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

# 2009 Integrated Resource Plan

December 2009

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 a resource plan 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 *2009 Integrated Resource Plan* (IRP). Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council, and the comments provided by other concerned citizens and customers.

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

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.

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# GLOSSARY OF ABBREVIATIONS

AC–Alternating Current

A/C–Air Conditioning

ADI–Ace Diversity Interchange

AFUDC–Allowance for Funds Used During Construction

AMPS–Associated Mountain Power System

aMW–Average Megawatt

B2H–Boardman to Hemingway Transmission Project

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

Btu–British Thermal Unit

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

$CO_2$–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DG–Distributed Generation

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EA–Environmental Assessment

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

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

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

GHG–Greenhouse Gas

GW–Gigawatt

HRSG–Heat Recovery Steam Generator

ICIP–Industrial Customers of Idaho Power

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

LED–Light-Emitting Diode

LOLE–Loss of Load Expectation

LT–Long Term

MIT–Massachusetts Institute of Technology

mm–Millimeter

MMBTU–Million British Thermal Units

MSA– Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NiCd–Nickel Cadmium

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

NOx–Nitrogen Oxide

NOI–Notice of Intent

NPV–Net Profit Value

NREL–National Renewable Energy Laboratories

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCC–Planning Coordination Council

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PTC–Production Tax Credit

PURPA–Public Utility Regulatory Policies Act of 1978

PV–Photovoltaic

QF–Qualifying Facility

REC–Renewable Energy Credit

RES–Renewable Electricity Standard

RFP–Request for Proposal

RISEC–River In-Stream Energy Conversion

RPS–Renewable Portfolio Standard

SAR–Surrogate Avoided Resource

SCCT–Simple Cycle Combustion Turbine

SMES–Superconducting Magnetic Energy Storage

$SO_2$–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

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

USFWS–United States Fish and Wildlife Service

USFS–United States Forest Service

VRB–Vanadium Redox Battery

WACC–Weighted Average Cost of Capital

WAQC–Weatherization Assistance for Qualified Customers

WECC–Western Electricity Coordinating Council

# 1. SUMMARY

## Introduction

The *2009 Integrated Resource Plan* (IRP) is Idaho Power's ninth 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 2009 IRP assumes that during the planning period (2010–2029), 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), 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 customers[1] and native load customers[2]. The 2009 IRP only evaluates the need for additional transmission capacity necessary to serve native load 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.

[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.

### Highlights

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

The number of customers in Idaho Power's service area is expected to increase from around 486,000 in 2008 to over 680,000 by the end of the planning period in 2029. Even with the current 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 upon a worse-than-median level of water. 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 baseload resources with long construction lead times along with the need for a 20-year resource plan to support Public Utilities Regulatory Policies Act (PURPA) contract negotiations, Idaho Power and the IRPAC 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 2009 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term through the *Energy Risk Management Policy* that was 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* 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. In earlier years, the public forum was called the Technical Advisory Panel. Idaho Power revised the public involvement process and formed the IRPAC when preparing the 2004 IRP and has continued working with the council in the preparation of the 2006 and 2009 resource plans.

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. A list of the IRPAC members can be found in *Appendix C—Technical Appendix*. Idaho Power continued the public involvement process for the 2009 IRP and 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 the 2009 IRP.

Idaho Power has found that working with members of the IRPAC and the public has been very rewarding and the company believes the 2004, 2006, and the 2009 IRPs are 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 2009 IRP are made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2009 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 resource plan and discusses the planning process with various civic groups and at educational seminars as requested.

## IRP Methodology

The preparation of Idaho Power's 2009 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. Idaho Power is committed to implementing all cost-effective DSM programs and the impact of the new programs is accounted for in the load and resource balance. 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 in order to determine the preferred portfolio. Idaho Power attempts to financially value all of the resource costs and benefits. Traditional resources have both a fuel cost and a market value for the delivered energy and Idaho Power includes both the cost and the value when evaluating resources. Further, the value of renewable energy credits (REC) is also included in the financial analysis.

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

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

For the 2009 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 (2010–2019), four resource portfolios were examined. The preferred resource portfolio from the first 10-year period was coupled with a variety of portfolios containing advanced technologies in the second 10-year period. Using the preferred portfolio from the first 10-year period insures that all of the advanced technologies are considered equally in the second 10-year period. It is not necessary for Idaho Power to commit to a single advanced technology at the present time. Idaho Power anticipates discussing its preferred long-term portfolio options with other Pacific Northwest utilities over the next several years and is contemplating forming a regional partnership to further explore some of the more promising advanced technologies.

## Demand-Side Management

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

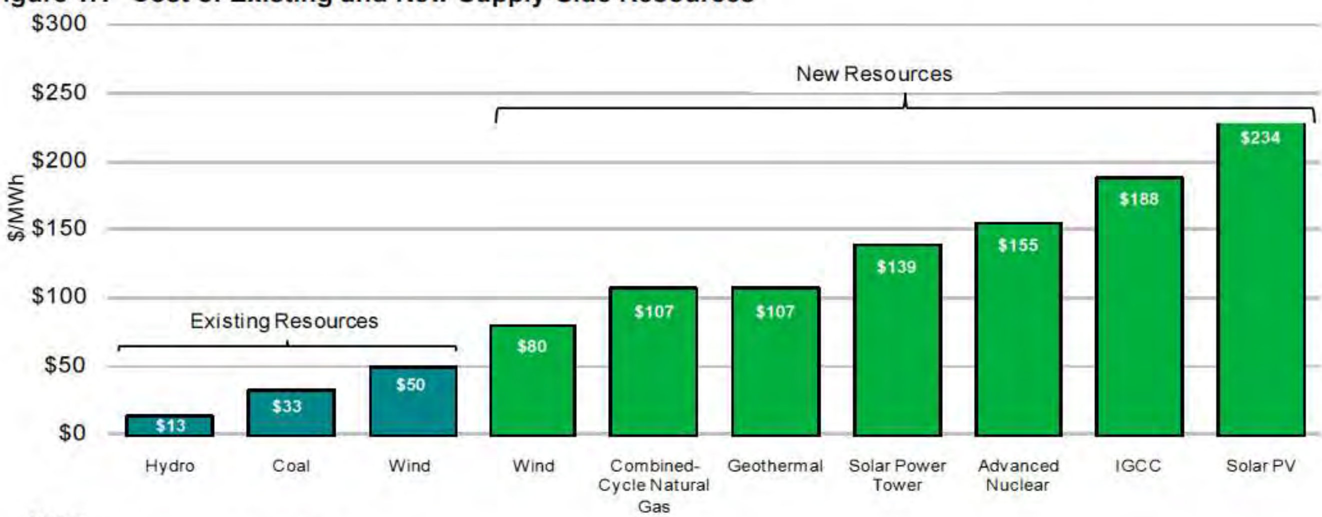
New and expanded demand response programs developed as part of the 2009 IRP are expected to reduce peak summer load by 323 MW by 2012 when the programs mature. This reflects tremendous growth over 2006 IRP forecasts where demand response programs were estimated to provide 78 MW of peak reduction by 2026.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

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

## Supply-Side Resource Costs

The 2009 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 2008 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 new resources considered in the 2009 IRP. Existing resource costs are based on 2008 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, plus a cost of $43 per ton for carbon-emitting resources.

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




NOTES:
1) Cost of existing resources based on 2008 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 percent of the wind generation purchased by Idaho Power during 2008).

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

## Risk Management

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

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

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

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

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

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

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

## Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, two natural gas-fired plants, one diesel-powered generator, and shares ownership in three coal-fired facilities. Idaho Power's carbon dioxide ($CO_2$) emission 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]/MWh), based on the report of 2006 $CO_2$ emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, released May 2008 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and PG&E Corporation.

In September 2009, Idaho Power's Board of Directors approved guidelines to establish a goal to reduce the $CO_2$ emission 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 $CO_2$ emission intensity for the 2010 through 2013 time period to a level of 10 percent—15 percent below the company's 2005 $CO_2$ emission intensity of 1,194 lbs/MWh. Since Idaho Power's $CO_2$ emission 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.

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

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

## Preferred Resource Portfolio

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

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

**Table 1.1 Preferred Portfolio**

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

*Committed resource

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2011 IRP and subsequent plans as more certainty regarding carbon regulation and a federal 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

Idaho Power has completed the competitive procurement process for the Langley Gulch CCCT and has nearly completed the RFP process for the 2012 wind resource. Both resources are expected to be on-line in 2012. Idaho Power anticipates expanding both the irrigation and commercial demand response programs in 2010 and 2011 to address expected growth in peak-hour loads. Idaho Power anticipates beginning construction of the Shoshone Falls Upgrade Project in 2012 with the project being completed by 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 |
|---|---|
| 2010 | Present and gain acceptance of 2009 IRP with regulatory commissions |
| | File wind contract resulting from the 2012 Wind RFP with the IPUC |
| | File geothermal contract with the IPUC (approximately 20 MW) |
| | Irrigation Peak Rewards program increases from 160 MW to 220 MW |
| | FlexPeak Management program increases from 20 MW to 40 MW |
| | Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins |
| | Langley Gulch CCCT construction continues |
| | Irrigation Peak Rewards demand response program increases from 220 MW to 250 MW |
| | FlexPeak Management program increases to from 40 MW to 45 MW |
| | File 2011 IRP with regulatory commissions |
| 2012 | Wind project on-line (approximately 150 MW) |
| | Langley Gulch CCCT on-line (300 MW) |
| | Geothermal project on-line (approximately 20 MW) |
| 2013 | Boardman to Hemingway construction begins |
| | Shoshone Falls Upgrade Project construction begins |
| | File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls Upgrade Project construction continues |
| | Boardman to Hemingway construction continues |
| 2015 | Shoshone Falls Upgrade Project on-line (49 MW) |
| | Boardman to Hemingway completed (250 MW) |
| | File 2015 IRP with regulatory commissions |
| 2016 | Geothermal project on-line (approximately 20 MW) |
| 2017 | Boardman to Hemingway additional capacity for market purchases (175 MW) |
| | File 2017 IRP with regulatory commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with regulatory commissions |

## Public Policy Issues

The 2009 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 the issues typically precludes a strong majority opinion from the IRPAC members. The public policy issues presented to the IRPAC are discussed below.

### *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. Each new customer dilutes the existing resource base and increases the cost to all customers.
The question of rate determination based on embedded resources is a significant public policy issue and Idaho Power senses a desire by some parties to discuss the existing rate determination principles.

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

### *Asset Ownership*

Idaho Power can develop and own generation assets, rely on power purchase agreements (PPAs) 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. Idaho Power's preference is to own the generation assets necessary to serve its customer load.

### *Renewable Energy Credits*

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

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

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. Because of recent increases in costs and customer rates, along with feedback from the IPUC, Idaho Power feels it would be prudent to sell the RECs until they are required by a federal RES. Additional information on RECs and the proposed federal legislation can be found in Chapter 2.

## Emission Offsets

Depending on market conditions and future regulations, it may be possible to purchase emission 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 emission risk by purchasing emission 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 or not carbon offsets purchased today will meet future carbon control requirements and regulations. In addition, draft federal legislation limits the amount of offsets that may be used to meet reduction targets.

Idaho Power believes it should investigate purchasing either emission offsets or options to acquire future carbon offsets. Idaho Power 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 emission offset options as well as the cost of any emission offsets purchased.

## Technology Risk and Joint Development Opportunities

In the 2009 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 chose 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 would 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 Pilot Project

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

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

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

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

## Political and Regulatory 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 has customers in both Idaho and Oregon, with approximately 95 percent of Idaho Power's customers being located in the state of Idaho. The following sections describe some of the federal and state regulatory issues facing Idaho Power.

### *Idaho Energy Plan*

In 2006, the Idaho State Legislature directed an 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 the citizens of Idaho. In January 2007, the committee completed the Idaho Energy Plan and concluded that all Idaho energy systems have performed very well with retail electric and natural gas prices that remain some of the lowest in the country.

The Idaho Legislature sets state energy policy in Idaho.

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 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."

**Highlights**

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

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

## 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 (the 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.

The purpose of the alliance is to enable 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 twelve volunteer task forces working in the following areas:

- Conservation and energy efficiency
- Wind
- Geothermal
- Hydropower
- 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.

## Idaho State Legislature—Senate Bill 1123

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

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

## Oregon Renewable Portfolio Standard

The state of Oregon's Renewable Portfolio Standard (RPS) requires utilities and electricity service suppliers serving Oregon load to include in their portfolio of power sold to retail customers a percentage of electricity generated from qualifying renewable energy sources. Like most states, Oregon's RPS is phased-in over a number of years, with final targets set for the year 2025. The Oregon RPS also includes a tiered system based on the amount of load a utility serves in Oregon. Larger utilities have higher RPS requirements and interim targets while smaller utilities have less rigorous requirements and no interim targets.

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

## Proposed Federal Energy Legislation

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

In June 2009, the U.S. House of Representatives narrowly passed H.R. 2454, the American Clean Energy and Security Act sponsored by Representatives Henry A. Waxman and Edward J. Markey. The Waxman-Markey bill proposes a cap-and-trade system that establishes a limit or cap on the total amount of GHG emissions. Under a cap-and-trade system, utilities would be allocated emission allowances that would be decreased over time in order to achieve a total emission 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. Details of the Waxman-Markey bill related to GHG reduction include:

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

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

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

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

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

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

## Renewable Energy Credits (Green Tags)

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 megawatt hour (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 regulatory compliance and 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 RPS requirements also typically specify a "shelf life" for RECs so they cannot be banked indefinitely.

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

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

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

## FERC Relicensing

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

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 Projects.

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 (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the Endangered Species Act (ESA); and other applicable federal laws.

The license for the Swan Falls project expires 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 anticipates NEPA consultation to initiate in early 2010.

Failure to relicense any of the existing hydropower 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 2009 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. 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 commenced in 1987 to define the nature and extent of water rights in the Snake River Basin. 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. The purpose of the agreement was to resolve litigation related to the company's water rights at the Swan Falls project. Idaho Power has filed claims for all of its hydropower 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.

Idaho Power has also actively participated in proceedings associated with the Comprehensive Aquifer Management Plan (CAMP) of the Eastern Snake River Plain Aquifer (ESPA). Remedial actions identified in CAMP are intended to address persistently declining aquifer conditions. 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 is hopeful the implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. For the 2009 IRP, it is assumed that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations 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. 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 | |
| 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 |

## Fixed Cost Adjustment

The IPUC regulates Idaho Power in Idaho.

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

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

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

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

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

## Operational and Technology Issues

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

### *Wind Integration*

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

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

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

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

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

## Clean Coal Technologies

### Integrated Gasification Combined Cycle

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

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

### Sequestration

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

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

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

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

### Carbon Recycling Using Algae

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

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

## Storage Technologies

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

### Pumped Storage

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

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

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

### Batteries

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

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

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

As the adoption of plug-in hybrid electric vehicles increases, batteries could be used for energy storage. Vehicle-to-grid technology would turn each vehicle into a 20 to 50 kWh distributed, load-balancing device or emergency power source. For example, during peak daytime hours when people tend to be at work and their vehicles are parked, utilities could draw power from the batteries. During off-peak nighttime hours when people and their cars are at home, the batteries would be recharged.

### Compressed Air

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

### Thermal

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

### Flywheel

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

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

### Hydrogen

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

### Superconducting Magnetic Energy Storage

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

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

### Fuel Conservation

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

# 3. Idaho Power Today

## Customer and Load Growth

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

Idaho Power commercial customers in downtown Boise.

Simple calculations using the data in Table 3.1 suggest that each new customer adds approximately 5.9 kilowatts (kW) to the peak-hour load and about 3.1 average kilowatts 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's total nameplate generation has increased from 2,635 MW to 3,276 MW. This includes Idaho Power's newest supply-side resource, a 170 MW simple-cycle combustion turbine (SCCT) at the Danskin Project that was completed in April 2008. The 641 MW increase in capacity represents enough generation to serve approximately 108,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

### Highlights

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

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

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

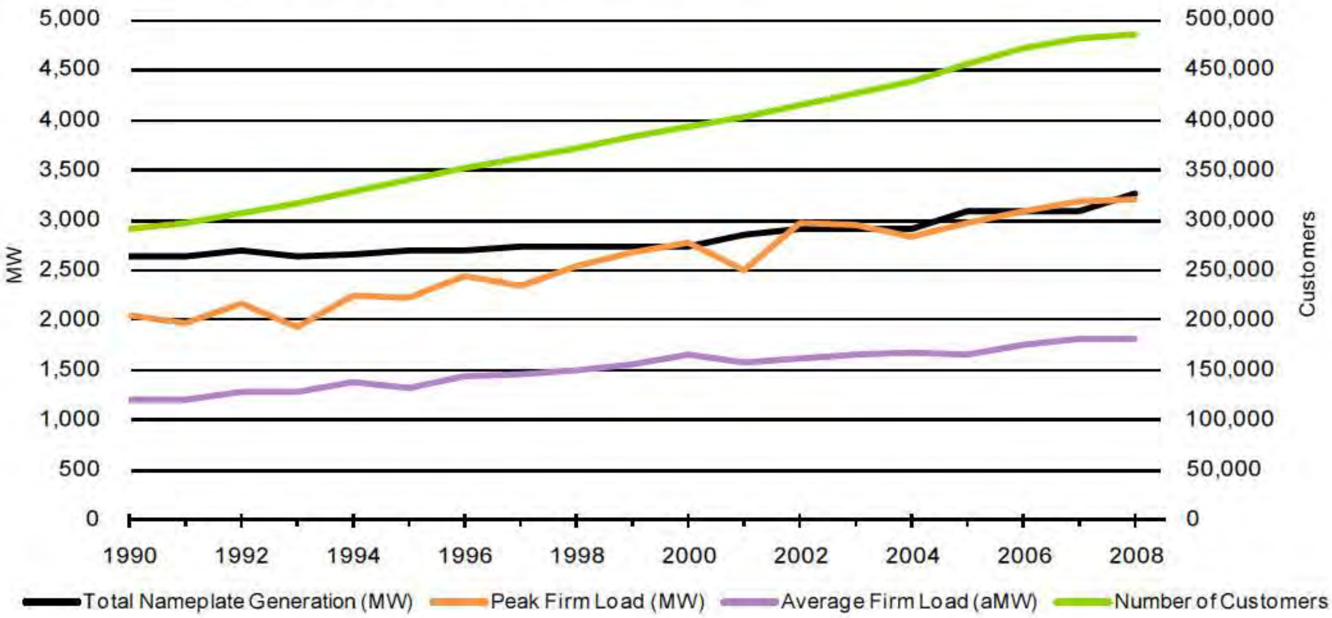



**Table 3.1 Historical Capacity, Load, and Customer Data**

| 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 |

Idaho Power anticipates adding nearly 10,000 customers each year throughout the planning period. The expected-case load forecast predicts that peak-hour load requirements are expected to grow at about 57 MW per year and average energy is forecast to grow at approximately 11 aMW per year. More detailed customer and load forecast information is presented in Chapter 4 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 three years throughout the entire planning period. However, this calculation does not include the expected impact demand response programs will have on peak-hour load. The near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 11.

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

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

## Existing and Committed Resources

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

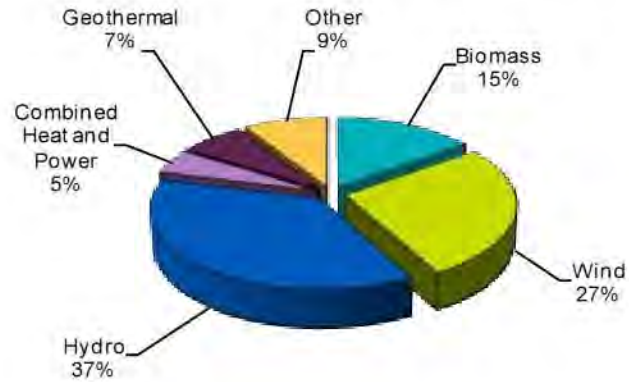
### *2008 Energy Sources*

In 2008, 79 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 2008, 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 3with other utilities and can typically be identified by resource type. In 2008, Idaho Power purchased 1,194,087 megawatt hours (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 2008 Energy Sources**


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




Electricity delivered to retail customers includes both electricity generated by Idaho Power-owned facilities 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 holds and retires an equivalent number of renewable energy credits (REC) in that year. Energy for which Idaho Power holds and retires an equivalent number of RECs will be counted as renewable energy delivered to customers in the year the RECs are retired.

Idaho Power has been directed by the IPUC to sell its eligible 2007 and 2008 RECs. The IPUC also has directed Idaho Power to file by December 31, 2009, a report explaining how the company intends to manage its RECs on an ongoing basis. Table 3.2 represents the electricity Idaho Power delivered to customers in 2008. 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 assumes that all 2008 RECs will be sold. If any of the 2008 RECs are retained and retired, the actual amount of renewable energy delivered to retail customers could be higher than what is presented in Table 3.2.

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

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

## *Existing Supply-Side Resources*

In order 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. 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 | East Idaho |
| *Total Existing Nameplate Capacity* | | *3,276.4* | |

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

## Hydro 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 the 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.

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

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 Endangered Species Act (ESA).

Brownlee Reservoir is the only one of the three Hells Canyon Complex reservoirs—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 United States Army Corps of Engineers (U.S. Army COE) 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 U.S. 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 reduces the power production capability of the project. The reduced power production may necessitate Idaho Power to acquire 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 do 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's C.J. Strike project on the Mid-Snake.

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

#### *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 allowing the company to request delivery as needed. Water lease agreements in 2008 included the release of 41,620 acre-feet of water from the Idaho Water District No.1 rental pool and 45,716 acre-feet from the Shoshone–Bannock Tribal Water Supply Bank. The water released under both of these agreements was delivered through the company's entire system of main stem Snake River hydroelectric projects.

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

In August 2009, the company 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, Idaho Power can schedule the releases of the water in order to maximize the value of the generation. 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. 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. Idaho Power intends to continue to pursue water lease opportunities as part of its regular operations.

#### Cloud Seeding

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

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

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

## Thermal Facilities

### *Jim Bridger*

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

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

### *Valmy*

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

### *Boardman*

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

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

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

## 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 simple-cycle combustion turbine and two 46 MW Siemens W251B12A combustion turbines. The 12-acre facility was initially constructed during 2001 and is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001 and the larger turbine was recently installed in 2008. The Danskin plant operates as needed to support system load.

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

### *Bennett Mountain*

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173 MW Siemens–Westinghouse 501F simple-cycle, natural gas-fired combustion turbine 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 primarily operated during emergency conditions.

## Solar Facilities

In 1994, a 25 kW photovoltaic (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 PV array for the U.S. Air Force near Grasmere, Idaho.


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

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

Idaho Power's net metering program also 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 77 PV installations under this program with a total capacity of 227 kW.

## 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.

The Elkhorn Valley Wind Project in northeast Oregon.

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

### *Raft River Geothermal Project*

The 2006 IRP identified a need for Idaho Power to acquire geothermal generation resources and a request for proposals (RFP) for geothermal energy was released in June 2006. In March 2007, Idaho Power identified U.S. Geothermal, Inc. as the successful bidder based on their proposal to supply 45.5 MW of geothermal energy. 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 Public Utilities Regulatory Policies Act (PURPA) contract with Idaho Power that was subsequently 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 RECs generated by the Raft River Geothermal Project. These RECs are also subject to IPUC Order No. 30818, as discussed above.

### *Neal Hot Springs Geothermal Project*

After extensive discussions with U.S. Geothermal, it was mutually agreed that development of the additional 32.5 MW of geothermal generation units originally proposed in the 2006 RFP process was not feasible within the terms and conditions as specified in the RFP. However, over the past two years Idaho Power continued discussions with U.S. Geothermal regarding the development of the Neal Hot Springs project in eastern Oregon. During much of 2009, Idaho Power negotiated a PPA with U.S. Geothermal. In December 2009, Idaho Power submitted a PPA to the IPUC for approval for approximately 20 MW of geothermal energy from the Neal Hot Springs 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 will be 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 is expected to begin 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 the energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined within the FERC regulations as a small renewable generation project or small cogeneration project. Individual states were given the task of 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 not located in the state of Oregon, 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.

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

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

#### *Published Avoided Costs*

A key component of the 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 costs. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost that Idaho Power is required to include in the PURPA contracts.

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

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

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

***Oregon Published Avoided Costs***

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

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

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

## Wholesale Contracts

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

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.

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

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

NorthWestern has provided load-following services for the Salmon, Idaho area which is located in the NorthWestern Balancing Authority Area. Idaho Power and NorthWestern are currently working together to move the Salmon area load into the Idaho Power Balancing Authority Area. 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.

### Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity. Idaho Power is especially dependent on the regional markets and the existing transmission system used to import these purchases during peak periods. 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 power cost adjustment (PCA).

## *Committed Supply-Side Resources*

### 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 combined-cycle combustion turbine (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. The Langley Gulch resource is included when calculating the energy and capacity deficits discussed later in the IRP.

### Wind RFP

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

### 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 which will result in a net upgrade of 49 MW.

In March 2007, Idaho Power received a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis from FERC that provided a 60-day comment period for interested parties. FERC issued a supplemental EA in December 2007 and Idaho Power expects a license amendment will be issued during 2010. For the 2009 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 renewable electricity standard (RES) requirements.

The Shoshone Falls Upgrade Project has been included in previous Idaho Power IRPs as a committed resource. For the 2009 IRP, the project was treated as an uncommitted resource; however, it was included in all the portfolios analyzed because it is the most cost-effective new supply-side resource available. In order to quantify the value of the project, the preferred portfolio was subsequently analyzed without the upgrade project included. The results of this analysis indicate the project adds approximately $11.5 million of value (excluding capital cost and REC value) to the portfolio each year (average annual nominal dollars for 2016–2019), and $15 million with RECs using the expected-case REC price curve.

In the 2009 IRP, the expected levelized cost of energy from the upgrade (without RECs) is $73 per MWh under median water assumptions, which makes the project the least expensive of all the supply-side options analyzed in the 2009 IRP. The project becomes even more economically attractive depending on the assumed future value of RECs. While the evaluation of the Shoshone Falls upgrade was 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. Additional details regarding water issues can be found in Chapter 2.

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

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

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

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

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

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

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 hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

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

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

### Distributed Generation

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

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

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

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

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

Both natural gas- and diesel-fueled distributed generation (DG) options were analyzed as part of the 2009 IRP. Because of air quality concerns the potential programs were analyzed at a lower capacity factor of 0.69 percent (60 hours-per-year), which more closely matches the capacity factor of demand response programs. At a capacity factor of 0.69 percent, the results of the analysis indicated a natural gas option would have a 30-year, levelized cost of $519 per MWh and $808 per MWh for diesel. The cost estimate for a natural gas-fired peaking resource (SCCT) is $234 per MWh at a 6 percent capacity factor and $1,165 per MWh at a capacity factor of 0.69 percent. Because the cost estimates for the DG options fall within the range of costs for a SCCT, Idaho Power has committed to work with the ICIP to determine if a cost-effective program can be established.

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

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# 4. Demand-Side Management

Demand-side management (DSM) customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with its 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 purchased power is most expensive. Energy efficiency and demand response programs address 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 collaborates with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities. *Appendix B—Demand-Side Management 2008 Annual Report* shows a detailed description of Idaho Power's energy efficiency program portfolio.

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

## DSM Potential Study

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

**Highlights**

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

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

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

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

### *Residential Efficiency Potential*

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

### *Commercial Efficiency Potential*

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

### *Industrial Efficiency Potential*

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

### *Irrigation Efficiency Potential*

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

## Appliance Standard Assessment

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

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

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

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

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

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

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

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

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

## Demand-Side Management Analysis

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

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

### *Energy Efficiency Cost Effectiveness*

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

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

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

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

## *Demand Response Cost Effectiveness*

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

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

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

# Energy Efficiency Programs

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

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

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

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

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

## Residential Program Planning

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

## Commercial Program Planning

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

## Demand Response Resources

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

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

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

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

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

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# 5. Planning Period Forecasts

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

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

## 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. In recent 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 2009 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 exactly follow the path suggested by the expected-case forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather.

### Highlights

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

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, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced the 2009 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 are also used in developing the 2009 IRP load forecast. The forecast of the number of households and employment projections, along with 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 meaning that 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 70th percentile and 90th 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 upon weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand the probabilities associated with the load forecasts apply to any given month and 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 2007 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the current recession has resulted in a reduction in new residential customer growth from an average of 2,000 new residential customers per month prior to the recession, to approximately 200 new customers per month at the present time. Commercial and industrial customer energy use has contracted and overall system energy use has declined by 3.6 percent in 2009 from the prior year; the first time that 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 that are 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 1.3 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 adjusted for DSM measures, results in a 0.7 percent residential load growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.7 percent annually from approximately 404,000 at the end of 2008 to over 563,000 by the end of the planning period in 2029.

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 0.6 percent (over the period 2010 through 2029) is comprised of residential load growth of 0.7 percent, commercial load growth of 0.7 percent, declining irrigation load growth of -0.3 percent, industrial load growth of 1.0 percent, and additional firm load growth of 2.3 percent.

The 2009 IRP average system load forecast is lower than the 2006 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 both serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include:

- For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. Retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- 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 collapse in the housing sector has significantly slowed the growth in the number of residential customers being added within Idaho Power's service area. The number of commercial customers being added has also slowed as a result of the economic downturn. Both forecasts of the number of residential and commercial customers were adjusted downward in the near term to reflect the current housing slowdown and credit crisis. By 2012, residential and commercial customer growth is expected to recover and customer additions are expected to be similar to the growth that occurred in the 1993–2003 timeframe, prior to the housing bubble.
- A somewhat higher irrigation sales forecast compared to recent years due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to 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.

- The uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contacted Idaho Power and expressed 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 number of large customers that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

## Peak-Hour Load Forecast

The firm 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 (excluding Astaris), 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 is 3,214 MW, which 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 has accelerated over the past 10 years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2009 IRP load forecast projects peak-hour load to grow by approximately 53 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 5.1 and Table 5.1 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 5.1 Peak-Hour Load Growth Forecast**

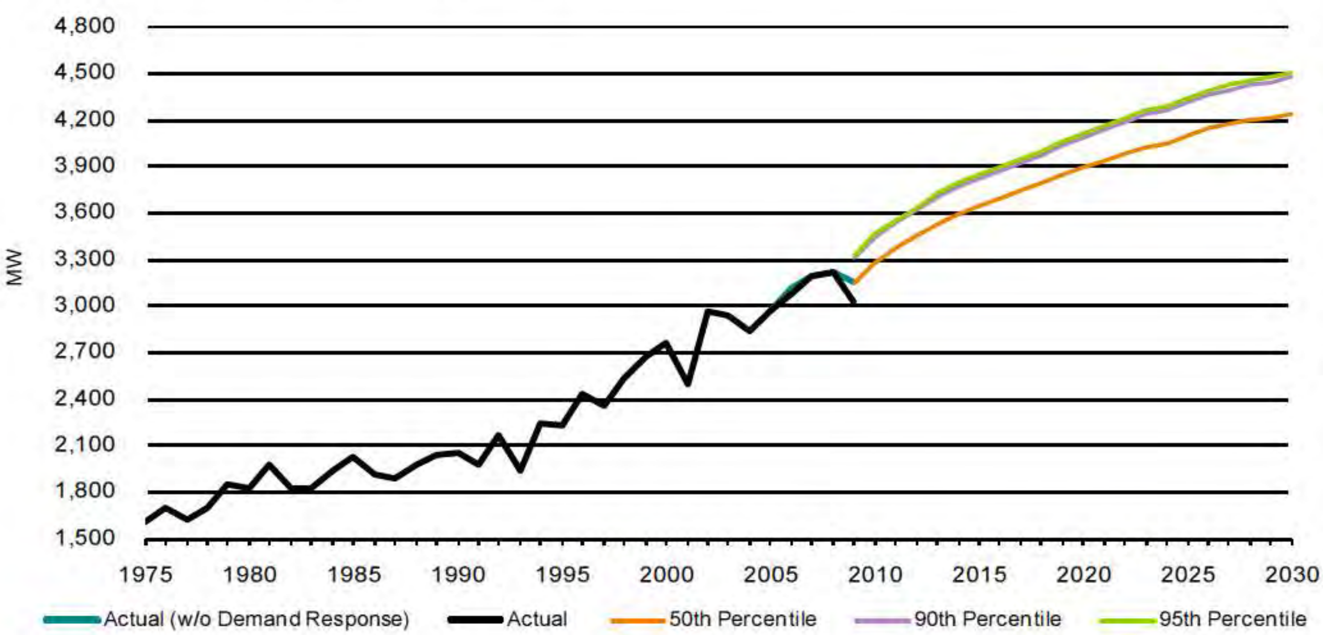


**Table 5.1 Load Forecast—Peak-Hour (MW)**

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

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

Idaho Power's winter peak-hour load record was 2,527 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 5.2 and Table 5.2 show the results of the four forecasts used in the 2009 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 0.7 percent.

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 hydro generation, and 95th percentile average peak day temperature to forecast monthly peak-hour load.

**Figure 5.2 Average Monthly Load Growth Forecast**

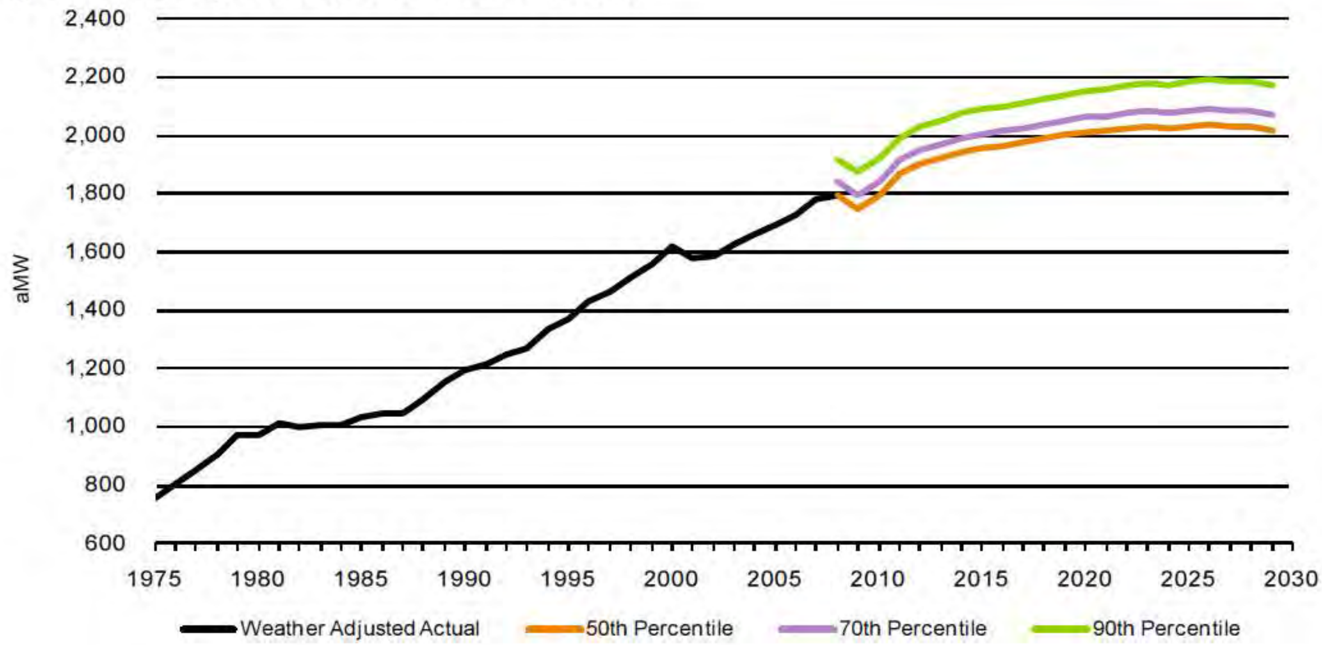



**Table 5.2 Load Forecast—Average Monthly Energy (aMW)**

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

## Additional Firm Load

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

### Micron Technology

Micron Technology is currently Idaho Power's largest individual customer. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200 millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. Micron Technology will continue to operate its 300 mm research and development fabrication facility in Boise and perform 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 Moody's forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

### 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 (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing sector for the Pocatello MSA.

### Idaho National Laboratory

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

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

### Hoku Materials, Inc.

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. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current 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 2012.

## Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies 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 5.3 provides a summary of six planning scenarios analyzed for the 2009 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 2009 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 2009 IRP are consistent with the criteria used in the 2006 IRP.

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

| | |
|---|---|
| **Average 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)** | $50^{th}$ Percentile Water, $90^{th}$ 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 $70^{th}$ percentile water and $70^{th}$ percentile average load. In addition, $50^{th}$ percentile water and $50^{th}$ percentile average load conditions are analyzed to represent a median condition, and $90^{th}$ percentile water and $70^{th}$ percentile average load are analyzed to examine the effects of low water conditions.

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

## Existing Resources

In order 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 that are accounted for in the load and resource balance regarding Idaho Power's hydro, thermal, and transmission resources.

## Hydro

Idaho Power manages stream flows for energy and wildlife.

For the 2009 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 2005. The normalized model accounts for current hydro conditions and historical hydro development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

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

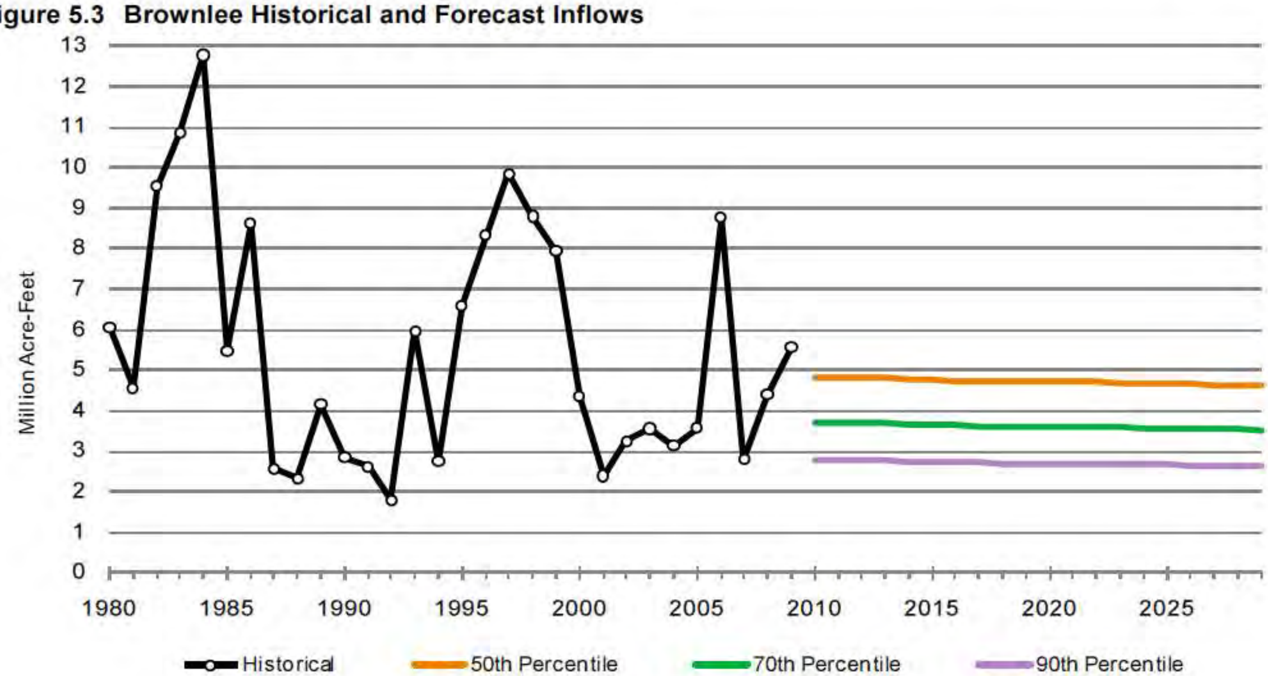
River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies have indicated a desire to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months 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. A federal study report indicates 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 has incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on preliminary resource planning analyses, monthly average hydroelectric generation for July under the 70$^{th}$ 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, an internally developed spreadsheet utilizing a commercial optimization routine is used to shape the monthly average generation for the Brownlee, Oxbow, and Hells Canyon projects into hourly generation profiles, while approximating compliance with Hells Canyon outflow ramp rate constraints, Brownlee Reservoir level constraints, and operating reserve obligations.

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 5.3 shows historical April–July Brownlee inflow as well as forecast Brownlee inflow for the 50$^{th}$, 70$^{th}$, and 90$^{th}$ 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.

**Figure 5.3 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 that 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 2009 IRP.

## Thermal

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

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 regularly scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydro generation, seasonally low market prices, and moderate customer load.

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

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

### Planned Upgrades at Thermal Facilities

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

### Coal Price Forecast

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

### Transmission Resources

Transmission constraints 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 constraints limit Idaho Power's ability to import additional energy.

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

From the hourly 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.

Historically, during Idaho Power's peak-hour load periods, off-system market purchases from the east and south have 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 2009 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90$^{th}$ percentile streamflows, 70$^{th}$ percentile load, and 95$^{th}$ percentile peak-hour load. The 95$^{th}$ percentile peak-hour load planning criterion means that there is a one in twenty 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 native load service 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 2009 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 Northwest Power and Conservation Council (NPCC), the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Global Insight.

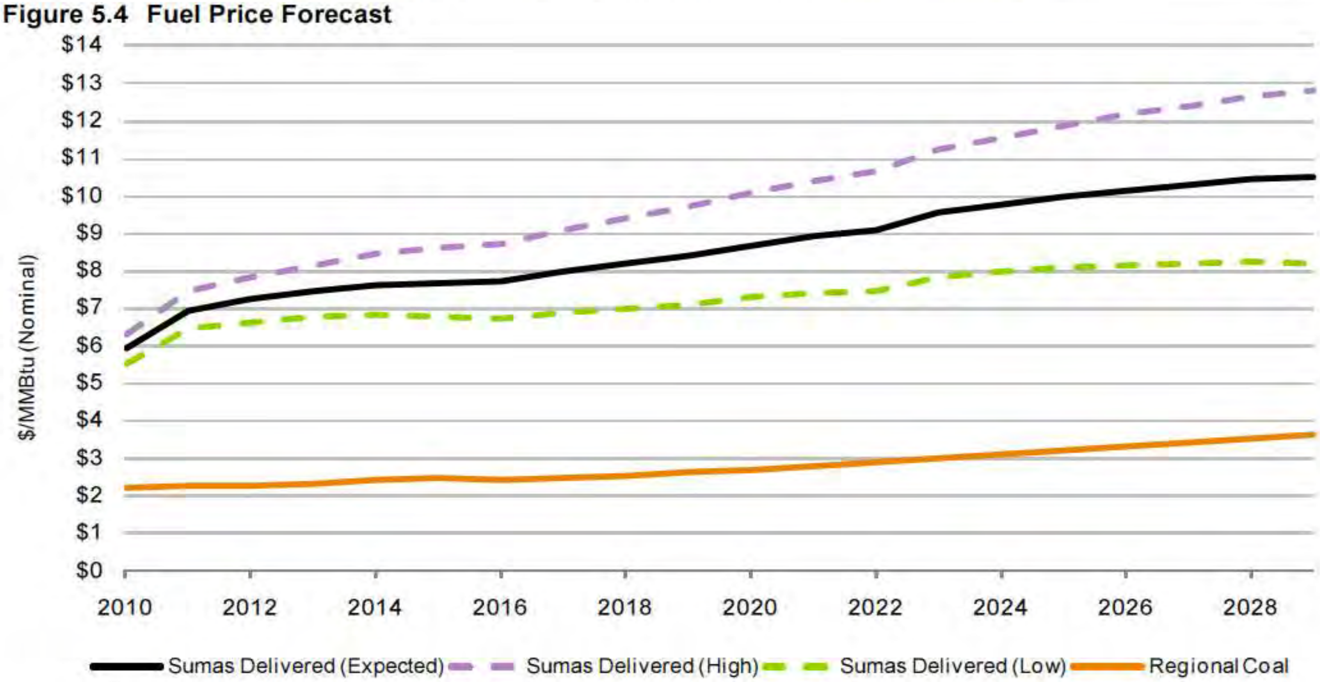
The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness when compared with other forecasts, and the current forward price of actual contracts 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 the longer term forecast which is weighted more heavily towards projected prices without underlying financial trades (EIA, Global Insight).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment 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 2009 IRP assumes pipeline transport capacity will be available for future resources at the current tariff rate that is included in the natural gas price forecast.

The Henry Hub price including the Sumas adjustment is shaped by month 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 spot seasonal 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 expects the majority of the gas planned for use in the resource portfolios will be scheduled and purchased on longer term contracts which will diminish Idaho Power's exposure to spot price and seasonal price volatility.

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

**Figure 5.4 Fuel Price Forecast**



## Cost of Carbon Emissions

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

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

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

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

# 6. Supply-Side Resources

Supply-side facilities are traditional generation resources. Early integrated resource plan (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 and today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe all of the supply-side resources that were considered when Idaho Power developed the resource portfolios for the 2009 IRP. Not all of the supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described below was considered.

## 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 2009 IRP, renewable resources were included in all portfolios analyzed in order to meet proposed federal renewable electricity standard (RES) legislation. Renewable resources are discussed in general terms in the following sections.

The Raft River Geothermal Project is located in southern Idaho.

### *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 of the 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. In addition, 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. Flash steam plants are applicable for geothermal resources where the fluid temperature is 300° Fahrenheit (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

**Highlights**

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

through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid (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 for binary cycle geothermal generation in the IRP are based on data from independent geothermal developers and information from the Geothermal Energy Association. Estimates for flashed steam geothermal generation are based on data from the Northwest Power and Conservation Council's (NPCC) Fifth Power Plan (2005).

## Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 megawatts (MW) each. The majority of the 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.

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

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

## Hydro

Hydropower is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants like fossil fuel based resources. 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 hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

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

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

## Solar

There are two primary types of solar technology; solar thermal and photovoltaic (PV). Solar thermal technologies utilize 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, creating 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 creating 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 three to seven 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 kilowatt hour (kWh)/$m^2$/day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratories (NREL) insolation charts show the Desert Southwest has the highest solar potential in the United States.

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

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

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

### Solar Generation Technologies

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

#### *Parabolic Trough*

Parabolic trough technology is a closed looped system that consists of a solar field where single axis parabolic mirrors heat pipes containing a transfer fluid. The hot fluid returns from the solar field where heat energy is transferred to water, creating steam at 700 F. The steam is then used to drive a turbine and generate electricity. In addition to heating water for steam, the hot fluid can also heat salt until the salt becomes molten. When the sun is not shining, the transfer fluid can be heated by the molten salt. After transferring the heat energy, the fluid returns to the solar field to be reheated.

#### 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 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.

#### Parabolic Dish Engine

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

#### Photovoltaic

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 which 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) which can then be used on-site, stored in a battery, or sent to the grid.

## Biomass

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


Biomass energy is produced from agricultural waste in southern Idaho.

## River In-stream Generation

River in-stream generation is the conversion of the kinetic energy of water in free flowing rivers and channels to electricity. River in-stream energy conversion (RISEC) technology is still largely in a conceptual stage of development, with a few small vendors focused on the technology and limited operating experience in natural waters. The use of in-stream generation has not proven to be economic for large scale or commercial power production. The cost estimates and operating parameters for in-stream generation are based on data from a feasibility study performed by the Electric Power Research Institute (EPRI) on two specific locations in Idaho Power's service area.

## Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine in order to generate electricity. CCCT are typically used for baseload energy, while less efficient SCCT 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.

### Combined-Cycle Combustion Turbines

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

Until recently, 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 less harmful emissions when compared to coal.

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 produces steam that drives a steam-turbine generator to produce electricity. In a CCCT plant, heat that would otherwise be wasted is used to produce additional power beyond that typically produced by a SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined cycle units.

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. If natural gas supplies become constrained, efforts will have to be made to identify additional regional sources or off shore sources through the construction of liquefied natural gas terminals.

### Simple-Cycle Combustion Turbines

Simple-cycle natural gas turbine technology involves pressurizing air which is then heated by burning gas in fuel combustors. The hot pressurized air is expanded through the blades of the turbine which is connected 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 the 2000–2001 time period 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 resources. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been constructed to meet peak load during the 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. Like CCCTs, feasible sites and gas supply currently exist for future SCCT development. The SCCT resources studied in the 2009 IRP are assumed to be located in southwestern Idaho in close proximity to the mainline fuel supply and near Idaho Power's main load center in the Treasure Valley. Furthermore, in the 2009 IRP, natural gas pipeline capacity is assumed to be available. Given the limits of available natural gas pipeline capacity, Idaho Power may need to begin acquiring additional transport capacity.

## 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 1,000 MW of pulverized coal generation in service. All of Idaho Power's pulverized coal generation is in neighboring states and is owned with other regional utilities.

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

A pulverized coal facility uses coal that is ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine and generator. Emission 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 Nitrous Oxide (NOx) burner technology to help reduce harmful emissions and particulates. Coal has the highest ratio of carbon-to-hydrogen of all the fossil fuels and significant research is being done in hopes of developing carbon capture and sequestration technology that can be economically added to existing coal facilities.

Even 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 to not 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 2009 IRP.

## Advanced Nuclear

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

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

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

## Resource Advantages and Disadvantages

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

## Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2009 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, Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as:

- Levelized fixed cost-per-kilowatt (kW) of installed (nameplate) capacity per month, and
- Total levelized cost-per-megawatt hour (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 the cost of capital, operating and maintenance (O&M) costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the cost of capital for 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 backbone upgrade costs were estimated by Idaho Power's transmission planning group. The cost of capital also includes Allowance for Funds Used During Construction (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 renewable energy credits (RECs) is not included in the levelized cost estimates.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, annual incentive or rebate payments, 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*.

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

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

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

## Emission 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 2009 IRP.

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

**Table 6.2 Emissions Adder Assumptions**

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

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

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

## 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 to be on-line by December 31, 2016, to be eligible for the federal production tax credits (PTCs) 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, which is adjusted annually for inflation is currently valued at $21 per MWh for wind and geothermal resources.

## Levelized Capacity (Fixed) Cost

The annual fixed revenue requirement 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 6.1 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 that distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources do have high operating costs, but the operating costs are not as important when the resource is only used 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 6.2. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emission adders; however, no value for RECs was assumed in this analysis. Resources such as DSM measures, the Shoshone Falls upgrade, geothermal, wind, and certain types of thermal generation appear to be the lowest cost for meeting baseload requirements.

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

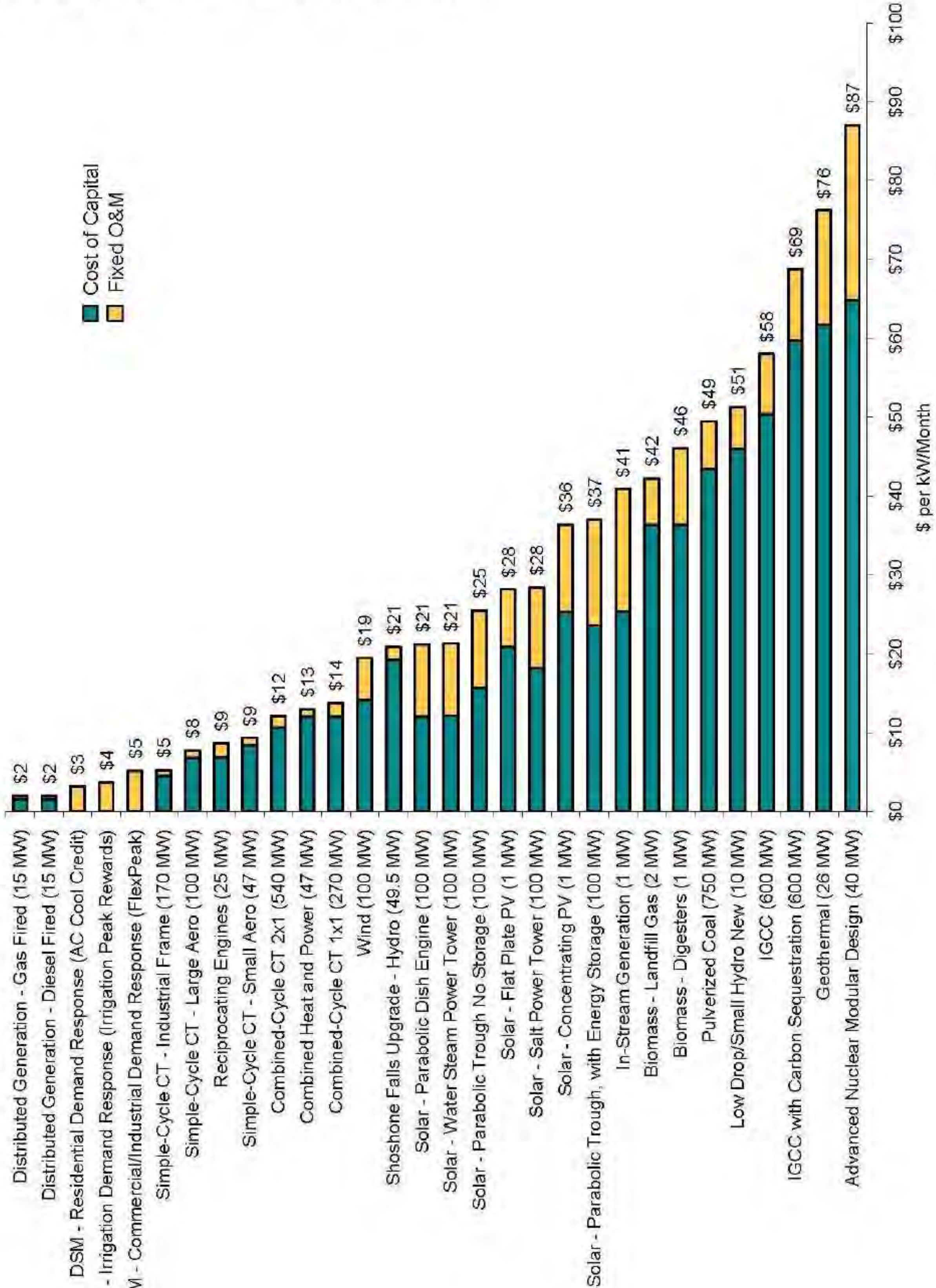
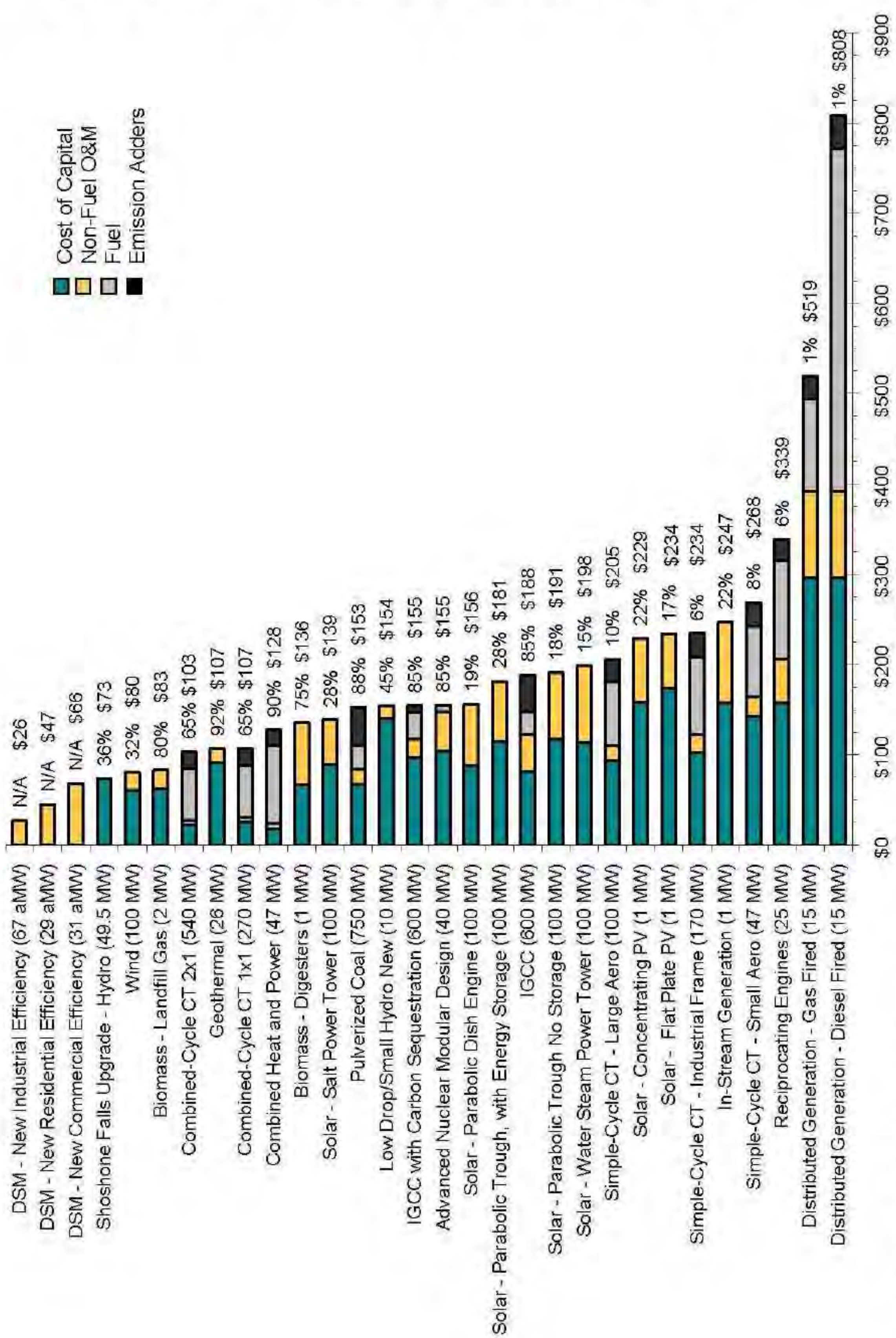


**Figure 6.2 30-Year Levelized Cost of Production (at Stated Capacity Factors)**




*REC value not included in cost of production*

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# 7. Transmission Resources

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

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

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 is able to purchase energy from the Mid-Columbia market to meet peak summer load and sell excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits Idaho Power's customers because the construction of additional peaking resources is avoided and revenue from off-system sales is returned to customers through the power cost adjustment (PCA).

## Transmission Interconnections

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

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

**Highlights**

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.
- Restrictions on the Brownlee-East and Northwest to Idaho 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 2015, would be a major addition to the Brownlee-East and Northwest to Idaho paths and will remove the existing constraints.

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

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

**Table 7.1 Transmission Interconnections**

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

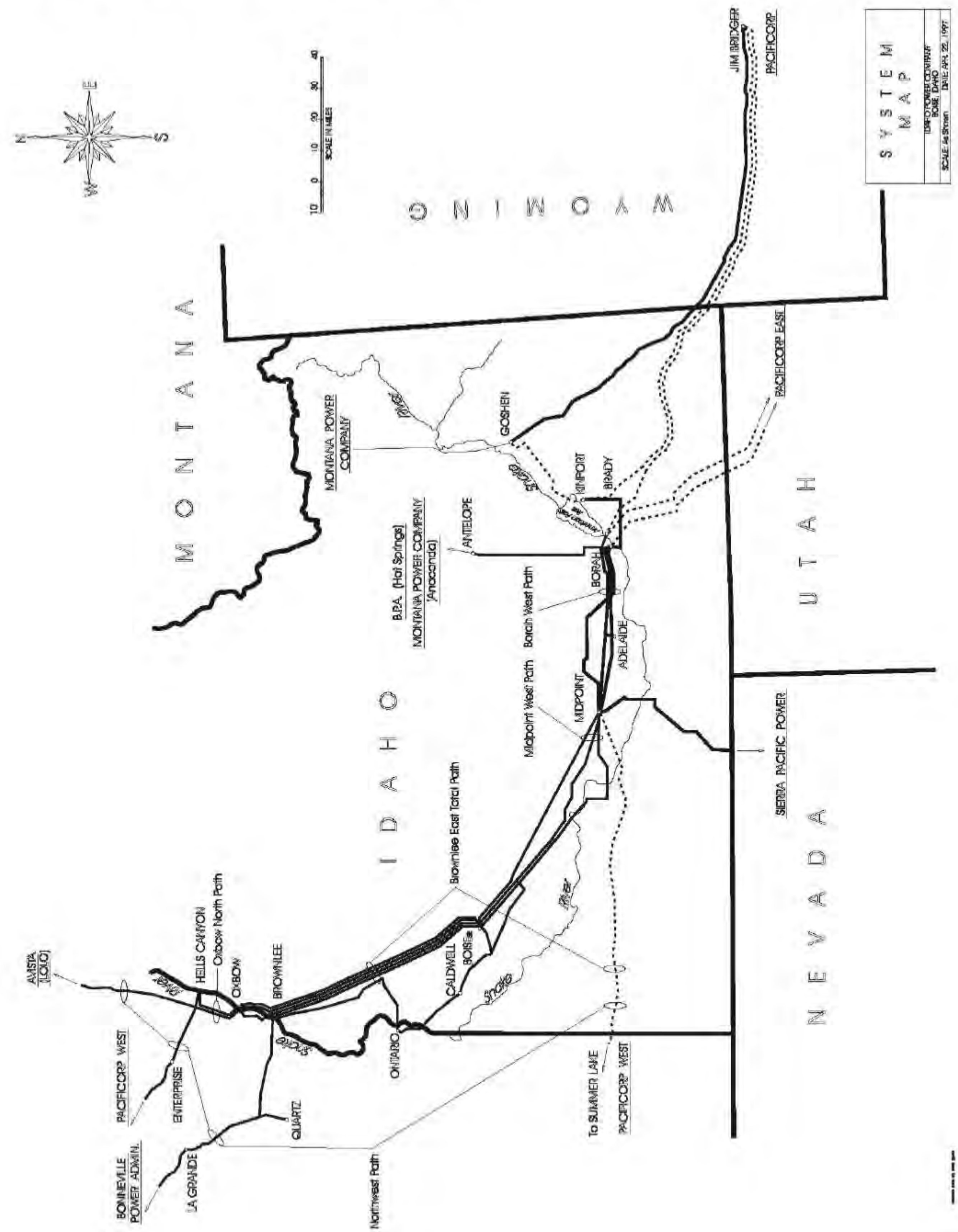
**Power Transfer Capacity for Idaho Power's Interconnections**

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

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

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

Figure 7.1 Idaho Power Transmission System Map



## Brownlee-East Path

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

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

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

## Oxbow-North Path

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

## Northwest Path

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

## Montana Path

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

# Transmission Planning

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

## Transmission Adequacy

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

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

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

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

## Northern Tier Transmission Group

The 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, Portland General Electric (PGE), Rocky Mountain Power/PacifiCorp and the Utah Associated Municipal Power Systems (UAMPS).

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

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

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

## Proposed Transmission Projects

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 regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of FERC and is obligated 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.

Because of the potential for renewable resource development in the region and the constraints on the existing transmission system, Idaho Power has considered two major transmission projects in the 2009 IRP—Boardman to Hemingway and Gateway West. These two projects were also evaluated in NTTG's regional, biennial planning process along with several other large projects. For the 2009 IRP, two portfolios requiring Boardman to Hemingway capacity were analyzed for the first 10 years of the planning horizon (2010–2019). In the second 10 years (2020–2029), the Gateway West project was included in every portfolio because current constraints require 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 will face increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including BPA's southern Idaho contracts and another 1,000 MW of energy that is expected to be wheeled through Idaho Power's system to other regional customers. The development of wind and other renewable resources in response to renewable portfolio standards (RPS) 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

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

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

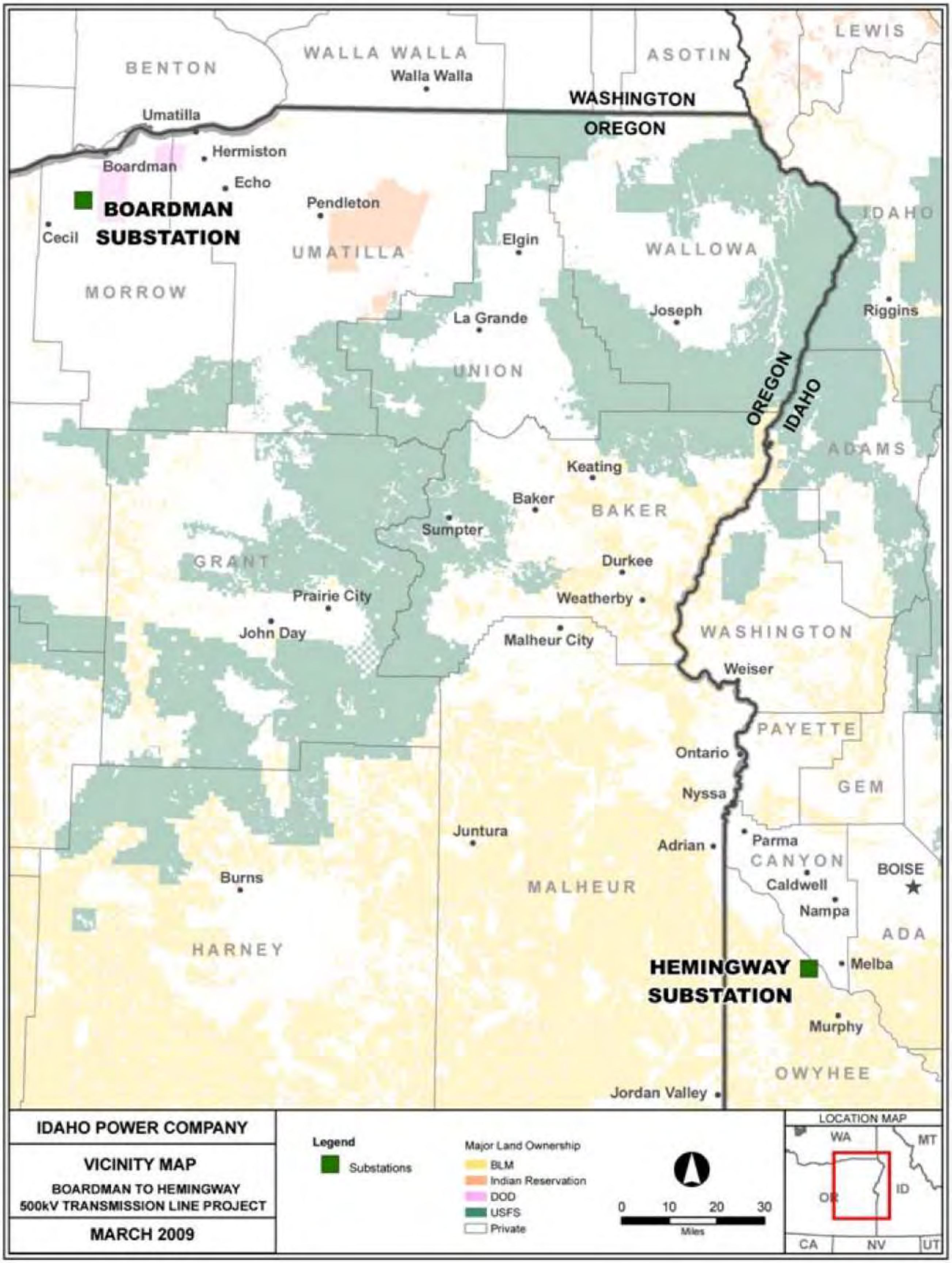
The project is expected to be completed and in service in 2015. The overhead, 500-kV, high-voltage transmission line will connect a switching yard at the Boardman Power Plant, near Boardman, Morrow County, Oregon to the Hemingway Substation, located in Owyhee County, Idaho. The proposed transmission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

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

The Boardman to Hemingway project is likely to utilize a bundled conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the WECC's rating process, the initial implementation of the Boardman to Hemingway project along with the Gateway West project is likely to result in an increased rating of approximately 1,400 MW from east to west (exports into the Pacific Northwest), 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.

The Boardman to Hemingway project capacity or sizing considerations and termination locations were developed in the public review process conducted by the NTTG and the project WECC phase 0 rating process (the regional planning phase). During the review process, it was determined a 230-kV project would be unable to meet Idaho Power's overall resource planning requirements and would underutilize a substantial 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 that 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.

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



Idaho Power has 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. There are currently active transmission service requests being studied that are expected to commence operations when the proposed Boardman to Hemingway project is completed. In the 2006 IRP, Idaho Power requested 225 MW of energy imports from the Pacific Northwest to Idaho Power's system. However, the 2009 IRP analyzed various levels of imports.

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. Idaho Power and Horizon Wind Energy recently developed the first phase of the 101 MW Elkhorn Valley Wind Project in Union County, Oregon. 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 U.S. Forest Service (USFS), and the Oregon Department of Energy (DOE).

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power to 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 enlists project advisory team members in three geographic regions within the project area. The members are familiar with the local areas and issues; the topography, recreation, wildlife and view shed issues; and work collaboratively with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009 and the process is expected to be completed in early 2010.

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

## 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 such that multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service as early as 2014.

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.

Significant resource development potential exists in Wyoming and southern and eastern Idaho. Idaho Power's transmission system is currently limited in the 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 Open Access Transmission Tariff (OATT).

The Gateway West project is currently undergoing a public involvement process regarding route selection, environmental studies, and 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 connections in central Idaho at the Midpoint and proposed Cedar Hill substations.

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 an additional 3,000 MW of transfer capacity. Similarly, the project extending east from 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 upon load service requirements and third-party transmission service request obligations. Additional information about the Gateway West project can be found at www.gatewaywestproject.com.

# 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 commission staff members and the public criteria as part of the 2002 Integrated Resource Plan (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.

## Planning Scenarios and Criteria

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies 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 70$^{th}$ percentile water and 70$^{th}$ percentile average load conditions. For peak-hour load conditions, the planning criteria used are 90$^{th}$ percentile water and 95$^{th}$ 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 although the median forecast 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.

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

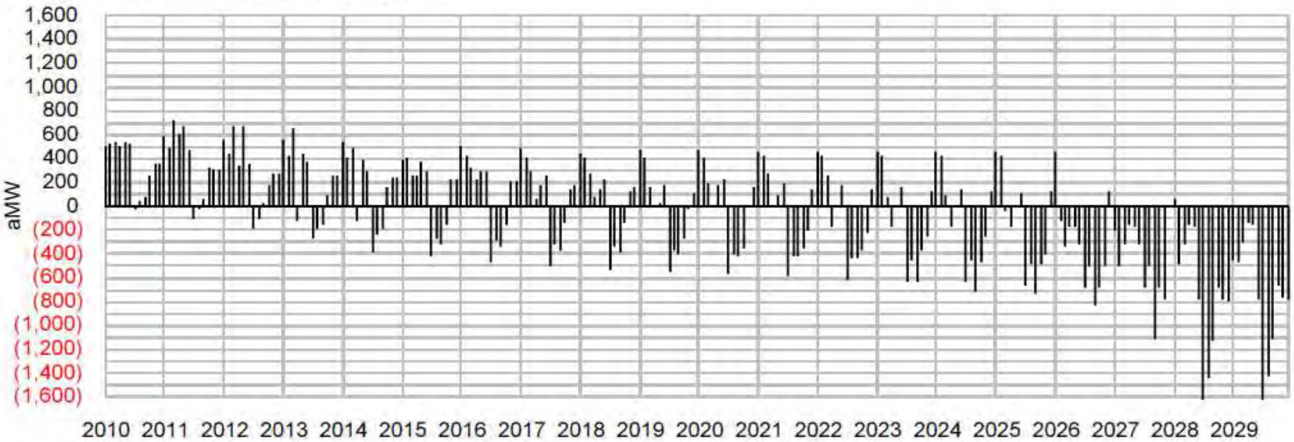
### Highlights

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

## Average Monthly Energy Planning

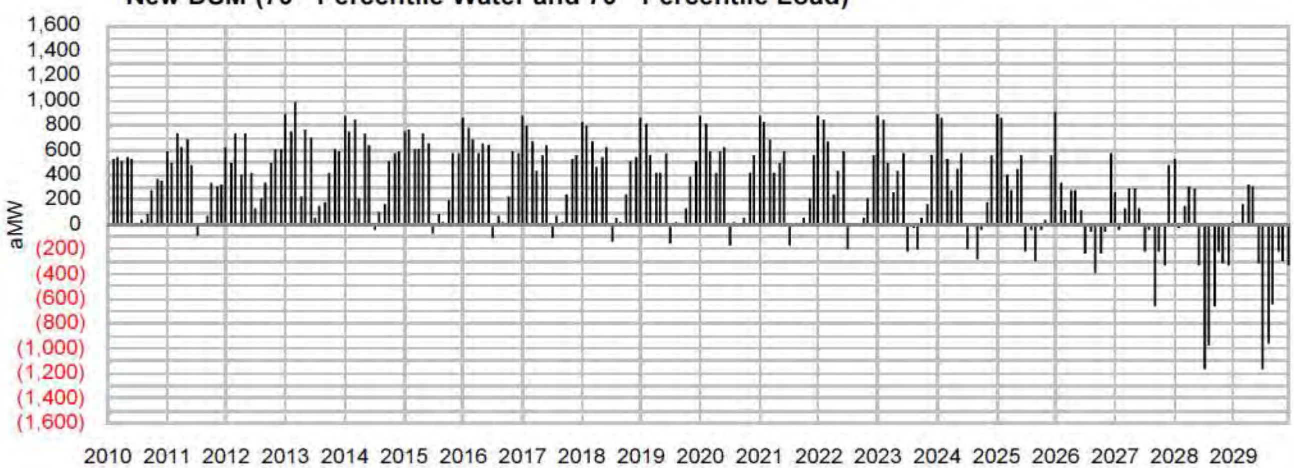
Average energy surpluses and deficiencies are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits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

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



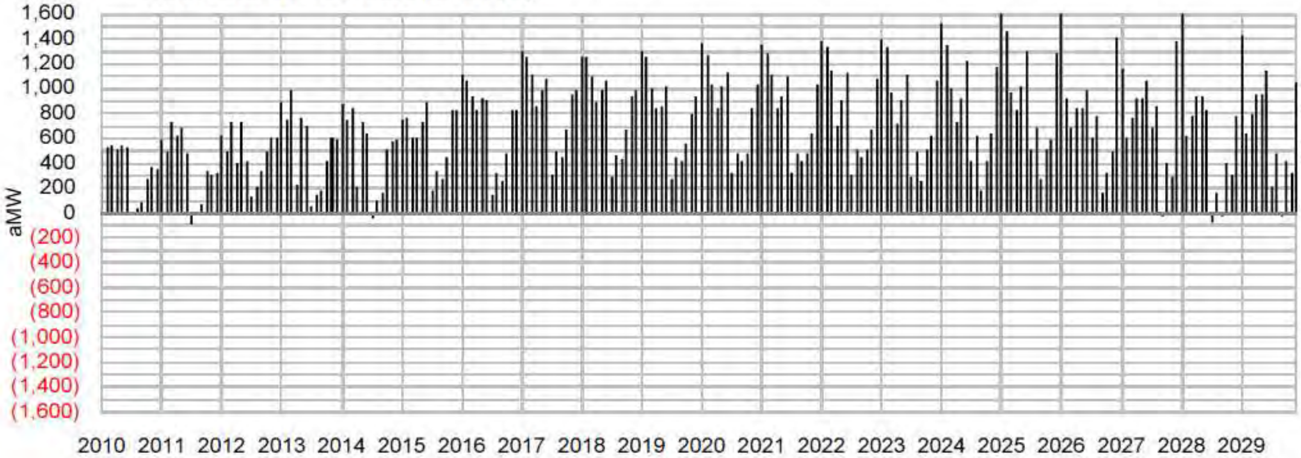

Resource deficits are substantially improved as shown in Figure 8.2 with the addition of committed resources from the 2006 IRP and the new DSM programs proposed in the 2009 IRP. The committed resources supply-side include the Langley Gulch combined-cycle combustion turbine (CCCT), the 2012 Wind Request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

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



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

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

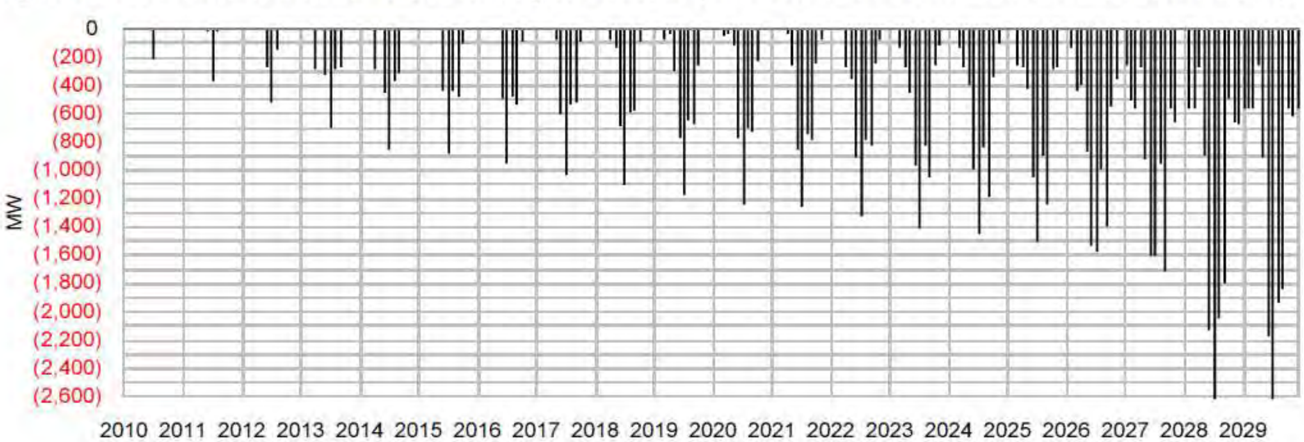



As shown in Figure 8.1, energy deficits of approximately 200 average megawatts (aMW) exist in July 2012 without the addition of the Langley Gulch project and the 2012 Wind RFP. As shown in Figure 8.2, with the addition of these two resources, deficiencies do not appear again until the 2014 to 2015 timeframe.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

## Peak-Hour Planning

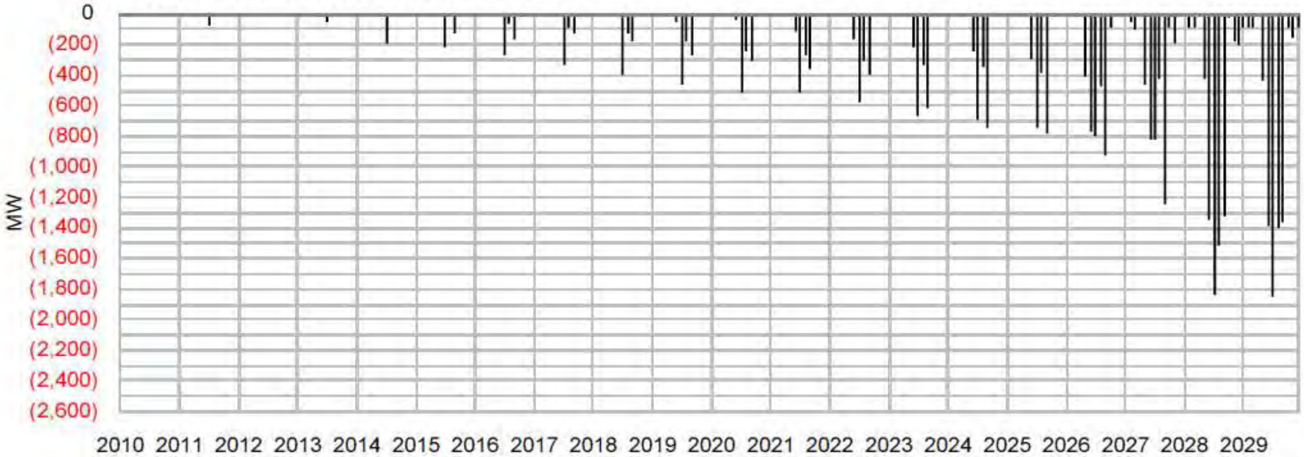
Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system to reduce any deficits. Monthly peak-hour deficits with existing resources are illustrated in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

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



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

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




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

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


Peak-hour load deficiencies 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 deficiencies. 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.

The deficits shown in Figure 8.5 account for the updated sales and load forecast, forecast performance of DSM programs, adjustments to the hydro generation forecast, the current level of PURPA development, the Langley Gulch CCCT, the 2012 Wind RFP and Idaho Power's natural gas-fired peaking resources. Similar to the deficits shown for average energy, the peak-hour analysis shows deficits beginning in 2014. With the addition of the 2009 IRP preferred portfolio, these deficits are substantially eliminated as shown in Figure 8.6. Additional details regarding the selection of the preferred portfolio are presented in Chapter 10.

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, then the company is 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.

## Portfolio Design and Selection

The 2009 IRP portfolio development strategy divides the study period into two 10-year periods; 2010 - through 2019, and 2020 through 2029. 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 renewable electricity standard (RES) will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the Waxman–Markey bill.

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

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

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

[1] B2H-Boardman to Hemingway
*Committed Resource

The first 10–year planning period has significant committed resources which are also shown in Figure 8.7. The committed resources included in all of the portfolios. The committed resources are not included in the capital cost for comparison between portfolios. The new resources shown are designed to reduce previously discussed deficiencies and to meet proposed RES requirements. Because the identified deficiencies are not large and the list of possible resources is limited, it was not necessary to analyze a large number of portfolios for the first 10-year period. The limited number of resource options results in similar portfolios with regards to fuel and technology. A description of the major differences between each portfolio is presented below.

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

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

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

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

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

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

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

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

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# 9. Modeling Approach and Assumptions

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

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

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

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

### 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 2009 IRP evaluates proposed carbon reduction legislation differently than previous IRPs by specifically defining carbon reduction targets and curtailing coal units.
- The 2009 IRP incorporates anticipated federal renewable electricity standard (RES) legislation and plans for the resources necessary to comply with the legislation.
- Two categories of transmission, backbone and interstate transmission, are accounted for in the IRP.

## AURORA Setup Enhancements

Idaho Power incorporated several changes to the AURORA database which are designed to increase AURORA's operational modeling realism. The Idaho Power changes to the database generally add additional hourly operational detail and move away from flat generation output, de-rates, and fixed capacity factors over the term of the study. The 2009 IRP also incorporates 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.

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

## Carbon Modeling Approach

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

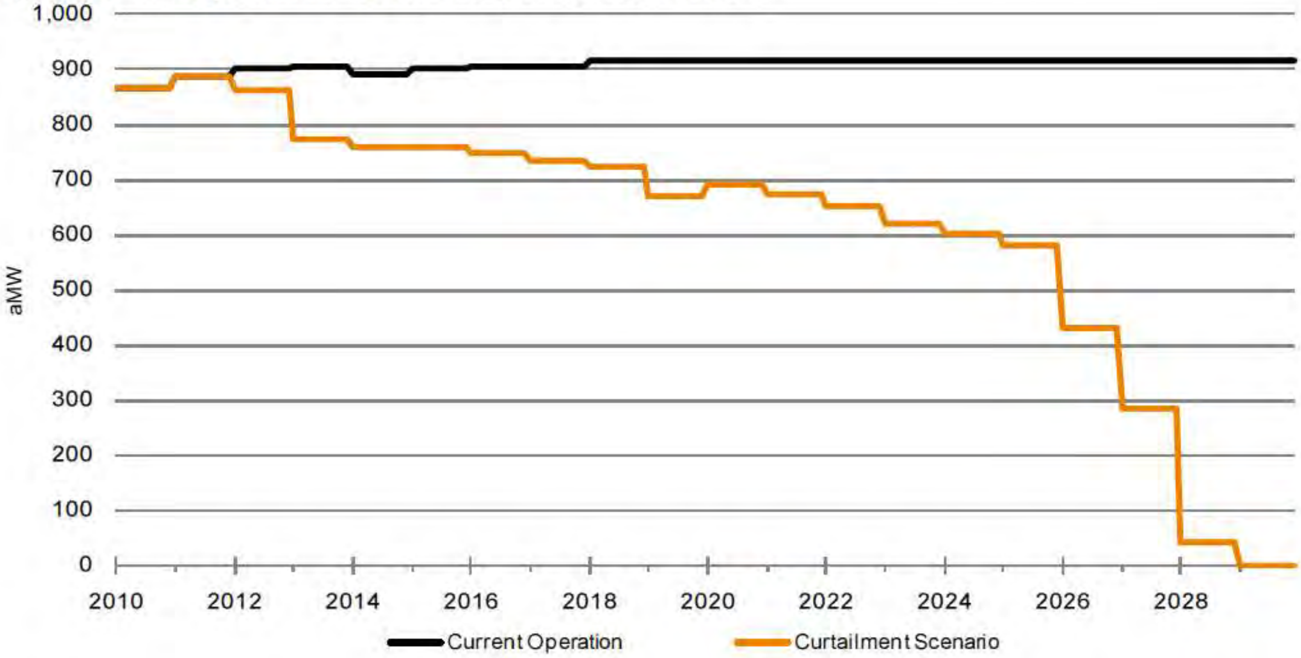
Although Idaho Power believes a cap-and-trade system is more likely, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has also done. However, the primary discussion in the 2009 IRP regarding carbon emissions is related to Idaho Power's attempt to model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

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

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

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

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




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

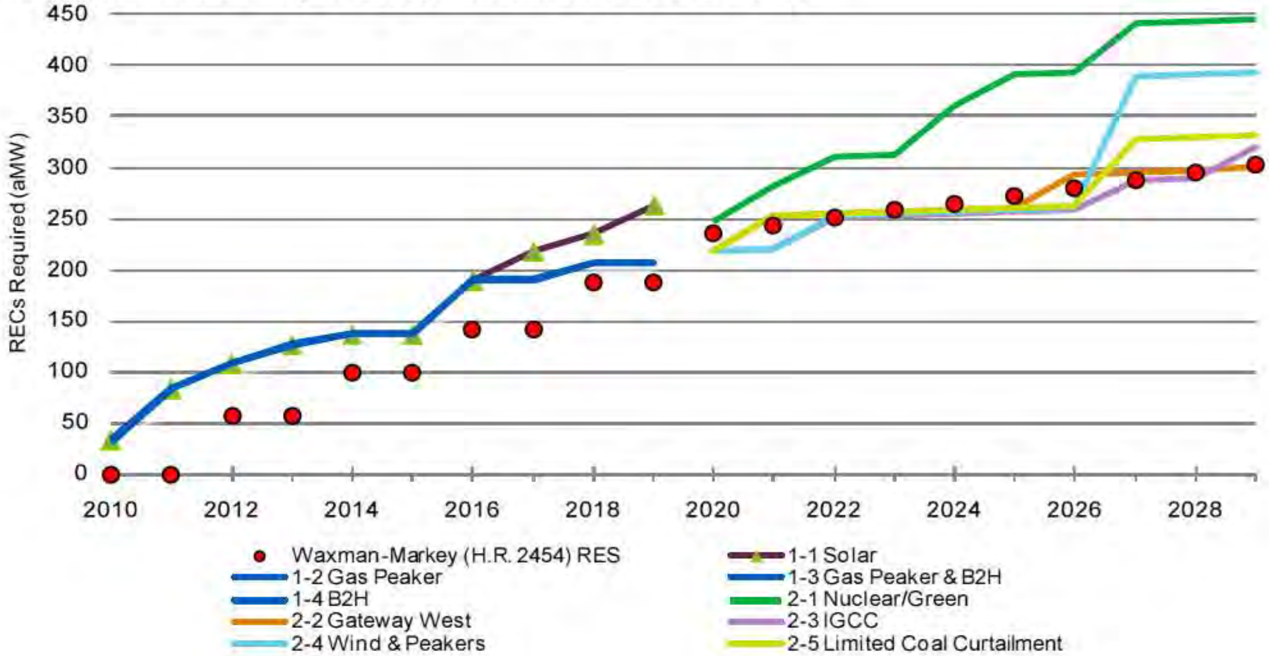
The three distinct carbon futures are modeled in AURORA for all of the resource portfolios; 1) coal curtailment (as described above), 2) a $43 carbon adder without coal curtailment, and 3) continuation of present operations with no carbon adder and no coal curtailment. The results of the analysis are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

## Renewable Energy Credits

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

Idaho does not have RPS and Idaho Power can meet the requirements of the Oregon RPS with a portion of the RECs from the Elkhorn Valley Wind Project. Idaho Power has not included defined RES planning criteria in previous resource plans. However, the increasing likelihood of a federal RES led Idaho Power to develop a formal plan to satisfy the expected future federal requirements. The planning goal in the 2009 IRP is to substantially satisfy the proposed federal RES targets with existing or new portfolio resources. Figure 9.2 shows the expected quantity of RECs Idaho Power would need under the Waxman–Markey bill along with the number of RECs each resource portfolio would provide. The resource portfolios analyzed for the 2009 IRP meet the requirements in the first 10 years and substantially meet the requirements in the second 10-year period.

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




## Transmission and Market Purchases

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

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

Two categories of transmission are accounted for in the IRP. The first is backbone transmission which integrates resources and allows energy to flow from the gen eration project to the load centers within a utility's own control area or service territory. Backbone transmission has a designated generating resource and is usually lower voltage and within the service territory. An example of backbone transmission is 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.

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

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

## Regional Transmission Planning (from the NTTG Plan)

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

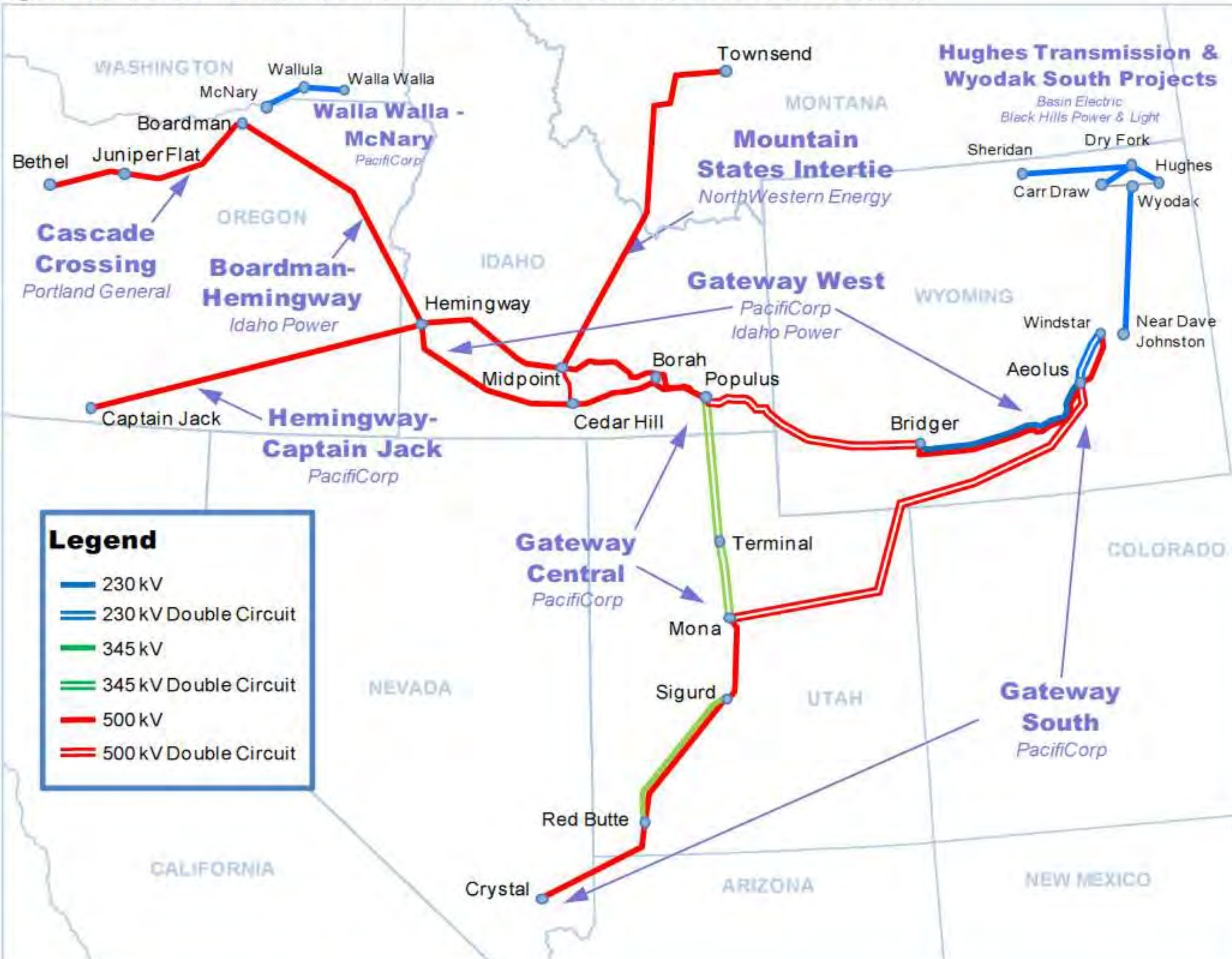
Planning is an iterative process and must work in concert with local transmission plans and IRPs, where they exist. The NTTG transmission plan is a result of a bottom-up load service process to ensure that the transmission planned for the NTTG footprint can reliably serve forecasted load growth and conditions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

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

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

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

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




## Market Purchase Assumptions

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

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

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

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

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 net present value (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.

## Economic Evaluation Components and Assumptions

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

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

**Table 9.1 Financial Assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount Rate (aka weighted average cost of capital [WACC]) | 6.98% |
| Composite Tax Rate | 39.10% |
| Deferred Rate | 35.00% |
| General O&M Escalation Rate | 3.00% |
| Emission Adder Escalation Rate | 2.50% |
| 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% |

# 10. Modeling Results and Risk Analysis

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

## Portfolio Modeling Results

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

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

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

*B2H–Boardman to Hemingway

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

### Highlights

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

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

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

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

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

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

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

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

## Risk Analysis and Results

Idaho Power evaluated all of the resource portfolios identified in the 2009 IRP for both quantitative and qualitative risks. The objective of risk analysis is to identify 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 present load forecast projects a relatively long period of diminished economic growth.

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

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

In addition, 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 renewable energy credits (REC). Limited, or ineffective, carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional fossil-fueled 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.

### *Quantitative Risk Analysis*

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

### Transmission Subscription by Third Parties

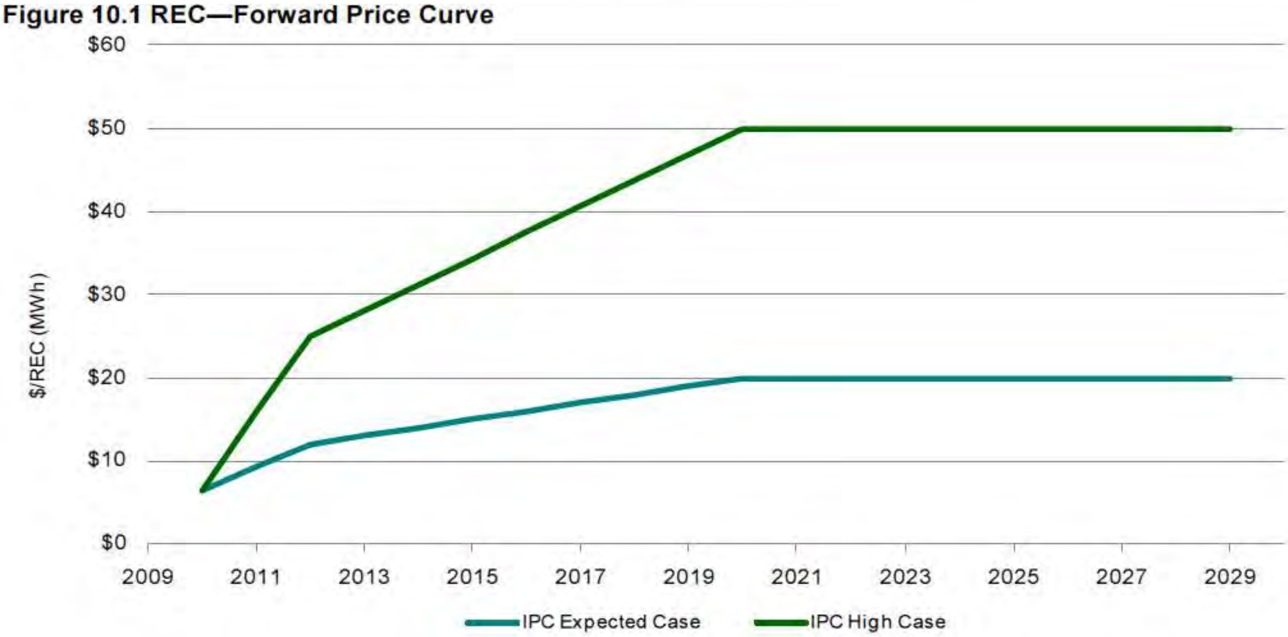
Interstate transmission projects are generally too expensive for a single utility to construct and regional utilities often form partnerships for large-scale transmission projects. Multiple parties commit to fund a portion of the project costs in return for a firm reservation of transfer capacity on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

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

### Renewable Energy Credit Prices

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

**Figure 10.1 REC—Forward Price Curve**



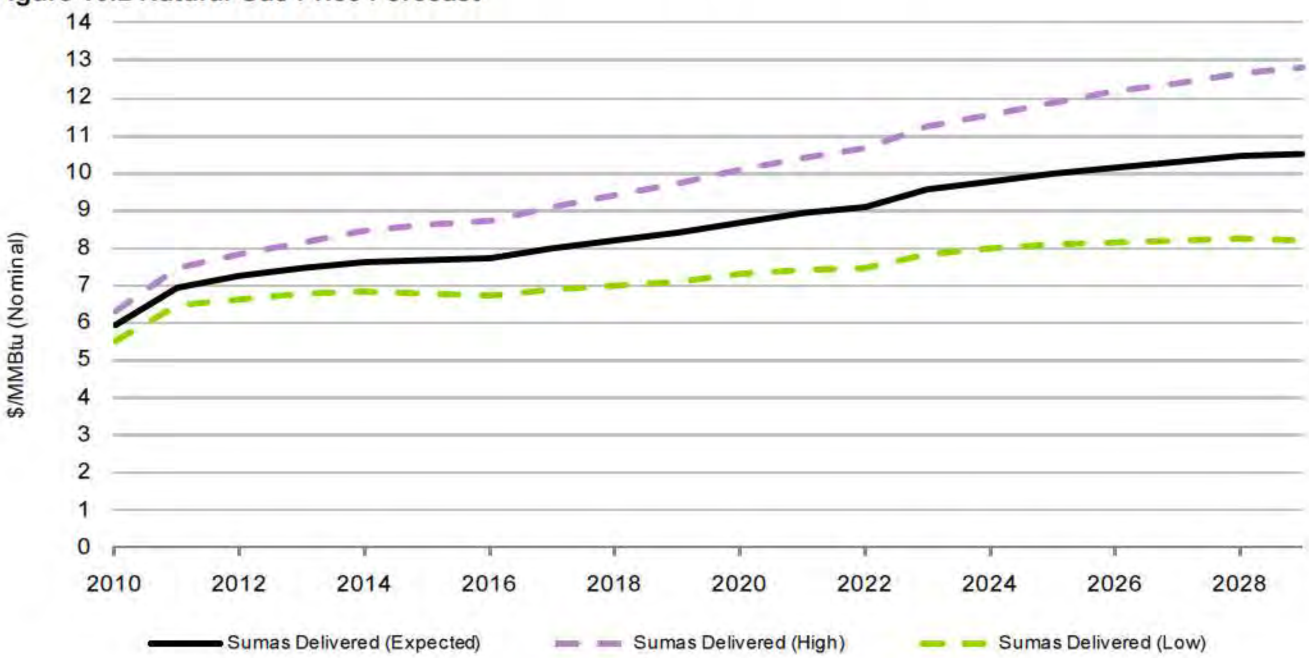
As shown in Figure 9.2 in Chapter 9, all of the resource portfolios considered in the 2009 IRP exceed the Waxman–Markey RES requirements for the first 10-year period. Portfolio 1-1 Solar generates the most RECs. Figure 10.5 shows the REC price risk for each of the portfolios.

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

## High Natural Gas Prices

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

**Figure 10.2 Natural Gas Price Forecast**




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

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

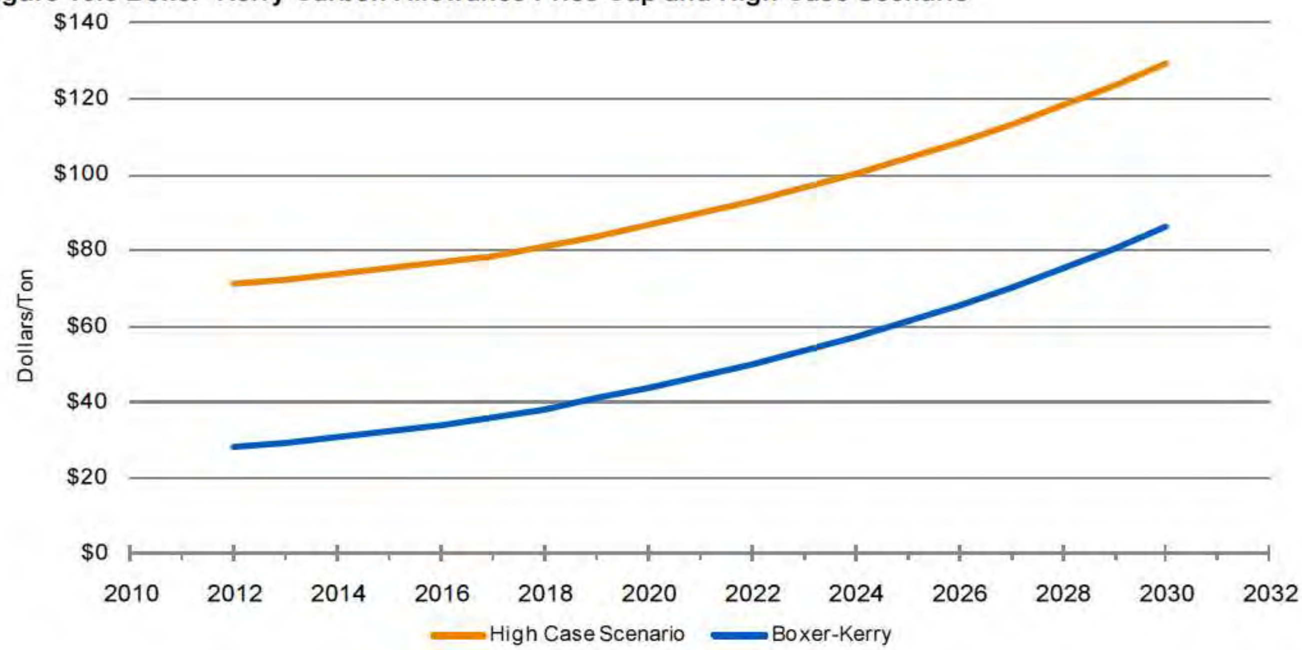
The risk analysis for the second 10 years showed that high gas prices would increase the expected portfolio cost for Portfolio 2-2 Gateway West and Portfolio 2-4 Wind and Peakers, with the Gateway West portfolio being exposed to market purchases and the Wind and Peakers portfolio containing a significant amount of natural gas resources. Portfolio 2-1 Nuclear/Green, Portfolio 2-3 and Portfolio 2-5 would benefit high gas prices and the resulting high energy prices because these portfolios do not rely on a significant amount of natural gas resources. Figure 10.6 shows the risk of high gas prices in all of the portfolios.

### $CO_2$ Allowance Prices

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

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

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



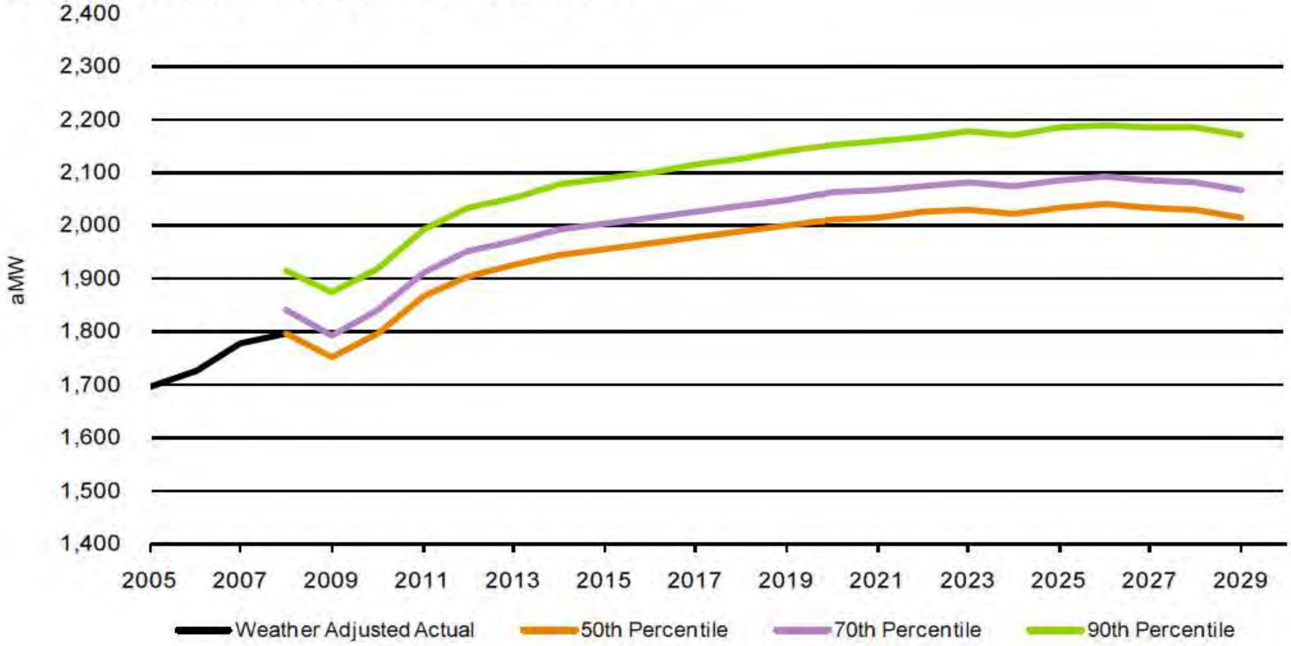

As expected, the high price case risk analysis resulted in a cost increase in all of the resource portfolios. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the greatest increase in costs and Portfolio 1-1 Solar had the lowest increase. Figure 10.5 shows the risk of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

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

### High Load Growth

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

**Figure 10.4 Average Monthly Load Growth Forecast**




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

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

## Low Conservation

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

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

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

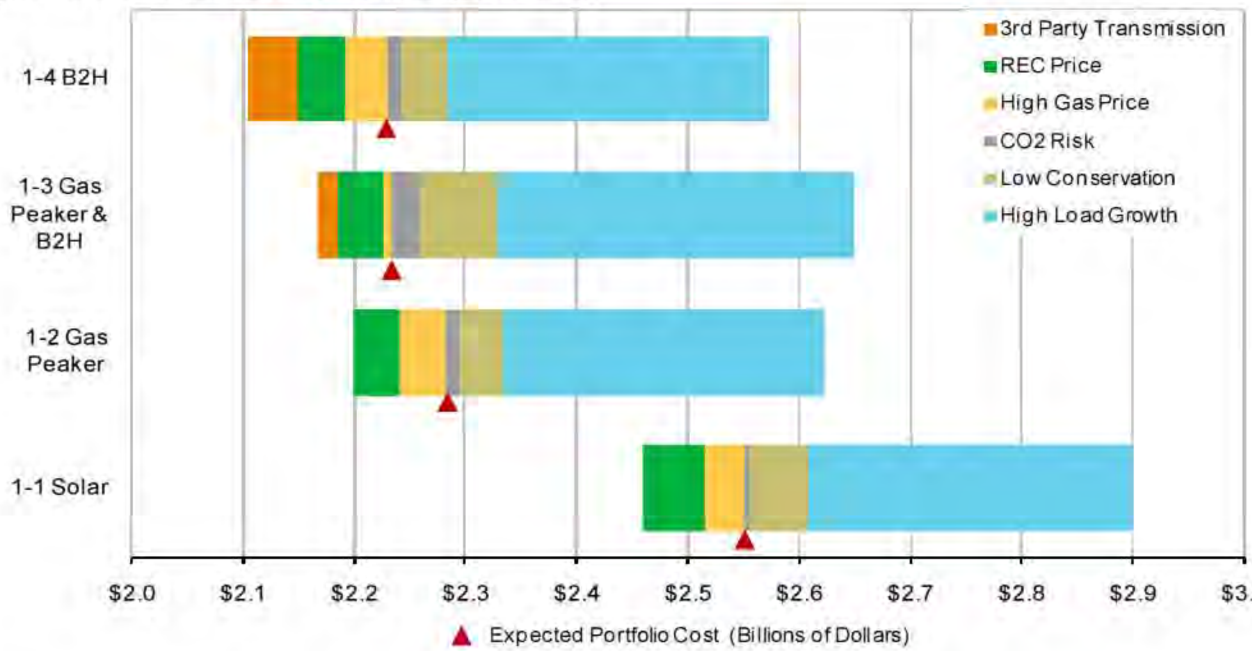
## Quantitative Risk Analysis Summary (2010–2019)

The summary conclusions of the quantitative risk analyses are:

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

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

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



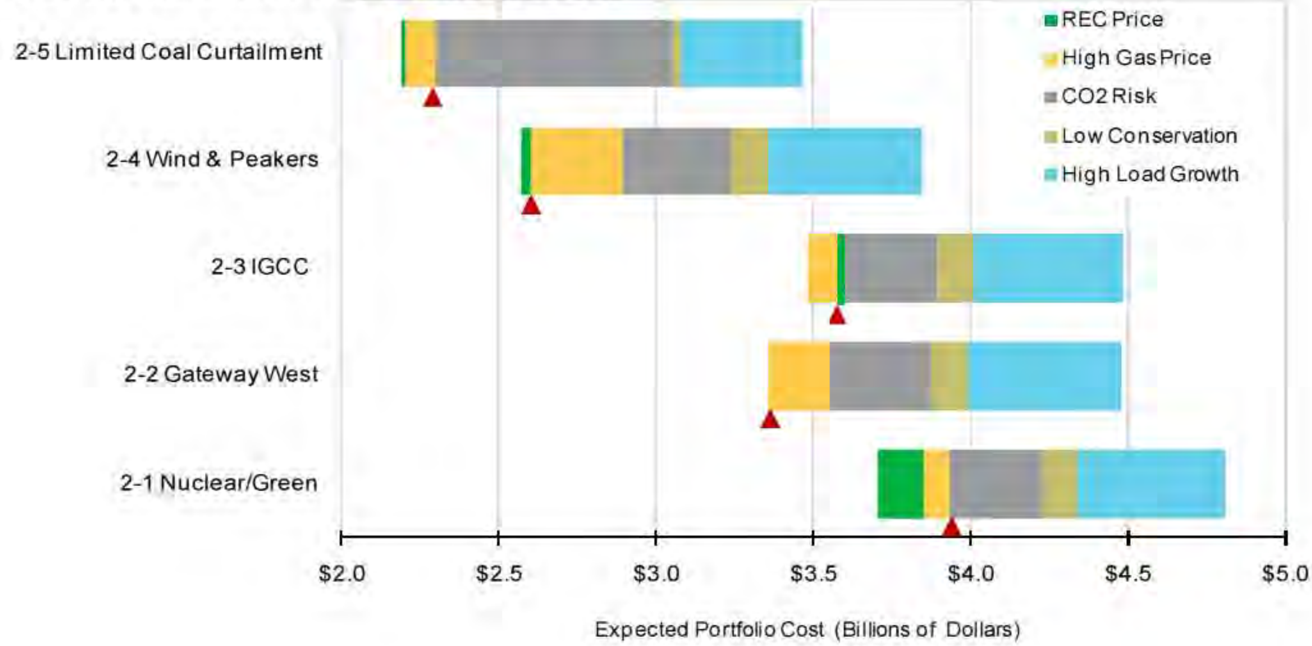

## Quantitative Risk Analysis Summary (2020-2029)

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

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

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

**Figure 10.6 Cumulative Portfolio Risk (2020–2029)**




## Qualitative Risk Analysis

The qualitative risks associated with the four 2010-2019 resource portfolios and the five 2020-2029 resource portfolios are more difficult to assess. Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Many of the qualitative factors are considered in public forums like the IRPAC meetings as well as in regulatory workshops and proceedings. For the 2009 IRP, Idaho Power qualitatively analyzed the risk associated with carbon regulation, technology, and resource siting.

### Carbon Regulation

Congress is embarking on the most comprehensive energy legislation in many years. While the Waxman–Markey bill (H.R. 2454) has emerged from the House with an extensive section on carbon regulation, at the time of this IRP, the form of carbon regulation from a Senate bill is still uncertain. Carbon regulation has become a contentious point in the Senate. Idaho Power has analyzed the Waxman–Markey bill and developed portfolios to comply with proposed carbon regulations. If the Senate were to pass an energy bill, the bill would then go to conference with the House of Representatives. Major components could be changed, particularly carbon regulation. In addition, political analysts and Washington D.C. insiders have speculated that due to the record federal deficit and continued high unemployment in the economy, President Obama could ask Congress to drop the carbon emission cap-and-trade provisions from the energy bill. If cap-and-trade was removed, carbon regulation could become an independent piece of legislation separate from any energy bill. Given the energy legislation uncertainty, Idaho Power believes that it is important to select a resource portfolio that has the flexibility to adapt to carbon regulation changes.

### Technology

Technology risk primarily occurs during the second 10-year period of the forecast. The principal area in which technology risk is considered in this resource plan is the uncertainty associated with developing new advanced nuclear and coal technologies, such as integrated gasification combined cycle (IGCC). IGCC resources provide increased efficiency, reduced emissions, and the ability to capture and potentially sequester $CO_2$ emissions at reduced costs. However, IGCC plants have higher capital costs and there is uncertainty regarding the performance of the proposed technology.

While there are certain risks associated with each type of generation resource, Idaho Power is specifically concerned about the technology risk associated with IGCC projects. IGCC projects have received a considerable amount of attention in the press recently. Idaho Power is supportive of IGCC technology and believes that the technology may play a significant role in meeting the nation's future energy needs. However, Idaho Power also believes that there is considerable technology risk associated with developing an IGCC project for use with western coals. With only two operating IGCC projects in the entire United States, much of the electric industry, including Idaho Power, does not consider IGCC to be a proven technology.

Considering Idaho Power's modest size and the significant cost of an IGCC project, Idaho Power believes it would be imprudent for the company to assume the IGCC development risk alone. Idaho Power is more comfortable taking a lesser share in a jointly-owned regional IGCC project and the company believes that an ownership share is the appropriate way for Idaho Power to allocate the IGCC technology risk if a future joint development opportunity becomes available.

### Market Risk

All market participants, including Idaho Power, face price risks when buying or selling in the market. The magnitude of the risk depends on the characteristics of the portfolio of power supply resources. Portfolios with a large quantity of either market sales or market purchases have greater exposure to changes in market prices. Additional factors to consider in the market price risk faced by each portfolio are the quantity and timing, e.g., spring, summer, daytime or nighttime of renewable resource generation, the quantity of natural gas-fired resources, and the seasonal cost of natural gas.

Idaho Power's current resource base consists primarily of low, marginal-cost coal and hydroelectric resources. Idaho Power's customers have historically benefited because the company can sell excess capacity to the market on a short-term basis during periods of high prices. To a lesser degree, Idaho Power can buy from the market during low-price periods and curtail existing resources, thereby shifting fuel (water and coal) use to more valuable hours. However, both opportunities are limited by existing transmission constraints.

In the 2009 IRP, Idaho Power's excess capacity is eventually consumed by load growth and the base case assumption of coal resource curtailment. These assumptions reduce seasonal excess capacity and limit the opportunities to capitalize on market price volatility. Tables 10.3 and 10.4 show the amount of market purchases and sales for each portfolio. "Resource Total" represents the total generation from existing resources and the new resources in each portfolio. "Native Load" represents the amount of generation required to serve customers.

As shown in Table 10.3, Portfolio 1-1 has the least exposure to market purchases and the greatest exposure to market sales, thus leaving it more exposed to a future of low prices when selling power in the wholesale electric market. On the other hand, Portfolio 1-2 has the least amount of market sales and the greatest amount of market purchases, leaving it more exposed to the risk of high market prices. Although there are differences between each of the portfolios in the amount of market purchases and sales, the differences are minor. The relatively small difference between the portfolios highlights the fact that Idaho Power is able to use market purchases and sales to increase the total value of any portfolio.

Compared to the first ten-year period, the second ten-year period shows a more significant variation between portfolios. The portfolios with large base-load units that are not impaired by carbon legislation (Portfolios 2-1, 2-2 and 2-5) show greater exposure to low market prices. The remaining portfolios (2-2 and 2-4) are significantly more exposed to high market prices due to a reliance on market purchases. Figure 10.4 shows the results of the analysis for the second ten-year period.

**Table 10.3 Market Purchases and Sales Summary (2010–2019)**

| MWh (000) | 1-1 Solar | 1-2 Gas Peaker | 1-3 Gas Peaker & B2H* | 1-4 B2H |
|---|---|---|---|---|
| Market Purchases | 8,312 | 8,861 | 8,771 | 8,828 |
| Market Sales | (26,395) | (25,175) | (25,722) | (25,178) |
| Resource Total | 187,614 | 185,845 | 186,482 | 185,881 |
| Native Load | 169,531 | 169,531 | 169,531 | 169,531 |
| Diff Market Purchases to Lowest | | 549 | 459 | 516 |
| Diff Market Sales to Lowest | (1,220) | | (547) | (3) |

*B2H–Boardman to Hemingway

**Table 10.4 Market Purchases and Sales Summary (2020–2029)**

| MWh (000) | 2-1 Nuclear/Green | 2-2 Gateway West | 2-3 IGCC | 2-4 Wind & Peakers | 2-5 Limited Coal Curtailment |
|---|---|---|---|---|---|
| Market Purchases | 7,186 | 19,629 | 8,475 | 15,566 | 11,135 |
| Market Sales | (34,372) | (18,645) | (34,170) | (19,246) | (28,063) |
| Resource Total | 204,869 | 176,698 | 203,378 | 181,363 | 194,610 |
| Native Load | 177,683 | 177,683 | 177,683 | 177,683 | 177,683 |
| Diff Market Purchases to Lowest | | 12,440 | 1,289 | 8,380 | 3,949 |
| Diff Market Sales to Lowest | (15,727) | | (15,525) | (601) | (9,418) |

## Resource Siting

Time delays and cost increases associated with resource siting and public acceptance are risks that Idaho Power considers when developing generation and transmission resources. Resource siting becomes even more critical when attempting to locate a generation resource close to an existing load center. In addition to the permitting requirements associated with developing generation resources, Idaho Power must also ensure that the public supports the project and that the project will remain productive throughout its useful life.

The problems that Alternate Energy Holdings, Inc has encountered during the past several years with a proposed nuclear generation plant near Bruneau, Idaho, and the difficulties MidAmerican Nuclear Energy Company, LLC faced with a proposed nuclear generation plant in Payette County are indicative of the risks associated with resource siting and public acceptance. Presently, Idaho Power recognizes there are siting concerns with portions of the Boardman to Hemingway transmission line and the company is working with the local communities and regulatory agencies to develop the project in appropriate areas. Resource siting is a potential issue with any of the generation and transmission resources identified in the IRP.

## Qualitative Risk Analysis Summary

Generation resources represent significant capital expenditures and resource development entails considerable risk. The public recognizes the risk and electric utilities are regulated to insure that the risks are prudent. One part of the risk assessment is the public involvement when developing long-term resource plans. A second part of the risk assessment is regular periodic review of the company's long-term resource strategy. Idaho Power develops its IRP on a biennial schedule to address the changing economic, regulatory, and technology risks. Idaho Power recognizes the capital risk in developing generation resources and understands that a diverse resource portfolio of a variety of supply-side, demand-side, and regional transmission resources will allow the company to maintain operational flexibility, minimize risk, and adapt to future economic, demographic, and regulatory conditions.

## Preferred Portfolio Selection

### *2010–2019 (Portfolio 1-4 Boardman to Hemingway)*

The selection Portfolio 1-4 Boardman to Hemingway is based primarily on the portfolio having the lowest expected portfolio cost. The low cost is a result of the portfolio having a relatively low new resource capital cost and low AURORA portfolio cost. Portfolio 1-4 has the highest transmission cost with a 37 percent stake in the Boardman to Hemingway project.

An important consideration in selecting a preferred portfolio is the ability to maintain flexibility in the face of uncertainty and not to foreclose various resource options. The flexibility to adjust to changes during the present period of unusually high regulatory uncertainty is very important. To maintain operational flexibility in some cases means Idaho Power must commit to long lead time resources, such as the Boardman to Hemingway project.

### *2020–2029 (Portfolio 2-4 Wind and Peakers)*

The theme of maintaining resource flexibility continues in the second 10-year period. Portfolio 2-4 focuses on relatively short lead time resources, such as wind projects and natural gas-fired resources. The coal curtailment assumption in Portfolio 2-4 will require significant replacement resources during the last years of the study horizon. In order to accommodate the needed quantity of replacement resources, a significant share (600 MW) of Gateway West is included in the preferred portfolio. The Gateway West transmission project enables access to the high-capacity wind regions of Wyoming (500 MW) as well as access to some energy-rich coal and natural gas deposits in southern Wyoming. The feasibility and risks of natural gas transport for 1,400 MW of new natural gas generation located near the load center in the Treasure Valley has not been included in this analysis.

Figures 10.7 and 10.8 show projections for Idaho Power's energy sources by resource type, for 2019 and 2029 respectively, assuming the preferred portfolio for each 10-year period and the carbon regulations proposed in the Waxman–Markey bill are implemented. The percentages presented in Figures 10.7 and 10.8 are estimates of Idaho Power's future energy sources and are not a representation of the energy expected to be delivered to customers. An accounting of the energy delivered to customers, by resource type, is posted on Idaho Power's Web site at www.idahopower.com.

It is important to note the Waxman–Markey bill presents only one scenario out of many possible futures for the regulation of carbon emissions. In addition, alternative compliance options implemented as part of any future carbon regulation may allow the continued operation of Idaho Power's coal resources.

The level of hydroelectric generation presented in Figures 10.7 and 10.8 is based on $50^{th}$ percentile or median water conditions. As shown in the figures, the addition of the Langley Gulch combined-cycle combustion turbine (CCCT) in 2012 increases the amount of natural gas generation in 2019 to 12 percent which increases to 29 percent in 2029 with the addition of the natural gas peaking units identified in the second 10 years of the planning period. The addition of gas peaking resources is necessary to integrate the wind resources (500 MW) in the preferred portfolio.

The annual percentage of energy supplied through power purchases is projected to increase from 7 percent in 2019 to 12 percent in 2029. The market purchases component of the power supply portfolio includes purchases from non-wind Public Utility Regulatory Policy Act (PURPA) resources and market-purchased power. Existing PURPA wind generation is accounted for in the wind generation category.

**Figure 10.7 2019 Supply-Side Resources**

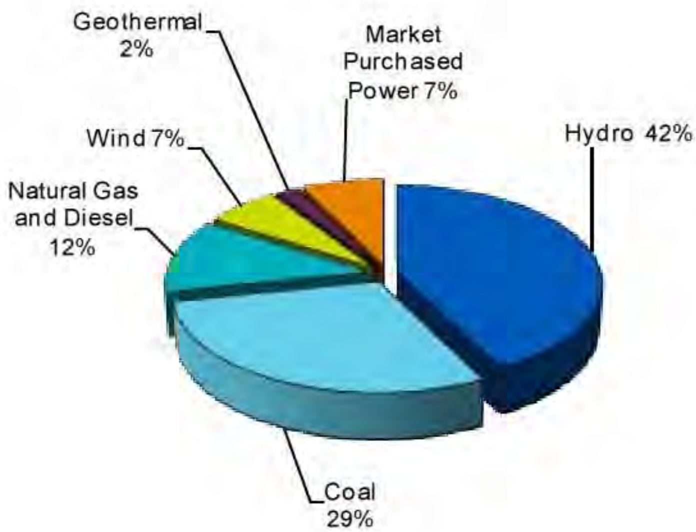
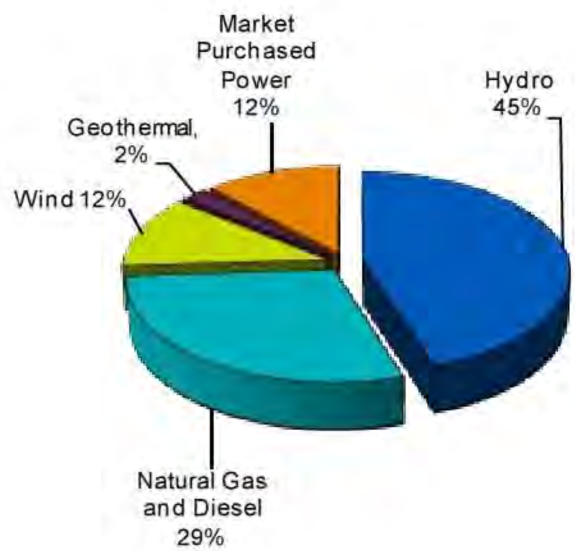



**Figure 10.8 2029 Supply-Side Resources**




Figures 10.7 and 10.8 represent Idaho Power's energy resource mix in 2019 and 2029 respectively, under the assumptions that Idaho Power's coal resources are curtailed as proposed in the Waxman–Markey bill, and portfolios 1-4 Boardman to Hemingway and 2-4 Wind and Peakers are implemented. If the cost of emitting carbon is less than $30 per ton, it may be more economical for Idaho Power to continue to operate existing coal resources.

## Developing Alternate Portfolios

Idaho Power developed two alternate resource portfolios that identify the resource choices should the assumptions used to determine the preferred portfolio not materialize. The most likely scenario leading to selecting an alternative portfolio in the near term is limited third-party interest in the Boardman to Hemingway transmission line. Idaho Power anticipates identifying other partners for the Boardman to Hemingway transmission line by the end of 2012. Should there be insufficient interest in the project, Idaho Power will assess the construction start date in 2013 and possibly delay construction until there is sufficient committed interest in the project. Idaho Power would likely replace the Boardman to Hemingway project with a natural gas-fired generation resource and begin the acquisition process for the natural gas resource with a competitive RFP in 2013. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. The preferred and alternate portfolios for the first 10-year period are shown in Table 10.5.

The alternate portfolio for the second 10-year period assumes Idaho Power curtails existing coal resources based on the Waxman–Markey bill through 2020 with no additional curtailment through the second 10 years of the planning period. Idaho Power believes this is a likely scenario and the alternate portfolio contains additional resources to offset the level of coal curtailment. The preferred and alternate portfolios for the second 10-year period are shown in Table 10.6.

**Table 10.5 Preferred and Alternate Portfolios (2010–2019)**

| Preferred Portfolio 1–4 Boardman to Hemingway | | | Alternate Portfolio 1–2 Gas Peakers | | |
|---|---|---|---|---|---|
| Year | Resource | MW | Year | Resource | MW |
| 2010 | | | 2010 | | |
| 2012 | Wind* | 150 | 2012 | Wind* | 150 |
| | CCCT (Langley Gulch)* | 300 | | CCCT (Langley Gulch)* | 300 |
| | Geothermal* | 20 | | Geothermal* | 20 |
| 2015 | Shoshone Falls | 49 | 2015 | Shoshone Falls | 49 |
| | Boardman to Hemingway | 250 | | SCCT (Frame Peaker) | 170 |
| 2016 | Geothermal* | 20 | 2016 | Geothermal* | 20 |
| 2017 | Boardman to Hemingway | 175 | 2017 | SCCT (Frame Peaker) | 170 |
| 2019 | | | 2019 | | |

* Committed Resource

**Table 10.6 Preferred and Alternate Portfolios (2020–2029)**

| Preferred Portfolio 2–4 Wind & Peakers | | | Alternate Portfolio 2–5 Limited Curtailment | | |
|---|---|---|---|---|---|
| Year | Resource | MW | Year | Resource | MW |
| 2020 | SCCT (Large Aero) | 100 | 2020 | | |
| 2021 | | | 2021 | Wind | 100 |
| 2022 | Wind | 100 | 2022 | SCCT (Large Aero) | 100 |
| 2023 | | | 2023 | | |
| 2024 | SCCT (Large Aero) | 200 | 2024 | | |
| 2025 | Gateway West | 100 | 2025 | | |
| 2026 | Large Aero | 200 | 2026 | SCCT (Large Aero) | 100 |
| 2027 | Wind | 400 | 2027 | Wind | 200 |
| | | | | SCCT (Large Aero) | 100 |
| 2028 | SCCT (Large Aero) | 400 | 2028 | | |
| 2029 | SCCT (Large Aero) | 500 | 2029 | | |

## Estimated Cost of Proposed Carbon Legislation

Meeting the proposed carbon legislation is not without cost. As mentioned in Chapter 9, Idaho Power prepared Portfolio 2-5 where carbon emissions are reduced up to 2020 and then held flat at the 2020 level throughout the remainder of the planning period. Idaho Power also prepared an additional resource portfolio, with no carbon emission reductions. The additional portfolio was used to isolate the estimated costs to comply with the proposed carbon legislation. Tables 10.7 and 10.8 compare the estimated costs of the no curtailment portfolio with the cost estimates for the preferred resource portfolios 1-4 and 2-4 for both time periods.

There are only minor costs of the proposed carbon legislation in the first 10 years of the planning period because the carbon legislation does not change Idaho Power's resource choices during the first 10 years. However, the proposed carbon legislation does affect how Idaho Power operates its resources in the first 10 years, but the effects are minor and result from reduced off-system sales.

The second 10-year period is considerably different. By the 2020–2029 time period, Idaho Power must replace the generation capacity lost due to coal curtailment with alternate generation resources. The analysis estimates the total cost of the carbon legislation to be almost one billion dollars. The total is composed of almost $700 million of generation capital and over $300 million in lost market sales.

Idaho Power will continue to evaluate the federal carbon emission legislation and the topic will be discussed in the 2011 IRP.

**Table 10.7 Carbon Legislation Costs (2010–2019)**

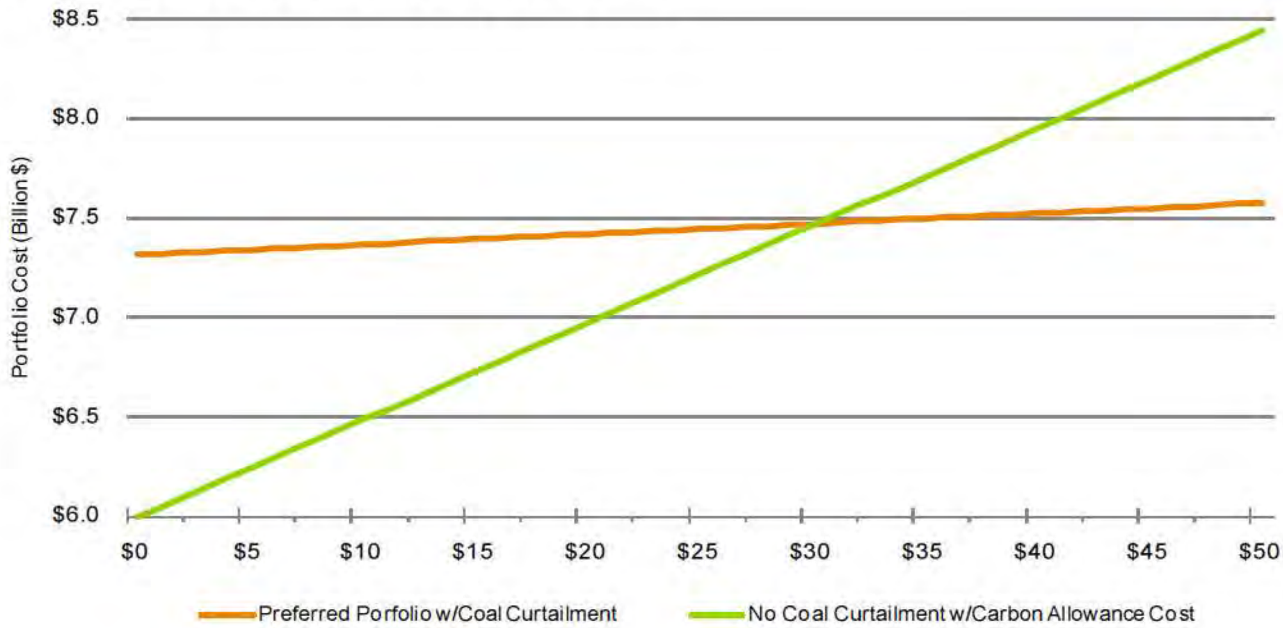
| | 1-4 Boardman to Hemingway | No Coal Curtailment | Difference |
|---|---|---|---|
| **Aurora Nominal ($000)** | | | |
| Market Purchases | $510,000 | $495,000 | $15,000 |
| Market Sales | (1,209,000) | (1,458,000) | 249,000 |
| Resources Total | 3,483,000 | 3,600,000 | (117,000) |
| Total | 2,784,000 | 2,637,000 | 147,000 |
| **Aurora NPV ($000)** | | | |
| Market Purchases | 381,000 | 372,000 | 9,000 |
| Market Sales | (889,000) | (1,055,000) | 166,000 |
| Resources Total | 2,561,000 | 2,631,000 | (71,000) |
| Total | 2,053,000 | 1,948,000 | 104,000 |
| **2009 Dollars** | | | |
| Transmission New | 110,870,000 | 110,870,000 | 0 |
| Generation Capital Costs | 96,951,000 | 96,951,000 | 0 |

**Table 10.8 Carbon Legislation Costs (2020–2029)**

| Aurora Nominal ($000) | 2-4 Wind & Peakers | No Coal Curtailment | Difference |
|---|---|---|---|
| **Aurora Nominal ($000)** | | | |
| Market Purchases | $1,162,000 | $509,000 | $653,000 |
| Market Sales | (1,221,000) | (2,600,000) | 1,379,000 |
| Resources Total | 4,003,000 | 5,088,000 | (1,085,000) |
| Total | 3,944,000 | 2,997,000 | 947,000 |
| **Aurora NPV ($000)** | | | |
| Market Purchases | 423,000 | 199,000 | 224,000 |
| Market Sales | (484,000) | (953,000) | 469,000 |
| Resources Total | 1,540,000 | 1,916,000 | (376,000) |
| Total | 1,479,000 | 1,162,000 | 317,000 |
| **2009 Dollars** | | | |
| Transmission New | 799,000,000 | 799,000,000 | 0 |
| Generation Capital Costs | 1,957,200,000 | 1,270,500,000 | 686,700,000 |

An analysis was performed to determine the sensitivity of total portfolio cost to the price of carbon allowances. The purpose of the analysis was to determine a "tipping point" where the cost of buying allowances and emitting carbon becomes high enough that coal curtailment becomes a lower cost option. The sensitivity of the total 20-year portfolio costs (AURORA nominal and Capital NPV) of both the preferred portfolios (1-4 and 2-4) and the no-coal curtailment scenario are shown in Figure 10.9. The results of the analysis indicate at an allowance price of less than $30, the no-coal curtailment scenario is a lower cost option. If the cost of carbon allowances exceeds $30, the coal curtailment scenario becomes the lowest cost option.

**Figure 10.9 Carbon Allowance Cost and Portfolio Costs**




## 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 instead driven 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 2009 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 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 forecasted 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 Pacific Northwest Power Pool. A 330 MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of one 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 10.9 and 10.10 at the end of this chapter.

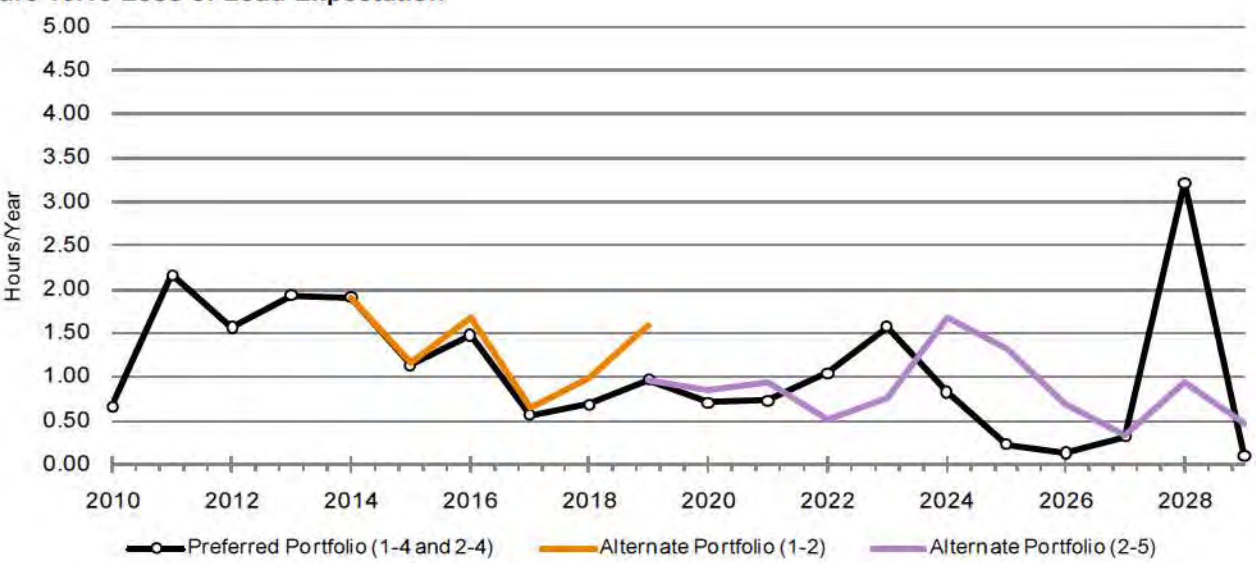
## Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2009 IRP. The assessment assumes critical water conditions at the existing hydro facilities and the planned additions for the preferred and alternate scenarios. As mentioned in the previous section, Idaho Power uses a Capacity Benefit Margin (CBM) of 330 MW in transmission planning to provide for the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2009 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 horizon. 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 2.4 hours/year. The results of the loss of load probability analysis are shown in Figure 10.10 and additional data can be found in *Appendix C–Technical Appendix*.

**Figure 10.10 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 10.10. The high value in 2028 indicates that a minor adjustment in the preferred portfolio would

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

be desirable from a reliability perspective. Moving two of the five 100-MW units scheduled in 2029 to an on-line date in 2028 would reduce the spike without changing the results for 2029.

The LOLE analysis indicates there are periods where a consistent capacity-based load and resource balance was not achieved, in part due to the uneven nature of capacity additions. In future IRPs, Idaho Power may use the LOLE model during the development of the initial resource portfolios to smooth out capacity additions.

### Table 10.9 Capacity Planning Margin (2010–2019)

| Load and Resource Balance | July-10 | July-11 | July-12 | July-13 | July-14 | July-15 | July-16 | July-17 | July-18 | July-19 |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast (95$^{th}$%)—Aug 2009 w/No DSM | (3,296) | (3,408) | (3,495) | (3,596) | (3,670) | (3,734) | (3,796) | (3,860) | (3,924) | (3,990) |
| Existing DSM (Energy Efficiency) | 17 | 33 | 48 | 64 | 79 | 93 | 107 | 121 | 135 | 149 |
| Load Forecast (95$^{th}$%)—w/EE DSM | (3,279) | (3,375) | (3,447) | (3,533) | (3,592) | (3,641) | (3,689) | (3,739) | (3,790) | (3,842) |
| Existing DSM (Irrigation Timer) | 8 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Existing DSM (AC Cool Credit) | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| Total Existing Demand Response | 59 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Peak-Hour Load Forecast w/Existing DSM | (3,220) | (3,318) | (3,390) | (3,476) | (3,535) | (3,585) | (3,633) | (3,683) | (3,733) | (3,785) |
| **Existing Resources** | | | | | | | | | | |
| Coal (w/Curtailment) | 967 | 972 | 978 | 983 | 983 | 982 | 980 | 980 | 977 | 977 |
| Hydro (50$^{th}$%)—HCC | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 |
| Hydro (50$^{th}$%)—Other | 254 | 254 | 253 | 252 | 249 | 246 | 245 | 244 | 243 | 243 |
| Sho-Ban Water Lease | 42 | 47 | 48 | 48 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,431 | 1,435 | 1,435 | 1,434 | 1,383 | 1,380 | 1,379 | 1,378 | 1,377 | 1,377 |
| CSPP (PURPA) | 133 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| 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 |
| Clatskanie Energy Exchange | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| EnergyPlus—Jefferson (83 MW) | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| East Side Purchase (50 MW) | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Mead Purchase | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| **Total Power Purchase Agreements** | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Firm Pacific NW Import Capability | 122 | 105 | 97 | 87 | 79 | 71 | 65 | 58 | 54 | 48 |
| Salmon Diesel | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| Subtotal | 3,309 | 3,309 | 3,307 | 3,302 | 3,243 | 3,231 | 3,221 | 3,214 | 3,206 | 3,199 |
| Net Position - Monthly Surplus/Deficit | 88 | (9) | (83) | (174) | (292) | (354) | (412) | (469) | (528) | (586) |
| Planning Margin | 2.7% | -0.3% | -2.4% | -5.0% | -8.3% | -9.9% | -11.3% | -12.7% | -14.1% | -15.5% |
| **2006 IRP Resources** | | | | | | | | | | |
| Wind RFP | 0 | 0 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 0 | 0 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 20 | 20 |
| Net Position—Remaining Monthly Surplus/Deficit | 88 | (9) | 225 | 153 | 35 | (26) | (84) | (122) | (180) | (238) |
| Planning Margin | 2.7% | -0.3% | 6.6% | 4.4% | 1.0% | -0.7% | -2.3% | -3.3% | -4.8% | -6.3% |
| **2009 IRP DSM** | Jul-10 | Jul-11 | Jul-12 | Jul-13 | Jul-14 | Jul-15 | Jul-16 | Jul-17 | Jul-18 | Jul-19 |
| Commercial (FlexPeak) | 40 | 45 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Irrigation Peak Rewards | 212 | 244 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 |
| Energy Efficiency Peak Reduction | 3 | 7 | 12 | 18 | 24 | 31 | 37 | 44 | 51 | 58 |
| **Total New DSM Peak Reduction** | 254 | 296 | 323 | 329 | 335 | 341 | 348 | 355 | 362 | 369 |
| Net Position - Remaining Monthly Surplus/Deficit | 343 | 287 | 547 | 482 | 370 | 315 | 264 | 233 | 182 | 130 |
| Planning Margin | 10.6% | 8.7% | 16.1% | 13.9% | 10.5% | 8.8% | 7.3% | 6.3% | 4.9% | 3.4% |
| **2009 IRP Resources** | Jul-10 | Jul-11 | Jul-12 | Jul-13 | Jul-14 | Jul-15 | Jul-16 | Jul-17 | Jul-18 | Jul-19 |
| Boardman-Hemingway Transmission | | | | | | 250 | 250 | 250 | 250 | 250 |
| Shoshone Falls Upgrade | | | | | | | 0 | 0 | 0 | 0 |
| Boardman-Hemingway Transmission | | | | | | | | 175 | 175 | 175 |
| Large Aero | | | | | | | | | | |
| Wind | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Gateway West Transmission | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Wind | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Large Aero | | | | | | | | | | |
| Net Position - Monthly Surplus/Deficit | 343 | 287 | 547 | 482 | 370 | 565 | 514 | 658 | 607 | 555 |
| Planning Margin | 10.6% | 8.7% | 16.1% | 13.9% | 10.5% | 15.8% | 14.1% | 17.9% | 16.2% | 14.7% |

## Table 10.10 Capacity Planning Margin (2020–2029)

| Load and Resource Balance | July-20 | July-21 | July-22 | July-23 | July-24 | July-25 | July-26 | July-27 | July-28 | July-29 |
|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast (95$^{th}$%)—Aug 2009 w/No DSM | (4,058) | (4,110) | (4,171) | (4,231) | (4,271) | (4,331) | (4,393) | (4,434) | (4,480) | (4,505) |
| Existing DSM (Energy Efficiency) | 163 | 177 | 191 | 205 | 219 | 233 | 247 | 261 | 275 | 289 |
| Load Forecast (95$^{th}$%)—w/EE DSM | (3,895) | (3,933) | (3,980) | (4,027) | (4,052) | (4,098) | (4,146) | (4,173) | (4,204) | (4,216) |
| Existing DSM (Irrigation Timer) | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Existing DSM (AC Cool Credit) | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| Total Existing Demand Response | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Peak-Hour Load Forecast w/Existing DSM | (3,839) | (3,877) | (3,923) | (3,970) | (3,995) | (4,041) | (4,089) | (4,116) | (4,148) | (4,159) |
| **Existing Resources** | | | | | | | | | | |
| Coal (w/Curtailment) | 977 | 977 | 977 | 977 | 977 | 977 | 977 | 977 | 0 | 0 |
| Hydro (50$^{th}$%)—HCC | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 | 1,134 |
| Hydro (50$^{th}$%)—Other | 242 | 241 | 240 | 240 | 239 | 238 | 237 | 236 | 235 | 234 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro** | 1,376 | 1,375 | 1,374 | 1,374 | 1,373 | 1,372 | 1,371 | 1,370 | 1,369 | 1,368 |
| CSPP (PURPA) | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 | 141 |
| 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 |
| Clatskanie Energy Exchange | 12 | 12 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| EnergyPlus—Jefferson (83 MW) | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 | 83 |
| East Side Purchase (50 MW) | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Mead Purchase | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| **Total Power Purchase Agreements** | 235 | 235 | 235 | 235 | 235 | 235 | 223 | 223 | 223 | 223 |
| Firm Pacific NW Import Capability | 41 | 34 | 28 | 23 | 19 | 13 | 6 | 2 | 0 | 0 |
| Salmon Diesel | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| Subtotal | 3,191 | 3,184 | 3,177 | 3,171 | 3,167 | 3,160 | 3,140 | 3,135 | 2,155 | 2,154 |
| Net Position - Monthly Surplus/Deficit | (647) | (693) | (747) | (799) | (828) | (882) | (949) | (981) | (1,993) | (2,005) |
| Planning Margin | -16.9% | -17.9% | -19.0% | -20.1% | -20.7% | -21.8% | -23.2% | -23.8% | -48.1% | -48.2% |
| **2006 IRP Resources** | | | | | | | | | | |
| Wind RFP | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Geothermal | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Net Position—Remaining Monthly Surplus/Deficit | (300) | (346) | (399) | (452) | (481) | (534) | (602) | (634) | (1,646) | (1,658) |
| Planning Margin | -7.8% | -8.9% | -10.2% | -11.4% | -12.0% | -13.2% | -14.7% | -15.4% | -39.7% | -39.9% |
| **2009 IRP DSM** | | | | | | | | | | |
| Commercial (FlexPeak) | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Irrigation Peak Rewards | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 | 254 |
| Energy Efficiency Peak Reduction | 66 | 73 | 80 | 87 | 95 | 103 | 111 | 119 | 127 | 127 |
| **Total New DSM Peak Reduction** | 376 | 383 | 390 | 398 | 406 | 413 | 421 | 429 | 438 | 438 |
| Net Position - Remaining Monthly Surplus/Deficit | 76 | 37 | (9) | (54) | (75) | (121) | (181) | (204) | (1,208) | (1,220) |
| Planning Margin | 2.0% | 1.0% | -0.2% | -1.4% | -1.9% | -3.0% | -4.4% | -5.0% | -29.1% | -29.3% |
| **2009 IRP Resources** | | | | | | | | | | |
| Boardman-Hemingway Transmission | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 |
| Shoshone Falls Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Boardman-Hemingway Transmission | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| Large Aero | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Wind | | | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Large Aero | | | | | 200 | 200 | 200 | 200 | 200 | 200 |
| Gateway West Transmission | | | | | | 100 | 100 | 100 | 100 | 100 |
| Large Aero | | | | | | | 200 | 200 | 200 | 200 |
| Wind | | | | | | | | 20 | 20 | 20 |
| Large Aero | | | | | | | | | 400 | 400 |
| Large Aero | | | | | | | | | | 500 |
| Net Position - Monthly Surplus/Deficit | 601 | 562 | 521 | 476 | 655 | 709 | 849 | 846 | 242 | 730 |
| Planning Margin | 15.7% | 14.5% | 13.3% | 12.0% | 16.4% | 17.6% | 20.8% | 20.5% | 5.8% | 17.5% |

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# 11. Action Plan

## Near-Term Action Plan

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years (2010–2019) as part of implementing the preferred portfolio. Because the near-term time period is so short, no long lead time generation resources, such as advanced nuclear or integrated gasification combined cycle (IGCC) are considered in the near-term plan. However, Idaho Power intends to continue its efforts to explore regional alliances and participate in regional utility planning forums as these technologies develop. Table 11.1 presents a list of the actions Idaho Power expects to take in the next 10 years as part of implementing the preferred portfolio.

**Table 11.1 Near-Term Action Plan**

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

## Long-Term Action Plan

The long-term action plan describes Idaho Power resource acquisitions during the 2020–2029 time period. The long-term action plan assumes that the near-term action plan is completed with only minor variations. The long-term action plan includes a combination of renewable resources and natural gas-fired resources to firm the output from wind resources. The main event in the long-term action plan is that Idaho Power continues to curtail the output from the coal-fired generation resources in order to meet the proposed federal carbon legislation. In this potential future, Idaho Power's coal-fired resource operations will be limited to seasonal needs in early years until they are fully curtailed by the end of the planning period. Table 11.2 presents a list of the actions Idaho Power expects to take from 2020 through 2029 as part of implementing the preferred portfolio.

**Table 11.2 Long-Term Action Plan**

| Year | Action |
|---|---|
| 2020 | Natural gas generation project on-line (approximately 100 MW) |
| 2021 | No action |
| 2022 | Wind project on-line (approximately 100 MW) |
| 2023 | No action |
| 2024 | Natural gas generation project on-line (approximately 200 MW) |
| 2025 | No action |
| 2026 | Natural gas generation project on-line (approximately 200 MW) |
| 2027 | Wind project on-line (approximately 400 MW) |
| 2028 | Natural gas generation project on-line (approximately 400 MW) |
| 2029 | Natural gas generation project on-line (approximately 500 MW) |

Delayed interest in the Boardman to Hemingway project may result in Idaho Power constructing both a replacement generation resource as well as constructing the transmission line at a later date.
The alternate resource portfolio may lead to constructing the Boardman to Heming project in the second 10-year period. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. Table 11.3 shows the changes to the near-term action plan if sufficient interest by third parties in the Boardman to Hemingway project does not materialize.

**Table 11.3 Alternate Portfolio Near-Term Action Plan**

| Year | Action |
|---|---|
| 2010 | File 2009 IRP with regulatory commissions<br>File wind contract (2012 Wind RFP) with the IPUC<br>File geothermal contract with IPUC<br>Irrigation Peak Rewards Program increases to 220 MW<br>FlexPeak Management program increases to 40 MW<br>Langley Gulch CCCT construction begins |
| 2011 | Wind project construction begins<br>Langley Gulch CCCT construction<br>Irrigation Peak Rewards Program increases to 250 MW<br>FlexPeak Management program increases to 45 MW<br>File 2011 IRP with regulatory commissions |
| 2012 | Wind project on line (approximately 150 MW)<br>Langley Gulch CCCT on-line (300 MW)<br>Geothermal generation on-line (approximately 20 MW)<br>***Natural gas generation resource one RFP*** |
| 2013 | File 2013 IRP with regulatory commissions |
| 2014 | Shoshone Falls upgrade construction<br>***Natural gas generation resource two RFP*** |
| 2015 | Shoshone Falls upgrade on-line (50 MW)<br>***Natural gas generation resource one on-line***<br>File 2015 IRP with regulatory commissions |
| 2016 | Geothermal Generation on-line (approximately 20 MW) |
| 2017 | ***Natural Gas generation resource two on-line***<br>File 2017 IRP with commissions |
| 2018 | No action |
| 2019 | File 2019 IRP with commissions |

## Conclusion

Each Idaho Power Integrated Resource Plan (IRP) builds on the foundation of earlier resource plans and each plan includes incremental changes due to forecasts of future events. The 2009 plan is no exception. However, the 2009 IRP is different in two key aspects.

First, 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 2009 IRP is the first company resource plan where the company and others in the region, must make a significant commitment to new interstate transmission projects.

Secondly, Idaho Power, and the nation, face the likelihood of significant carbon legislation. There has been considerable discussion on aspects of the legislation; however, all recognize the objective of the proposed legislation is to reduce the quantity of carbon released into the earth's atmosphere. Reducing carbon emissions will require curtailment of certain resources as either demand declines or additional energy is produced from alternate resources. Idaho Power has chosen to directly face the issue of curtailment and the 2009 IRP attempts to quantify the impact of proposed carbon legislation.

Idaho Power would like to thank the IRP Advisory Council (IRPAC) members and the public for their contributions to the 2009 IRP. The IRPAC debated these two major issues along with a significant number of other social topics. Idaho Power's 2009 IRP is better because of the contributions from the IRPAC members and the public.

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

Idaho Power prepares an integrated resource plan biennially. At the time of the next plan in 2011, Idaho Power will have additional information regarding supply-side resources, demand-side management (DSM) 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 renewable electricity standard (RES), and the feasibility of advanced nuclear, IGCC, and other technology issues.

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 and the OPUC, and concerned customers to revisit the resource plan 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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