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2. Political, Regulatory, and Operational Issues

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

The IPUC regulates Idaho Power in Idaho.

Idaho Energy Plan

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

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

Idaho Strategic Energy Alliance

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

Highlights

- Idaho Power continues to operate the Hells Canyon Complex under annual licenses issued by FERC until a new license is issued.
- The 2011 IRP assumes a federal RES will be enacted in the future.
- Idaho Power is preparing an updated wind integration study in association with the 2011 IRP.

The alliance promotes the development of a sound energy portfolio for Idaho that diversifies energy resources and provides stewardship of the environment. The alliance consists of a board of directors and 13 volunteer task forces working in the following areas:

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

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

FERC Relicensing

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

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

The Hells Canyon Complex license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1978* (ESA); and other applicable federal laws.

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

Relicensing costs of $134 million and $5 million for the Hells Canyon Complex and Swan Falls projects, respectively, were recorded by Idaho Power as of March 2011. Administrative work on relicensing is expected to continue until new licenses are issued in 2012 for Swan Falls and 2014 for the Hells Canyon Complex. Once new licenses are issued, further costs will be incurred to comply with the terms of the new licenses. Given the new licenses for Swan Falls and the Hells Canyon Complex have not been issued, and discussions on the PM&E packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include: 1) coordination of the relicensing process; 2) consulting with regulatory agencies, tribes, and interested parties; 3) preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites; 4) preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, reservoir contours and volumes; 5) study and data analysis; 6) preparing all necessary reports, exhibits, and filings; 7) responding to requests for additional information from FERC; and 8) legal consultation. This estimate includes costs for all areas of Idaho Power related to the relicensing effort.

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

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed was assumed as part of the 2011 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional generation resources.

Idaho Water Issues

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

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984.

In 1984, the Swan Falls Agreement resolved a struggle between the state of Idaho and Idaho Power over the company's water rights at the Swan Falls hydroelectric facility. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet-per-second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The agreement placed the portion of the company's water rights beyond those minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked that the court resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. It also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the state are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board.

Idaho Power actively participates in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between ESPA and the Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River.

The company hopes implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. It is assumed in the 2011 IRP that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations, to be implemented over a 5–10-year period, consist of a combination of ground-water to surface-water conversions, managed aquifer recharge, demand reduction programs, and weather-modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre feet. Additional funding mechanisms are being explored to implement measures outlined in the ESPA CAMP.

Further discussion of the ESPA CAMP is included in *Appendix C—Technical Appendix*. The Phase I measures with associated target water volumes are shown in Table 2.1.

Table 2.1 Phase I measures

Measure	Target (acre-feet)
Ground water to surface water conversions	100,000
Managed aquifer recharge	100,000
Demand reduction	0
Surface-water conservation	50,000
Crop mix modification	5,000
Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP)	40,000
Weather modifications	50,000

Wind Integration Study

Total installed wind-generation capacity continues to expand in Idaho and the Pacific Northwest. A recent surge in wind development in southern Idaho by independent power producers has heightened concerns over Idaho Power's ability to integrate additional wind resources beyond the 395 MW currently online. The cost of integrating additional intermittent wind resources and the potential impact on system reliability is of primary concern. As a result of these concerns, Idaho Power is updating its study in association with the 2011 IRP.

The objective of the updated study is to assess the costs incurred in modifying operations of dispatchable generating resources in order to allow them to respond to the variable and intermittent nature of wind resources such that the reliable delivery of electrical power to customers is unaffected. Idaho Power considers the assessment of these costs an important part of efforts to ensure the price paid to acquire wind energy is fair to independent developers and Idaho Power customers. Although the purpose of the study is to estimate the cost of integrating wind, the actual impact of integrating large amounts of wind generation on a day-to-day basis will create ongoing operational and reliability issues for Idaho Power's system dispatchers.

Idaho Power has been concerned about wind integration issues since late 2010 when 771 MW of requests for PPAs by wind developers were made under PURPA. Initial efforts were focused on determining the value of the energy from these PURPA contracts, and in early 2011, Idaho Power entered into a contract with PLEXOS Solutions, LLC, for technical support in determining the cost of integrating wind and the impact on system reliability.

The study is designed to investigate the impact and cost of integrating wind on Idaho Power's system by modeling a range of wind build-out cases (600 MW, 800 MW, 1,200 MW, and 1,600 MW) and comparing the system operation and cost of these cases against a base case. The concept behind this approach is that a set of dispatchable generating resources is operated differently in the wind build-out cases to provide balancing reserves necessary for responding to the intermittency and variability associated with wind generation. These reserves, necessary to maintain system reliability, are provided at a cost.

An important consideration for the study, as well as wind integration in practice, is the designation of the set of resources responsible for integrating wind. For the updated study, Idaho Power's existing resources capable of providing balancing reserves includes the hydroelectric units of the Hells Canyon Complex, the coal-fired units at the Jim Bridger and North Valmy power plants, the company's fleet of SCCTs located in Mountain Home, Idaho, and the Langley Gulch CCCT expected to be commercially available in July 2012. In addition, the study will evaluate the benefits of the proposed Boardman to Hemingway transmission line project (planned for 2016) on the cost of integrating wind generation.

In March 2011, Idaho Power held a public workshop for interested stakeholders where the proposed study methodology was explained and input on the design of the study was solicited. The company anticipates holding a second public workshop in conjunction with the completion of the study in July 2011, and a final study report is expected to be released shortly thereafter.

Fixed Cost Adjustment

Under the fixed cost adjustment (FCA), rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs that Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in DSM resources. The FCA Pilot is currently limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through energy charges.

On October 1, 2009, the company filed an application with the IPUC to convert the FCA to an ongoing and permanent rate schedule. On April 29, 2010, the IPUC issued Order No. 31063 extending the original 3-year FCA Pilot for an additional two years, effective January 1, 2010.

During the 4-year period that the FCA (Schedule 54) has been in effect, Idaho Power has made progress in promoting energy efficiency and DSM activities. During the term of the FCA Pilot, the company has increased the number of DSM programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained via DSM. Results from the first four years of the pilot indicate the true-up mechanism is working as intended and operating to mitigate the unintended adverse effects of DSM by ensuring that the fixed costs the IPUC authorized the company to recover are being recovered via the FCA mechanism.

As part of a general rate case filed with the IPUC on June 1, 2011, the company has again requested to convert the FCA to an ongoing and permanent rate schedule. The company believes the FCA has proved to be an effective rate mechanism for removing the financial disincentives that exist when Idaho Power invests in DSM resources and if made permanent will continue to serve in the best interests of its customers.

Renewable Energy Certificates

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

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

Renewable Portfolio Standards

Under the state of Oregon's RPS, Idaho Power is classified as a "smaller utility" because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 10 percent RPS requirement beginning in 2025.

While the state of Idaho does not have an RPS, Idaho Power believes a federal RES, requiring Idaho Power to retire RECs for compliance, will be passed by Congress in the future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

REC Management Plan

Idaho Power's acquisition of RECs has created an issue regarding the disposition of the RECs until either a state RPS or federal RES requirement exists. Two options exist: 1) retire RECs, which would allow Idaho Power to represent to customers that renewable energy is being delivered to them, or 2) sell RECs and use the proceeds to reduce customer rates.

This issue was debated by the IRPAC during the preparation of both the 2009 IRP and the 2011 IRP. In general, environmental representatives felt future RECs should be retired while customer representatives felt they should be sold so that the value could be returned to customers.

In December 2009, Idaho Power filed with the IPUC a REC Management Plan that detailed the company's plans to continue to acquire long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near term and return to customers their share of the proceeds through the power cost adjustment (PCA) mechanism. Public comments regarding the plan mirrored the positions expressed by IRPAC members, many of whom filed comments with the IPUC. In June 2010, the IPUC accepted Idaho Power's REC Management Plan.

Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment, including air, water, and solid waste. Current and pending legislation relates to, among other items, climate change, GHG emissions and air quality, RES, Hg and other emissions, hazardous wastes, and polychlorinated biphenyls (PCB). Environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power discontinue operating certain power generation plants.

Federal Climate Change Legislation

Future federal climate-change legislation could affect regulated utilities, such as Idaho Power.

For the past several years, Congress has considered comprehensive federal energy legislation requiring reductions in GHG emissions. Proposed GHG regulations target the reduction of carbon and other GHG emissions nationwide. The most recent and prominent bills that have been proposed are 1) the *American Clean Energy and Security Act of 2009* (Waxman–Markey), sponsored by Representatives Henry A. Waxman and Edward J. Markey; 2) the *Clean Energy Jobs and American Power Act of 2009* (Boxer–Kerry), sponsored by Senators Barbara Boxer and John Kerry in the Senate; and 3) the *American Power Act of 2010* (Kerry–Lieberman), sponsored by Senators John Kerry and Joe Lieberman.

In June 2009, the US House of Representatives narrowly passed the Waxman–Markey bill. The draft bill included a GHG emissions reduction goal of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and more than 80 percent by 2050. The Waxman–Markey bill proposed to accomplish the reductions under a cap-and-trade system that would establish a limit or cap on the total amount of GHG emissions. Although the Waxman–Markey bill passed in the House of Representatives, it did not pass in the Senate.

Under a cap-and-trade system, utilities would be allocated emissions allowances that would be decreased over time to achieve a total emissions reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society.

In September 2009, the Boxer–Kerry bill was introduced in the Senate. The draft bill included a GHG emissions reduction goal of 20 percent below 2005 levels by 2020. The Boxer–Kerry bill did not include a federal RES provision.

In May 2010, the Kerry–Lieberman bill was introduced in the Senate. The proposed legislation included a cap-and-trade system for reducing GHG emissions by 17 percent in 2020 and by over 80 percent in 2050. None of the proposed federal climate change legislation has been able to gain enough support to be passed by both the House of Representatives and the Senate.

In the summer of 2011, the Environmental Protection Agency (EPA) plans to begin regulating GHG emissions. However, some members of Congress are currently working to remove EPA's authority to regulate GHGs through legislative action and budget cuts.

Environmental Protection Agency

Idaho Power co-owns three coal-fired power plants and owns two natural gas-fired combustion turbine power plants that are subject to air-quality regulation. The coal-fired plants are Jim Bridger (one-third interest) located in Wyoming; Boardman (10 percent interest) located in Oregon; and Valmy (50 percent interest) located in Nevada. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. In addition, Idaho Power is currently in the process of constructing the Langley Gulch power plant, a natural gas-fired CCCT generating plant with a nameplate capacity of approximately 300 MW.

The *Clean Air Act* (CAA) establishes controls on the emissions from stationary sources like those owned by Idaho Power. The EPA adopts many of the standards and regulations under the CAA, while states have the primary responsibility for implementation and administration of these air-quality programs. Idaho Power continues to actively monitor, evaluate, and work on air-quality issues pertaining to federal and state Hg emissions rules, possible legislative amendment of the CAA, Regional Haze–Best Available Retrofit Technology (RH BART), National Ambient Air Quality Standards (NAAQS), and New Source Review (NSR) permitting.

Regional Haze–Best Retrofit Technology

In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. The Wyoming Department of Environmental Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) have conducted assessments of the Jim Bridger and Boardman plants pursuant to the RH BART process. These states have also evaluated the need for additional controls at Jim Bridger and Boardman to achieve reasonable progress toward a long-term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

On November 3, 2010, PacifiCorp, the majority owner and operator of the Jim Bridger plant, and the WDEQ signed a settlement agreement under which PacifiCorp agreed to install selective catalytic reduction (SCR) technology, alternative add-on nitrogen oxide (NO_x) controls, or otherwise achieve a 0.07 pounds-per-million British thermal units (MMBtu) 30-day rolling average NO_x emissions rate by December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. In addition, PacifiCorp has agreed to install SCR technology, alternative add-on NO_x controls, or otherwise achieve a 0.07 pounds-per-MMBtu 30-day rolling average NO_x emissions rate by December 31, 2021, for Unit 2 and December 31, 2022, for Unit 1. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan that are consistent with the terms of the settlement agreement. In light of the settlement agreement, WDEQ issued a revised RH BART permit for Jim Bridger on November 24, 2010.

In August 2010, Portland General Electric (PGE), the majority owner and operator of the Boardman plant, submitted a new plan to the ODEQ that would cease coal-fired operations at the Boardman plant in 2020, but contemplated additional emissions reductions relative to PGE's previous 2020 closure plan.

Following an extensive public process, in December 2010, the Oregon Environmental Quality Commission approved PGE's August and October 2010 plan to cease coal-fired operations at the Boardman plant no later than December 31, 2020. The new rules implementing the plan are expected to contain the following measures:

- Install new low-NO_x burners and modified overfire air ports by July 2011 to comply with BART standards for NO_x
- Conduct pilot studies for the dry sorbent-injection system to verify that set sulfur dioxide (SO_2) limits for 2014 and 2018, are achievable
- Install a dry sorbent-injection system by July 2014, to comply with BART standards for SO_2
- Repeal the ODEQ's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more expensive suite of emissions controls
- Permanent cessation of coal-fired operation no later than December 31, 2020

National Ambient Air Quality Standards

In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). In December 2006, the EPA revised the NAAQS for PM2.5. This new standard is the subject of a legal challenge by a number of groups. However, all counties in Idaho, Nevada, Oregon, and Wyoming—where Idaho Power's power plants operate currently—were designated as meeting attainment with the revised PM2.5 NAAQS.

In January 2010, the EPA adopted a new NAAQS for NO_2 at a level of 100 parts-per-billion averaged over a 1-hour period. In addition, in June 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts-per-billion averaged over a 1-hour period. The EPA has not yet designated areas as attaining or not attaining these new standards. Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations.

Hazardous Air Pollutants–Maximum Achievable Control Standard

On March 16, 2011, EPA issued proposed rules to reduce emissions of Hazardous Air Pollutants (HAP) from coal- and oil-fired electric utility steam-generating units. These rules target certain heavy metals, acid gases, organics, dioxins, and furans. EPA grouped these HAPs into the following categories; Hg, non-Hg HAP metals, acid gases, organics, and dioxins/furans. Of these groups, all but organics and dioxin/furan have numerical limits that must be met. Two of the groups (non-Hg HAP metals and acid gases) allow for "surrogate" pollutants to be used to demonstrate compliance with the limits. To demonstrate compliance with organic HAPs and dioxin/furans, the EPA has proposed Work Practice Standards.

Continuous emissions-monitoring systems of Hg have been installed on all the coal-fired units at the Jim Bridger, Boardman, and Valmy plants, and tests to confirm the accuracy of the data being collected are underway. In 2008, the state of Oregon adopted an Hg rule requiring the Boardman plant to reduce Hg emissions by 90 percent or meet an emissions rate of 0.6 pounds-per-trillion Btus by July 2012. Idaho Power continues to monitor Wyoming and Nevada actions related to Hg emissions. Idaho Power is unable to predict at this time what actions the EPA or the other states may take to reduce Hg emissions from their coal-fired power plants. In April 2010, the US District Court for the District of

Columbia approved, by consent decree, a timetable that would require the EPA to propose a standard to control Hg emissions from coal-fired power plants by May 2011 and to finalize it by November 2011.

Clean Air Transport Rule

In July 2009, the EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in SO_2 and NO_x emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule is intended to help states attain NAAQS set in 1997 for ozone and fine particulate-matter emissions. This rule replaces the Bush administration's Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS.

Idaho Power does not own generating units in states identified by the Transport Rule and thus will not be directly impacted; however, the company intends to monitor amendments to the Transport Rule closely, particularly since there is some indication that the 2014 revisions to the Transport Rule will extend the geographic scope of impacted states.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs are currently considered exempt wastes under an amendment to the *Resource Conservation and Recovery Act of 1976* (RCRA); however, in 2010, the EPA proposed to regulate CCRs for the first time. The EPA is considering two possible options for the management of CCRs. Both options fall under the RCRA.

Under the first option, the EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition, including the closure of disposal units. Under the second option, the EPA would regulate CCRs as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. A final ruling is expected in 2012.

3. Idaho Power Today

Customer Load and Growth

An Idaho Power employee installs a new Smart Meter.

In 1990, Idaho Power served approximately 292,000 general business customers. Today, Idaho Power serves more than 492,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW in 2006–2009. In June 2008, the peak-hour load reached 3,214 MW, which is the system peak-hour record. Idaho Power's successful demand reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand in both 2009 and 2010.

Average firm load (excluding Astaris/FMC) increased from nearly 1,200 aMW in 1990 to over 1,800 aMW in 2008. Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,276 MW. The 641-MW increase in capacity represents enough generation to serve approximately 100,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 300-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is being constructed in the western Treasure Valley in Payette County, Idaho. Construction began in August 2010, and the plant is expected to be operational in July 2012.

The data in Table 3.1 suggests each new customer adds approximately 6.5 kW to the peak-hour load and about 1.5 average kilowatts (akW) to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 200,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 200,000 customers require over 1,100 MW of additional peak-hour capacity and about 600 aMW of energy.

Highlights

- Idaho Power had over 492,000 retail customers at the end of 2010.
- The 300-MW Langley Gulch natural gas-fired CCCT is expected to begin operating in July 2012.
- Since 2003, Idaho Power has been operating a cloud-seeding program that increases snow accumulation and provides increased generation at the company's hydroelectric facilities.

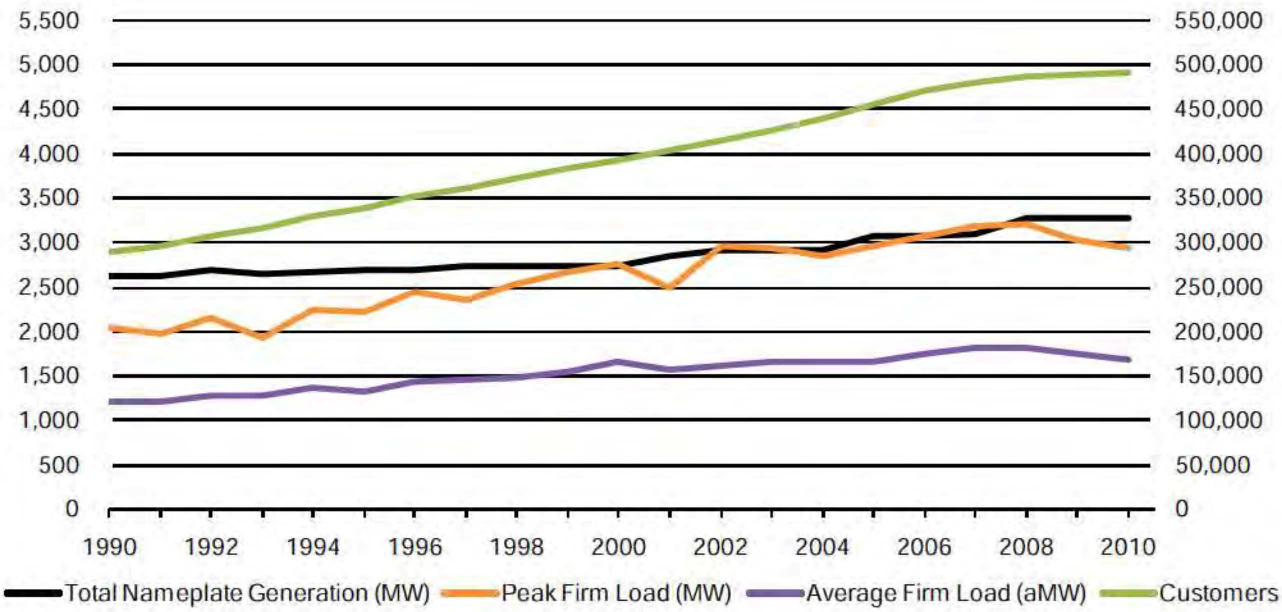

Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers
1990	2,635	2,052	1,205	290,492
1991	2,635	1,972	1,206	296,584
1992	2,694	2,164	1,281	306,292
1993	2,644	1,935	1,274	316,564
1994	2,661	2,245	1,375	329,094
1995	2,703	2,224	1,324	339,450
1996	2,703	2,437	1,438	351,261
1997	2,728	2,352	1,457	361,838
1998	2,738	2,535	1,491	372,464
1999	2,738	2,675	1,552	383,354
2000	2,738	2,765	1,653	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,622	414,062
2003	2,912	2,944	1,657	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,660	456,104
2006	3,085	3,084	1,745	470,950
2007	3,093	3,193	1,808	480,523
2008	3,276	3,214	1,815	486,048
2009	3,276	3,031	1,744	489,927
2010	3,276	2,930	1,680	492,073

Idaho Power anticipates adding approximately 8,000 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 69 MW per year, and the average energy requirement is forecast to grow at 29 aMW per year. More detailed customer and load forecast information is presented in Chapter 6 and in *Appendix A–Sales and Load Forecast*.

The simple peak-hour load growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 173-MW Bennett Mountain plant every 3 years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 10.

The generation costs per kW included in Chapter 6 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5.0–5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5.0–5.5 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,000 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

2010 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities and long-term PPAs to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year. The next sections provide specific details on Idaho Power's sources of energy in 2010 followed by a description of Idaho Power's existing and committed resources.

In 2010, 86 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.2 shows Idaho Power's electricity sources for 2010, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

Long-term power purchases are electric power contracts with independent power producers and firm PPAs with other utilities and can typically be identified by resource type. In 2010, Idaho Power purchased 1,399,661 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.3. Long-term power purchases that cannot be identified by resource type are shown as "other" in the chart.

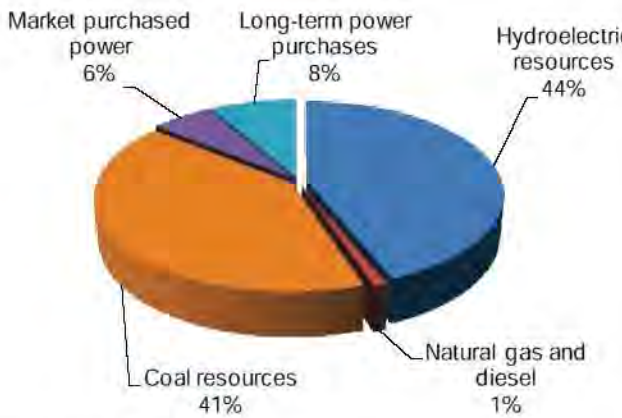

Figure 3.2 2010 energy sources

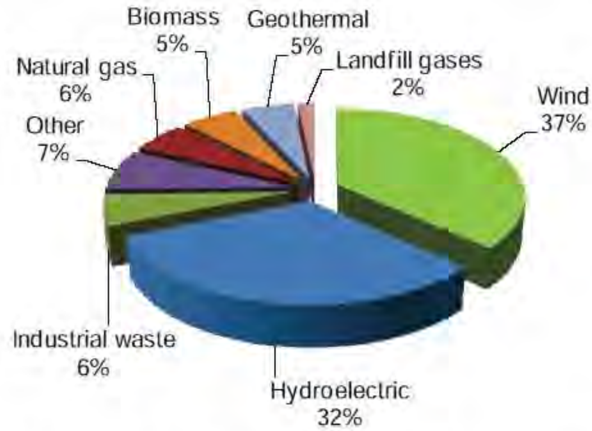

Figure 3.3 2010 long-term power purchases by resource type

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. Electricity produced by resources typically considered to be renewable, such as wind, biomass, geothermal, etc., is not counted as renewable energy delivered to retail customers in a given year, unless Idaho Power retires an equivalent number of RECs in that year.

In December 2009, Idaho Power filed with the IPUC a REC Management Plan that detailed Idaho Power's plans to continue to acquire long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near-term and return the customers' share of the proceeds through the PCA mechanism.

Table 3.2 shows Idaho Powers' energy sources and the subsequent electricity delivered to retail customers in 2010. Because Idaho Power sells electricity to other utilities and to retail customers, not all electricity purchased or generated by Idaho Power is delivered to its retail customers. Table 3.2 shows that no wind or geothermal generation was delivered to retail customers in 2010, the RECs associated with this generation were sold to others who have purchased the right to claim the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with this generation, the company would have been able to claim the renewable energy had been delivered to customers. Idaho Power also has several small hydroelectric projects that qualify under the state of Nevada's RPS, and RECs from these projects were sold to NV Energy in 2010. Idaho Power's Green Power Program retired 23,056 RECs in 2010, this energy can be reported as renewable energy delivered to customers.

Table 3.2 Electricity delivered to customers (2010)

Resource by Type (MWh)	Generation	RECs Sold[1]	RECs Purchased and Retired[2]	Delivered to Customers
Hydroelectric	7,344,433	-188,336		7,156,097
Coal	6,863,870			6,863,870
Natural Gas & Diesel	159,586			159,586
Purchased Power	1,992,584	573,438	-23,056	2,542,966
Wind	313,256	-313,256		0
Geothermal	71,846	-71,846		0
Renewable (Green Power Program)	0		23,056	23,056
Total	**16,745,575**	**0**	**0**	**16,745,575**

[1] When RECs are sold, Idaho Power can no longer claim the environmental attributes associated with the renewable resource. Therefore, the energy from REC sales is reclassified as Purchased Power.

[2] Idaho Power's Green Power Program retired 23,056 RECs in 2010; this energy is reported as renewable energy delivered to customers enrolled in the Green Power Program.

Existing Supply-Side Resources

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

Table 3.3 Existing Resources

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

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

Hydroelectric Facilities

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

Hells Canyon Complex

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

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

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

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

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

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

The US Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The periodic releases are part of the flow augmentation implemented by the 2000 FCRPS biological opinion. The flow augmentation water travels through Idaho Power's Mid-Snake projects and eventually through the Hells Canyon Complex before reaching the FCRPS projects.

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

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

Mid-Snake Projects

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

Idaho Power has completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail, a species listed as threatened under the ESA.

The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to license the Upper Salmon, Lower Salmon, Bliss, and C.J. Strike hydroelectric projects. During the study, Idaho Power operated the Bliss and Lower Salmon facilities under both run-of-river and load-following operations. Study results indicated that while load following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A Bliss Rapids Snail Protection Plan developed in consultation with FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company will be able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has filed license amendment applications with FERC for both projects that would allow load-following operations to resume.

Water Lease Agreements

Idaho Power views the lease of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. This approach is particularly attractive for water-lease agreements that allow the company to request delivery as needed. Acquiring water through leases also helps the company to improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex.

The company signed rental agreements in 2009 and 2010 with Water District 63 in the Boise River system to lease 13,500 and 15,400 acre feet of storage water released in December 2009 and January 2011, respectively.

In 2011, Idaho Power signed a lease agreement with Water District 1 (WD 1) in the upper Snake River system for 25,000 acre feet of storage water for release during summer 2011. The company is participating in development discussions with the WD 1 Rental Pool Committee and the upper Snake advisory committee, the Committee of Nine, regarding a supplemental rental pool for use by the company for releases below Milner Dam.

In August 2009, Idaho Power also entered into a five-year (2009–2013) water-lease agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre feet of American Falls storage water. Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of main stem Snake River hydroelectric projects.

In 2011, the company is pursuing an extension of the Shoshone–Bannock lease for two additional years, 2014 and 2015. The company plans to schedule delivery of the water between July and October of each year during the term of the lease. The Shoshone–Bannock agreement was executed in part to offset the impact of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Idaho Power intends to continue to pursue water-lease opportunities as part of its regular operations.

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snow accumulation in the south fork of the Payette River watershed. In 2008, Idaho Power expanded its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River system above Milner Dam.

Idaho Power seeds clouds by introducing silver iodide into winter storms. This process increases precipitation from passing winter storm systems. If a storm has a combination of an abundance of super-cooled liquid water vapor and appropriate temperatures, the conditions are optimal for cloud seeding to increase precipitation.

Idaho Power uses two methods to seed clouds: 1) install ground generators at high elevations, or 2) attach special flares to modified airplanes. Either method successfully releases silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide particles and eventually grow and fall to the ground as snow.

Silver iodide has been used as a seeding agent in numerous western states for decades without any known harmful effects. Analyses conducted by Idaho Power since 2003, indicate the annual snowpack in the Payette River basin increased between 5 and 15 percent (depending on the year). Idaho Power estimates cloud seeding will provide an additional 120,000 to 180,000 acre-feet of water for the Hells Canyon Complex. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

Cloud seeding station in the Payette basin.

For the 2010–2011 winter season, the program included 10, remote-controlled, ground-based generators and one airplane for operations in the Payette Basin. The program in the Upper Snake River Basin included 15, remote-controlled, ground-based generators operated by Idaho Power and 25, manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

Thermal Facilities

Jim Bridger

Idaho Power owns one-third, or 706 MW (net dependable capacity), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The plant consists of four generating units. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

North Valmy

Idaho Power owns 50 percent, or 260.5 MW (net dependable capacity) of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The plant consists of two generating units. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

Boardman

Idaho Power owns 10 percent, or 58.5 MW (net dependable capacity), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. PGE has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative (PRC) has 10 percent ownership. As the majority partner of the plant, PGE is the operator of the Boardman facility.

The 2011 IRP assumes Idaho Power's share of Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

At the end of 2010, the net-book value of Idaho Power's share of the Boardman facility was approximately $19.3 million. In order to continue operating the plant until 2020, the addition of new emissions controls will likely be required. Idaho Power's share of the additional capital cost for the new equipment is estimated to range from $1 million to $37 million depending on the final ruling from the EPA. Until the EPA formally approves the agreement, it would be difficult to estimate the net book value of Idaho Power's share of the plant in 2020.

Peaking Facilities

Danskin

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

Bennett Mountain

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

Salmon Diesel

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

Solar Facilities

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

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

Net Metering Program

Idaho Power's net metering program allows customers to install small-scale, renewable generation projects on their property and connect to Idaho Power's system. Under the program, net energy generated beyond what the customer uses is sold back to Idaho Power. A majority of the program's participants are solar projects. Currently, there are 130 solar PV installations under this program with a total capacity of 607 kW.

Oregon Solar Photovoltaic Pilot Program

In 2009, the Oregon Legislature passed ORS 757.365 as amended by House Bill 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to its customers in Oregon. Under the pilot program, Idaho Power will acquire up to 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW was allocated, and the remaining 200 kW will be offered during the next enrollment period in October 2011.

In addition to the smaller facilities under the pilot program, Idaho Power is required to either own or purchase the generation from a 500-kW, utility-scale solar PV facility by 2020. Under the rules, if the utility-scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the state of Oregon RPS.

Power Purchase Agreements

Elkhorn Valley Wind Project

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

Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly.

For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the total RECs generated by the project.

Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project is under development and is expected to begin commercial operations in 2012. Under the PPA, Idaho Power receives all the RECs from the project.

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the newly constructed 18-MW power plant at Arrowrock Dam on the Boise River; and in exchange, Idaho Power provides Clatskanie PUD energy of equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Public Utility Regulatory Policies Act

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

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The forecast used in the 2011 IRP was completed in September 2010 and did not include approximately 500 MW of wind contracts that were signed in late 2010. Because Idaho Power's future resource needs are driven by capacity requirements and not energy, the exclusion of these new contracts does not have a material impact on the 2011 IRP. At the 5-percent peak-hour capacity factor used for wind resources for planning purposes, the 500 MW of PURPA wind contracts represent only 25 MW of capacity for peak-hour planning.

As of March 31, 2011, Idaho Power had 127 PURPA contracts with independent developers for approximately 1,190 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, solar projects, and various other small, renewable-power projects. Of the 127 contracts, 91 were on line as of March 31, 2011, with a cumulative nameplate rating of approximately 491 MW. Figure 3.4 shows the total nameplate capacity of each resource type under contract. Figure 3.4 includes 294 MW from 13 PURPA wind contracts that were recently disapproved by the IPUC. Additional details on these contracts are presented in the next section.

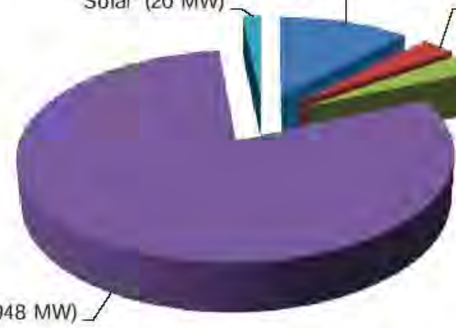

Figure 3.4 PURPA contracts by resource type

Published Avoided Cost Rates

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

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04 and GNR-E-11-01). These issues include the disaggregation of larger, utility-scale projects in order to qualify for the published avoided cost rate and the methods used to calculate the published rate. As of June 2011, this case was not resolved, and the outcome may impact some of the existing PURPA contracts for projects not yet constructed as well as future PURPA project development.

On June 8, 2011, the IPUC issued Order 32262 in this case. The order recognized that the disaggregation issue could not be solved without simultaneously addressing pricing and other issues related to PURPA. In addition, the order established that the published avoided cost rate is available for only wind and solar projects with a nameplate rating of less than 100 kW. For all other resource types, the eligibility cap will remain at 10 aMW. The order goes on to state that the next phase of the case will be a thorough review of the energy pricing methods to be used for PURPA. The order requests the parties in the case meet no later than July 8, 2011, to establish a schedule to process the next phase of the case.

In addition to Order 32262, on June 8, 2011, the IPUC issued separate orders disapproving 13 PURPA wind contracts that Idaho Power had filed requesting IPUC approval. Idaho Power expects some of the counterparties to these contracts to request the IPUC reconsider these orders. The parties have 21 days from the date of the order to file the request for reconsideration, at which time the IPUC will take requests under consideration and issue additional rulings. Rulings on the reconsideration process and other orders in the case will not be complete by the June 30, 2011, IRP filing deadline.

Wholesale Contracts

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. The agreement was established as a full-requirements contract after being approved by FERC and the Public Utilities Commission of Nevada. This contract has been renewed annually for several years; however, it is expected to expire at the end of September 2011.

Idaho Power continues to use its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during summertime heavy-load hours from PPL EnergyPlus, LLC. Although the purchase agreement expires in 2012, Idaho Power plans to continue to use the available transmission capacity during the summer months as needed until the Boardman to Hemingway transmission line is completed.

Market Purchases and Sales

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

Committed Supply-Side Resources

Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility and are treated like existing resources in the IRP analysis.

Langley Gulch

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

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

Shoshone Falls Upgrade Project

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

In July 2010, FERC issued a license amendment for the project. This amendment allows two years to begin construction and five years to complete the project. For the 2011 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in October 2015. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median water conditions, some uncertainty exists regarding future Snake River streamflows that would not only impact the Shoshone Falls project, but all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls Upgrade Project, it is included in the 2011 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the state of Idaho. Prior to filing for a CPCN with the IPUC, Idaho Power plans to update the economic analysis of the project, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

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4. Demand-Side Resources

Idaho Power's Long Valley Operations Center in Lake Fork was granted LEED gold status due in part to its energy-efficient design.

DSM customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with customers to promote energy efficiency and produce the same output or provide the same level of service with lower energy consumption. Through demand response programs, Idaho Power provides incentives to customers to identify applications where a short-term load reduction can be timed to coincide with peak energy consumption when all other resources, including transmission capacity to purchase energy, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side base load resources. Energy efficiency and demand response programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities since 2001. Due to the indirect nature of savings from market transformation, NEEA impacts are not accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of avoided power generation costs exceed the costs of offering an energy efficiency or demand response program, are published annually, and the most recent analysis can be found in the *Demand-Side Management 2010 Annual Report Supplement 1: Cost Effectiveness*. Each program in the existing portfolio of demand-side resources are reviewed as part of the IRP process for their potential impact over the 20-year IRP planning horizon. The resulting forecast of energy savings and demand-reduction potential, along with prior program performance, is then incorporated into the load forecast process. For a description of this process, see *Appendix A–Sales and Load Forecast.*

In addition to reviewing the existing portfolio of DSM resources, new opportunities for demand-side resources are evaluated for inclusion into the existing portfolio of programs and their impacts are

Highlights

- Energy Efficiency efforts from both the existing portfolio and program expansion will provide 233 aMW of system reduction over the 20-year planning period avoiding over $1.1 billion in power supply costs in 2011 dollars.
- Total peak summer capacity of the demand response program portfolio is targeted at 330 MW in 2011 and increases to 351 MW by 2016.
- Demand response programs will cost $48 per kW, and new energy efficiency will cost 5.1 cents per kWh over the IRP planning period.

forecasted. Idaho Power adopts all new demand-side resources when they are determined to be cost-effective. Energy efficiency resources are consistently one of the least-cost resources available for Idaho Power's resource stack.

All cost-effectiveness analyses for DSM forecasts for both the existing portfolio and new acquisition accounted for in the 2011 IRP are either presented as a summary in the IRP or in more detail in *Appendix C–Technical Appendix*. *Appendix B–Demand-Side Management 2010 Annual Report* contains a detailed description of Idaho Power's 2010 energy efficiency program portfolio along with historical program performance.

Energy Efficiency Program Portfolio Analysis

Each energy efficiency program currently offered to customers as part of the existing portfolio is reviewed to forecast average demand reduction. The forecast of potential programs over the IRP planning horizon considers where the program is in its life cycle (i.e., ramping up or ramping down). Also, recent program participation trends, future changes in codes and standards that will affect program measures, along with program design changes are taken into consideration.

Idaho Power placed primary emphasis on the first five years (2011–2015) when reviewing program potential; then future program performance was assumed to be held constant at 2015 levels unless known codes and standards or other mitigating circumstances justified ramping the program down early. Many unknown factors may affect program participation for the second 10 years, including multiple changes in codes and standards or technology. Therefore, programs included in the 2020 portfolio are ramped down by the end of the 20-year IRP planning period.

Historical demand-side reductions are assumed to influence customer energy-usage behavior and are accounted for in the 2011 IRP load forecast methodologies. Therefore, the current portfolio is analyzed starting in 2011 and looks at 2011–2030 impacts only. The program performance forecast assumes customers will not replace existing efficiency measures with less-efficient measures once useful life expires, and the forecasted impact of energy efficiency programs accumulates from year-to-year. For example, in 2015, Idaho Power assumes all efficient measures installed during 2011–2014 are still in place, along with incremental 2015 energy savings.

Annual savings are measured in MWh; for the IRP analysis they are divided by 8,760 hours (hours in a year), or corresponding monthly hours, to convert to average annual or monthly demand reduction (aMW) to compare with supply-side resources. All forecasts are prepared in terms of generation equivalency and include line losses of 10.9 percent, which accounts for energy lost as a result of transmitting energy between the generation source and the customer.

Table 4.1 shows the forecast impact of the current portfolio of energy efficiency programs for 2011, 2015, 2020, and 2030, in terms of average demand reduction (aMW) by customer class. In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C–Technical Appendix*.

Table 4.1 Energy efficiency current portfolio forecasted impacts (2011–2030)

	2015 (aMW)	2020 (aMW)	2025 (aMW)	2030 (aMW)
Industrial	23	46	61	66
Irrigation	5	8	11	11
Commercial	30	60	80	86
Residential	11	20	26	28
Total	**69**	**133**	**178**	**191**

Table 4.2 shows the forecast cost-effectiveness of the current portfolio of energy efficiency programs. The table shows the net-present-value analysis of the 20-year forecast of utility costs, resource costs, and avoided energy. Utility costs are the costs to administer the energy efficiency programs, while total resource costs account for both the utility costs and the customer investment in efficiency technologies and measures offered through the programs. Utility costs and total resource costs were estimated based on 2010 program performance for industrial, commercial, and residential classes and a three-year average performance for irrigation to allow for annual fluctuations between custom- and menu-driven irrigation efficiency. Avoided energy is the benefit of the programs calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing portfolio of generation resources.

Table 4.2 Existing energy efficiency portfolio cost-effectiveness summary

	2030 Load Impact (aMW)	Utility Costs (20-Year NPV*)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Utility Cost: Benefit/Cost Ratio	Utility Levelized Costs ($/kWh)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost Levelized Costs ($/kWh)
Industrial	66	$49,398,586	$96,635,806	$257,704,824	5.2	$0.015	2.7	$0.028
Irrigation	11	$14,229,458	$38,651,984	$43,667,373	3.1	$0.023	1.1	$0.061
Commercial	86	$60,885,631	$119,966,128	$335,208,357	5.5	$0.014	2.8	$0.027
Residential	28	$60,023,978	$103,519,281	$181,086,911	3.0	$0.040	1.7	$0.069
Total	**191**	**$184,537,652**	**$358,773,200**	**$817,667,465**	**4.4**	**$0.019**	**2.3**	**$0.036**

*Net present value (NPV)

The value of avoided energy over the 20-year investment in the energy efficiency measures was more than twice the total resource cost when comparing benefits and costs. This resulted in an overall benefit cost ratio of 2.3. The levelized cost to reduce energy demand by 191 aMW is 3.6 cents per kWh from a total resource cost perspective. Figure 6.9 in Chapter 6 compares energy efficiency program costs with Idaho Power's other supply-side resource options from an energy perspective.

New Energy Efficiency Resources

During each IRP planning period, Idaho Power uses various resources, including existing portfolio program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill future resource needs.
New energy efficiency opportunities are evaluated through a cost-effectiveness analysis similar to the existing programs. Forecasting assumptions for new residential efficiency for the 2011 IRP were aided by the planning model that was developed by Nexant Inc., from the *2009 Demand Side Management Potential Study*.

Along with identifying new opportunities for energy efficiency it is also important to identify the barriers that may face new program measures and expansions. One challenge the company will continue to face going forward is to increase the understanding of behaviors and decisions that residential customers make in regards to energy efficiency investments and providing the correct level of incentive to motivate them while maintaining cost-effectiveness. Much of the expansion to residential programs analyzed for the 2011 IRP include measures requiring increased customer investments, such as improved weatherization in electric home and multi-family housing. It will become increasingly important to understand the purchasing decisions of prior participants and continue forward with Idaho Power's efforts of targeted marketing and demographic analysis to work to overcome customers' investment barriers. Ongoing process evaluations of energy efficiency programs will also continue to be an important source of information for understanding customer participation in programs and for developing strategies to increase participation and program delivery. Examples of past process evaluations for energy efficiency programs can be found in the *Demand-Side Management 2010 Annual Report Supplement 2: Evaluation*.

Industrial Efficiency

Efficiency projects, through the Custom Efficiency program, which provides efficiency projects to large commercial and industrial customers continues to exceed expectations and has performed well since the program began providing incentives in 2004. Projects can include any combination of approved custom measures and process improvements that show energy efficiency enhancements. Some of the most common projects include measures, such as higher-efficiency lighting, fans, compressed air, and pumps.

Program changes, including moving some smaller lighting projects of less than 100,000 annual kWh of savings to other programs, will allow increased capacity for more custom projects over the next few years. This will lead to an increased expansion of 13 aMW over the 20-year IRP planning horizon. The increased efficiency will cost approximately 2.6 cents per kWh.

Commercial Efficiency

Program changes in the commercial and industrial efficiency programs in 2011 will shift some lighting projects into the Easy Upgrades prescriptive program that previously would have paid through the Custom Efficiency program. These potential savings were not accounted for in the original commercial program portfolio forecast and will result in an additional 6.6 aMW of average demand reduction potential over the IRP planning horizon.

Residential Efficiency

New residential efficiency includes expanded weatherization measures identified in the *Idaho Power Demand-Side Management Potential Study*, published in 2009, along with growth in incentives for heat pumps for electrically heated homes, and expansion of existing programs into the multi-family sector. During 2011 and 2012, plans are being made to add additional weatherization measures to Idaho Power's Home Improvement Program, which currently provides incentives for increasing levels of attic insulation. The additional measures are also expected to be made available to multi-family housing and will focus on windows, infiltration, and HVAC duct sealing. These program additions for electrically heated homes are forecasted to add 20.1 aMW of savings to the program over the IRP planning horizon.

Increased incentives for air-source heat pumps in 2011 will encourage customers to transition from electric, forced-air furnaces and will add 0.3 aMW of average demand reduction to the program. Weatherization Solutions for Eligible Customers, a weatherization program for income-qualified customers, will be expanded to eastern Idaho in 2011. Idaho Power forecasts the new targeted area will provide 2 aMW of increased program reduction over the IRP planning horizon.

Table 4.3 shows the forecast combined contribution in reduced average consumption over the IRP planning horizon. In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Table 4.3 New energy efficiency portfolio forecasted impacts (2011–2030)

	2015 (aMW)	2020 (aMW)	2025 (aMW)	2030 (aMW)
Industrial	7	10	12	13
Commercial	2	5	6	7
Residential	4	10	16	23
Total	**13**	**25**	**35**	**42**

Table 4.4 presents a summary of the cost and cost-effectiveness of new energy efficiency efforts. The overall benefit/cost ratio for all new energy efficiency measures is 3.2 at a levelized total resource cost of 5.1 cents per kWh. Additional details on annual costs and benefits can be found in *Appendix C–Technical Appendix*.

Table 4.4 New energy efficiency portfolio cost-effectiveness summary

	2030 Load Impact (aMW)	Utility Costs (20-Year NPV)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Utility Cost: Benefit/Cost Ratio	Utility Levelized Costs ($/kWh)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost: Levelized Costs ($/kWh)
Industrial	13	$10,293,124	$20,135,886	$56,034,905	5.4	$0.013	2.8	$0.026
Commercial	7	$4,468,872	$8,607,815	$25,770,482	5.8	$0.013	3.0	$0.025
Residential	23	$35,582,870	$69,027,549	$228,851,046	6.4	$0.045	3.3	$0.086
Total	**42**	**$50,344,865**	**$97,771,250**	**$310,656,434**	**6.2**	**$0.026**	**3.2**	**$0.051**

Demand Response Resources

The goal of demand response programs at Idaho Power is to reduce summer peak load during periods of extremely high demand and minimize or delay the need to build new supply-side resources. Demand response programs were first implemented in summer 2004 when a 6.1-MW peak-hour load reduction was measured. Idaho Power's demand response portfolio has grown since that time, and 330 MW of peak-hour load reduction has been targeted for summer 2011. Three programs 1) A/C Cool Credit, 2) Irrigation Peak Rewards, and 3) FlexPeak Management allow residential, irrigation, commercial, and industrial customers to participate in potential peak-hour load reduction efforts.

An Idaho Power customer representative discusses the Irrigation Peak Rewards program with a farmer.

A complete description of the demand response programs can be found in *Appendix B–Demand-Side Management 2010 Annual Report*.

An analysis that focused on the optimal level of demand response resources along with the costs and the most effective method of utilization was conducted as part of the 2011 IRP. The conclusions drawn from this analysis were that 1) there is a defined optimal amount of demand response for Idaho Power's system; 2) in conjunction with each IRP, Idaho Power will update the targets for demand response; 3) the program managers will work to align program design with system needs; 4) stakeholders will be involved in this process; and 5) program designs and pricing options will be reassessed. In this analysis, the costs from an energy perspective for demand response was compared to the energy costs of owning and operating an SCCT. The results of this analysis indicated actual program energy costs were inherently more because of the limitations on the number of hours the programs could be operated (60 hours) and the limited time of the year when the programs were available. The program continues to be less expensive than an SCCT from a capacity perspective, which is how the program cost-effectiveness is determined. However, from an energy perspective, it is among the most expensive resources evaluated in the IRP.

Because of the results of the analysis, Idaho Power filed with the IPUC Case No. IPC-E-10-46 asking for significant changes to the Irrigation Peak Rewards program, including a method of paying participants with a variable component based on the level of use. The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period. Demand response, because of its limited availability, cannot continually satisfy all of the load and resource balance deficits throughout the IRP planning period; rather, the goal of setting the appropriate levels of demand response is to delay the addition of new supply-side resources.

Table 4.5 presents a summary of the cost-effectiveness of the demand response programs. The Irrigation Peak Rewards program is forecast to provide 260 MW of peak-hour load reduction. The A/C Cool Credit program is expected to have 40,000 residential customer participants and is expected to provide a peak-hour load reduction of 51 MW. The FlexPeak Management program is forecast to provide 40 MW of reduction and is controlled by EnerNoc, Inc., a third-party program administrator.

Table 4.5 Demand response cost-effectiveness summary

	2030 Load Impact (MW)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost: Levelized Costs ($/kW)
Commercial/Industrial	40	$29,797,258	$46,640,850	1.6	$65
Irrigation	260	$122,250,426	$238,224,468	2.0	$45
Residential	51	$25,242,292	$52,905,340	2.1	$46
Total/Summary	**351**	**$177,289,977**	**$337,770,659**	**1.9**	**$48**

Across the demand response portfolio, the value of reduced demand compared with building a supply-side capacity resource is nearly twice the value of the cost to run the programs. The benefit/cost ratio is 1.9 with a levelized cost of $48 per kW. Detailed annual forecast costs and benefits of demand response resources are presented in *Appendix C–Technical Appendix*.

5. Supply-Side Resources

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. The company has done that; today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources considered when Idaho Power developed the resource portfolios for the 2011 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.

A vintage generator still in operation at Idaho Power's Thousand Springs power plant.

Renewable Resources

Renewable resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. In the 2011 IRP, renewable resources were included in all portfolios analyzed to meet proposed federal RES legislation. Renewable resources are discussed in general terms in the following sections.

Geothermal

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

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300ºFahrenheit (F) or greater. Binary-cycle technology is used for lower-temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid

Highlights

- The cost of solar PV technology has continued to decline as technology improvements have improved efficiency and the supply of PV panels has increased. The 2011 IRP cost estimate for solar PV is $3,750 per kW.
- Idaho Power continues the permitting process for the Boardman to Hemingway and Gateway West transmission projects that will provide additional access to the regional electricity market.
- The 2011 IRP assumes advanced nuclear, IGCC, and carbon capture and sequestration technologies will not be available until the 2020s.

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

Cost estimates and operating parameters used for binary-cycle geothermal generation in the IRP are based on data from independent geothermal developers and cost information from a PPA Idaho Power has with U.S. Geothermal, Inc., for the generation from the Neal Hot Springs geothermal project located in eastern Oregon. The capital cost estimate used in the IRP for geothermal resources is $6,250 per kW, and the 30-year levelized cost of production is $117 per MWh.

Wind

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

The Pacific Northwest and Intermountain regions are good areas for the development of wind resources, as evidenced by the number of existing and planned projects. However, wind resources present challenges for utilities due to the variable and intermittent nature of the generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2011 IRP, Idaho Power used an annual average capacity factor of 32 percent and a capacity factor of 5 percent for peak-hour planning.

Cost estimates and operating parameters used for wind generation in the IRP are based on data from independent developers and cost information obtained from the 2012 Wind RFP issued by Idaho Power. The 2012 Wind RFP did not ultimately result in the identification of a successful bidder due in large part to a recent surge in PURPA wind development in southern Idaho. The capital cost estimate used in the IRP for wind resources is $1,450 per kW, and the 30-year levelized cost of production is $89 per MWh, which includes a cost for wind integration. In 2008, the IPUC approved a settlement stipulation establishing a wind integration cost of $6.50 per MWh, which was less than Idaho Power's estimated cost to integrate wind.

Hydroelectric

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

Small Hydroelectric

Because small hydroelectric, such as run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydroelectric, the IRPAC expressed an interest in evaluating small hydroelectric in the 2011 IRP. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in the state of Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital cost estimate used in the IRP for small hydroelectric resources is $4,000 per kW and the 30-year levelized cost of production is $144 per MWh.

Pumped Storage

Pumped storage is a type of hydroelectric power generation used to change the "shape" or timing when electricity is produced. The technology stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times in order to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change. The capital cost estimate used in the IRP for pumped storage is $5,000 per kW, and the 30-year levelized cost of production is $155 per MWh.

Solar

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

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods, generally for 3–7 hours. PV technology uses panels that convert the sun's rays directly to electricity. Even on cloudy days, a PV system can still provide 15 percent of the system's rated output.

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

There are several types of solar thermal technologies, including power tower, parabolic dish engine, and parabolic trough. In designing initial portfolios that included solar resources, Idaho Power chose the power tower technology because of its lower overall cost. The company also selected the solar PV technology because of the increased availability of PV panels and the recent declining cost trend.

Power Tower

Power tower technology uses thousands of small, flat, two-axis mirrors, called heliostats, to reflect the sun's rays onto a boiler at the top of a central tower. The concentrated sunlight strikes the boiler's pipes, heating the water inside to 1,000°F. The high-temperature steam is then piped from the boiler to a turbine where electricity is generated. The power tower technology can use molten salt as a storage medium to store energy. It has a storage time of 6.9 hours that has been used to evaluate this resource in the IRP. The capital cost estimate used in the IRP for the power tower technology with storage is $3,220 per kW, and the 30-year levelized cost of production is $109 per MWh.

Photovoltaic

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

Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPS requirements, have made PV resources more cost competitive with other renewable and conventional generating technologies. The capital cost estimate used in the IRP for PV resources is $3,750 per kW, and the 30-year levelized cost of production, based on a 17-percent annual capacity factor, is $150 per MWh. Idaho Power will continue to closely follow the decreasing price trend of solar PV as this technology continues to become more cost competitive with more traditional resource alternatives.

Natural Gas-Fired Resources

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

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2011 IRP assumes new natural gas resources would require building additional pipeline capacity. This additional cost is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

Combined-Cycle Combustion Turbines

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

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

Several CCCT plants, including Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

The capital cost estimate used in the IRP for CCCT resources is $1,120 per kW, and the 30-year levelized cost of production at a 65-percent annual capacity factor is $108 per MWh with the carbon adder and $98 per MWh without the adder. If a CCCT were run at a 90-percent annual capacity factor, the 30-year levelized cost would be $100 per MWh with the carbon adder and $90 per MWh without the adder.

Simple-Cycle Combustion Turbines

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

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

Idaho Power currently has approximately 430 MW of SCCT capacity. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been built to meet peak load during critical high-demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest.

The 2011 IRP evaluated two different SCCT technologies, 1) a 47-MW small, aeroderivative unit and 2) a 170-MW industrial-frame unit. The capital cost estimate used in the IRP for the small, aeroderivative unit is $1,050 per kW, and an industrial-frame unit is $610 per kW. Because of the higher efficiency of the aeroderivative unit, it is assumed to have an annual capacity factor of 8 percent, while the industrial-frame unit is expected to have an annual capacity factor of only 6 percent.

Based on these annual capacity factors, the 30-year levelized cost of production (including the estimated cost of carbon emissions) is $319 per MWh for the small, aeroderivative unit and $316 per MWh for the industrial-frame unit. These levelized costs are nearly identical as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If an SCCT resource is identified in the IRP preferred portfolio, Idaho Power would evaluate these two technologies in greater detail prior to issuing an RFP in order to determine which technology provided the greatest benefit.

Combined Heat and Power

Combined Heat and Power (CHP), or cogeneration, typically refers to simultaneous production of both electricity and useful heat from a single plant. CHP plants are typically located at, or near, commercial or industrial facilities capable of using the heat generated in the process. These facilities are sometimes referred to as a steam host. Generation technologies frequently used in CHP projects are gas turbines or engines with a heat-recovery unit.

The main advantage of CHP is that higher overall efficiencies can be obtained because the steam host is able to use a large portion of the heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, building additional transmission capacity can also often be avoided. In addition, reduced costs for the steam host provides a competitive advantage that will ultimately help the local economy.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different.

Although a CHP resource was not identified in the 2011 IRP preferred portfolio, Idaho Power is committed to continuing its investigation into CHP opportunities on a case-by-case basis. While the actual cost of a CHP resource may be less as previous discussed, the capital-cost estimate used in the IRP for CHP is $1,860 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 93 percent, is $111 per MWh, which also accounts for the assumed cost of carbon emissions.

Several IRPAC members noted that, when considering the total societal benefit of a project, using CHP projects to produce both electrical energy and useful heat results in an overall reduction of CO_2 and other emissions. The 2011 IRP assumes emissions costs are associated with a new facility because it would be owned and operated by Idaho Power. For the next IRP, Idaho Power plans to raise this issue with the IRPAC early in the process to determine if it would be appropriate to remove some or all of the emissions cost adders from CHP resources.

Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in October 2009 with the IOER and the Amalgamated Sugar Company (TASCO), one of Idaho Power's large industrial customers. The agreement establishes the framework for a feasibility study for a CHP resource as large as 100 MW to be performed at TASCO's Nampa, Idaho facility. The TASCO facility currently uses coal to produce steam, and switching to natural gas as a fuel source would result in reduced CO_2 emissions and improve air quality in the Treasure Valley. The results of the first phase of the study looks promising, and a second, more detailed study is expected to be completed by June 2011.

Distributed Generation

In September 2010, Idaho Power received a proposal to implement and manage a distributed generation program that would use existing emergency generators owned by some of Idaho Power's largest customers. The proposal included a load-shed option and a grid-synchronized option. Both options were analyzed as part of the 2011 IRP.

In the resource stack cost analysis, the load-shed option had a cost of almost $8,500 per MWh, and the grid-synchronized option was over $10,000 per MWh. These costs are high due to the limited amount of generation these programs are expected to produce and, therefore, must also be analyzed to determine the value they provide when included with Idaho Power's other generation resources.

The load-shed option was evaluated for the first 10-year period in the IRP (2011–2020). In portfolio 1-9, this program was assumed to be available beginning in 2012. To ascertain the marginal value of the program, the other resources in portfolio 1-9 were identical to portfolio 1-4 which contained simple-cycle peaking resources. It was not necessary to evaluate the grid synchronization option because of the higher costs associated with the program.

The results of the analysis of the load-shed option showed that the distributed generation portfolio (portfolio 1-9) had a higher NPV cost of $5.6 million for the 10-year period compared to the simple-cycle portfolio under the base case assumptions used in the IRP. Idaho Power will continue to evaluate distributed generation programs in the future; however, at this time the company does not intend to pursue the implementation of a distributed generation program.

Conventional Coal Resources

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. Traditional pulverized-coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,100 MW of coal resources that are jointly owned with other utility partners who operate the facilities. Idaho Power's coal resources are located in the neighboring states of Wyoming (Jim Bridger), Nevada (Valmy), and Oregon (Boardman).

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

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

In 2007, Idaho Power decided not to pursue the development of a coal-fired resource identified in the 2006 IRP. In addition to considering the cost of a coal-based resource, the company considered the uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly owned facilities as well as monitoring the development of clean coal technologies. However, due to the uncertainty regarding future carbon regulations, conventional coal resources were not included in any of the portfolios analyzed in the 2011 IRP.

Integrated Gasification Combined-Cycle and Carbon Sequestration

IGCC is an evolving coal-based technology designed to substantially reduce CO_2 emissions. If the cost of CO_2 emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of the country's coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow CO_2 to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or "syngas" that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

The addition of CO_2-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. CO_2 has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of CO_2 produced would require the development of underground sequestration methods.

Carbon sequestration involves taking captured CO_2 and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent.

Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. For the 2011 IRP, Idaho Power is assuming this technology will not be available until the year 2024. The capital cost estimate used in the IRP for IGCC with carbon sequestration is $3,776 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $191 per MWh.

Advanced Nuclear

The nuclear power industry has been working to develop and improve reactor technology for some time. In Idaho Power's 2006 IRP, an advanced nuclear resource was included in the preferred portfolio in the year 2023, based on the assumption that an advanced-design reactor would be built on the Idaho National Laboratory (INL) site in eastern Idaho. Updated information from INL suggests the plant, if built, would be located near an industrial manufacturing hub with a high baseload energy need, most likely outside of Idaho. High capital cost coupled with a great amount of uncertainty in the actual cost of building an advanced reactor prevented a nuclear resource from being included in the preferred portfolio in Idaho Power's 2011 IRP.

The recent earthquake and tsunami in Japan, and the impact on the nuclear reactors located there, have created a global concern over the safety of nuclear power generation. While there will undoubtedly be new design and safety measures implemented, it is difficult to know the impact this disaster will have on the future of nuclear power generation.

For the 2011 IRP, an advanced nuclear resource was assumed to not be commercially available until 2023. Additionally, if the IRP identified a nuclear resource in the preferred portfolio, Idaho Power would plan to partner with other utilities in a plant built around a smaller modular design with Idaho Power's share being approximately 250 MW. Similar to the 2009 IRP, the capital cost of an advanced nuclear reactor is considerable, and the IRP risk analysis continues to account for a great amount of uncertainty in the actual cost. The capital cost estimate used in the IRP for an advanced nuclear resource is $3,820 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $229 per MWh.

Transmission

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

The Hemingway Substation is located in southwestern Idaho.

Idaho Power's transmission system is currently limited in its ability to transmit energy from markets or new resources to load centers in Idaho and eastern Oregon. Because of the need to access markets, improve reliability, integrate new resources, and facilitate renewable resource development in the region, Idaho Power has considered two major transmission projects for a number of years ; they are both included in the 2011 IRP—Boardman to Hemingway and Gateway West. These two projects were also evaluated in Idaho Power's 2009 IRP and sub-regional and regional transmission planning processes.

For the 2011 IRP, one portfolio requiring Boardman to Hemingway capacity was analyzed for the first 10 years of the planning horizon (2011–2020). In the second 10 years (2021–2030), one portfolio included additional capacity to the Pacific Northwest and another included additional capacity to the east side of Idaho Power's system. These two portfolios were designed to evaluate the cost of market purchases on either side of Idaho Power's system. The Gateway West project was included in portfolios for the second 10-year period when current constraints required the addition of new transmission capacity for resources to be added in southern Idaho, east of the Treasure Valley load center. However, the amount of Gateway West capacity is different in each portfolio, depending on other included resources.

Idaho Power faces increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including Bonneville Power Administration's (BPA) southern Idaho contracts. The development of wind and other renewable resources in response to state RPS requirements is anticipated to further increase the demand for transmission capacity between the Intermountain Region and the Pacific Northwest.

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

Boardman to Hemingway

The proposed Boardman to Hemingway project involves constructing, operating, and maintaining a new, single-circuit, 500-kV transmission line approximately 300 miles in length. The proposed route is between northeast Oregon and southwest Idaho. The new line will provide many benefits, including 1) greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area; 2) improved system reliability and reduced capacity limitations on the Pacific Northwest's transmission system as demand for energy continues to grow; and 3) assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon.

The project is expected to be completed and in service in 2016. The overhead, 500-kV, high-voltage transmission line will connect a future substation near Boardman, Oregon, to the Hemingway Substation, located near Melba, Idaho. The proposed transmission line will connect with other transmission lines on either end of the project to convey electricity on a regional scale. Figure 5.1 shows a map of the region with the proposed route of the new line.

In the 2006 IRP, Idaho Power anticipated the new line would interconnect at the McNary substation; however, there is insufficient room at the existing McNary substation for major transmission expansion options. A number of utilities are also considering a northeast Oregon (NEO) substation to provide future interconnectivity of regional projects. The exact location and in-service date for the NEO substation is unknown at this time. The proposed Boardman to Hemingway project is not dependent on completion of the NEO substation project or any of the other transmission proposals to satisfy Idaho Power's load-serving need or other existing service requests.

The Boardman to Hemingway project will use a bundled-conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the Western Electricity

Coordinating Council's (WECC) rating process, the initial implementation of the Boardman to Hemingway project is likely to result in an Idaho to Northwest path increase of 1,300 MW from east-to-west (exports into the Pacific Northwest), on completion of the Gateway West Project and about 850 MW from west-to-east (imports into Idaho Power's balancing authority area). The ratings are subject to technical peer review and will be revisited as other regional projects continue to develop. As additional projects reinforce the transmission network, additional capacity rating increases of the Boardman to Hemingway project may occur.

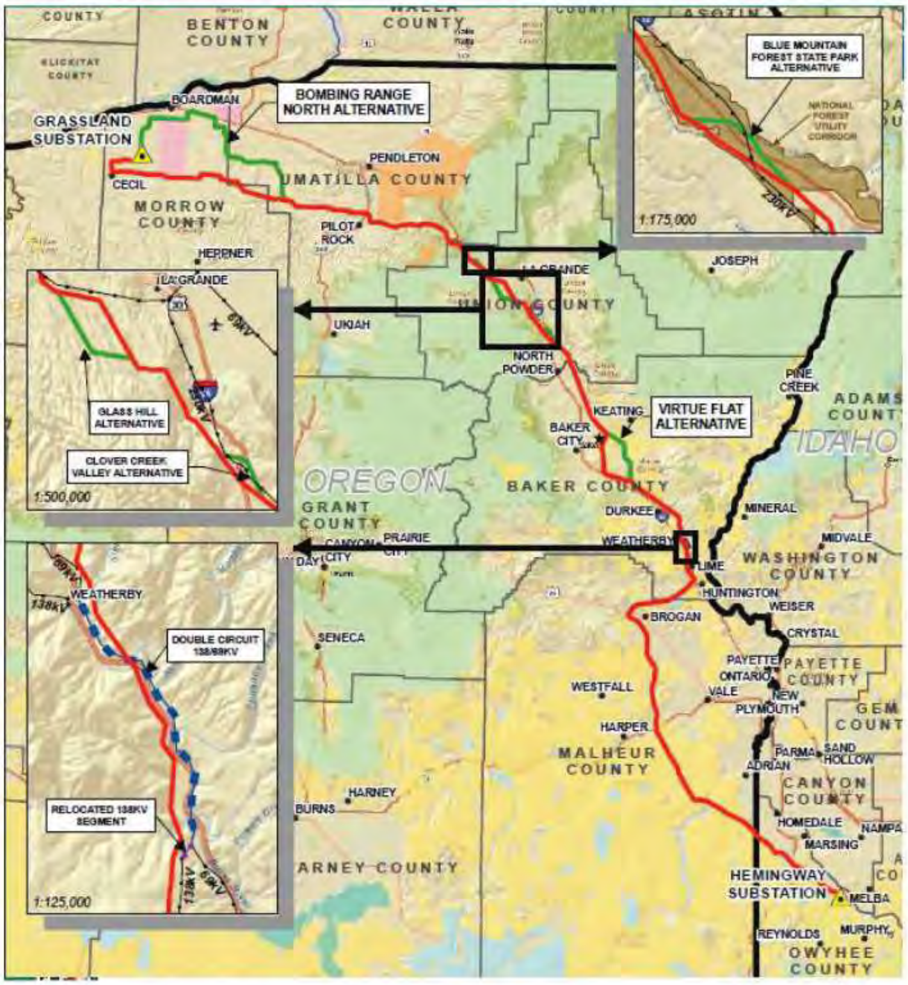

Figure 5.1 Boardman to Hemingway line project map

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

Idaho Power received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho–Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. In the 2006 IRP, Idaho Power identified a need for 225 MW of energy imports from the

Pacific Northwest to Idaho Power's system. The 2009 IRP analyzed various levels of imports, and the final preferred portfolio included 425 MW of capacity on Boardman to Hemingway. The updated analysis in the 2011 IRP indicates 450 MW of capacity is needed on the line to meet Idaho Power's needs.

The Boardman to Hemingway project is important for the development of renewable resources as northeast Oregon has the potential for both wind and geothermal resource development. In 2007, Idaho Power and Horizon Wind Energy developed the first phase of the 101-MW Elkhorn Valley Wind Project in Union County, Oregon, and Idaho Power purchases the output from the facility under a long-term PPA. Firm transmission capacity existed for the first 66 MW of the wind project. The remaining 34 MW of output from the Elkhorn project may face curtailment during times of transmission congestion. Further renewable resource development in northeast Oregon will require additional transmission resources.

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

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power conduct more extensive outreach as part of identifying a route for the new transmission line. In response, Idaho Power initiated the Community Advisory Process (CAP) to engage communities from Boardman, Oregon to Melba, Idaho in siting the Boardman to Hemingway project. The CAP enlisted project advisory team members in five geographic regions within the project area. The members were familiar with the local areas and issues and understand the topography, recreation, wildlife, and view-shed issues; they collaboratively worked with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009. The CAP process was completed in July 2010; however, Idaho Power continues to meet with landowners and work with local communities as the project moves forward through the local-, state-, and federal-review processes.

Additional information about the Boardman to Hemingway project can be found at http://www.boardmantohemingway.com.

Updated Cost Estimate

The 2011 IRP contains an updated cost estimate for the Boardman to Hemingway line. Idaho Power worked with two primary contractors, Pike Energy Solutions and Tetra Tech EC, Inc., to prepare the updated estimate. The new estimate also updates Idaho Power's internal costs in addition to the estimates provided by Pike Energy Solutions and Tetra Tech EC, Inc. As a result of the analysis, the updated cost estimate increased from the 2009 IRP estimate of $634 million to $820 million.

Pike Energy Solutions provided the line and stations engineering and construction costs for the project and Tetra Tech EC, Inc. provided the environmental permitting and mitigation cost estimates for the project. In addition, Idaho Power included estimated costs for internal labor hours, right-of-way overheads, property taxes, allowance for funds used during construction (AFUDC), and contingency estimates in support of the entire project. The detailed estimate included in *Appendix C–Technical Appendix* shows the combination of third-party cost estimates provided by Pike Engineering Solutions, Tetra Tech EC, Inc., and estimates for Idaho Power's internal costs.

The updated costs show significant increases in material prices and construction costs, primarily due to increased material and labor prices and line-route modifications to move the routing away from agricultural land. The AFUDC estimate has also increased due to a projected rate increase of 5 percent to 7.5 percent. Property taxes were not included in the 2009 IRP estimate and have now been included in the updated estimate.

For the 2011 IRP, the contingency estimate has been reduced from 30 percent to 20 percent because of the higher level of project definition and detail and increased level of confidence in the line location and the engineering and design aspects of the project. The contingency estimate is consistent with Idaho Power's estimating practices and industry standards for contingency estimating. The updated cost estimate does not include any estimated impacts of future inflation that may occur following the date of the estimate; however, the IRP analysis assumes a general inflation rate of 3 percent, which is applied consistently to all resources.

The results of the 2011 IRP analysis indicate the Boardman to Hemingway transmission line will be a well-used resource that benefits Idaho Power's retail and transmission customers, as well as consumers and generators in both the Pacific Northwest and the Intermountain Region. The capital cost of the Boardman to Hemingway project, as measured on a dollars-per-kW-of-capacity basis, has the lowest capital cost of any supply-side resource alternative.

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,150 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming to the Hemingway substation near Melba, Idaho. The project is being designed so multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service in the 2015–2017 timeframe. Numerous routes under consideration are shown in Figure 5.2.

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

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

The Gateway West project is currently undergoing an extensive and ongoing public involvement process to identify proposed and alternate routes. The outreach work is being done in conjunction with the NEPA process related to environmental studies, as well as local jurisdictions for permitting. The project as proposed in Idaho includes two separate 500-kV lines between the Populus substation in southeast Idaho, and the Hemingway Substation in southwestern Idaho, with connection in central Idaho between the Midpoint Substation and the proposed Cedar Hill substation.

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

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

Figure 5.2 Gateway West line project map

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6. Planning Period Forecasts

The IRP process requires Idaho Power prepare numerous forecasts that can be grouped into four main categories, 1) load forecasts, 2) a generation forecast, 3) fuel price forecasts, and 4) financial assumptions. The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2011 IRP.

Forecasting load growth is essential for Idaho Power to meet the future needs of customers.

Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning in the months of June, July, and August. For a number of years, the growth rate of peak-hour load has exceeded the growth of average monthly load. However, both measures are important in planning for future resources and are part of the load forecast prepared for the 2011 IRP.

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

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

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics,

Highlights

- Idaho Power's summer peak load record of 3,214 MW was set in June 2008.
- Idaho Power's customers set a new winter system peak record of 2,528 MW on December 10, 2009, during several days of below-normal temperatures.
- The 2011 IRP assumes an expected-case carbon adder of $20 per ton starting in 2015.
- For the first time, the IRP load forecast includes the expected impact of electric vehicles.
- The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period.

Inc.'s July 2010 macroeconomic forecast strongly influenced the 2011 IRP load forecast. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., are also used in developing the 2011 IRP load forecast. The forecast of the number of households, employment projections, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

Weather Impacts

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

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

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

Economic Impacts

The national recession that began in 2008 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the recession resulted in a collapse in new residential customer growth from the addition of 15,000 new residential customers each year prior to the recession, to approximately 2,000 new customers added each year at the present. Commercial and industrial customer energy use contracted and overall system energy use declined by 3.5 percent in 2009, followed by a 1.2 percent decline in 2010—the first time overall energy use has declined since the energy crisis of 2001.

Increased population in Idaho Power's service area—due to migration to Idaho from other states—is expected to continue throughout the planning period and has been included in the load forecast model. Idaho Power also continues to receive requests from prospective new large-load customers attracted to southern Idaho due to the relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual, county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with estimated consumption per household and considerations made for DSM measures, results in a 1.5-percent residential load growth rate.

The number of residential customers in Idaho Power's service area is expected to increase 1.4 percent annually from approximately 409,000 at the end of 2010 to nearly 536,000 by the end of the planning period in 2030.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A–Sales and Load Forecast*. For example, the expected annual average system load growth of 1.4 percent (over the period 2011 through 2030) is comprised of residential load growth of 1.5 percent, commercial load growth of 1.3 percent, irrigation load growth of 0.3 percent, industrial load growth of 1.7 percent, and additional firm load growth of 2.0 percent.

The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow significantly. In addition, the significant increase in assumed DSM combined with retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified in the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP) and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario in the 2009 IRP, Idaho Power curtailed coal resources to comply with target emissions levels.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service-area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power customers. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to slowly recover; by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004). The cost of carbon impact on the 2011 IRP load forecast was not material because of the cap-and-trade assumption used in the 2009 IRP, which was the basis for carbon costs in the 2011 IRP load forecast.
- In this year's forecast, an additional customer referred to as "Special" was included in the additional firm load category even though a long-term contract had not yet been fully executed.

At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough for it to be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

- There continues to be significant uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contact Idaho Power and express interest in locating production operations within Idaho Power's service area and the unknown magnitude of the energy and peak demand requirements. The current sales and load forecast reflects only those customers that have a high probability of locating in the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron, Inc.'s residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron, Inc.'s SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast compared to earlier forecasts (prior to 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand-lines to electrically operated pivots may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand-lines has triggered the substitution of labor with electrically operated pivots.

Peak-Hour Load Forecast

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

Idaho Power's system peak-hour load record, 3,214 MW, was recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as air conditioning became standard in nearly all new residential home construction and new commercial buildings. The growth in peak demand slowed considerably in 2008 and 2009 due to a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also served to reduce peak demand. The 2011 IRP load forecast projects peak-hour load to grow by approximately 69 MW per year throughout the planning period.

The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance.

Figure 6.1 and Table 6.1 summarize three forecast outcomes of Idaho Power's estimate of annual system peak load considering median, 90th percentile, and 95th percentile weather impacts on the expected (median) peak forecast. The 95th percentile forecast uses the 95th percentile peak-day average temperature to determine monthly peak-hour demand. The planning criteria for determining the need for peak-hour capacity assumes the 95th percentile peak-day temperature conditions.

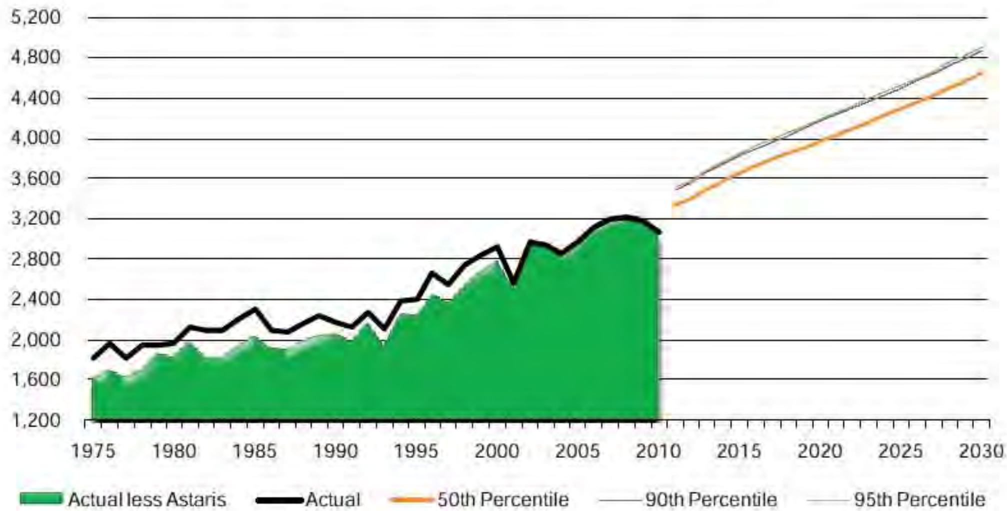


Figure 6.1 Peak-hour load growth forecast (MW)

Table 6.1 Load forecast—peak-hour (MW)

Year	Median	90th Percentile	95th Percentile
2010 (Actual)	2,930	2,930	2,930
2011	3,334	3,494	3,515
2012	3,392	3,555	3,577
2013	3,496	3,662	3,684
2014	3,577	3,747	3,770
2015	3,657	3,831	3,854
2016	3,725	3,902	3,925
2017	3,787	3,967	3,991
2018	3,847	4,031	4,056
2019	3,911	4,098	4,123
2020	3,973	4,164	4,190
2021	4,034	4,229	4,254
2022	4,098	4,296	4,323
2023	4,165	4,367	4,394
2024	4,229	4,435	4,462
2025	4,291	4,501	4,529
2026	4,358	4,571	4,599
2027	4,419	4,635	4,664
2028	4,498	4,718	4,747
2029	4,569	4,792	4,822
2030	4,643	4,870	4,901
Growth Rate (2011–2030)	**1.8%**	**1.8%**	**1.8%**

The median or expected-case peak-hour load forecast predicts peak-hour load will grow from 3,334 MW in 2011 to 4,643 MW in 2030, an average annual compound growth rate of 1.8 percent. The projected average annual compound growth rate of the 95th percentile peak forecast is 1.8 percent. In the 95th percentile forecast, summer peak-hour load is expected to increase from 3,515 MW in 2011 to 4,901 MW in 2030. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on Thursday, December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to the variability of peak day temperatures in winter months, which is far greater than the variability of peak-day temperatures in summer months.

Average-Energy Load Forecast

Potential monthly average energy use by customers in Idaho Power's service area is defined by a series of four load forecasts that reflect a range of load uncertainty resulting from differing economic growth and weather-related assumptions. Figure 6.2 and Table 6.2 show the results of the four forecasts used in the 2011 IRP to estimate the boundaries of annual system load growth over the planning period. There is approximately a 90-percent probability that Idaho Power's load growth will exceed the low-load growth forecast, a 50-percent probability of load growth exceeding the expected-case forecast, a 30-percent probability of load growth exceeding the 70th percentile forecast, and approximately a 10-percent probability that load growth will exceed the high-growth forecast. The projected 20-year average annual compound growth rate in the expected-load forecast is 1.4 percent.

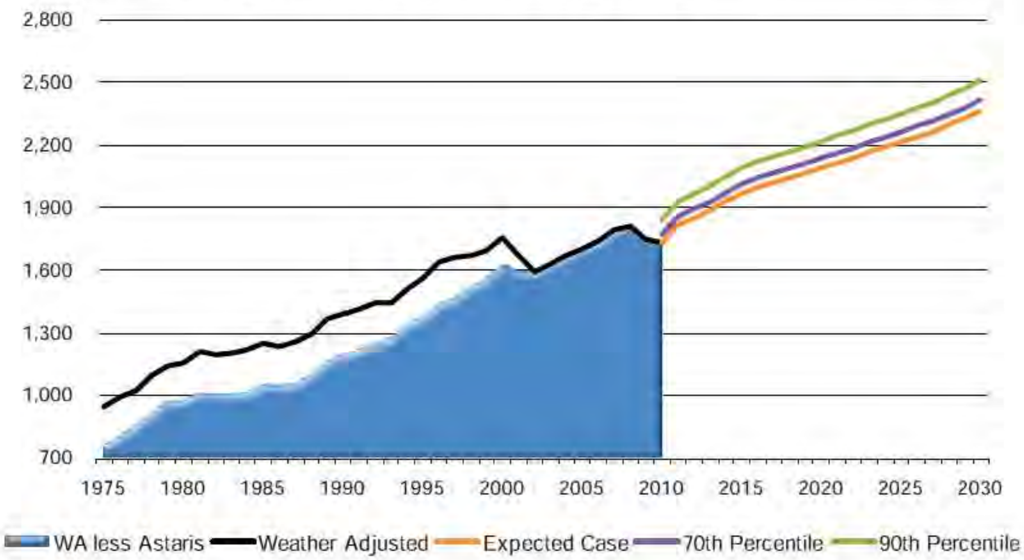


Figure 6.2 Average monthly load growth forecast (aMW)

Table 6.2 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	Low	High
2011	1,819	1,860	1,793	1,878
2012	1,852	1,893	1,814	1,936
2013	1,890	1,931	1,836	1,987
2014	1,932	1,974	1,866	2,043
2015	1,970	2,013	1,894	2,094
2016	1,998	2,042	1,913	2,135
2017	2,023	2,067	1,927	2,170
2018	2,045	2,090	1,940	2,203
2019	2,070	2,115	1,956	2,238
2020	2,090	2,136	1,970	2,271
2021	2,114	2,160	1,983	2,303
2022	2,139	2,186	2,000	2,338
2023	2,166	2,214	2,019	2,375
2024	2,189	2,237	2,036	2,410
2025	2,214	2,263	2,051	2,443
2026	2,241	2,290	2,070	2,480
2027	2,263	2,313	2,084	2,511
2028	2,298	2,349	2,113	2,560
2029	2,329	2,380	2,133	2,598
2030	2,362	2,414	2,158	2,642
Growth Rate (2011–2030)	**1.4%**	**1.4%**	**1.0%**	**1.8%**

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

Additional Firm Load

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each individual, large-power customer. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement.

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River Rural Electric Cooperative. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special-contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered imminent. In this year's forecast, the company has included the anticipated load of an additional special-contract customer referred to as "Special" in the additional firm load category even though a long-term special contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special-contract customers and the new "Special" contract together make up the additional firm-load category.

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010) Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013. In the time since the IRP load forecast was prepared, Hoku Materials has delayed the ramp up of its operations; however, this delay is not expected to impact the results of the 2011 IRP.

"Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm-load category even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within the Idaho Power service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact.

Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficits for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison.

Table 6.3 provides a summary of the six planning scenarios analyzed for the 2011 IRP, and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2011 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2011 IRP are consistent with the criteria used in the 2009 IRP.

Table 6.3 Planning criteria for average monthly and peak-hour load

Average monthly load/energy (aMW)	50th Percentile Water, 50th Percentile Average Load **70th Percentile Water, 70th Percentile Average Load** 90th Percentile Water, 70th Percentile Average Load
Peak-hour load (MW)	50th Percentile Water, 90th Percentile Peak-Hour Load 70th Percentile Water, 95th Percentile Peak-Hour Load **90th Percentile Water, 95th Percentile Peak-Hour Load**

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

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

Existing Resources

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

Brownlee Dam is part of the Hells Canyon Complex.

Hydroelectric Resources

For the 2011 IRP, Idaho Power continues the practice of using 70th percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means that basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

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

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

The 50th, 70th, and 90th percentile streamflow forecasts used in the IRP are derived from a streamflow planning model developed by the Idaho Department of Water Resources (IDWR). The IDWR streamflow planning model is used by Idaho Power to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The normalized model accounts for current hydroelectric conditions and historical hydroelectric development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70th percentile year in 2010 is identical to a 70th percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface water outflow from the river basin. The ESPA CAMP includes demand reduction and weather modification measures that will add new water to the basin water budget. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years is expected to resume and result in a return to declining basin outflows that is assumed to persist through at least the first 10 years of the 2011 IRP planning horizon. The declining basin outflows for this IRP are assumed to continue through 2023, with no further decline assumed for the remainder of the planning period through 2030. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on the projected date at which basin hydrologic conditions equilibrate as a standard part of forecasting hydroelectric generation for future IRPs.

River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies continue to support efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of the naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years.

Because worse-than-median water is assumed in the IRP, and the importance of July as a resource-constrained month, Idaho Power incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP and continues to incorporate the modified flow augmentation for the 2011 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on resource planning analyses, monthly average hydroelectric generation for July under the 70th percentile streamflow condition is projected to decline by approximately 115 aMW as a result of the water being shifted out of the month of July.

Monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the Hells Canyon Complex as run-of-river plants. The generation model mathematically manages reservoir storage in the Hells Canyon Complex to meet the remaining system load, while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April–July runoff period. Figure 6.3 shows historical April–July Brownlee inflow as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability, but do include reductions related to declining base flows in the Snake River. As noted previously in this section of the report, these declines are assumed to equilibrate beyond 2023.

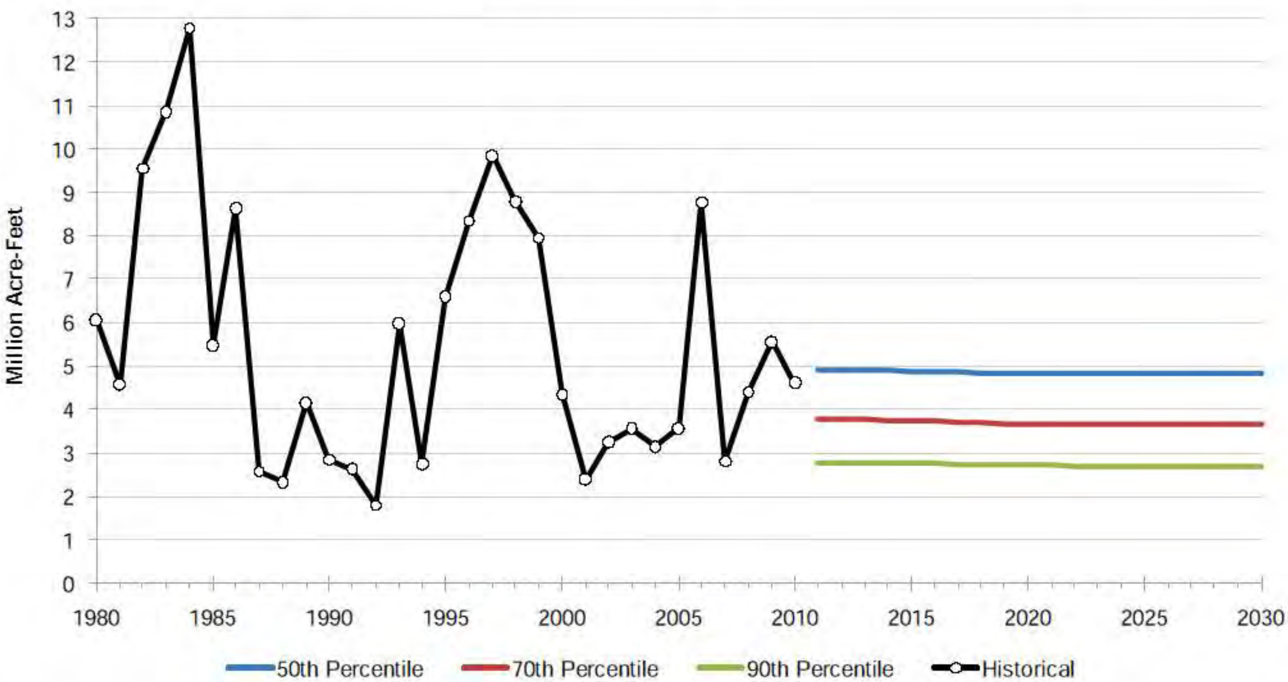


Figure 6.3 Brownlee historical and forecast inflows

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2011 IRP.

Coal Resources

Idaho Power's coal-fired generating facilities have operated typically as fully dispatched baseload resources. Monthly average-energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low-market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the full-rated, maximum dependable capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C–Technical Appendix*.

Plant modifications required to maintain compliance with air-quality standards are projected for the Boardman plant in 2011, 2014, and 2018, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The total effect of the air-quality modifications is a reduction in coal-fired generation of less than 1 percent.

The 2011 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

Planned Upgrades at Jim Bridger

Turbine upgrades are continuing at the Jim Bridger plant with the replacement of the high-pressure/intermediate-pressure turbine on unit 2 planned for 2013. The high-pressure/intermediate-pressure turbine on unit 1 was upgraded in 2010. Upgrades of the high-pressure/intermediate-pressure turbines on units 3 and 4 and upgrades to the low-pressure turbines on all four units are currently being evaluated.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs. These resources are typically operated during high-load occurrences in summer and winter months. The monthly average energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during the months of January, June, July, August, and December, producing on average approximately 230 aMW of gas-fired generation for the selected months. With respect to peak-hour output, the SCCTs are assumed capable of producing on-demand peak capacity of 416 MW. While this dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power is currently constructing the Langley Gulch CCCT, which is expected to be commercially available in July 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. For the 2011 IRP, Langley Gulch is forecast to contribute 251 aMW of energy per month, with on-demand peaking capacity of 300 MW.

Transmission Resources

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

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

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

For the 2011 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90th percentile streamflows, 70th percentile load, and 95th percentile peak-hour load. The 95th percentile peak-hour load planning criterion means that there is a 1-in-20 chance that Idaho Power will be required to initiate more drastic measures, such as curtailing load, if attempts to acquire energy and transmission access from the spot market are unsuccessful.

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

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

Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2011 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The forecast sources include the NPCC, the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Moody's Analytics, Inc.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness of the forecasts when compared with others, and the current forward price of actual contracts being executed on various exchanges. In the near-term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to longer-term forecasts that are weighted more heavily towards projected prices without underlying financial trades (EIA, Moody's, Inc.).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment (basis) based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate. Figure 6.5 shows the major natural gas pipeline transportation paths in the Pacific Northwest.

The Henry Hub price, including the Sumas Basis, is shaped monthly to reflect the normal seasonal supply and demand price variation. The gas price forecast in all future years receives the same monthly price shaping. Sumas gas prices can have high seasonal spot price variability, especially in the winter months, and the Sumas price volatility is not included in the regional adjustment. Idaho Power's geographic position between Sumas gas and Rockies gas allows Idaho Power to access two independent gas markets that may not have high-price correlation. Also, Idaho Power hedges a portion of its short- and mid-term gas planned for use in the resource portfolio. This hedging activity is intended to reduce the spot and seasonal-price volatility of natural gas costs incurred by customers.

The 2011 IRP analyzes three gas price scenarios as shown in Figure 6.4. The expected-case forecast has a 20-year levelized cost of $7.92 per MMBtu, while the high case is $9.82 per MMBtu and the low case is $6.01 per MMBtu. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

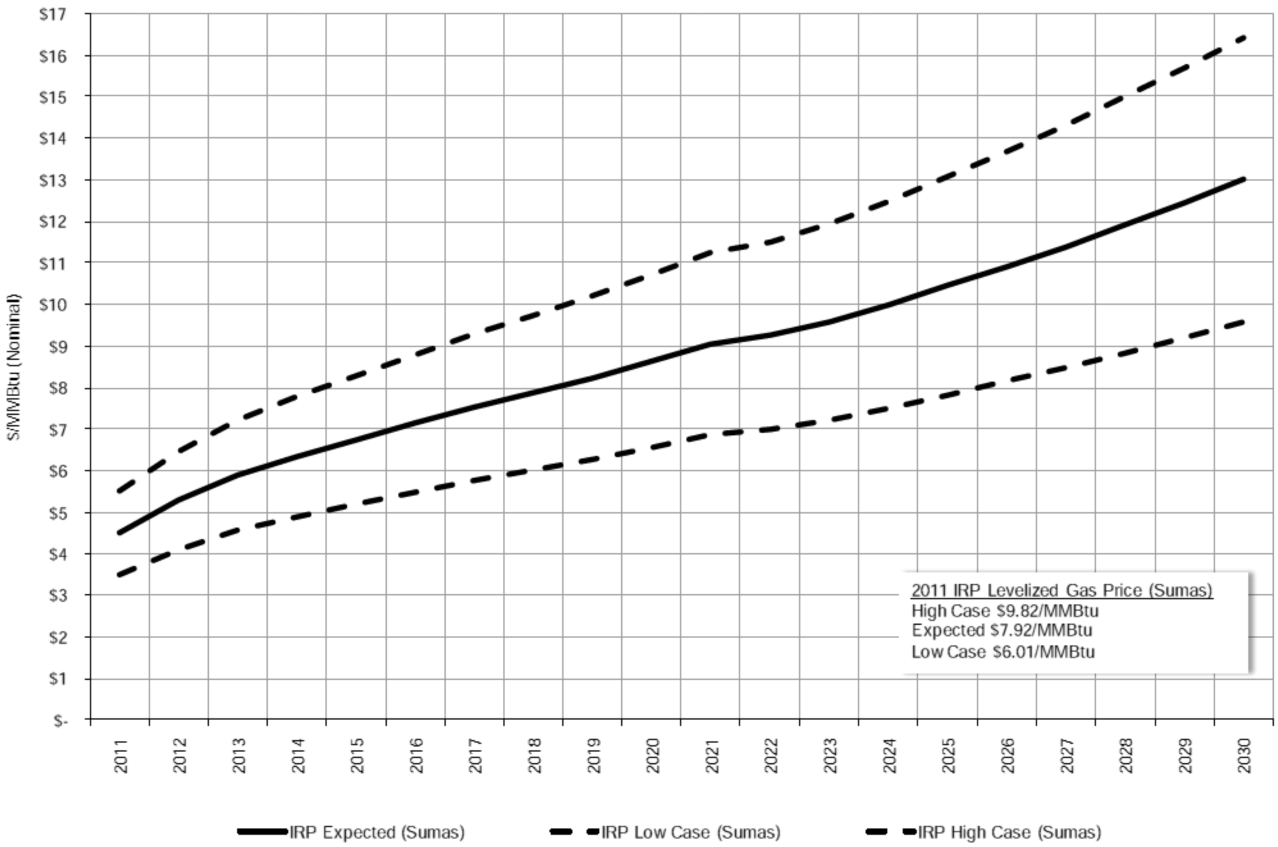


Figure 6.4 Natural gas price forecast

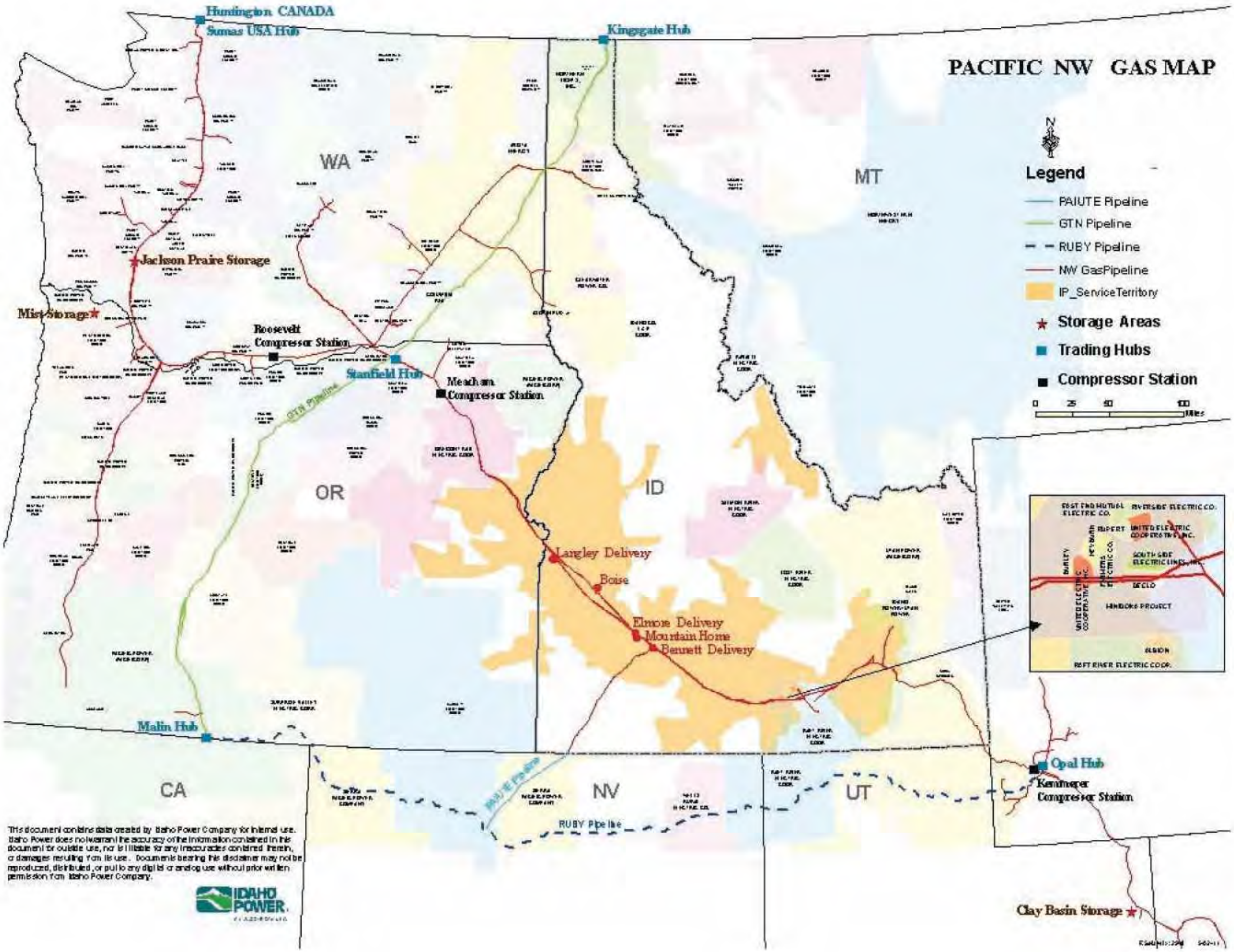


Figure 6.5 Pacific Northwest natural gas transportation paths

Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2011 IRP. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources, including, but not limited to, the NPCC, the US Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as follows:

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

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine capital cost of the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system upgrade costs were estimated by Idaho Power's transmission planning group and were included in the total portfolio cost. The capital costs also includes AFUDC (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

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

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

Emissions Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of the environmental and social costs. It is likely that further emissions regulations will be implemented during the period covered in the 2011 IRP.

In the analysis, Idaho Power incorporated estimates for the future cost of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emissions adders for CO_2, NO_x, Hg, and SO_2. The additional costs are assumed to begin in 2015. Table 6.4 provides the emissions intensity rates assumed in the analysis and the emissions adder costs shown in Table 6.5 were used to calculate the total emissions costs of the various fossil fuel-based resources that were analyzed. Additional information regarding the cost of carbon emissions is provided in the next section.

In addition to including the emission adders in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for CO_2, NO_x, Hg, and SO_2 emissions for each portfolio in the first 10-year and second 10-year planning periods. The expected case regulatory environmental compliance costs for each planning period is shown in *Appendix C–Technical Appendix.* A sensitivity analysis (low-case and high-case) for these compliance costs can also be found in *Appendix C–Technical Appendix.*

Table 6.4 Emissions intensity rates (lbs/MWh)

Adder	CO_2	NO_x	Hg	SO_2
Pulverized Coal	1,901	3.38	0.000050	8.5339
IGCC	2,279	0.21	0.000006	0.1490
IGCC with Carbon Sequestration	420	0.43	0.000006	0.1833
Distributed Generation Natural Gas	1,115	1.07	N/A	0.0096
SCCT	1,413	1.36	N/A	0.0122
CCCT	809	0.08	N/A	0.0070

Table 6.5 Emissions adder cost assumptions

Adder	Emission Adder Cost	First Year Applied	Annual Escalation
GHG	$20 per ton	2015	5.0%
NO_x	$2,600 per ton[1]	2015	2.5%
Hg	$1,443 per ounce[1]	2015	2.5%
SO_2	$1.75 per ton	2011	2.5%

[1] 2011 dollars

Cost of Carbon Emissions

Although Idaho Power believes a cap-and-trade system is more likely than a carbon tax to be implemented in the future, regulatory requirements dictate the analysis be performed using a carbon adder or tax, which Idaho Power has done for the 2011 IRP. The purpose of a carbon adder is to account for all of the costs in the price of energy produced by carbon-emitting resources.

Four carbon-adder scenarios were analyzed as part of the 2011 IRP: 1) the expected case starting at $20 per ton in 2015 and escalating at 5 percent annually, 2) the high case starting at $25 per ton in 2015 and escalating at 7.5 percent annually, 3) the low case starting at $15 per ton and escalating at 2.5 percent annually, and 4) the zero-cost case where there is no future cost associated with carbon emissions. The carbon adder assumptions used in the 2011 IRP are shown in Figure 6.6. A discussion of the analysis results of the cost of carbon emissions is contained in Chapter 9.

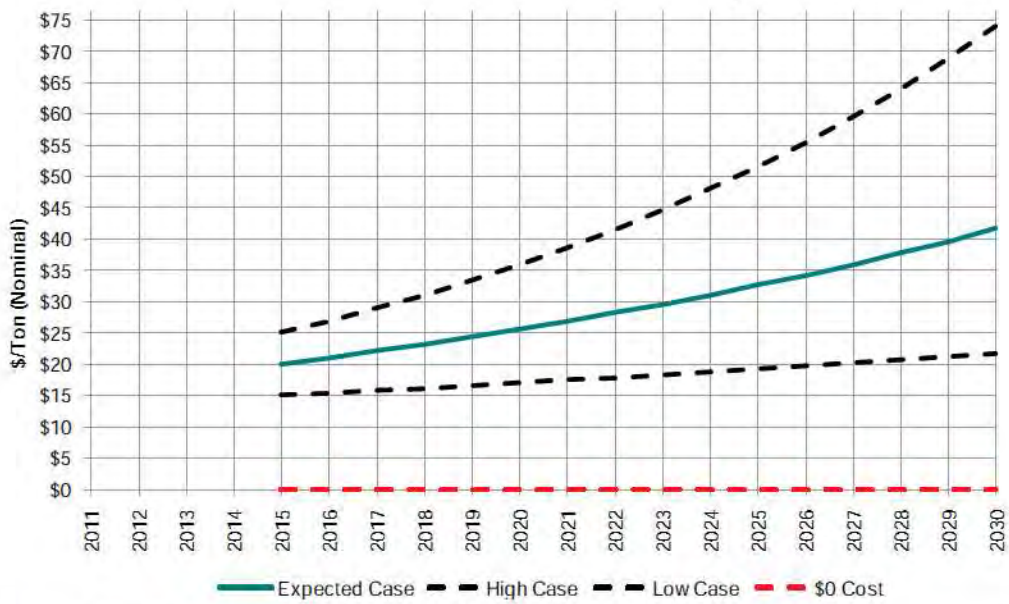


Figure 6.6 Carbon-adder assumptions

Production Tax Credits for Renewable Generating Resources

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

Renewable Energy Credits

While the state of Idaho does not have an RPS requirement, Idaho Power believes a federal RES requiring Idaho Power to retire RECs for compliance will be passed by Congress in the near future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010 by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Three different scenarios for the future value of RECs were analyzed as part of the 2011 IRP: 1) the expected-case scenario where RECs are valued at $7 in 2013 and escalated at 3 percent annually, 2) a high-case scenario where RECs are valued at $21 in 2013 and escalated at 3 percent annually, and 3) a low-case scenario where RECs have no value beginning in 2013. The three REC price assumptions used in the 2011 IRP are presented in Figure 6.7. A discussion of the analysis of the value of RECs in each of the portfolios analyzed in the 2011 IRP is presented in Chapter 9.

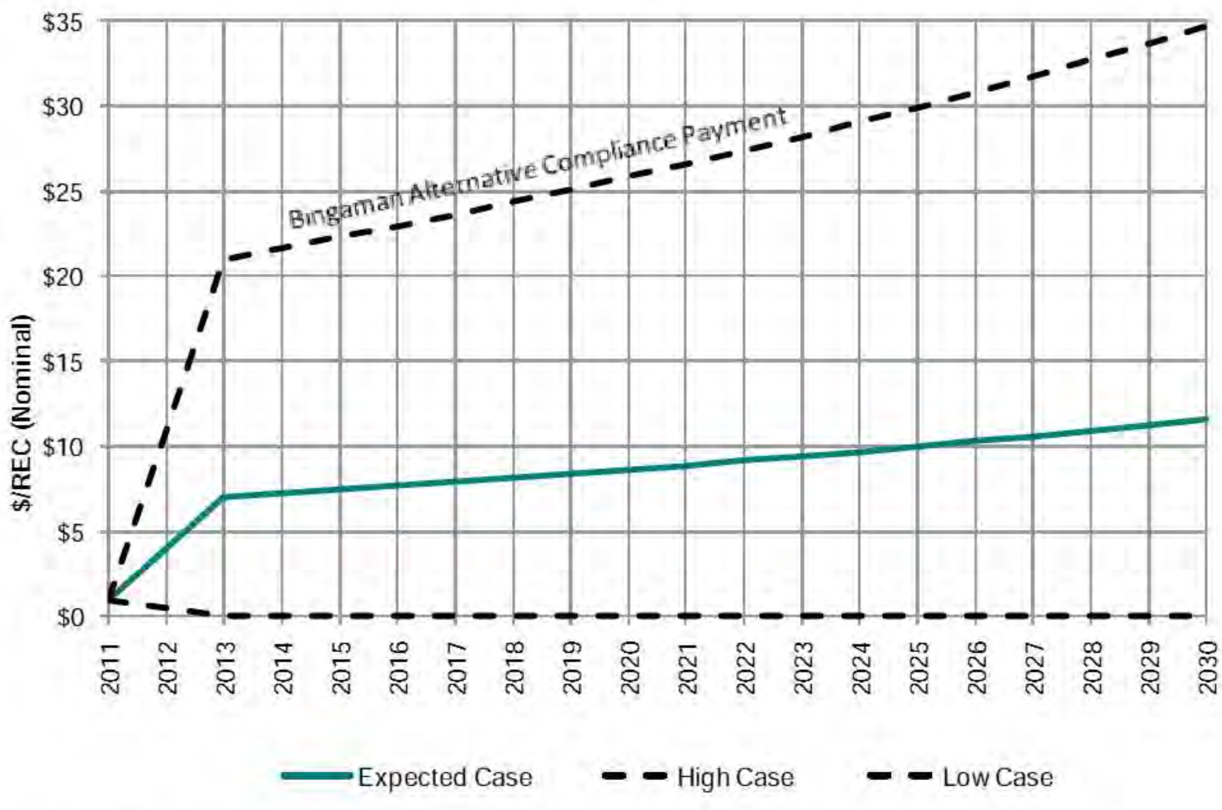


Figure 6.7 REC price assumptions

Levelized Capacity (Fixed) Cost

The annual fixed revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars-per-kW of plant nameplate capacity per month. Included in these costs were the cost of capital and fixed O&M estimates. Figure 6.8 provides a combined ranking of all the various resource options, in order of lowest to highest levelized fixed cost-per-kW-per-month. The ranking shows distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours-per-year to meet peak-hour demand.

Levelized Cost of Production

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

The nominal, levelized cost of production assuming the expected capacity factors for each resource-type is shown in Figure 6.9. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost of production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost of production calculation for a generation resource is the assumed level of annual capacity utilization over the life of the resource, referred to as capacity factor. A capacity factor of 50 percent would suggest that a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost will be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity factor assumptions reduce the MWh and the levelized cost would be higher.

Resource capital costs are annualized over a 30-year period for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.

Figure 6.8 30-year levelized capacity (fixed) costs

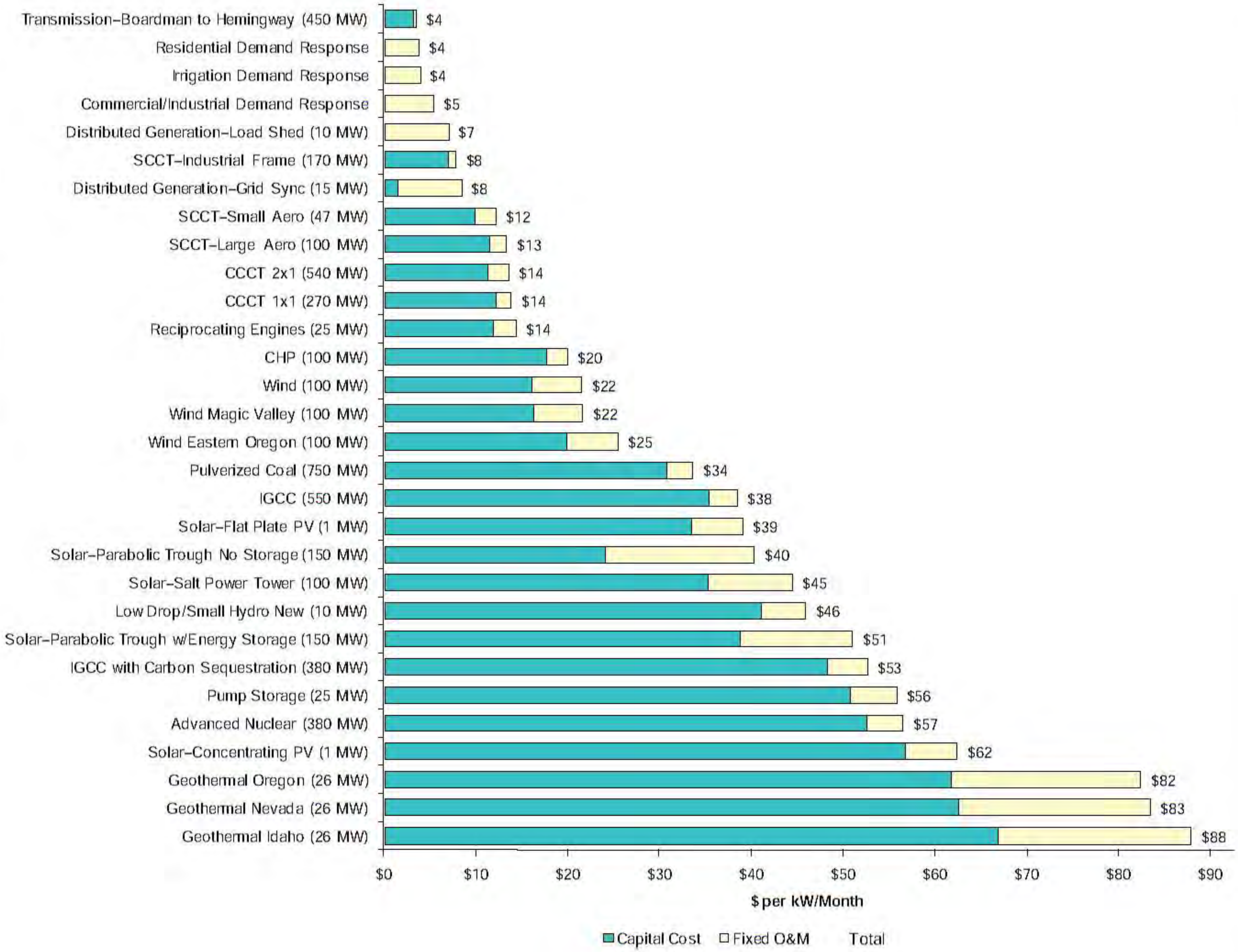
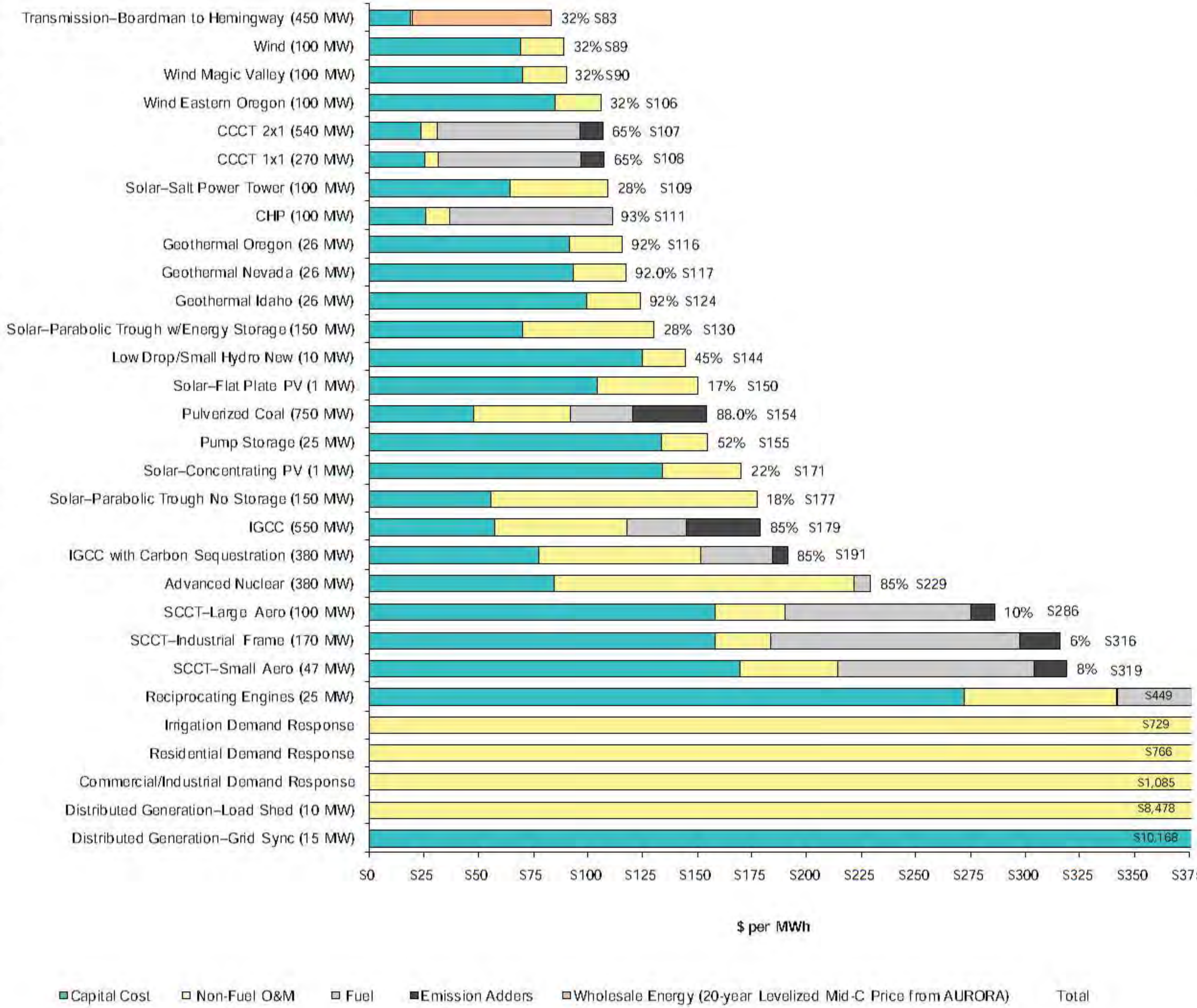


Figure 6.9 30-year levelized cost of production (at stated capacity factors)



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7. Transmission Planning

Past and Present Transmission

High-voltage transmission lines are necessary to deliver electricity to load and connect with other regional utilities.

High-voltage transmission lines have been vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that have served the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the Hells Canyon Complex and on to the Treasure Valley were central to the development of the Hells Canyon Complex in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three, coal-fired power plants located in neighboring states, which supply approximately 40 percent of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric resources with access to wholesale energy markets.

The regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of this, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load and sells excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits the environment and Idaho Power's customers because the construction of additional peaking resources to serve summer peak load is delayed or avoided, revenue from off-system sales during the winter and spring is credited to customers through the PCA, and revenue from others' use of the transmission system is credited to customers in general rates.

Transmission Planning Process

In recent years, FERC has mandated several aspects of the transmission planning process. One regulation requires Idaho Power to participate in transmission planning on a local, sub-regional, and regional basis, as described in Attachment K of the Idaho Power OATT and summarized in the following sections.

Highlights

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Restrictions on the Brownlee East Total and Idaho–Northwest transmission paths limit the import of Hells Canyon Complex generation and off-system purchases from the Pacific Northwest.
- The 500-kV Boardman to Hemingway project, expected to be in service in 2016, will significantly increase the capacities of the Brownlee East Total and Idaho–Northwest paths.

Local Transmission Planning Process

The expansion planning of Idaho Power's transmission network occurs through a local area transmission advisory process, and the biennial local transmission planning process.

Local Area Transmission Advisory Process

Idaho Power develops long-term local area transmission plans with community advisory committees. These committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for full development of the area limited by the land-use plan and other resources of the local area. The plans identify the approximate year the project will be placed in service. Local area plans have been created for four load centers in southern Idaho, 1) eastern Idaho, 2) Magic Valley, 3) Wood River Valley, and 4) Treasure Valley. Development of a fifth plan for the western Treasure Valley and eastern Oregon is in progress.

Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the transmission upgrades identified in the Local Area Transmission Advisory Process, the forecasted network customer load (e.g., BPA customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and point-to-point transmission customer requirements. By identifying potential resource areas and load-center growth, the required transmission capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the sub-regional transmission planning process.

Sub-Regional Transmission Planning

Idaho Power is active in sub-regional transmission planning through the NTTG. NTTG was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). NTTG also relies on a biennial process to develop the sub-regional transmission plan and incorporates the member's biennial local transmission plans. A public stakeholder process evaluates transmission needs as determined by state-mandated IRPs and load forecasts, proposed resource development and generation interconnection queues, and forecast uses of the transmission system by wholesale transmission customers.

Regional Transmission Planning

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the regional transmission planning facilitator in the western United States. Specifically, TEPPC has three distinct functions, 1) oversee data management for the western interconnection, 2) provide policy and management of the planning process, and 3) guide the analyses and modeling for Western Interconnection economic transmission expansion planning. In addition to providing the means to model the transmission implications of various load and resource scenarios at a regional level, these functions serve to fulfill the requirement to coordinate planning between transmission owners/operators and sub-regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. These activities include regional resource adequacy analyses and corresponding North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission-line rating process.

Existing Transmission System

Idaho Power's transmission system spans southern Idaho from eastern Oregon to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as "transmission paths." There are defined transmission paths to other states and between the southern Idaho load centers mentioned earlier in this chapter. Idaho Power's transmission system and paths are shown in Figure 7.1.

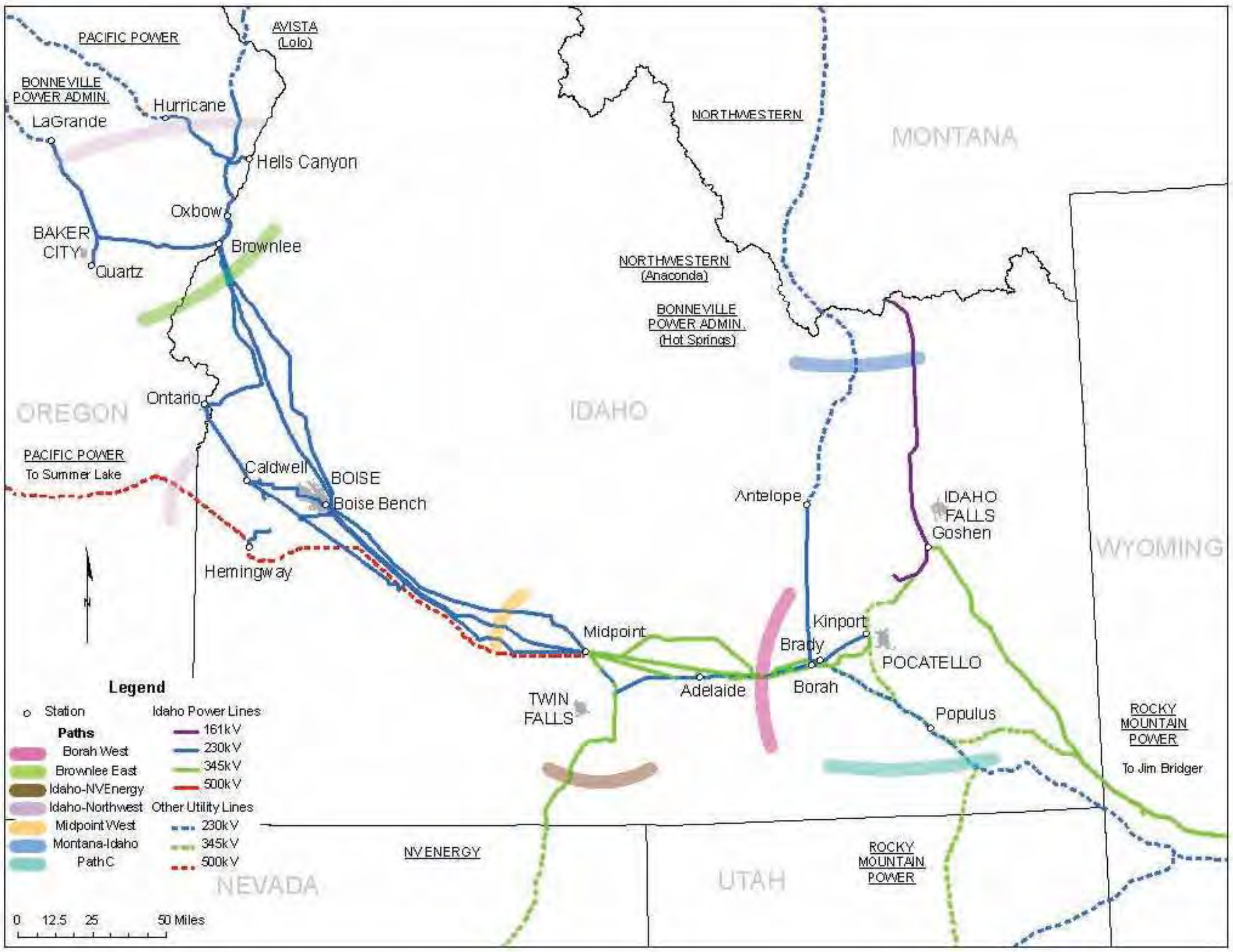


Figure 7.1 Idaho Power transmission system map

The transmission paths identified on the map are described in the following sections, along with descriptions of the conditions that result in capacity limitations.

Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three, 230-kV lines between the Hells Canyon Complex and the Pacific Northwest, and the 115-kV interconnection at Harney substation near Burns, Oregon. The Idaho–Northwest path is most likely to be capacity-limited during summer months in low-to-normal water years due to transmission-wheeling obligations for BPA's eastern Oregon and south Idaho loads and energy imports from the Pacific Northwest to serve Idaho Power's retail load. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to eastern Oregon and southern Idaho.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 7.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the Hells Canyon Complex, and Quartz substation, near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Brownlee East Total path. The capacity limitation on the Brownlee East transmission path is located between Brownlee and the Treasure Valley.

The Brownlee East transmission path has different capacity limitations than the Northwest path. The Brownlee East path is most likely to face capacity limitations in the summer during normal-to-high water years. The capacity limitations result from a combination of Hells Canyon Complex hydroelectric generation flowing east into the Treasure Valley, concurrent with transmission-wheeling obligations for BPA's eastern Oregon and southern Idaho loads and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the Hells Canyon Complex, as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Jefferson–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power and others move energy south from Montana into Idaho.

Borah West Path

The Borah West transmission path is internal to the Idaho Power system. The path is comprised of 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation, located near American Falls, Idaho. Idaho Power's share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric and energy imports from Montana, Wyoming, and Utah. The Borah West path is capacity limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production moves east-to-west across the system. Additional transmission capacity will likely be required if new resources, including market purchases, are located east of the path to deliver the energy to the Treasure Valley load center.

Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint substation, located near Jerome, Idaho. Capacity on the Midpoint West path is fully subscribed with east-side Idaho Power resources and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources (or market purchases), are located east of the path to deliver the energy to the Treasure Valley load center.

Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the Valmy power plant was built in northern Nevada. Idaho Power is allocated 100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the Valmy generation plant.

Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path operator and owner of all of the transmission lines; however, several of the lines terminate at Idaho Power-owned substations. The path effectively feeds into the Borah West path when power is moving from east-to-west and, consequently, the import capability of Path C is limited by Borah West path capacity limitations.

Table 7.1 Available transmission import capacity

	Total Transmission Capacity*		
Transmission Path	Import Direction	Capacity (MW)	Available Transmission Capacity (MW)
Idaho–Northwest	West-to-East	1,200	0
Idaho–Nevada	South-to-North	262	0
Idaho–Montana	North-to-South	166	0
Brownlee East	West-to-East	1,915	0
Midpoint West	East-to-West	1,027	0
Borah West	East-to-West	2,557	0
Idaho–Utah	South-to-North	1,250	198**

*Total transmission capacity and available transmission capacity as of May 1, 2011.
**Idaho Power estimated value, actual available transmission capacity managed by PacifiCorp.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions in order to determine the transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements are dependent on the location and size of the resource. The transmission assumptions and transmission upgrade requirements are summarized in Table 7.2.

The Hemingway substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

Table 7.2 Transmission assumptions

Resource Type	Geographic Area	Resource levels (per portfolio)	Additional Transmission Requirements
Gas Turbines*	Elmore County	0 MW–150 MW	No upgrades required
		150 MW–325 MW	New 230-kV line into Treasure Valley
		>325 MW	Additional 230-kV line into Treasure Valley
Solar*	Elmore County	0 MW–150 MW	No upgrades required
		150 MW–325 MW	New 230-kV line into Treasure Valley
		>325 MW	Additional 230-kV line into Treasure Valley
CHP	Treasure Valley	0 MW–100 MW	No upgrades required
	Magic Valley	100 MW–200 MW	No upgrades required
Geothermal	Northern Nevada	0 MW–26 MW	No upgrades required
	Cassia County	26 MW–52 MW	No upgrades required
Pumped Storage	Anderson Ranch Reservoir	0 MW–80 MW	No upgrades required
		80 MW–240 MW	New 230-kV line into Treasure Valley

* Because gas and solar resources are assumed to be in the same geographic area, the resource levels and corresponding transmission requirements are cumulative.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. For example, the location of a pumped storage resource listed in Table 7.2 will require a new 230-kV transmission line if sized greater than 80 MW, where other resources of that size may not require such improvements when located in another geographic area. An additional analysis of the transmission requirements was undertaken when these supply-side resources were arranged into portfolios. A transmission plan that provided the required transmission capacity from the new resources to the growing Treasure Valley load center was developed for each portfolio. This analysis of the first 10-year portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

8. Planning Criteria and Portfolio Selection

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

Idaho Power relies on a collaborative process to develop the IRP.

Planning Scenarios and Criteria

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

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

Load and Resource Balance

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

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. The updated load and resource balance showing Idaho Power's existing and committed resources for

Highlights

- Idaho Power uses 70th percentile average load and 70th percentile water conditions for energy planning.
- For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour loads.
- Growth in summertime peak-hour demand continues to drive Idaho Power's needs for additional resources.

average energy and peak-hour load is shown in *Appendix C–Technical Appendix.*

Average Monthly Energy Planning

Average energy surpluses and deficits are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 8.1 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available. Figure 8.1 illustrates that, starting in July 2018, monthly average energy deficit positions grow steadily in magnitude and number of months affected. By July 2030, these energy deficits exceed 600 aMW.

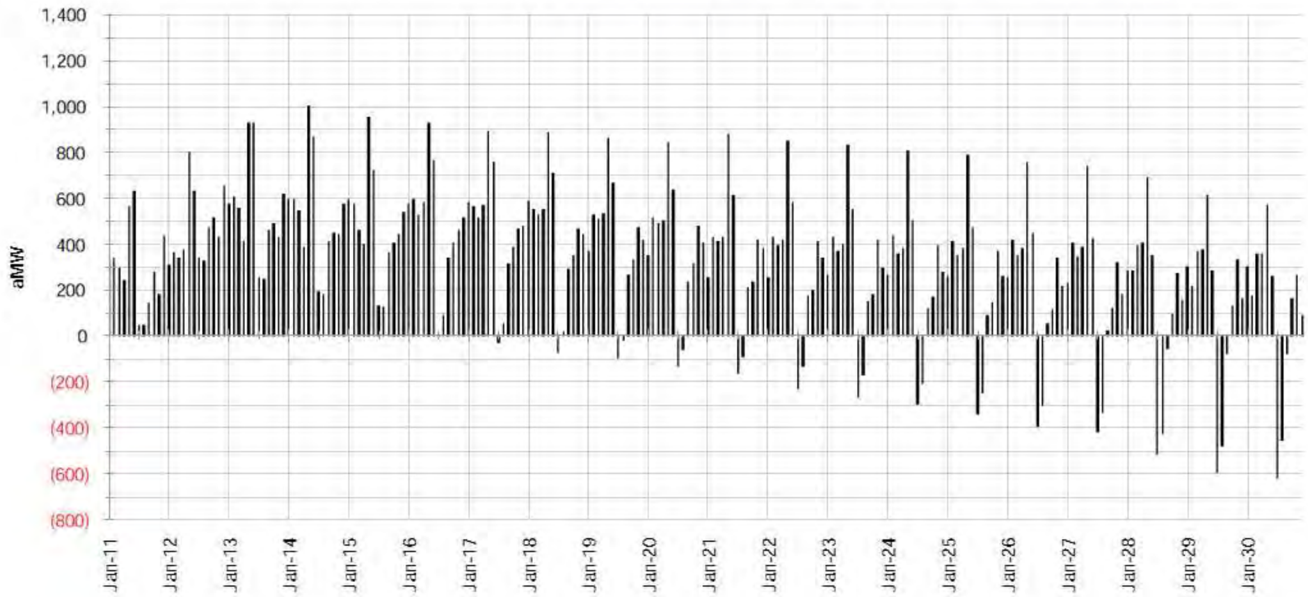


Figure 8.1 Monthly average energy surpluses and deficits with existing and committed resources and existing DSM (70th percentile water and 70th percentile load)

Idaho Power is committed to implementing all cost-effective energy efficiency programs in the IRP prior to evaluating supply-side resource options. Figure 8.2 shows the monthly average energy surplus and deficit data from Figure 8.1 with the addition of all new cost-effective energy efficiency. With the new energy efficiency programs accounted for, monthly average energy deficits in 2030 are reduced to approximately 550 aMW.

Energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy, as this is the case in the 2011 IRP.

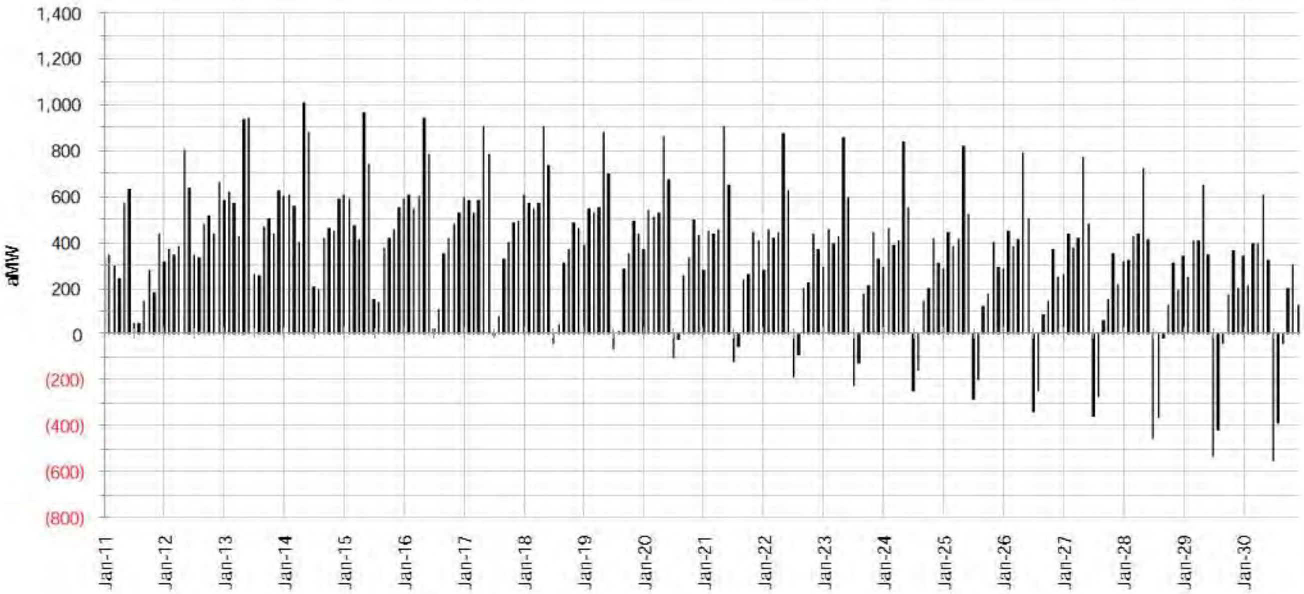


Figure 8.2 Monthly average energy surpluses and deficits with new DSM (70th percentile water and 70th percentile load)

Peak-Hour Planning

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

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

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

Figure 8.3 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 8.3 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available.

A deficit of approximately 100 MW in September 2011 highlights the need for the Langley Gulch CCCT plant as demand response programs are not available in the month of September. Idaho Power is actively managing this near-term deficit in accordance with its *Energy Risk Management Policy and*

Standards. Starting in July 2015, monthly peak-hour deficit positions grow steadily in magnitude and number of months affected. By July 2030, these capacity deficits are approximately 1,300 MW.

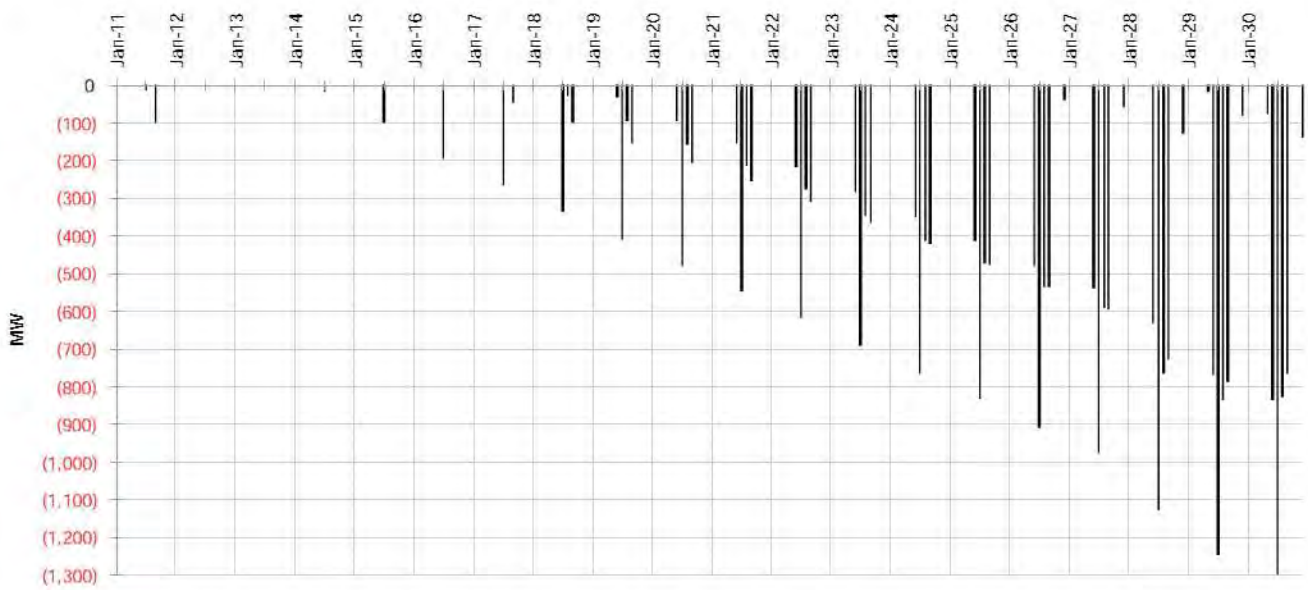


Figure 8.3 Monthly peak-hour deficits with existing and committed resources and existing DSM (90th percentile water and 95th percentile load)

As discussed in Chapter 4, the evaluation of demand response programs was switched from an "all cost-effective DSM" approach to a "needs-based" approach in the 2011 IRP. The new method was designed to identify annual levels of demand response needed to delay the addition of new supply-side peaking resources until the capacity of a SCCT would be greater than the seasonal limitations on demand response programs. Figure 8.4 shows the monthly peak-hour deficit data from Figure 8.3 with the addition of all new DSM under this methodology. With the new DSM accounted for, monthly peak-hour deficits in 2030 are reduced to approximately 1,230 MW.

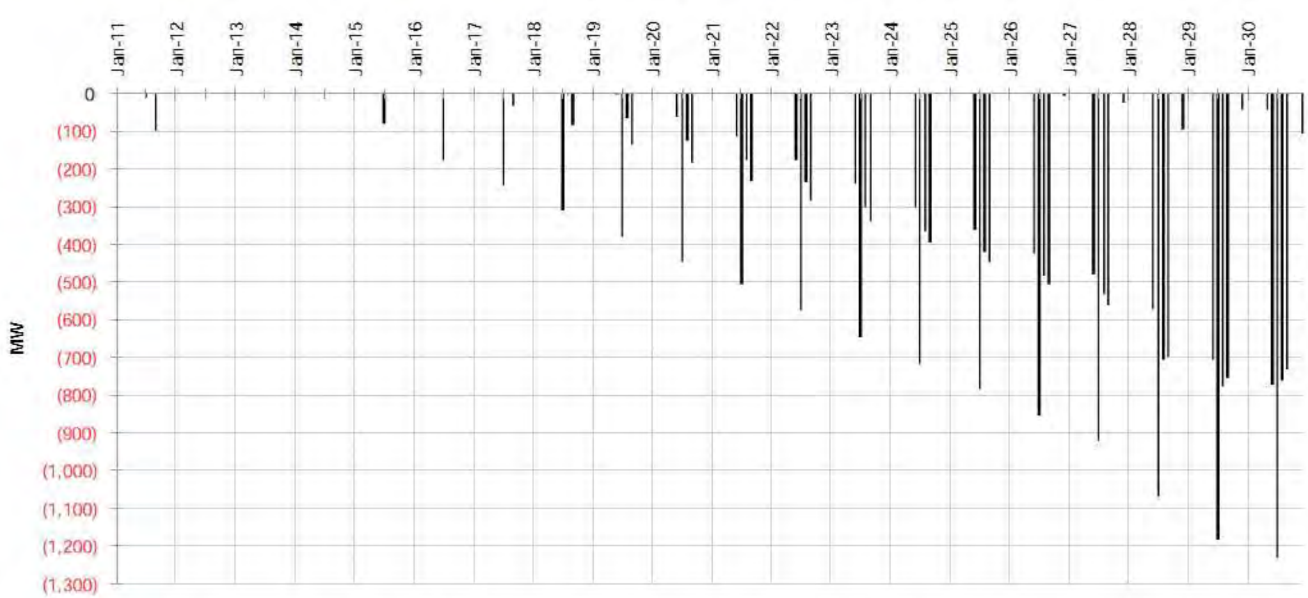


Figure 8.4 Monthly peak-hour deficits with new DSM (90th percentile water and 95th percentile load)

Capacity and energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 8.4 were used to design the portfolios analyzed in the 2011 IRP. In addition to eliminating the peak-hour deficits identified in Figure 8.4, the initial resource portfolios described in the next section also eliminated the energy deficits identified in Figure 8.2.

Portfolio Design and Selection

The 2011 IRP portfolio development strategy divides the study period into two, 10-year periods, 2011–2020 and 2021–2030. Resource portfolios in each 10-year period are designed to satisfy the energy and peak-hour deficits shown in the load and resource balance.

Idaho Power also believes a federal RES will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

First 10 Years (2011–2020)

The first 10-year planning period has significant committed resources, including the Langley Gulch CCCT and the Shoshone Falls upgrade. These committed resources are treated as existing resources for the purpose of analyzing each portfolio of new resources. The capital cost of these committed resources is not included in the comparison between portfolios.

For the first 10-year period, the 2011 IRP analyzed nine different resource portfolios. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the first 10 years of the planning horizon is shown in Figure 8.5, and a description of each portfolio follows.

1-1 Sun & Steam		1-2 Solar		1-3 B2H		1-4 SCCT		1-5 CCCT	
2011		2011		2011		2011		2011	
2012	Solar PV-1	2012		2012		2012		2012	
2013	Solar PV-5	2013		2013		2013		2013	
2014	CHP-75	2014	Solar PV-5	2014		2014		2014	
2015	Solar PV-30	2015	Solar PT-100	2015	Eastside Purchase	2015	SCCT Frame	2015	CCCT
2016	CHP-100	2016	Solar PT-100	2016	B2H-450	2016		2016	
2017	Geothermal-52	2017	Solar PT-125	2017		2017	SCCT Frame	2017	
2018	Solar PT-125	2018	Solar PV-50	2018		2018		2018	
2019	Solar PV-30	2019	Solar PT-100	2019		2019	SCCT S Aero-94	2019	SCCT Frame
2020	Solar PT-75	2020	Solar PV-50	2020		2020		2020	
MW	493	MW	530	MW	450	MW	434	MW	470

1-6 CHP		1-7 Balanced		1-8 Pumped Storage		1-9 Distributed Gen	
2011		2011		2011		2011	
2012		2012		2012		2012	Dist Gen-10
2013		2013		2013		2013	
2014		2014		2014		2014	
2015	CHP-100	2015	CHP-100	2015	Pump St-80	2015	SCCT Frame
2016	SCCT Frame	2016	SCCT Frame	2016	SCCT Frame	2016	
2017		2017	Solar PV-10	2017		2017	SCCT Frame
2018	CHP-50	2018	Solar PT-100	2018	Pump St-80	2018	
2019	CHP-50	2019	Geothermal-26	2019	SCCT S Aero-47	2019	SCCT S Aero-94
2020	SCCT S Aero-94	2020	SCCT S Aero-47	2020	Pump St-80	2020	
MW	464	MW	453	MW	457	MW	444

Figure 8.5 Initial resource portfolios (2011–2020)

- **1-1 Sun and Steam**—This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and power tower resources with geothermal and CHP. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 493 MW.

- **1-2 Solar**—This resource portfolio includes a mixture of solar PV and power tower resources and is designed to test the performance of a portfolio consisting entirely of solar resources. The total nameplate capacity of this portfolio is 530 MW.
- **1-3 Boardman to Hemingway**—This resource portfolio includes the Boardman to Hemingway transmission line project is anticipated to be available in 2016. A more expensive market purchase on the east side of Idaho Power's system was needed to meet a peak-hour deficit in the summer of 2015 prior to the Boardman to Hemingway line becoming available. The total nameplate capacity of this portfolio is 450 MW.
- **1-4 SCCT**—This resource portfolio includes three SCCT's—two industrial-frame units and two small aeroderivative units (47 MW each). The purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building gas-peaking capacity near load. The total nameplate capacity of this portfolio is 434 MW.
- **1-5 CCCT**—This resource portfolio includes one CCCT and one SCCT. Like portfolio 1-4, the purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building baseload gas capacity near load. The total nameplate capacity of this portfolio is 470 MW.
- **1-6 CHP**—This resource portfolio includes a mixture of CHP resources with two SCCTs. The purpose of this portfolio is to compare the cost of CHP resources to the cost of CCCT and SCCT technologies. The total nameplate capacity of this portfolio is 464 MW.
- **1-7 Balanced**—This resource portfolio includes a mixture of CHP, SCCTs, geothermal, and solar resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 453 MW.
- **1-8 Pumped Storage**—This resource portfolio includes a mixture of pumped storage resources and SCCTs. The purpose of this portfolio is to compare the cost of pumped storage to other resource alternatives. The total nameplate capacity of this portfolio is 457 MW.
- **1-9 Distributed Generation**—This resource portfolio is identical to portfolio 1-4 SCCT with the exception that it includes a 10-MW distributed generation resource. The purpose of this portfolio is to evaluate the cost and value of the proposed distributed generation program. Additional details on the distributed generation program can be found in Chapter 5. The total nameplate capacity of this portfolio is 444 MW.

Second 10 Years (2021–2030)

For the second 10-year period, the 2011 IRP analyzed 10 different resource portfolios. The second 10-year planning period is more of an academic exercise than the first 10-year period, where resources are identified that will require a financial commitment. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the second 10 years of the planning horizon is shown in Figure 8.6, and a description of each portfolio follows.

2-1 Nuclear		2-2 IGCC		2-3 SCCT/Wind		2-4 CCCT/Wind		2-5 Hydro/CHP	
2021	Solar PT-100	2021	Geothermal-52	2021	SCCT S Aero-141	2021	CCCT	2021	Hydro Sm-60
2022	Pump St-50	2022	SCCT Frame	2022	Wind-100	2022	Wind-150	2022	CHP-75
2023	Solar PT-100	2023		2023	SCCT S Aero-141	2023		2023	Pump St-80
2024	Nuclear	2024	CHP-50	2024	Wind-100	2024		2024	CHP-100
2025		2025	Solar PT-75	2025	SCCT S Aero-94	2025		2025	Hydro-40
2026		2026	IGCC w/CS	2026	Wind-100	2026	CCCT	2026	Pump St-80
2027		2027		2027	SCCT S Aero-141	2027		2027	Hydro Sm-100
2028	Nuclear	2028	Solar PT-75	2028	SCCT S Aero-141	2028	Wind-150	2028	SCCT S Aero-141
2029	Pump St-50	2029		2029	SCCT S Aero-94	2029	SCCT Frame	2029	Hydro Sm-80
2030		2030		2030		2030		2030	Hydro Sm-60
MW	**800**	**MW**	**802**	**MW**	**1,052**	**MW**	**1,070**	**MW**	**816**

2-6 Balanced 1		2-7 Balanced 2		2-8 PNW Transmission		2-9 E/S Transmission		2-10 Renewable	
2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	CHP-75
2022	SCCT Frame	2022	CHP-75	2022	PNW Purchase	2022	E/S Purchase	2022	Pump St-80
2023		2023	SCCT Frame	2023		2023		2023	Solar PT-150
2024	Solar PT-50	2024		2024		2024		2024	
2025	CCCT	2025	Geothermal-52	2025		2025		2025	CHP-75
2026		2026	CHP-75	2026		2026		2026	Solar PT-150
2027		2027	Hydro Sm-60	2027	Solar PV-20	2027	Solar PV-20	2027	Solar PV-150
2028	Hydro Sm-60	2028	CCCT	2028	Geothermal-52	2028	Geothermal-52	2028	Geothermal-52
2029	SCCT Frame	2029		2029	SCCT Frame	2029	SCCT Frame	2029	Hydro Sm-100
2030		2030		2030		2030		2030	Solar PV-200
MW	**802**	**MW**	**784**	**MW**	**794**	**MW**	**794**	**MW**	**1,032**

Figure 8.6 Initial resource portfolios (2021–2030)

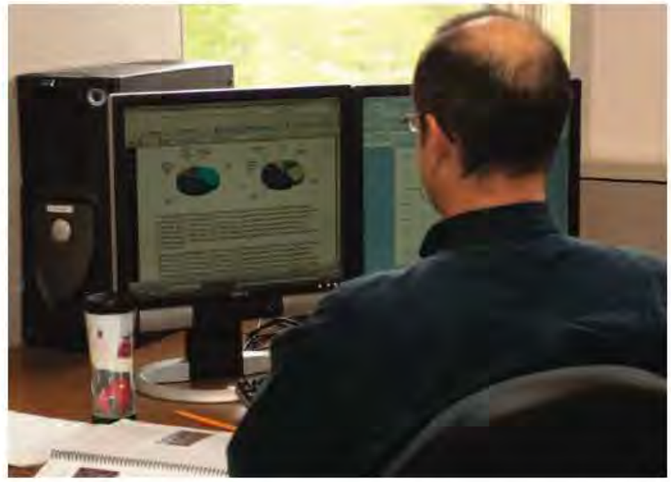
- **2-1 Nuclear**—This resource portfolio includes a mixture of pumped storage and solar resources combined with 500 MW of nuclear resources. The purpose of this portfolio is to evaluate the cost of the advanced nuclear technology against other resource alternatives. The total nameplate capacity of this portfolio is 800 MW.
- **2-2 IGCC**—This resource portfolio includes a mixture of geothermal, solar, CHP, and SCCT resources combined with a 380-MW IGCC resource. The purpose of this portfolio is to evaluate the cost of the IGCC technology against other resource alternatives. The total nameplate capacity of this portfolio is 802 MW.
- **2-3 SCCT/Wind**—This resource portfolio includes a combination of wind and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas peaking units that provide capacity. The total nameplate capacity of this portfolio is 1,052 MW.
- **2-4 CCCT/Wind**—This resource portfolio includes a combination of wind and CCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas baseload resources that provide capacity and energy. The total nameplate capacity of this portfolio is 1,070 MW.
- **2-5 Hydro/CHP**—This resource portfolio includes a combination of small hydroelectric, pumped storage, CHP and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains hydroelectric and CHP resources. The total nameplate capacity of this portfolio is 816 MW.
- **2-6 Balanced 1**—This resource portfolio includes a mixture of geothermal, solar, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 802 MW.

- **2-7 Balanced 2**—This resource portfolio includes a mixture of geothermal, CHP, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 784 MW.
- **2-8 PNW Transmission**—This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity to the Pacific Northwest. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on increased market purchases from the Pacific Northwest. The total nameplate capacity of this portfolio is 794 MW.
- **2-9 Eastside Transmission**—This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity across southern Idaho and into Wyoming. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on market purchases from the east side of Idaho Power's system. The total nameplate capacity of this portfolio is 794 MW.
- **2-10 Renewable**—This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and power tower resources, geothermal, CHP, small hydroelectric, and pumped-storage resources. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 1,032 MW.

Details on how the portfolios were modeled and the assumptions used in the analysis are provided in Chapter 9. Chapter 9 also presents the risk analysis and the process that lead to the selection of a preferred and alternate portfolio for each 10-year period.

9. Modeling Analysis and Results

Idaho Power uses the AURORAxmp® (AURORA) electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data.



Computer modeling is an essential part of preparing the IRP.

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

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS, Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results. Updates to the database generally add additional hourly operational detail and move away from flat generation output, de-rates, and fixed-capacity factors. The updates also incorporate detailed generating resource scheduling, which results in a model that is more deterministic in character and provides a more specific operational view of the WECC.

Economic Evaluation Components and Assumptions

The total cost of each portfolio analyzed for the IRP is determined by four components: 1) variable operating costs (determined with AURORA), 2) the capital cost of new resources in each portfolio,

Highlights

- Idaho Power uses the AURORA Electric Market Model as the primary tool for determining future resource build out of operations and portfolio cost impacts for the 20-year IRP planning period.
- The 2011 IRP incorporates anticipated federal RES legislation and plans for the resources necessary to comply with the legislation.
- Quantitative risk factors analyzed in the 2011 IRP include the cost of carbon emissions, natural gas prices, capital cost, load growth, DSM program performance, REC prices, electric market prices, and third-party transmission subscription.

3) the cost of transmission upgrades necessary for each portfolio, and 4) the value of RECs generated by renewable resources in each portfolio. In addition, numerous financial assumptions are necessary to calculate the total portfolio cost. The financial assumptions used in the 2011 IRP are shown in Table 9.1.

Table 9.1 Financial assumptions

Plant Operating (Book) Life	30 Years
Discount rate (weighted average cost of capital)	7.00%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	3.00%
Emissions adder escalation rate	2.50%
Carbon adder escalation rate	5.00%
Annual property tax escalation rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premium (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.00%
Production tax credit escalation rate	3.00%

AURORA Modeling

Idaho Power uses the AURORA model to evaluate the variable cost of production for existing and committed resources along with the new resources proposed in the portfolios. Operational constraints are approximated along with energy purchases and sales in the regional market. While more extreme planning criteria are used to determine the average energy and peak-hour capacity of existing resources in the load and resource balance, median or 50th percentile conditions are used in AURORA for modeling load and hydroelectric generation. The following sections describe additional variable operating costs also included in the analysis.

Carbon Cost

The potential cost of carbon emissions is accounted for in the IRP by applying a carbon adder or tax. The carbon adder is applied to all carbon-emitting resources within the WECC starting in 2015. Including the carbon adder cost for all carbon-emitting resources in the AURORA model results in market prices that reflect the anticipated future cost of carbon emissions. Therefore, the cost of carbon emissions is captured for specific resources and in the price of market purchases and sales.

The carbon adder increases the dispatch cost of each carbon-emitting resource in AURORA, which affects how the model economically dispatches resources. Once a unit is dispatched, the carbon adder can also affect how much generation is produced from each unit. Past experience shows the carbon adder has to be very large to completely curtail units; however, smaller carbon adders reduce generation compared to a similar unit with no carbon adder. Additional details on the carbon adder and the values used for the high, expected, low and no carbon scenarios can be found in Chapter 6.

Transmission Modeling

The need for additional power from new resources or market purchases will require additional transmission. Idaho Power faces severe transmission capacity limitations when evaluating additional supply-side resources. These transmission limitations were a major factor in evaluating supply-side resources, such as Bennett Mountain, Danskin, the Elkhorn Valley Wind Project, and Langley Gulch in previous IRPs.

The 2011 IRP uses different transmission assumptions for each of the 10-year periods. For the first 10-year period, transmission capacity is increased only to the extent necessary to deliver the energy from the new resources to the Treasure Valley in southwest Idaho. Idaho Power has adopted a conservative approach for the first 10 years and includes additional transmission capacity for market purchases only when market-need is specifically identified in a resource portfolio.

For the second 10-year period, transmission capacity identified in the preferred portfolio from the first 10-year period is included, plus any additional transmission necessary for each resource portfolio in the second 10-year period.

Natural Gas Transportation Cost

For the 2011 IRP analysis, the cost of gas transportation for existing resources, including the Langley Gulch project, is based on the cost of existing pipeline capacity. Because existing pipeline capacity is close to being fully utilized, the transportation cost for new gas resources reflects the cost of adding additional pipeline capacity for delivery to Idaho Power's service area.

The increased cost for new pipeline capacity is approximately twice the current tariff rate. For the IRP, the additional cost for new pipeline capacity was added to the cost of each new gas resource outside the AURORA model. Additional details on transportation costs can be found in *Appendix C–Technical Appendix*. The natural gas price forecast described in Chapter 6 is based on a Sumas hub price and does not include any transportation cost.

Capital Cost

Idaho Power uses an internal financial analysis model to evaluate the capital cost of new resources and to estimate the associated revenue requirements. Estimated construction costs are escalated at the base inflation rate of 3 percent per year and included in the model.

Estimated capital costs are translated into an annual revenue requirement that corresponds to the size and timing of the investment required for each resource. The annual revenue requirement for each resource portfolio is then discounted and summed. The annual revenue requirement analysis has the benefit of matching the annual revenue requirements with the corresponding annual energy benefits. The annual revenue requirement analysis eliminates the need to estimate resource values beyond the study period because resource capital costs and resource benefits are matched annually within the study period.

Transmission Cost

For the IRP, the total estimated transmission cost of each resource portfolio is used to determine the annual transmission revenue requirement, and the NPV of the cost is included in the portfolio evaluation. A more detailed presentation of the transmission assumptions for each portfolio can be found in *Appendix C–Technical Appendix*.

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

Two categories of transmission are accounted for in the IRP. The first is the transmission that integrates resources and allows energy to flow from a generation resource to Idaho Power's load centers.

An example of this type of transmission are the transmission lines that deliver generation from the Hells Canyon Complex to the load center in the Treasure Valley.

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

In the first 10-year portfolios (2011–2020), only portfolio 1-3 Boardman to Hemingway included a proposed interstate transmission project. This was the Boardman to Hemingway project with an on-line date of 2016 and Idaho Power's share of the line at 450 MW. For the second 10-year period (2021–2030), all the portfolios assume that the preferred portfolio 1-3 Boardman to Hemingway is built, and only portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission included additional interstate transmission projects. In portfolio 2-8 Pacific Northwest Transmission, Idaho Power adds 500 MW of additional capacity between Idaho and the Pacific Northwest in 2022. In portfolio 2-9 Eastside Transmission, the Gateway West project is built in 2022, allowing Idaho Power to have an additional 500 MW of transmission capacity for market purchases from the east side of Idaho Power's service area.

Renewable Energy Certificates

For the 2011 IRP analysis, each portfolio is designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Because it is impossible to exactly match the number of RECs Idaho Power would need to meet this requirement with the amount of RECs created by individual resources, the value of additional RECs and the cost of purchasing RECs if short is captured in the total cost of each portfolio. With the exception of portfolio 2-4 CCCT & Wind, all the portfolios analyzed had a net benefit from the value of surplus RECs. This value is shown as a negative cost in Tables 9.2 and 9.3. The forward price curve for RECs used in the analysis is presented in Chapter 6.

Expected-Case Portfolio Analysis Results

The NPV total portfolio cost is calculated by summing the variable operating costs calculated in AURORA, the capital and transmission costs, and the value of RECs from each portfolio. The expected-case NPV total portfolio cost of each of the portfolios analyzed for the first 10-year period are shown in Table 9.2.

Under expected case conditions, for the first 10-year period, portfolio 1-3 Boardman to Hemingway is the lowest cost portfolio at $3.18 billion, while portfolio 1-4 SCCT is the second lowest at $3.22 billion. These results are similar to the results of the 2009 IRP analysis where the Boardman to Hemingway project was evaluated against a portfolio of SCCT resources that could be built close to load centers.

Table 9.2 Expected case total portfolio cost (2011–2020)

	NPV Portfolio Costs (2011 dollars, 000's)				
Base Case	**Variable (AURORA)**	**Capital**	**Transmission**	**RECs**	**Total**
1-1 Sun & Steam	$3,041,735	$552,164	$17,925	($24,396)	**$3,587,428**
1-2 Solar	$2,924,308	$683,497	$20,865	($32,033)	**$3,596,637**
1-3 Boardman to Hemingway	$3,088,318	$0*	$98,929	($9,940)	**$3,177,308**
1-4 SCCT	$3,099,029	$108,835	$22,748	($9,940)	**$3,220,672**
1-5 CCCT	$3,115,384	$188,415	$19,546	($9,940)	**$3,313,406**
1-6 CHP	$3,162,397	$190,436	$15,798	($9,940)	**$3,358,691**
1-7 Balanced	$3,085,533	$293,344	$16,349	($15,384)	**$3,379,843**
1-8 Pumped Storage	$3,093,051	$416,887	$23,099	($15,206)	**$3,517,831**
1-9 Distributed Generation	$3,099,323	$114,153	$22,748	($9,940)	**$3,226,284**

*Portfolio 1-3 Boardman to Hemingway capital cost is included in the transmission column.

Table 9.3 shows the NPV total cost of each portfolio analyzed for the second 10-year period. Under expected-case conditions, the NPV cost of portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission are close at $3.30 billion and $3.32 billion respectively. Portfolio 2-6 Balanced 1 is the next lowest-cost portfolio at $3.50 billion.

Table 9.3 Expected case total portfolio cost (2021-2030)

	NPV Portfolio Costs (2011 dollars, 000's)				
Base Case	**Variable (AURORA)**	**Capital**	**Transmission**	**RECs**	**Total**
2-1 Nuclear	$2,548,176	$1,806,082	$25,300	($713)	$4,378,845
2-2 IGCC	$2,665,714	$958,555	$59,523	($2,908)	$3,680,885
2-3 SCCT & Wind	$3,079,453	$515,846	$27,147	($2,545)	$3,619,901
2-4 CCCT & Wind	$3,095,043	$498,966	$26,688	$246	$3,620,943
2-5 Hydro & CHP	$3,014,673	$880,443	$27,622	($6,669)	$3,916,069
2-6 Balanced 1	$2,937,689	$555,581	$10,646	($2,646)	$3,501,270
2-7 Balanced 2	$2,952,566	$668,771	$10,849	($8,840)	$3,623,346
2-8 Pacific Northwest Transmission*	$2,933,037	$335,516	$29,278	($1,773)	$3,296,059
2-9 Eastside Transmission*	$2,929,353	$335,516	$53,373	($1,773)	$3,316,469
2-10 Renewable	$2,910,691	$1,112,624	$10,504	($11,537)	$4,022,282

*2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission capital costs are included in the transmission column.

Portfolio Carbon Emissions

Figure 9.1 shows the average CO_2 intensity for each portfolio analyzed for the first 10-year period. The average intensity for each portfolio includes emissions from new resources in addition to emissions from Idaho Power's existing and committed resources. The intensity rates range from approximately 775 lbs-per-MWh to 805 lbs-per-MWh and are all well below Idaho Power's 2005 intensity rate of 1,194 lbs-per-MWh.

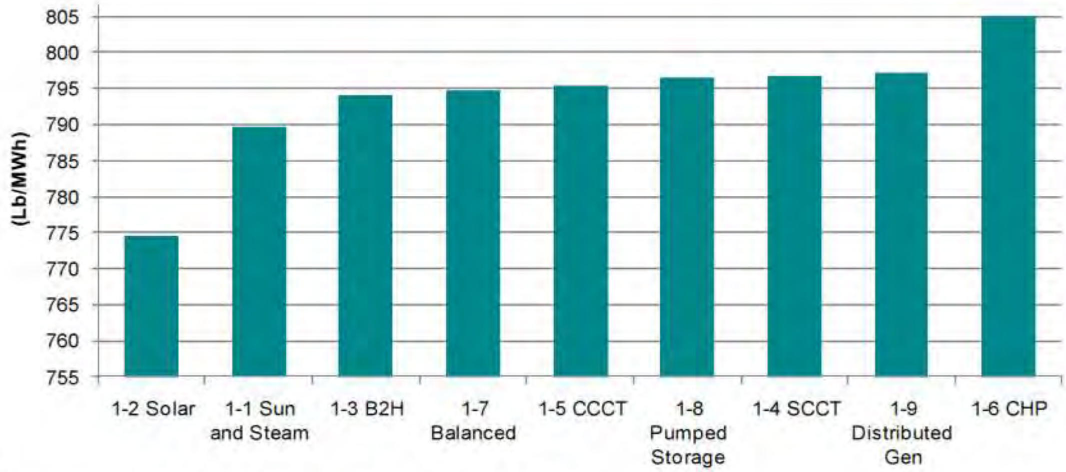


Figure 9.1 Average CO_2 intensity by portfolio (2011–2020)

Figure 9.2 shows similar information for the portfolios analyzed for the second 10-year period, which assumes portfolio 1-3 Boardman to Hemingway is built. The intensity rates range from approximately 660 lbs-per-MWh to 745 lbs-per-MWh, which shows a further reduction from the portfolios analyzed in the first 10-year period.

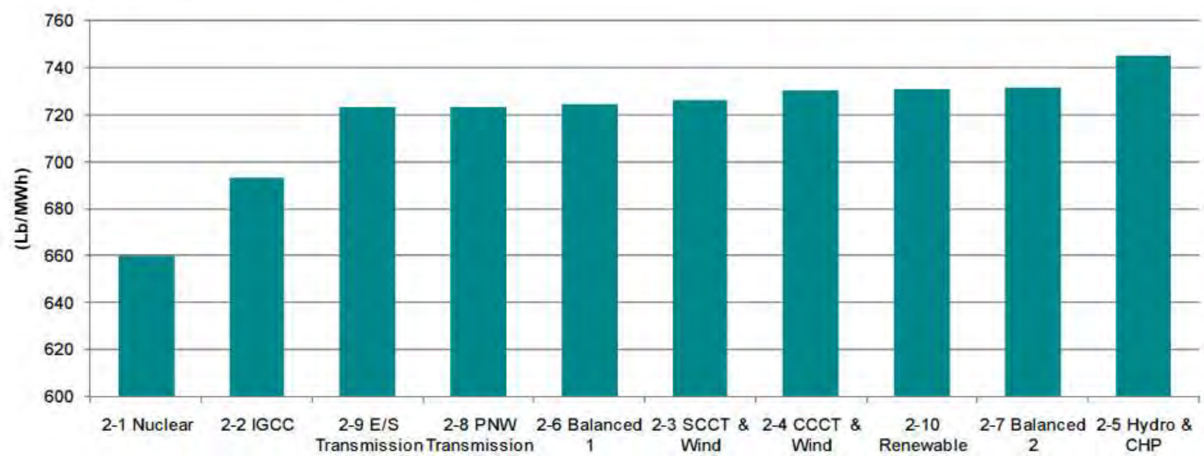


Figure 9.2 Average CO_2 intensity by portfolio (2021–2030)

The lower emissions intensity rates presented in Figures 9.1 and 9.2 are the result of the carbon adder used in the IRP analysis in addition to the reduced operation of Idaho Power's coal resources at times when market prices are lower than the dispatch cost of the coal resources. These results also indicate a majority of the risk associated with the future regulation of carbon is related to Idaho Power's existing resources.

Risk Analysis and Results

Idaho Power evaluated all the resource portfolios identified in the 2011 IRP for both qualitative and quantitative risks. Risk analysis identifies resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

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

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

Electric vehicles are another factor having the potential to increase load. Study reports completed by the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory were used to estimate load impacts associated with electric-vehicle charging. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. Further discussion on electric vehicles is contained in *Appendix A–Sales and Load Forecast*.

Many of the other risk factors are regulatory in nature. Idaho Power faces regulatory uncertainty associated with carbon regulation and a federal RES. Idaho Power is planning for a resource future that restricts the quantity of carbon that can be released into the earth's atmosphere. The proposed carbon legislation is anticipated to restrict the quantity of carbon emissions and increase the price of RECs. Limited or ineffective carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional, fossil-fuel plants.

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

Qualitative Risk Analysis

Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Idaho Power discussed the qualitative factors in public forums, including the IRPAC meetings, as well as in regulatory workshops and proceedings. Some of the qualitative risks, such as planning for new large loads, may be considered policy issues and are discussed in Chapter 1. The qualitative risk of schedule delays and siting issues associated with the Boardman to Hemingway transmission project are addressed by identifying both a preferred and alternate resource portfolios. Many of the qualitative risks, such as carbon policy, resource technology, and market price risk, are covered in the quantitative analysis through variations in carbon emissions prices, capital cost, and natural gas prices. In general, Idaho Power addresses the qualitative risks through policy discussions with the IRPAC and regulatory agencies or by associating the risk with proxy variables in the quantitative analysis.

Quantitative Risk Analysis

For the 2011 IRP, Idaho Power analyzed high, low, and expected cases for the following risk factors: 1) carbon, 2) natural gas prices, 3) capital cost, 4) DSM variability, 5) load variability, and 6) REC prices. In addition to the high, low, and expected cases for carbon, a no-carbon cost case was also analyzed.

The results of the quantitative risk analysis show a change from the expected cost of each portfolio for each risk factor analyzed. The results of the quantitative risk analyses are presented in terms of NPV total portfolio cost resulting in a side-by-side comparison of the range of potential costs for each risk factor.

Carbon Risk (2011–2020)

Four carbon adder scenarios, an expected case and three alternate cases, were analyzed as part of the 2011 IRP. A description of the four cases is contained in Chapter 6. With respect to the cost of carbon, the nine portfolios perform relatively similarly for the three alternate levels of carbon cost considered.

As expected—given their renewable focus, the 1-1 Sun and Steam and 1-2 Solar portfolios are not as adversely affected by high carbon costs (costs estimated to increase slightly less than costs for other portfolios), nor are they benefitted as much by lower or zero carbon costs. However, the modest differences between portfolios in comparing the estimated cost effects associated with the levels of carbon cost suggest that much of the cost of carbon is driven by the operation of Idaho Power's existing and committed resources. Thus, based on the varying levels of carbon cost risk considered, none of the portfolios are likely to lead to a catastrophic financial outcome occurring as a result of carbon costs deviating from expected costs.

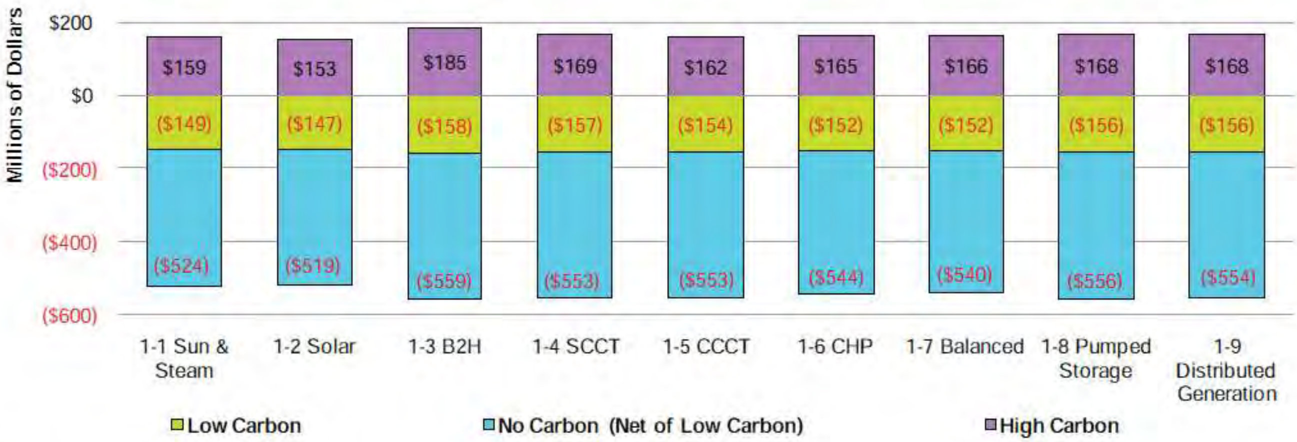


Figure 9.3 Carbon risk analysis results (2011–2020)

Natural Gas Price Risk (2011–2020)

Three natural gas price scenarios were analyzed for the 2011 IRP—high, expected, and low. Additional details of the natural gas price scenarios are presented in Chapter 6, and the results are presented in Figure 9.4. As expected, portfolios having SCCT, CCCT, or CHP resources show a greater range of risk associated with natural gas prices. The portfolios having elevated risk related with higher-than-expected natural gas prices include 1-1 Sun and Steam, 1-6 CHP, and 1-7 Balanced. Conversely, these portfolios are likely to experience greater cost decreases in the event of lower-than-expected natural gas prices. The risk analysis also indicates that the 1-5 CCCT portfolio is projected to benefit disproportionately from lower-than-expected natural gas prices, because the CCCT is economically dispatched more frequently under the low natural gas price scenario.

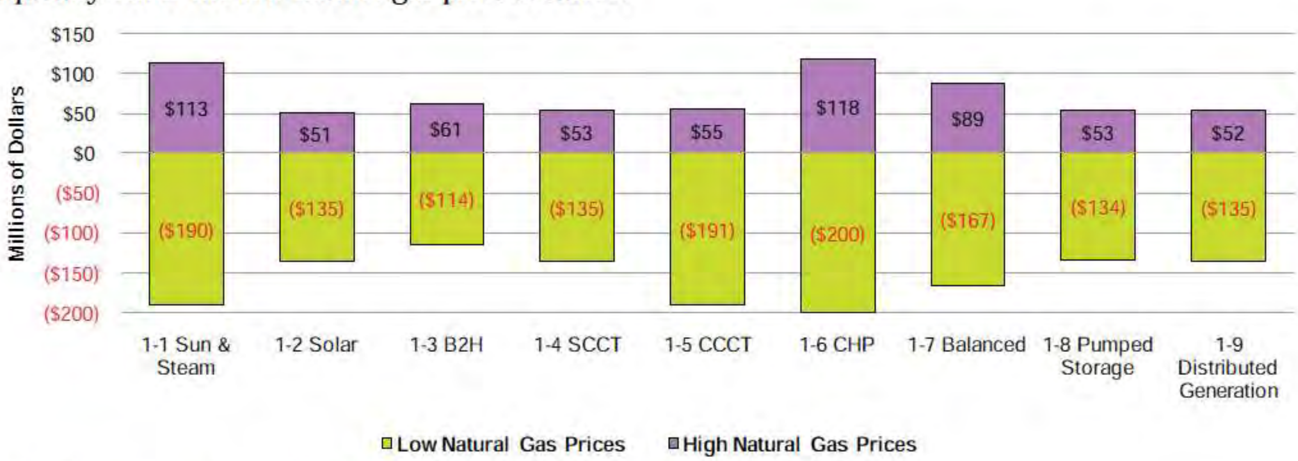


Figure 9.4 Natural gas price risk analysis results (2011–2020)

Capital Cost Risk (2011–2020)

For the 2011 IRP, Idaho Power introduced asymmetry into the estimates of capital cost risk. The introduction of this bias is consistent with comments received from the IRPAC suggesting that development costs for particular resources do not have equal increase/decrease potential. Figure 9.5 illustrates the assumed range in capital costs for considered generating resources, where the horizontal dash for each resource is the expected-case cost in dollars per kW, and the vertical bar reflects the potential capital cost risk for each resource relative to its expected-case cost. Figure 9.5 includes resources used in portfolios for both the first and second 10-year periods of the analysis.

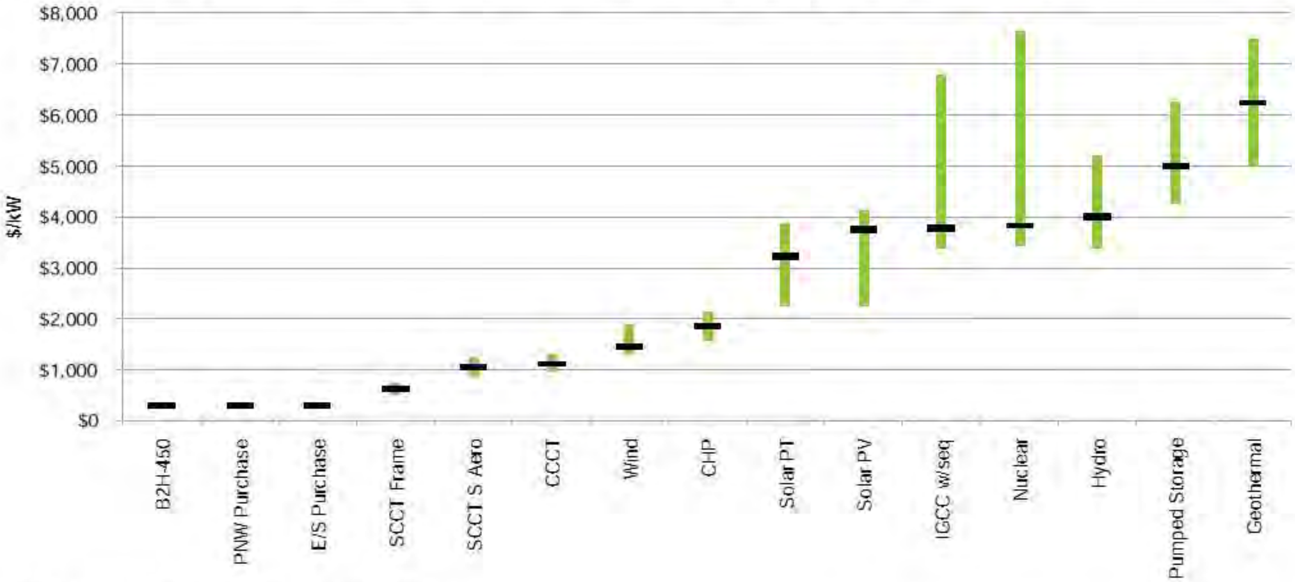


Figure 9.5 Capital cost risk analysis

The results of the capital cost risk analysis demonstrate that resource portfolios comprised of high-capital-cost resources have the greatest potential for deviating from expected-case portfolio cost estimates. The asymmetry in the capital-cost risk is particularly evident for portfolio 1-1 Sun and Steam, 1-2 Solar, and 1-8 Pumped Storage. Solar resources (thermal and PV) are expected to have a greater potential for capital cost decrease versus cost increase; consequently, the two, solar-based portfolios are likely to have the greatest cost-reduction potential. Solar-powered resources are also estimated to have substantial potential for increased capital costs. Consequently, the potential cost increase for portfolios containing solar resources either matches or exceeds that of other portfolios. The results of the capital-cost risk analysis are presented in Figure 9.6.

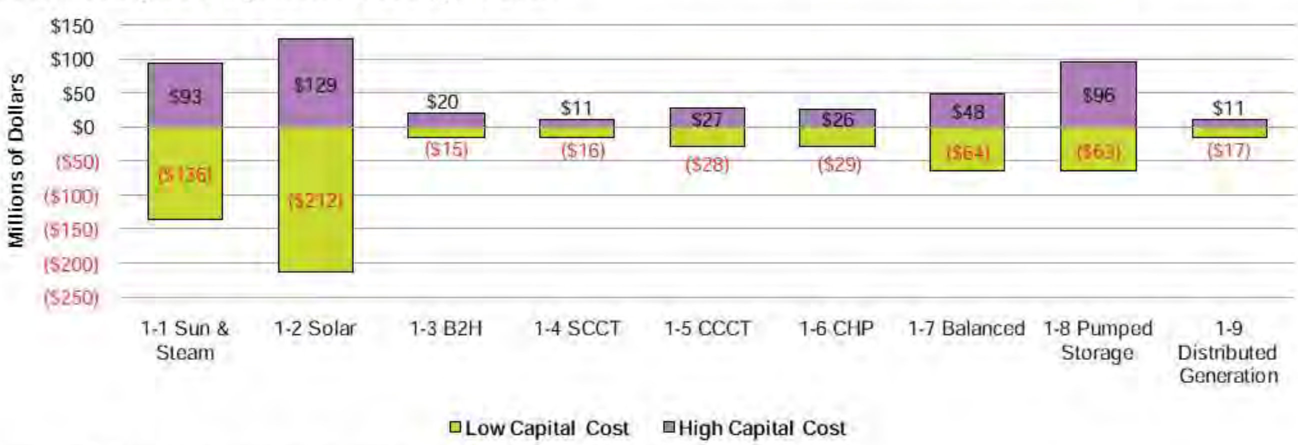


Figure 9.6 Capital-cost risk analysis results (2011–2020)

Risk Due to DSM Variability (2011–2020)

The 2011 IRP risk analysis also evaluated the costs associated with higher-than-expected and lower-than-expected levels of DSM. For the high-DSM case, DSM levels resulting in load being 8 percent lower than expected are reached by the mid-2020s. For the low-DSM case, lower than expected DSM levels resulting in load being 4 percent higher-than-expected are reached by the mid-2020s. The DSM risk scenarios analyzed are shown in Figure 9.7.

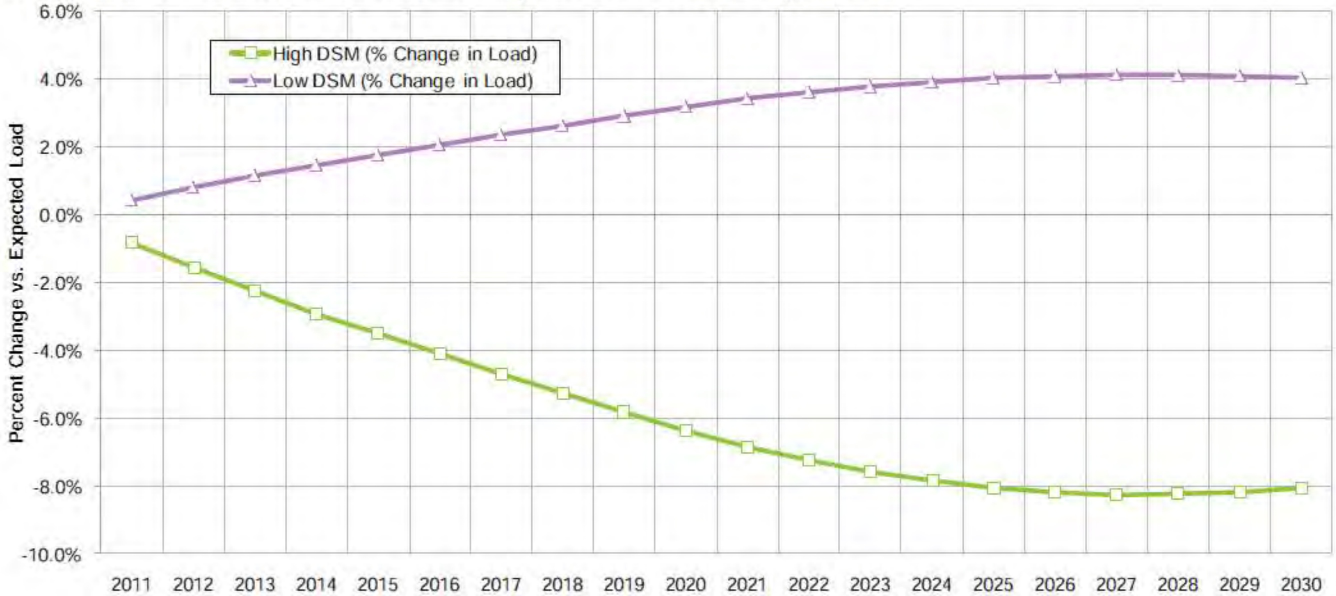


Figure 9.7 DSM variability risk analysis

Figure 9.8 indicates that deviations of DSM program performance from the expected-case forecast have a relatively small impact on total portfolio costs, and the estimated impacts are relatively uniform across portfolios.

Figure 9.8 DSM variability risk analysis results (2011–2020)

Risk Due to Load Variability (2011–2020)

For the 2011 IRP, high- and low-load risk scenarios were derived to analyze the impact of deviations in the IRP load forecast. Figure 9.9 shows the range in load analyzed as a percentage of the expected-case load forecast. For the high-case, loads are approximately 10 percent higher than the expected-case forecast by the end of the planning period in 2030. For the low-case, loads are nearly 10 percent lower than the expected-case forecast in 2030.

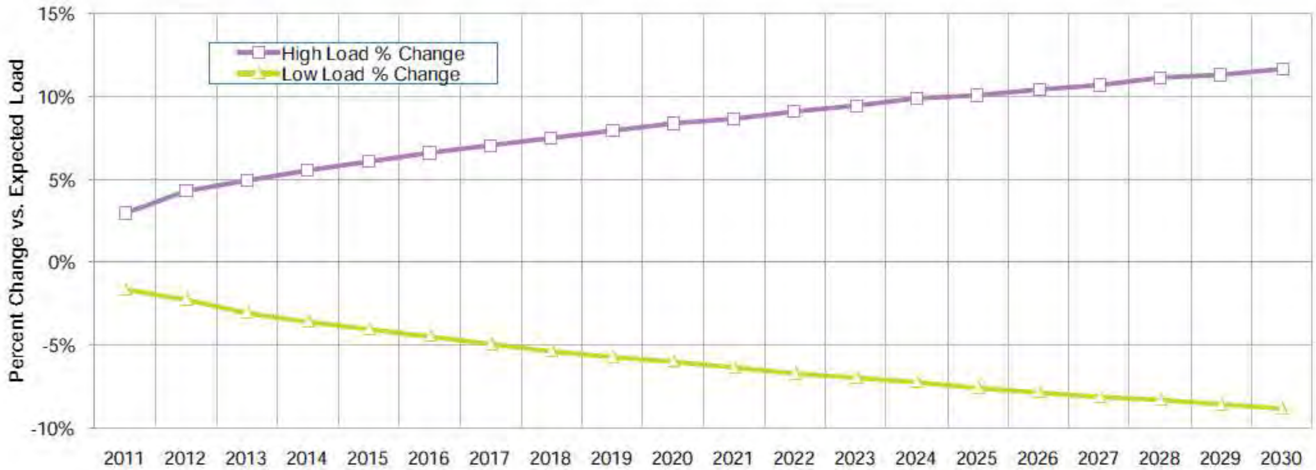


Figure 9.9 Load variability risk analysis

Figure 9.10 indicates that load deviations from the expected-case forecast have the potential to significantly impact portfolio costs. However, the estimated impacts are fairly uniform across portfolios, suggesting equal exposure with respect to load risk for the portfolios. Furthermore, the analysis accounts only for power supply costs and does not include revenues associated with retail sales being higher or lower than expected.

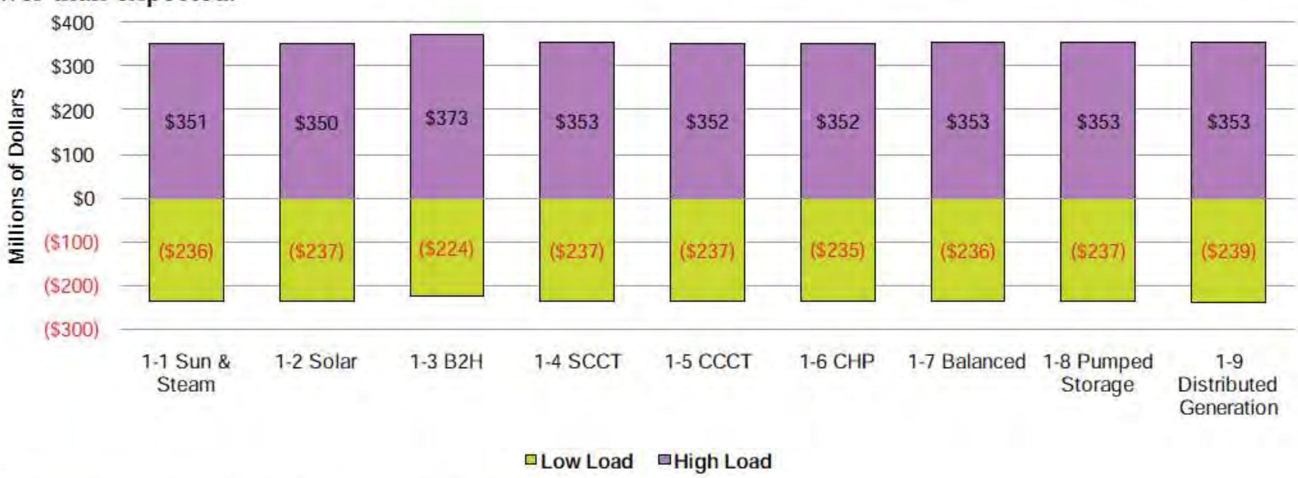


Figure 9.10 Load risk analysis results (2011–2020)

REC Price Risk (2011–2020)

In addition to an expected case for REC prices, high- and low-price scenarios were also analyzed. Additional details on the REC price scenarios is presented in Chapter 6. The results of the analysis indicate none of the portfolios are exposed to severe risk potential with respect to REC price. This is expected because each portfolio was designed to have approximately the number of RECs needed to be compliant with a federal RES.

Because a majority of the portfolios have surplus RECs, high REC prices result in lower portfolio costs relative to the expected REC price case. Similarly, RECs having little or no value leads to higher portfolio costs. The small differences between portfolios follow expected trends. For example, portfolios that generate more RECs (1-1 Sun and Steam and 1-2 Solar) will see a greater cost decrease as a consequence of high REC prices. Conversely, the cost of these portfolios increases more under the low REC price scenario.

Figure 9.11 REC price risk analysis results (2011–2020)

Quantitative Risk Analysis Summary (2011–2020)

Several conclusions can be drawn from the quantitative risk analysis performed for the first 10-year period. Those conclusions include the following:

- Portfolios with solar resources (1-1 Sun and Steam and 1-2 Solar) could have substantially lower-than-expected capital costs, and therefore lower total portfolio costs. However, this lower cost potential is insufficient to overcome the disparity between the expected costs of these portfolios and the expected cost of portfolio 1-3 Boardman to Hemingway.
- The portfolios are designed for REC compliance, and, consequently, carry minimal exposure to REC price risk.
- Portfolio 1-3 Boardman to Hemingway has minimal potential for cost increases or decreases associated with capital costs deviating from expected costs.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources.

The following sections present a similar analysis for the second 10 year period (2021–2030).

Carbon Risk (2021–2030)

Portfolio 2-1 Nuclear, with no incremental carbon-producing resources, has the least potential for cost deviations as a result of the high, low, and no carbon cost scenarios. However, the differences between this portfolio and the other portfolios, with respect to the cost of carbon, are relatively modest. Again, this suggests that carbon risk is primarily due to Idaho Power's existing and committed resources. Figure 9.12 shows the results of the carbon risk analysis for the second 10-year period.

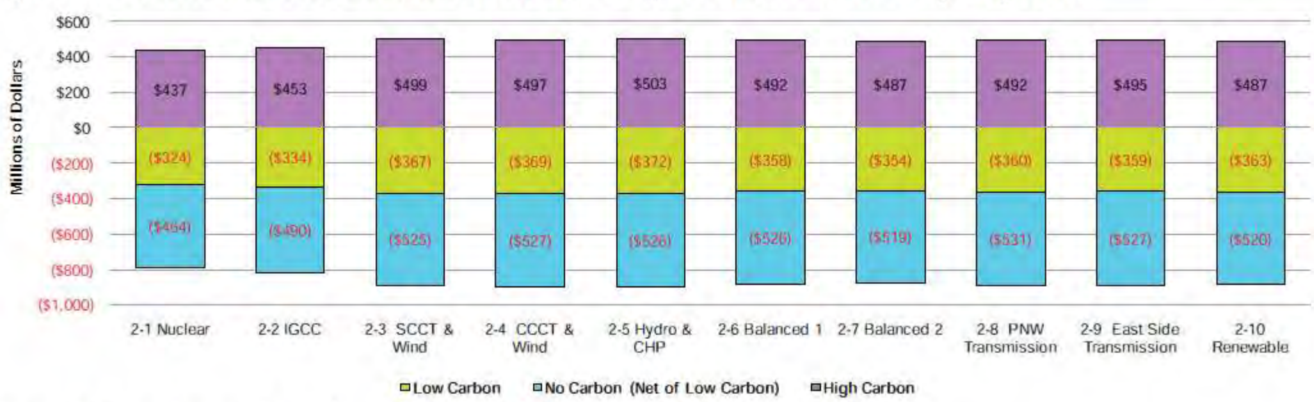
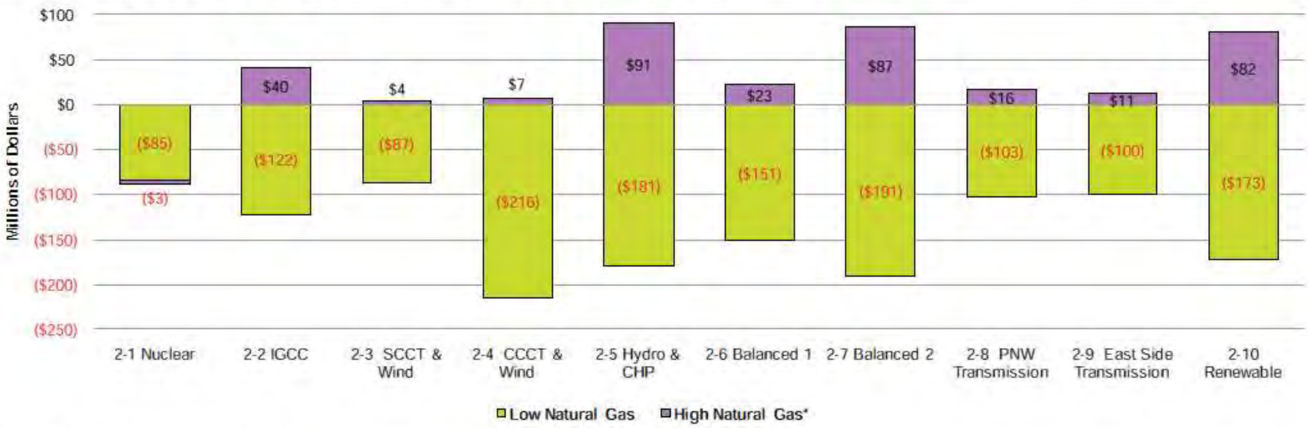


Figure 9.12 Carbon risk analysis results (2021–2030)

Natural Gas Price Risk (2021–2030)

Lower-than-expected natural gas prices lead to portfolio costs that are lower than those occurring under expected natural gas price conditions. The portfolio cost reductions are greatest for the portfolios containing new gas resources. Under higher-than-expected natural gas prices, portfolio 2-5 Hydro and CHP and portfolio 2-7 Balanced 2 have the highest risk under a high-gas-price scenario. These portfolios contain CHP resources, which are typically operated at high-capacity factors to meet the needs of the steam host. Portfolio 2-6 Balanced 1 has a modest potential for cost deviations occurring in response to different-than-expected natural gas prices. Figure 9.13 shows the results of the natural gas price risk analysis for the second 10-year period.



*In portfolio 2-1 Nuclear, high natural gas prices results in a reduced portfolio cost of ($3).

Figure 9.13 Natural Gas price risk analysis results (2021–2030)

Capital Cost Risk (2021–2030)

Figure 9.14 shows the range of costs for portfolios due to capital cost risk. The results of the analysis shows that nuclear generating facilities have considerably greater potential for capital-cost increases versus their potential for cost decrease. This is evident in the potential cost increase of portfolio 2-1 Nuclear, which could have an NPV cost of $1.3 million more than expected under the high capital-cost scenario. Portfolio 2-2 IGCC also has a substantially greater risk for cost increases relative to other portfolios. Portfolio 2-6 Balanced 1 is among the group of portfolios having the lowest exposure to capital cost risk.

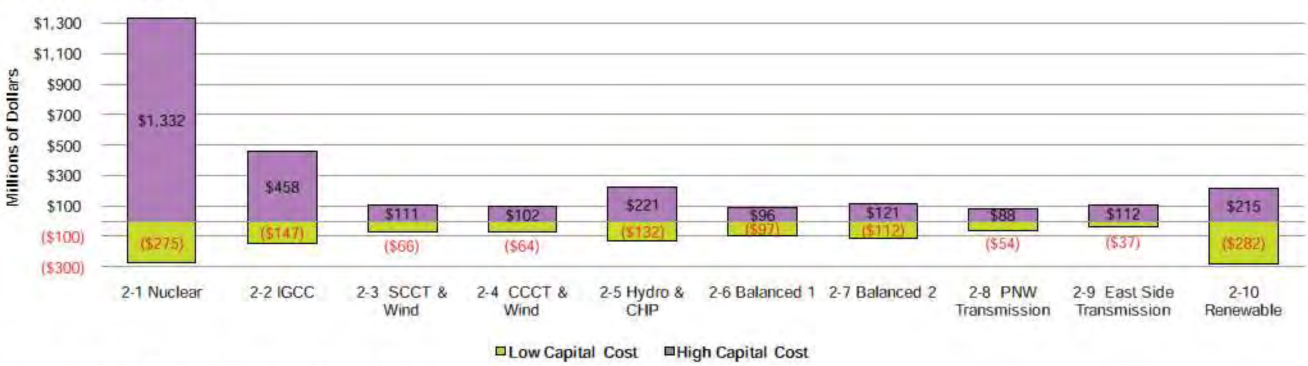


Figure 9.14 Capital cost risk analysis results (2021–2030)

Risk Due to DSM Variability (2021–2030)

The 10 resource portfolios considered for the second 10 years contain the same energy efficiency and demand response programs. The potential for portfolio costs to deviate as a result of different-than-expected DSM program performance is very similar between the portfolios.

Thus, the DSM risk is not a characteristic that can be used to discriminate between the different resource portfolios.

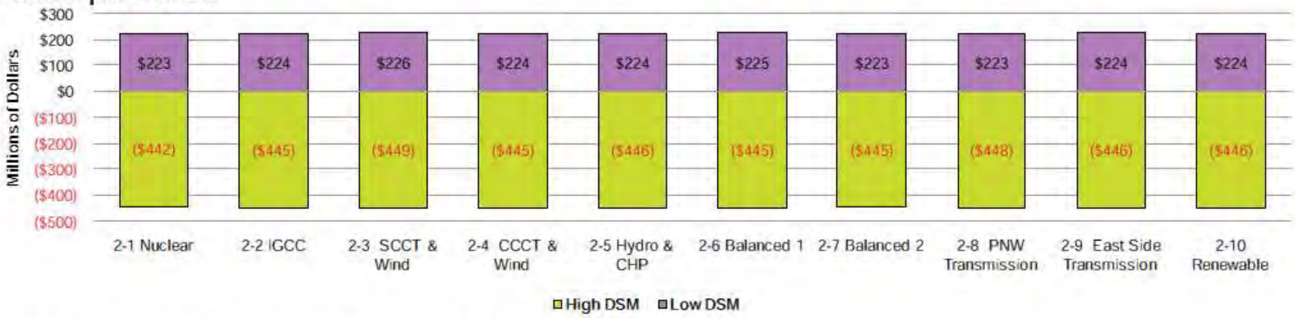


Figure 9.15 DSM risk analysis results (2021–2030)

Risk Due to Load Variability (2021–2030)

Different-than-expected load conditions also increase or decrease costs similarly between the portfolios considered for the second 10 years. This suggests that the portfolios have equal exposure to load variability risk.

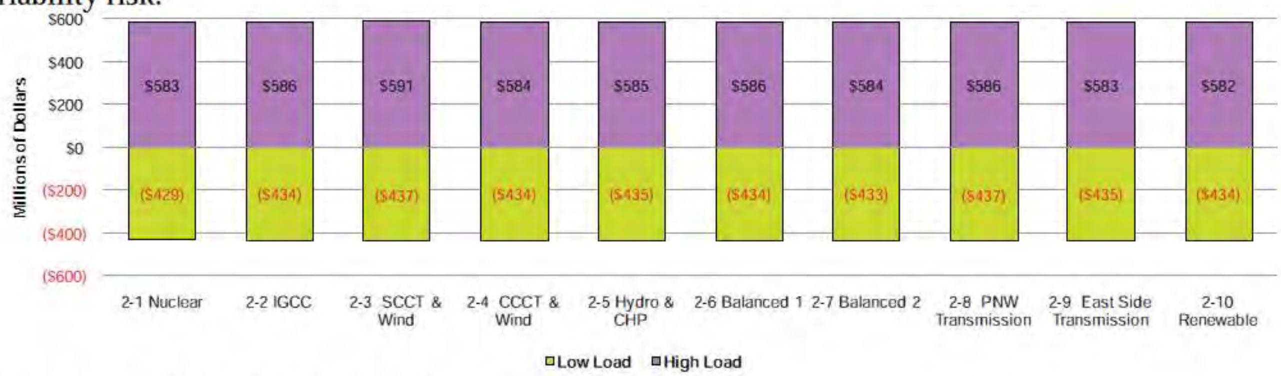
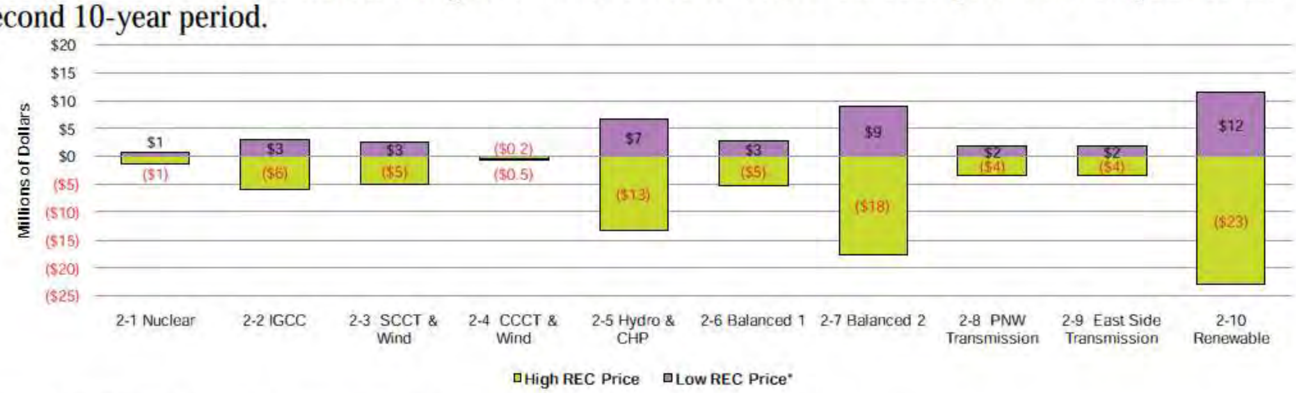


Figure 9.16 Load variability risk analysis results (2021–2030)

REC Price Risk (2021–2030)

As seen in the analysis for the first 10-year period, REC prices have a minimal impact on total portfolio costs. Portfolio 2-10 Renewable produces the greatest amount of surplus RECs and, consequently, has the highest potential for a cost decrease as a result of higher-than-expected REC prices. Conversely, this portfolio has the greatest risk for increased costs due to lower-than-expected REC prices. However, the potential cost changes due to the high- and low-REC price scenarios are similar between portfolios and relatively small compared to other risk factors. This suggests the portfolios are similarly exposed to REC price risk, which is minimal. Figure 9.17 shows the results of the REC price risk analysis for the second 10-year period.



*In portfolio 2-4 CCCT & Wind, a low REC price results in a reduced portfolio cost of ($.02).

Figure 9.17 REC price risk analysis results (2021–2030)

Quantitative Risk Analysis Summary (2021–2030)

Under higher-than-expected capital costs, portfolios 2-1 Nuclear and 2-2 IGCC have the greatest exposure to higher costs relative to the other portfolios. With this exception, the differences between the portfolios with respect to the risk factors considered are generally modest, suggesting that the portfolios contain a similar amount of risk exposure. Other conclusions from the 2021–2030 risk analysis include the following:

- All portfolios are designed to be compliant with a federal RES and, consequently, carry minimal exposure to REC price risk.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources. However, there is some incremental carbon risk associated with all the portfolios except portfolio 2-1 Nuclear. This incremental exposure is evidenced by the greater potential for cost increase/decrease of the other portfolios relative the nuclear portfolio.
- Portfolio 2-10 Renewable has the greatest potential for total cost decrease occurring as a result of lower-than-expected capital costs, reflecting the expectation that solar-powered resources have a greater potential for capital cost decreases than increases.
- The 2-6 Balanced 1, 2-8 PNW Transmission, and 2-9 Eastside Transmission portfolios are among the group of portfolios having the lowest exposure to capital cost risk.

Stochastic Analysis

Stochastic analysis is a statistical technique often used in resource planning. The OPUC recognized the benefits of stochastic analysis and included stochastic analysis as part of its Resource Planning Guidelines (Oregon Docket UM 1056, Order 07-047, February 9, 2007, Appendix A, page 4, Guideline 4 b). The entire Oregon order listing the resource planning guidelines is included in *Appendix C–Technical Appendix*. Idaho Power has used a probabilistic analysis to model loss of load in the 2011 IRP as well as in previous resource plans. Idaho Power applied a stochastic analysis to the natural gas price forecast in the 2009 IRP, and the 2011 IRP is Idaho Power's first application of a stochastic analysis to the expected cost of the various resource portfolios.

Idaho Power modeled the combined effects of the risk variables on the resource portfolio costs for each of the 10-year periods. The results of the stochastic analysis were then used as the determining factor in identifying the preferred and alternate portfolios.

To complete the stochastic analysis, Idaho Power identified six risk variables, calculated the incremental resource portfolio cost at the extremes of the range for each risk variable, divided the cost range for each risk variable into five sections, and randomly sampled from the five sections to calculate a distribution of resource portfolio costs. The key points for the analysis of the first 10-year period include the following:

- Nine resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

Risk Variables

Idaho Power identified six risk variables that are included in the stochastic analysis, 1) natural gas price, 2) REC price, 3) carbon cost, 4) load variation, 5) DSM variation, and 6) capital cost. Idaho Power and the IRPAC identified a range for each of the six variables, and Idaho Power applied the range to each risk variable and calculated the range of portfolio costs for the risk variable using the AURORA model. For example, in the year 2020 natural gas prices were expected to be within the approximate range of \$6.50 to \$10.50 per MMBtu. Idaho Power then used AURORA and the identified range to calculate the cost of each resource portfolio at the two natural gas price extremes. For portfolio 1-3 Boardman to Hemingway the values are—base cost: \$86 million; high natural gas price: \$96 million; and low natural gas price: \$108 million.

Portfolio 1-3 Boardman to Hemingway shows an interesting result. Of the three possibilities analyzed, the base cost with intermediate natural gas prices had the lowest overall cost. Under high gas prices, Idaho Power paid more for energy, and the costs increase; under low gas costs, off-system energy sales were not as profitable for Idaho Power and its customers.

In the case of natural gas prices, the range used in the stochastic analysis was from the low value of \$86 million to the high value of \$108 million, or a range of \$22 million. Similarly, a range was calculated for each of the six risk variables for all nine resource portfolios in the first 10 years. The low value for most of the risk variables in most of the resource portfolios was lower than the base portfolio cost.

After determining the high and low values for each risk variable, the portfolio cost range was divided into five equal segments. For the Boardman to Hemingway portfolio example, the range from \$86 million to \$108 million was divided into five segments with each segment equal to \$4.4 million. Similarly, the range was divided into five equal segments for each of the six risk variables. The entire process was repeated for each of the nine resource portfolios. Five possible states for each of the six risk variables create over 15,000 possible combinations.

Stochastic Modeling

The objective of the stochastic modeling was to estimate the distribution of the incremental portfolio costs. The distribution was calculated by randomly sampling from the range for each risk value, combining the effects of the six risk values, and calculating the resulting resource portfolio cost. The sampling process was repeated 100,000 times for each resource portfolio to estimate the distribution of the resource portfolio costs.

Each risk variable was assumed to be uniformly distributed over the range of values. The uniform distribution means that there is an equal chance of sampling from each of the five segments of the range. For natural gas prices and the 1-3 Boardman to Hemingway portfolio, the uniform distribution means that each \$4.4-million segment was equally likely to be sampled. In 100,000 draws, each segment is expected to be sampled 20,000 times.

Three of the six risk variables were considered independent: load variation, DSM variation, and capital cost. For capital costs, independence means that the result of any other risk variable is presumed to have no, or only minor, influence on the capital cost.

The first three risk variables were assumed to show some level of coincidence: natural gas price, REC price, and carbon cost. Specifically, carbon cost was assumed to be the primary risk factor. REC prices were assumed to be 80-percent coincident with carbon cost, and natural gas price was assumed to be 60-percent coincident with carbon cost. The coincidence means that if the sample for carbon cost is from the highest segment in the risk range, there is an 80-percent chance that the sample of the REC price will also be in the highest segment, with a 60 percent chance that the sample of the natural gas price will also be in the highest segment. Likewise for a sample from any of the other four segments in the carbon cost range. The coincidence was added to the model to reflect the thought that the three variables may be correlated. Even though each of the six risk variables was uniformly distributed, Idaho Power assumed that there is a coincidence factor between three of the six risk variables.

Stochastic Analysis Results and Portfolio Selection (2011–2020)

The results of 100,000 samples for portfolio 1-3 Boardman to Hemingway are shown in the histogram in Figure 9.18.

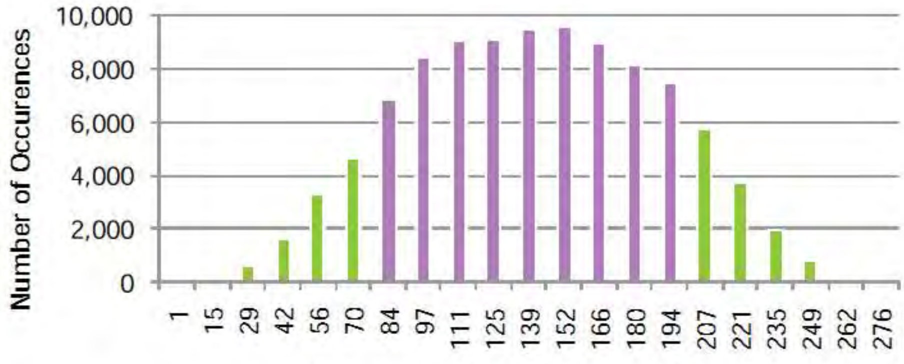


Figure 9.18 Sampling results from portfolio 1-3 Boardman to Hemingway

Based on the sampling of the stochastic analysis, the incremental cost of the Boardman to Hemingway portfolio is expected to range from approximately $1 million to $276 million, with a median value of $133 million. The green bars show the lowest 10 percent and the highest 10 percent of the distribution, and the purple bars represent the middle 80 percent of the distribution. The distribution for portfolio 1-3 Boardman to Hemingway appears to be a normal distribution; however, other resource portfolios had distributions that appear less like a normal distribution. The histogram for portfolio 1-4 SCCT is shown in Figure 9.19. The stochastic cost range for the SCCT portfolio does not appear to be normally distributed; the histogram is roughly flat from an incremental portfolio cost of $100 million up to $200 million and declines on either end. The summary data for all of the resource portfolios, including the distribution charts, is included in *Appendix C–Technical Appendix*.

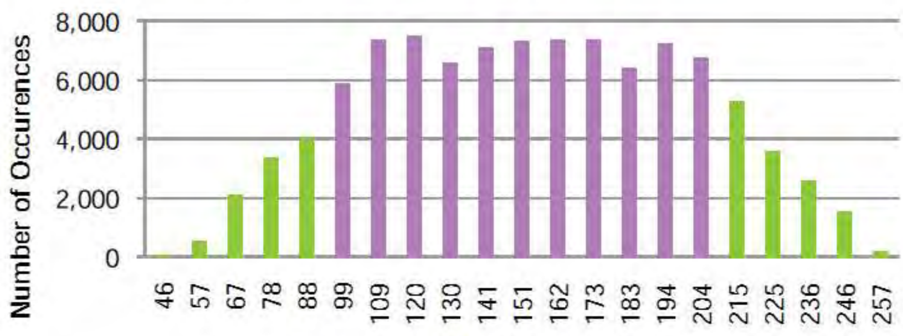


Figure 9.19 Sampling results from portfolio 1-4 SCCT

Table 9.4 compares the nine resource portfolios during the 2011–2020 time period. The table shows the base cost of each resource portfolio, the rank of the base cost in the stochastic analysis, the median of the stochastic analysis, some values defining the range of the stochastic analysis. The base rank is the percentile in the stochastic analysis representing the base cost of the resource portfolio. For example, the base cost of 1-3 Boardman to Hemingway is approximately $86 million, and $86 million would fall at the 19th percentile in the stochastic distribution—19 percent of the draws have a cost less than the 1-3 Boardman to Hemingway base cost of $86 million, and 81 percent of the draws have a higher cost than the base cost of $86 million.

Table 9.4 Stochastic analysis results (2011–2020)

	Portfolio Cost Calculations (000)				Risk Analysis Range (000)				
	Base	Base Rank	Stochastic Median	Difference	Lower	10th	Median	90th	Upper
1-1 Sun & Steam	$496,198	54%	$488,367	-$7,831	$201,786	$356,662	$488,367	$612,505	$808,750
1-2 Solar	$505,407	58%	$478,897	-$26,510	$162,718	$321,382	$478,897	$628,336	$805,521
1-3 Boardman to Hemingway	$86,079	19%	$133,582	$47,503	$1,143	$67,712	$133,582	$198,852	$276,164
1-4 SCCT	$129,443	36%	$148,643	$19,200	$46,060	$88,149	$148,643	$210,860	$256,889
1-5 CCCT	$222,177	60%	$208,242	-$13,935	$66,345	$138,884	$208,242	$277,954	$368,603
1-6 CHP	$267,462	44%	$277,183	$9,721	$104,783	$195,179	$277,183	$361,535	$486,767
1-7 Balanced	$288,613	44%	$299,237	$10,624	$115,778	$217,378	$299,237	$381,340	$507,002
1-8 Pumped Storage	$426,601	31%	$462,254	$35,653	$287,183	$376,777	$462,254	$550,862	$645,560
1-9 Distributed Generation	$135,055	39%	$151,697	$16,642	$49,879	$91,196	$151,697	$212,500	$259,478

Figure 9.20 shows an overview of the stochastic analysis for all of the resource portfolios for the 2011–2020 time period.

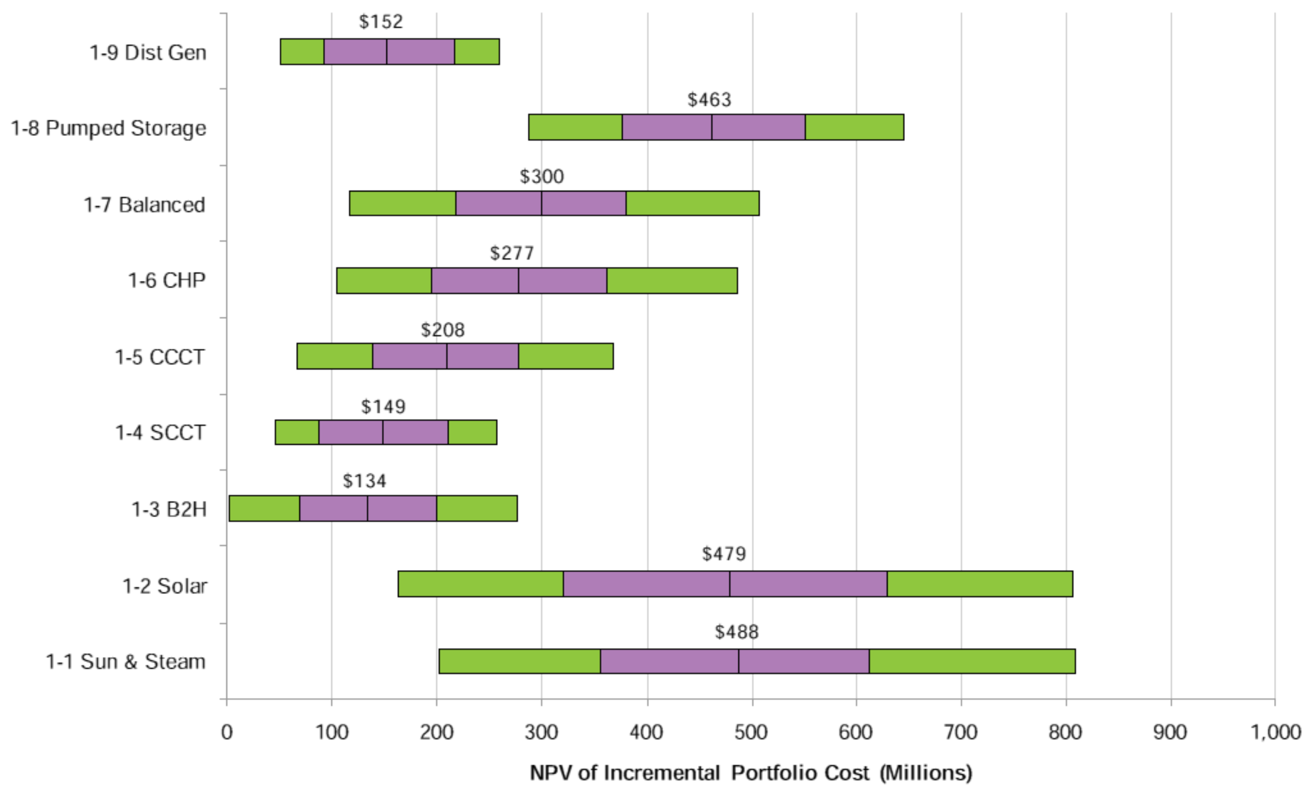


Figure 9.20 Stochastic analysis results (2011–2020)

The length of the bars in Figure 9.20 show the stochastic range of the incremental portfolio costs. The purple portion of the bar represents the middle 80 percent of the distribution, and the green bars at either end represent the 10-percent tails of the distribution similar to the colors in the histogram presented in Figure 9.19. The upper and lower limits, median, 10th, and 90th percentile values represented in Figure 9.20 are also shown in Table 9.4.

The capital cost risk variable seems to have the greatest effect on the stochastic range for a resource portfolio and the stochastic range of a resource portfolio increases as the capital cost of the portfolio cost increases. Portfolio 1-4 SCCT has the lowest capital cost, and 1-1 Sun and Solar and 1-2 Solar have the highest capital cost.

The link between the stochastic range and the capital cost is a direct result of Idaho Power's summer capacity deficit as described in Chapter 8 and Figure 8.1. The effect of the summer capacity deficits is that Idaho Power needs energy during a limited number of summer hours each year to meet customers' peak demand. Limited operation of a generation resource leads to low total operating costs, even if the hourly operating costs are high, because the resource operates only during a limited number of hours each year to meet peak demand.

Limited operation means that variations in the capital costs can overshadow any variations in operating costs when the corresponding capital costs are high, even for resources with extremely low operating costs. An example is a solar PV resource where the operating costs are very low, but the capital costs are high. What the range also indicates is if the capital costs of a resource, such as solar, decline sufficiently, both the overall portfolio cost and the stochastic range will be reduced.

The conclusion of the stochastic analysis indicates that the two resource portfolios with SCCT generation, 1-4 SCCT and 1-9 Distributed Generation have the smallest stochastic price risk range. Portfolio 1-3 Boardman to Hemingway has the lowest expected cost and a slightly larger risk range. Capital costs overshadow the operating costs for the other resource portfolios, especially for the resource portfolios with a large amount of solar generation, 1-1 Sun and Solar and 1-2 Solar. The resource portfolios with the lowest capital cost have the smallest stochastic price range.

The stochastic analysis is a key part of the portfolio selection process used by Idaho Power in the 2011 IRP. Based on the expected low cost, and the limited risk spread, Idaho Power selected two resource portfolios for the first 10 years of the planning period (2011–2020), 1-3 Boardman to Hemingway (preferred) and 1-4 SCCT (alternate).

Stochastic Analysis Results and Portfolio Selection (2021–2030)

Idaho Power followed the same process to analyze the second 10 years of the planning period:

- Ten resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

The 2011 IRP also identifies a preferred portfolio and an alternate portfolio for the 2021–2030 time period. However, the selection of these two portfolios is not as straightforward as the selection for the first 10-year period. The preferred portfolio is 2-6 Balanced 1, which incorporates geothermal, solar, small hydroelectric, and natural gas resources. The alternate portfolio for the second 10-year period is 2-8 Pacific Northwest Transmission which substantially relies on additional market purchases from the Pacific Northwest. An explanation of the rationale for the selection of these portfolios follows.

Figure 9.21 shows the incremental cost distribution for portfolio 2-6 Balanced 1, and Figure 9.22 shows the same information for the 2-8 Pacific Northwest Transmission portfolio.

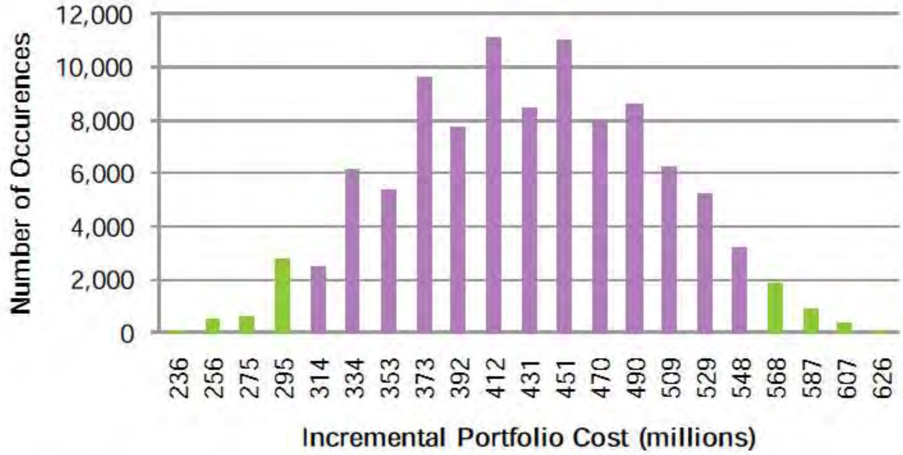


Figure 9.21 Sampling results from portfolio 2-6 Balanced 1

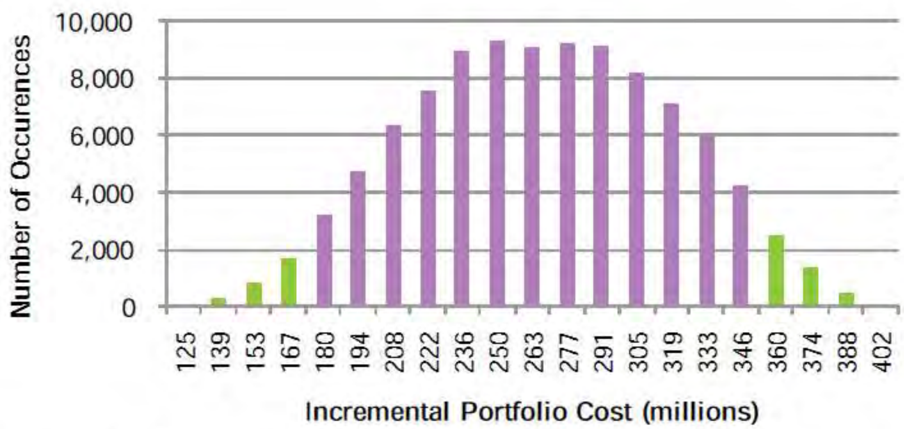


Figure 9.22 Sampling results from portfolio 2-8 Pacific Northwest Transmission

Like the first 10 years of the planning period, the distribution of the results from stochastic analysis of some resource portfolios more closely approximates a normal distribution than for other resource portfolios. Having a normal distribution is an interesting finding, but the normal distribution is not critical to the analysis or to the selection of a preferred portfolio. The main information resulting from the stochastic analysis is the cost range for the resource portfolio.

Table 9.5 shows the cost distribution for all 10 resource portfolios considered in the stochastic analysis of the second 10 years of the planning period, and Figure 9.23 shows the graphical results of the stochastic analysis for all of the resource portfolios for the 2021–2030 time period.

The nuclear resource portfolio has the highest expected cost and the broadest cost range. Like the analysis of the first 10 years, the cost distribution is driven by capital costs, and nuclear generation has a very high capital cost. The preferred and alternate portfolios, 2-6 Balanced 1 and 2-8 Pacific Northwest Transmission, both have relatively low-expected costs and a narrow range of possible costs.

Although the results of the stochastic analysis show portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission have a lower expected total portfolio cost, neither was selected as the preferred portfolio. Because of uncertainty regarding the ability to build new long-distance, high-voltage transmission projects in the second 10-year planning period, Idaho Power does not believe either portfolio presents the best option. In addition, the low cost of these portfolios is contingent on long-term, low market prices that are currently the result of a surplus of energy in the Pacific Northwest for portfolio 2-8, and the anticipation of low market prices on the east side of Idaho Power's system due to considerable amounts of wind generation being built in Wyoming.

Table 9.5 Stochastic analysis results (2021–2030)

	Portfolio Cost Calculations (000)				Risk Analysis Range (000)				
	Base	Base Rank	Stochastic Median	Difference	Lower	10th	Median	90th	Upper
2-1 Nuclear	$1,323,279	13%	$1,906,067	$582,788	$937,479	$1,258,961	$1,906,067	$2,558,841	$2,826,562
2-2 IGCC	$625,319	25%	$774,304	$148,985	$355,848	$524,204	$774,304	$1,024,405	$1,200,846
2-3 SCCT & Wind	$564,334	35%	$591,640	$27,306	$460,369	$516,699	$591,640	$667,135	$725,935
2-4 CCCT & Wind	$565,377	78%	$511,684	-$53,693	$332,030	$421,411	$511,684	$599,584	$722,088
2-5 Hydro & CHP	$860,503	44%	$879,828	$19,325	$586,902	$720,494	$879,828	$1,042,838	$1,221,484
2-6 Balanced 1	$445,704	63%	$421,349	-$24,355	$236,458	$326,718	$421,349	$513,673	$626,463
2-7 Balanced 2	$567,780	59%	$546,270	-$21,510	$283,996	$412,351	$546,270	$674,989	$855,880
2-8 Pacific Northwest Transmission	$240,492	53%	$234,915	-$5,577	$104,988	$169,359	$234,915	$300,819	$373,437
2-9 Eastside Transmission	$260,903	50%	$261,081	$178	$125,155	$192,356	$261,081	$328,692	$401,798
2-10 Renewable	$966,716	63%	$904,983	-$61,733	$523,823	$692,378	$904,983	$1,121,324	$1,333,728

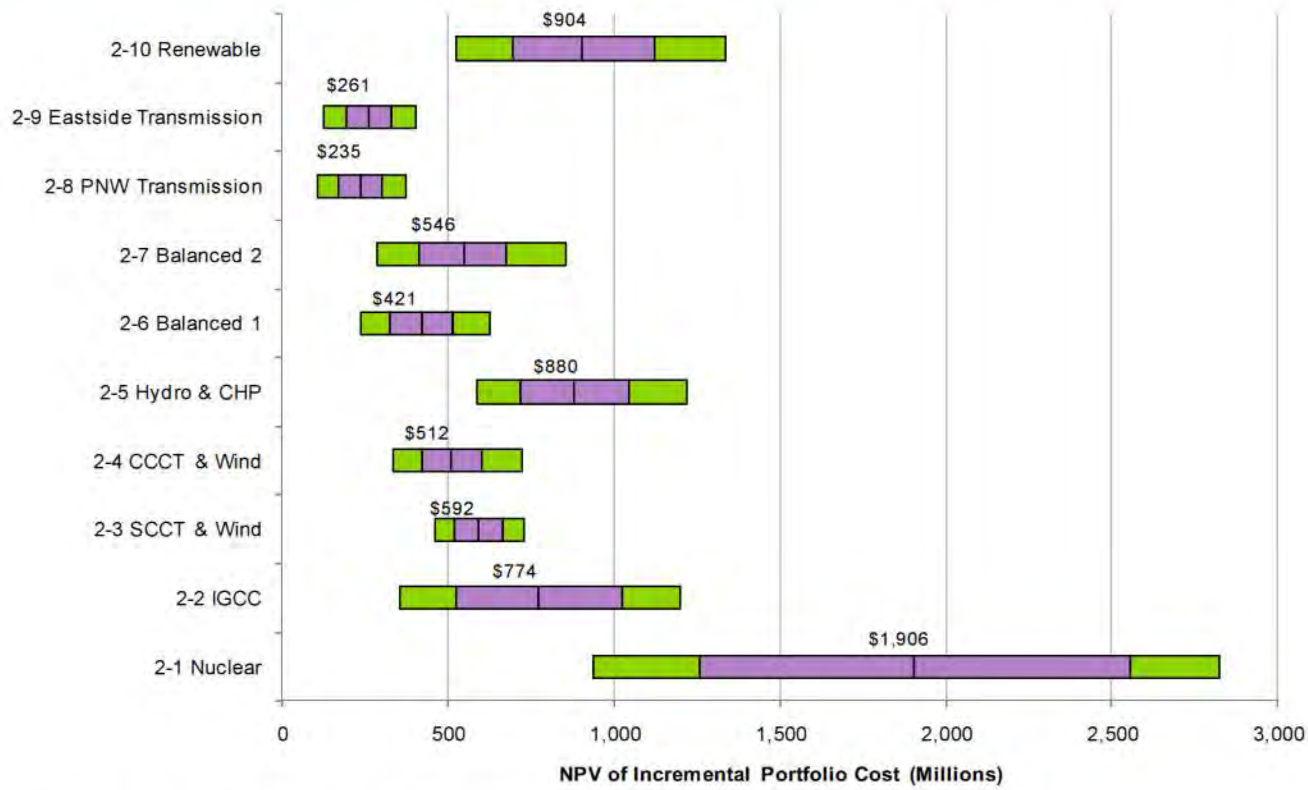


Figure 9.23 Stochastic analysis results (2021–2030)

Although it has a slightly higher expected cost, portfolio 2-6 Balanced 1 was selected as the preferred portfolio because it contains a diversified set of resources that are low risk, it does not rely on substantial technology improvements, and Idaho Power is confident it could be implemented.

Tipping Point Analysis—Market Risk

Idaho Power examined the effect of wholesale market prices on the cost of portfolio 1-3 Boardman to Hemingway relative to the cost of the less-market-dependent 1-4 SCCT portfolio. While the cost of purchased power rises with increased market prices, the revenues associated with surplus power sales also increase. Therefore, the Boardman to Hemingway portfolio remains the lower-cost portfolio under all elevated market price scenarios, and a tipping point does not exist.

However, further investigation into just the purchased power component of these two portfolios provides some useful information related to market price risk. The NPV total cost of the Boardman to Hemingway portfolio is approximately $43 million less than the cost of the SCCT portfolio. The Boardman to Hemingway portfolio also has an additional 62,000 MWh of market purchases when compared to the SCCT portfolio.

To make up the difference in total portfolio cost, average market prices for the additional 62,000 MWh of purchases in the Boardman to Hemingway portfolio would need to be more than $700 per MWh. While this analysis ignores the benefit of surplus sales at higher market prices, it offers insight on the level market prices would have to rise to in order to make the Boardman to Hemingway portfolio no longer the least-cost option.

Tipping Point Analysis—Boardman to Hemingway

The 2011 IRP analysis assumes Idaho Power has 28-percent equity ownership in the Boardman to Hemingway project. If third-party equity interest in the project is less than expected, the company's share of the capital cost for the project will be higher, and the total cost of portfolio 1-3 Boardman to Hemingway will also be higher. Therefore, a tipping point analysis was performed to determine how great of an ownership share Idaho Power could take in the project in order for the total cost of portfolio 1-3 Boardman to Hemingway to be equivalent to the next best alternative, portfolio 1-4 SCCT.

The results of the analysis indicate Idaho Power's share of the project could go as high as 42 percent before the cost of the two portfolios were equal. This analysis assumes that Idaho Power's use of the Boardman to Hemingway line is the same as it was under the expected 28-percent ownership scenario, and the incremental capital cost associated with a greater equity share is not offset by economic utilization of the additional capacity. Figure 9.24 presents the graphical results of the analysis and additional details of the calculations can be found in *Appendix C–Technical Appendix*.

Figure 9.24 Boardman to Hemingway ownership tipping point analysis

Tipping Point Analysis—Cost of Solar Resources versus Market Purchases

Recent trends in the decreasing cost of solar PV technology generated significant interest from members of the IRPAC. If this trend continues, solar PV will become more cost competitive with other available resource options. A tipping point analysis was performed to determine how low the cost of solar PV would have to be in order to be competitive with portfolio 1-3 Boardman to Hemingway, which relies on market purchases.

For the tipping point analysis, Idaho Power investigated the capital cost decrease necessary to make the total cost of portfolio 1-2 Solar equivalent to the total cost of portfolio 1-3 Boardman to Hemingway. Figure 9.25 shows the results of the tipping point analysis. The figure notes that average solar costs (average of solar thermal and PV) are expected to be $3,614 per kW and would need to decrease by 72 percent to $1,012 per kW to match the total cost of portfolio 1-3 Boardman to Hemingway. This analysis assumes that capital cost decreases affecting the solar resources are specific to these resources, and would not place downward pressure on the capital cost of the Boardman to Hemingway transmission project or on wholesale power market prices. If wholesale power market prices rise, a smaller reduction in solar capital costs is necessary for the portfolio costs to be equal. Current federal tax incentives available for solar technologies are included in this analysis.

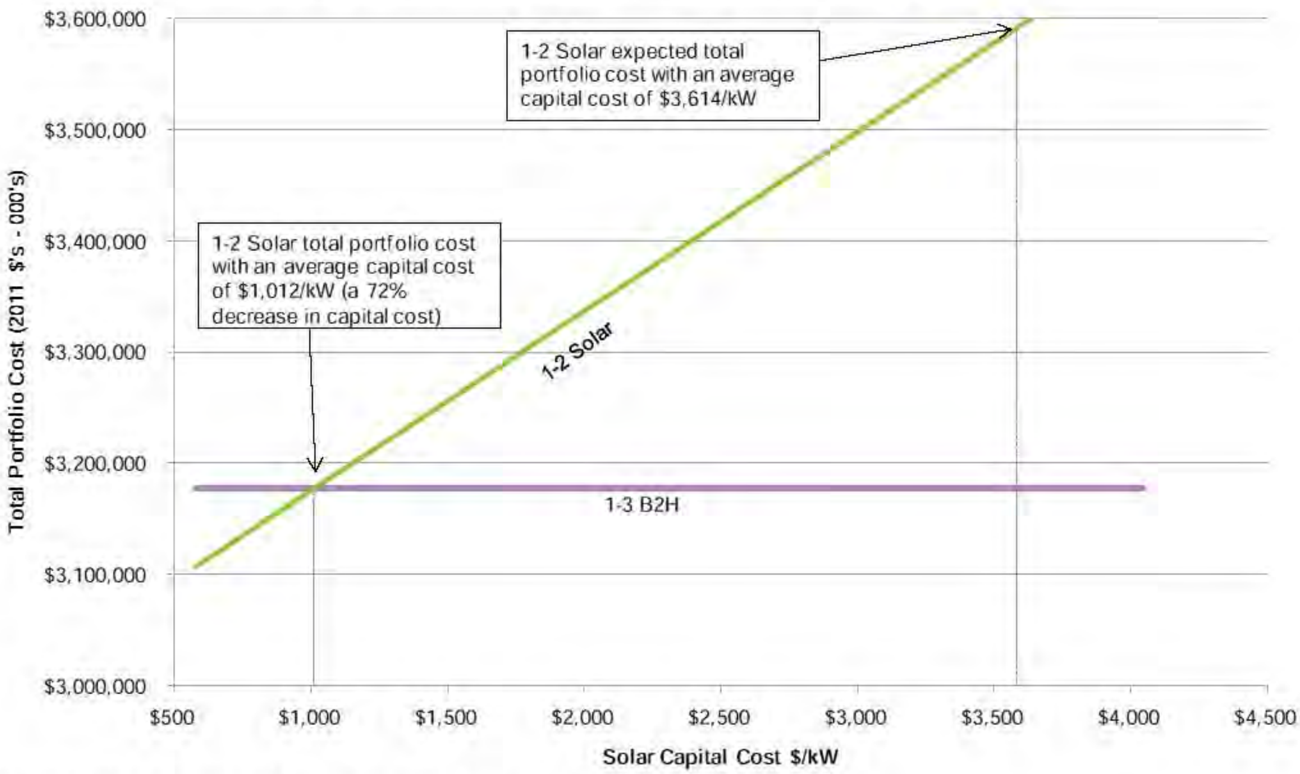


Figure 9.25 Cost of solar tipping point analysis

Capacity Planning Margin

Idaho Power discussed planning criteria assumptions with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin.

As part of preparing the 2011 IRP, Idaho Power has calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected-case (50^{th} percentile) water and load conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with expected-case (50^{th} percentile) peak-hour load, with the excess resource capacity designated as planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Tables 9.6 and 9.7.

Table 9.6 Capacity planning margin (2011–2020)

Capacity Planning Margin										
Load and Resource Balance	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
Load Forecast (50th%) - Aug 2010 w/No DSM	(3,367)	(3,440)	(3,560)	(3,656)	(3,750)	(3,832)	(3,908)	(3,982)	(4,060)	(4,136)
Existing DSM (Energy Efficiency)	33	48	64	79	93	107	121	135	149	163
Load Forecast (50th% w/EE)	(3,334)	(3,392)	(3,496)	(3,577)	(3,657)	(3,725)	(3,787)	(3,847)	(3,911)	(3,973)
Existing Demand Response	330	310	315	315	321	351	351	351	351	351
Peak-Hour Forecast w/DR	**(3,004)**	**(3,082)**	**(3,181)**	**(3,262)**	**(3,336)**	**(3,374)**	**(3,436)**	**(3,496)**	**(3,560)**	**(3,622)**
Existing Resources										
Coal	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	0	300	300	300	300	300	300	300	300	300
Hydro (50th%)—HCC	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Hydro (50th%)—Other	286	286	286	285	284	283	282	281	281	280
Shoshone Falls Upgrade	0	0	0	0	0	4	4	4	4	4
Sho-Ban Water Lease	47	48	48	48	48	0	0	0	0	0
Total Hydro (50th%)	1,453	1,454	1,454	1,453	1,452	1,407	1,406	1,405	1,405	1,404
CSPP (PURPA)	160	161	166	166	166	166	166	166	166	166
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	20	20	20	20	20	20	20	20
Clatskanie Exchange - Take	12	12	12	12	12	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (83 MW)	83	83	0	0	0	0	0	0	0	0
Mead Purchase	75	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	185	110	47	47	47	35	35	35	35	35
Firm Pacific NW Import Capability	126	233	229	225	222	218	214	209	205	201
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	**3,302**	**3,637**	**3,574**	**3,569**	**3,565**	**3,504**	**3,499**	**3,494**	**3,489**	**3,484**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(3)**	**(71)**	**(138)**
2011 IRP DSM	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
Industrial	2	3	5	6	7	8	8	9	10	10
Commercial	0	1	1	2	2	3	3	3	4	4
Residential	1	2	4	6	8	10	12	15	17	20
Total New DSM Peak Reduction	3	6	10	14	17	20	24	27	31	34
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(40)**	**(103)**
2009 IRP Resources	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
2015 Eastside Purchase	0	0	0	0	83	0	0	0	0	0
2016 B2H	0	0	0	0	0	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	83	450	450	450	450	450
Remaining Monthly Surplus/Deficit	302	561	403	321	329	600	537	475	410	347
Planning Margin	10.0%	18.2%	12.7%	9.8%	9.9%	17.8%	15.6%	13.6%	11.5%	9.6%

Table 9.7 Capacity planning margin (2021–2030)

Capacity Planning Margin										
Load and Resource Balance	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
Load Forecast (50th%) - Aug 2010 w/No DSM	(4,211)	(4,289)	(4,370)	(4,448)	(4,524)	(4,605)	(4,680)	(4,773)	(4,858)	(4,918)
Existing DSM (Energy Efficiency)	177	191	205	219	233	247	261	275	289	275
Load Forecast (50th% w/EE)	(4,034)	(4,098)	(4,165)	(4,229)	(4,291)	(4,358)	(4,419)	(4,498)	(4,569)	(4,643)
Existing Demand Response	351	351	351	351	351	351	351	351	351	351
Peak-Hour Forecast w/DR	**(3,683)**	**(3,747)**	**(3,814)**	**(3,878)**	**(3,940)**	**(4,007)**	**(4,068)**	**(4,147)**	**(4,218)**	**(4,292)**
Existing Resources										
Coal	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300
Hydro (50th%)—HCC	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Hydro (50th%)—Other	280	280	280	280	280	280	280	280	280	280
Shoshone Falls Upgrade	4	4	4	4	4	4	4	4	4	4
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0
Total Hydro (50th%)	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404
CSPP (PURPA)	166	166	166	166	166	166	166	101	63	93
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (83 MW)	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	257	254	250	246	243	238	234	231	227	224
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	**3,485**	**3,482**	**3,478**	**3,474**	**3,471**	**3,466**	**3,462**	**3,394**	**3,352**	**3,379**
Monthly Surplus/Deficit	**(198)**	**(265)**	**(336)**	**(404)**	**(469)**	**(541)**	**(606)**	**(753)**	**(866)**	**(913)**
2011 IRP DSM	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
Industrial	11	11	12	12	13	13	13	13	13	13
Commercial	5	5	5	6	6	6	6	6	6	6
Residential	22	24	27	30	32	35	38	40	43	45
Total New DSM Peak Reduction	38	41	44	48	51	54	57	59	62	65
Remaining Monthly Surplus/Deficit	**(160)**	**(224)**	**(292)**	**(357)**	**(419)**	**(487)**	**(550)**	**(694)**	**(804)**	**(848)**
2009 IRP Resources	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0
2016 B2H	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	170	170	170	170	170	170	170	170	170
2024 Solar Power Tower	0	0	0	44	44	44	44	44	44	44
2025 CCCT	0	0	0	0	300	300	300	300	300	300
2028 Small Hydro	0	0	0	0	0	0	0	52	52	52
2029 SCCT Frame	0	0	0	0	0	0	0	0	170	170
New Resource Subtotal	502	672	672	716	1,016	1,016	1,016	1,068	1,238	1,238
Remaining Monthly Surplus/Deficit	342	448	380	360	598	529	467	374	434	390
Planning Margin	9.3%	11.9%	10.0%	9.3%	15.2%	13.2%	11.5%	9.0%	10.3%	9.1%

Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2011 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred and alternate portfolios. As mentioned in previous chapters, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2011 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator/purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has chosen to calculate LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5–1.0 hours per year. The results of the loss of load probability analysis are shown in Figure 9.26, and additional data can be found in *Appendix C–Technical Appendix*.

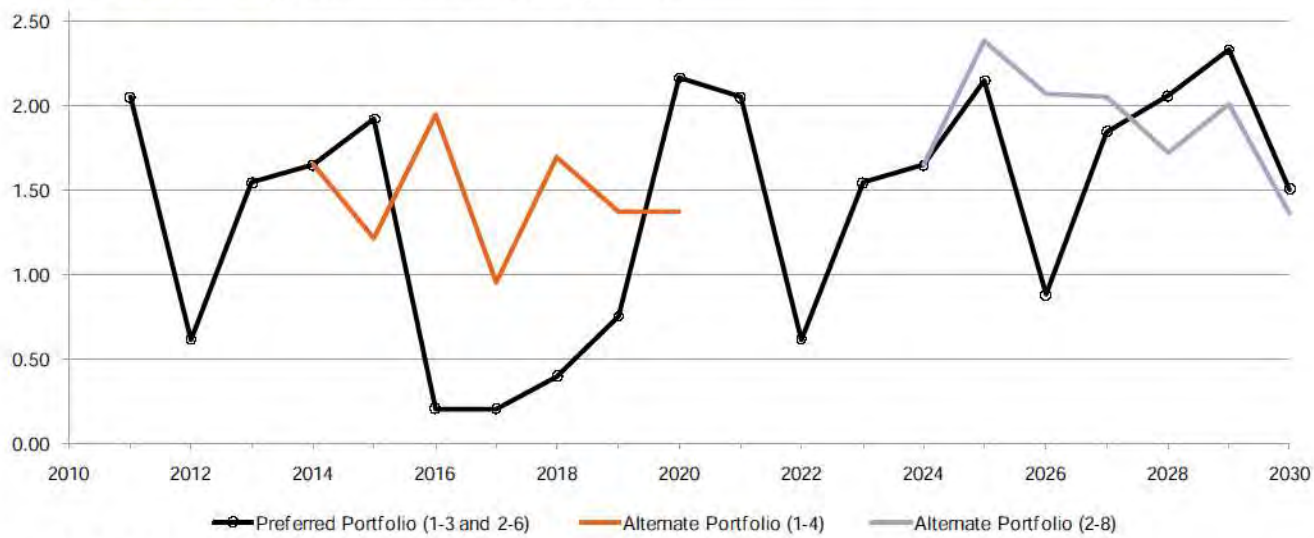


Figure 9.26 Loss of load expectation

In performing the analyses, there were several instances where extending purchases of east-side energy similar to the purchases contemplated in 2010–2012 were necessary to achieve the results shown in Figure 9.26.

[3] Based on Roy Billinton "Power System Reliability Evaluation" Chapter 2&3, Copyright 1970.

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10. Action Plans

Action plans describe how Idaho Power will implement the results of the IRP.

Once the final preferred portfolio has been selected, an action plan is necessary to identify the steps that must be taken to implement the plan. Like the portfolio analysis, the action plan is split into two, 10-year periods. The near-term action plan addresses the years 2011–2020, and the long-term action plan covers the years 2021–2030. The two action plans represent the culmination of the IRP process.

Near-Term Action Plan (2011–2020)

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years to implement the preferred portfolio (2011–2020). No long-lead-time generation resources, such as advanced nuclear or IGCC are considered in the near-term plan. However, Idaho Power intends to continue its efforts to participate in regional utility planning forums and to explore regional alliances as generation resource, energy storage, energy efficiency, and transmission technologies develop.

Table 10.1 presents a list of the resources Idaho Power expects to add to its generation portfolio over the next 10 years for both the preferred portfolio and an alternate portfolio. An alternate portfolio is also identified in the IRP in the event substantial changes impact the assumptions used to select the preferred portfolio.

Table 10.1 Near-term action plan (2011–2020)

Year	Preferred Resource Portfolio 1-3 Boardman to Hemmingway	Alternative Resource Portfolio 1-4 SSCT
2011		
2012		
2013	Solar Demonstration Project (500kW–1 MW)	Solar Demonstration Project (500kW–1 MW)
2014		
2015	Eastside PPA (83 MW)	SCCT (170 MW)
2016	Boardman to Hemingway (450 MW)	
2017		SCCT (170 MW)
2018		
2019		SCCT (94 MW)
2020		

Highlights

- The Boardman to Hemingway transmission line is the primary resource in the near-term action plan, and the long-term action plan includes a diverse set of renewable and gas-fired resources.
- Idaho Power is proposing a solar demonstration project as part of the 2011 IRP.
- IRPAC members and members of the public made significant contributions through the nine public meetings conducted while preparing the 2011 IRP.

Preferred Portfolio Near-Term Action Plan

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term action plan preferred portfolio. The new transmission line was first identified in Idaho Power's 2006 IRP, and the company continues working to acquire the necessary regulatory approvals and permits necessary to begin construction. Construction of the Boardman to Hemingway transmission line is expected to start in early 2014, after completing the permitting, regulatory, and engineering work. If the Boardman to Hemingway project is substantially delayed, Idaho Power will have to consider implementing the alternate portfolio.

The preferred portfolio also includes a market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016. Idaho Power has used the east side for market purchases in the past, but prices have historically been higher than the prices at the Mid-C hub in the Pacific Northwest. A purchase on the east side does not require substantial lead time, and Idaho Power will continue to monitor market prices, load growth, and the status of the Boardman to Hemingway project prior to committing to this purchase.

As part of the 2011 IRP, Idaho Power is proposing to construct a solar demonstration project. Details of this proposal are explained in Chapter 1 and the project could be on line as early as late 2012.

Alternate Portfolio Near-Term Action Plan

The alternate portfolio presents the actions Idaho Power will take if the Boardman to Hemingway transmission line is significantly delayed or canceled. In the alternate resource portfolio, Idaho Power anticipates adding natural gas-fired SCCTs to meet capacity deficits. The company expects to acquire the generation resources identified in the alternate portfolio through a competitive RFP process meeting the requirements of Oregon Order 06-446 issued on August 10, 2006, as well as any revisions to the requirements resulting from Oregon Docket UM 1182.

Although the alternate portfolio identifies the first 170-MW SCCT in 2015, in the event the alternate portfolio is implemented, Idaho Power will continue to evaluate resource needs and may alter the size, timing, and technology of the combustion turbine depending on market conditions at the time an RFP is issued.

Should the permitting, regulatory, engineering work, or construction of the Boardman to Hemingway project be delayed, Idaho Power will face the decision to acquire the first resource identified in the alternate portfolio. To meet the competitive procurement guidelines, Idaho Power would need to initiate the resource procurement process by issuing an RFP as early as 2012. Beginning the procurement process in 2012 is necessary to achieve an on-line date in 2015. The resource procurement process would most likely begin prior to the completion of Idaho Power's 2013 IRP, which is scheduled to be filed in June 2013.

Long-Term Action Plan (2021–2030)

The long-term action plan describes Idaho Power's planned resource acquisitions during the second 10 years of the planning period (2021–2030). The long-term action plan assumes that the near-term action plan is completed with only minor variations. If the Boardman to Hemingway project is significantly delayed or canceled and Idaho Power implements the alternate resource plan in the first 10 years of the planning period, Idaho Power may reconsider its concerns about over-reliance on market purchases and select the alternate resource portfolio relying on a regional transmission project for the second 10 years of the planning period.

It is important to note that the Gateway West project was included in each resource portfolio for only the second 10-year period when current transmission constraints required the addition of new transmission capacity for resources to be added in southern Idaho east of the Treasure Valley load center. The amount of Gateway West capacity is different in each portfolio, depending on other included resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

With the exception of the Gateway West transmission project, both the preferred and alternate resource portfolios for the second 10 years of the planning period include a combination of renewable and natural gas-fired resources. The long-term action plan for both the preferred and alternate portfolios is shown in Table 10.2.

Table 10.2 Long-term action plan (2021–2030)

Year	Preferred Resource Portfolio 2-6 Balanced 1	Alternative Resource Portfolio 2-7 PNW Transmission
2021	Geothermal (52 MW)	Geothermal (52 MW)
2022	SCCT (170 MW)	Pacific NW Purchase (500 MW)
2023		
2024	Solar Power Tower (50 MW)	
2025	CCCT (300 MW)	
2026		
2027		Solar PV (20 MW)
2028	Small Hydro (60 MW)	Geothermal (52 MW)
2029	SCCT (170 MW)	SCCT (170 MW)
2030		

Preferred Portfolio Long-Term Action Plan

The preferred portfolio selected for the second 10 years consists of a diverse mixture of renewable and natural gas resources. With the possible exception of the solar power tower technology, none of the identified resources present a technological challenge. The longest lead-time resource in the preferred portfolio is the CCCT identified to come on line in 2025, which would require approximately four years to design, permit, and construct. Therefore no significant actions are required in the next two years to pursue this portfolio.

After the 2011 IRP, Idaho Power's next IRP will be completed in June 2013. Idaho Power will continue to evaluate "balanced" portfolios, as they have historically performed well in the IRP analysis.

Alternate Portfolio Long-Term Action Plan

The alternate portfolio for the second 10 years presents a dilemma. Although this portfolio performed well, as covered in Chapter 9, concerns regarding an over-reliance on market purchases and the future ability of utilities to permit and construct long-distance, high-voltage transmission raise questions regarding the viability of this portfolio.

Idaho Power will continue to monitor forward market prices and the progress that can be made on the Boardman to Hemingway and Gateway West projects between now and the completion of the 2013 IRP. Based on recent experience, new long-distance, high-voltage transmission projects require a lead time of 8–10 years. If additional transmission capacity to either the Pacific Northwest or to the east side of

Idaho Power's system continues to perform well in the IRP analysis, Idaho Power will need to begin work on permitting and initial designs for new transmission projects shortly after the completion of the 2013 IRP.

Conclusion

Each Idaho Power IRP builds on the foundation of earlier resource plans, and each plan includes incremental changes due to forecasts of future events. The 2011 IRP is no exception.

Idaho Power and other utilities in the West face major regional transmission decisions. No significant interstate transmission has been built in the region for many years. Idaho Power's 2006 IRP was the first of the company's resource plans where Idaho Power made a significant commitment to new interstate transmission projects. Idaho Power continues its commitment to regional transmission with the 2011 IRP.

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term preferred resource portfolio, and Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction. As part of acknowledging the 2009 IRP, the OPUC requested Idaho Power treat the Boardman to Hemingway project as an uncommitted resource in the 2011 IRP. And, once again, the Boardman to Hemingway transmission project has outperformed other alternatives.

In the 2011 plan, Idaho Power conducted a thorough analysis of resource alternatives, including generation, transmission, demand-response, and energy efficiency. The only committed resources not yet constructed but included in the 2011 IRP are the Langley Gulch CCCT and an upgrade at the company's Shoshone Falls hydroelectric project. The Boardman to Hemingway transmission project was analyzed using the same methods as other uncommitted resources. After the analysis, the Boardman to Hemingway transmission line is again the preferred resource to meet customer needs in Idaho and Oregon.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2011 IRP. The IRPAC discussed many technical aspects of the 2011 resource plan along with a significant number of political/societal topics at nine meetings conducted during the second half of 2010 and the first half of 2011. Idaho Power's resource planning process is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP biennially. At the time of the next plan in 2013, Idaho Power will have additional information regarding supply-side resources, demand-side management programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the development of a federal RES, and the feasibility of advanced nuclear, IGCC, and other resource options that currently face technological challenges.

One of the key strengths of Idaho Power's planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the IRPAC, the IPUC, the OPUC, and concerned customers to revisit the IRP and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near-term action plan allows for discussion and adjustment of the IRP as warranted.

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Glossary of Abbreviations

AC–Alternating Current

A/C–Air Conditioning

ACOE–United States Army Corps of Engineers

AFUDC–Allowance for Funds Used During Construction

akW–Average kilowatt

aMW–Average Megawatt

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

CAA–Clean Air Act

CAES–Center for Advanced Energy Studies

CAIR–Clean Air Interstate Rule

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CCR–Coal Combustion Residuals

CCX–Chicago Climate Exchange

CFI–Carbon Financial Instrument

cfs–Cubic-Feet-per-Second

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

CPCN–Certificate of Public Convenience and Necessity

CO_2–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

EPA–Environmental Protection Agency

EPRI–Electric Power Research Institute

ESA–Endangered Species Act

ESPA–Eastern Snake River Plain Aquifer

F–Fahrenheit

FCA–Fixed-Cost Adjustment

FCP–Formal Consultation Package

FCRPS–Federal Columbia River Power System

FEIS–Final Environmental Impact Statement

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

FWS–US Fish and Wildlife Service

GHG–Greenhouse Gas

HAP–Hazardous Air Pollutants

Hg–Mercury

HRSG–Heat Recovery Steam Generator

IDWR–Idaho Department of Water Resources

IGCC–Integrated Gasification Combined Cycle

INL–Idaho National Laboratory

IOER–Idaho Office of Energy Resources

IPUC–Idaho Public Utilities Commission

IRP–Integrated Resource Plan

IRPAC–IRP Advisory Council

kV–Kilovolt

kW–Kilowatt

kWh–Kilowatt Hour

lbs–Pounds

LOLE–Loss of Load Expectation

LTP–Local Transmission Plan

m^2–square meters

mm–Millimeter

MMBtu–Million British Thermal Units

MSA–Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NAAQS–National Ambient Air Quality Standards

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NERC–North American Electric Reliability Corporation

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

NO_x–Nitrogen Oxide

NPV–Net Present Value

NWPP–Northwest Power Pool

NREL–National Renewable Energy Laboratory

NSR–New Source Review

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

ODEQ–Oregon Department of Environmental Quality

ODOE–Oregon Department of Energy

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCB–Polychlorinated Biphenyls

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PRC–Power Resources Cooperative

PTC–Production Tax Credit

PURPA–*Public Utility Regulatory Policies Act of 1978*

PV–Photovoltaic

QF–Qualifying Facility

RCRA–*Resource Conservation and Recovery Act of 1976*

REC–Renewable Energy Certificate

RES–Renewable Electricity Standard

RFP–Request for Proposal

RH BART–Regonal Haze Best Available Retrofit Technology

RPS–Renewable Portfolio Standard

SCCT–Simple-Cycle Combustion Turbine

SCR–Selective Catalytic Reduction

SO_2–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TASCO–The Amalgamated Sugar Company

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

USFS–United States Forest Service

WDEQ–Wyoming Department of Environmental Quality

WECC–Western Electricity Coordinating Council

W–Watt