2013

Integrated Resource Plan

June 2013

IDAHO POWER
An IDACORP Company

2013
Integrated Resource Plan

June 2013

IDAHO POWER®
An IDACORP Company

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

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

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

SAFE HARBOR STATEMENT

Printed on recycled paper

TABLE OF CONTENTS

LIST OF TABLES

List of Figures

LIST OF APPENDICES

1. SUMMARY

Introduction

The *2013 Integrated Resource Plan* (IRP) is Idaho Power's 11th 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 Idaho Power resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within the Idaho Power 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 supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

The 2013 IRP assumes that during the 20-year planning period—2013 through 2032—Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of the retail electricity customers in the company's Idaho and Oregon service areas and that Idaho Power will continue to operate as a vertically integrated electric utility.

The number of customers in the Idaho Power service area is expected to increase from approximately 500,000 in 2012 to nearly 670,000 by the end of the planning period in 2032. Population growth in the Idaho Power service area will require the company to add physical resources to meet the energy demands of the growing customer base.

Hydroelectric generation is the foundation of Idaho Power's energy production. Idaho Power has an obligation to serve customer loads regardless of the water conditions. Public input and regulatory support encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP, and Idaho Power continues to develop the resource plans using more conservative streamflow projections and planning criteria than median water planning but less stringent than critical water planning. Further discussion of the Idaho Power planning criteria can be found in Chapter 5.

Demand-side management (DSM) is another key resource used by Idaho Power to meet customer load. Idaho Power's main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from the demand response programs as determined through the IRP planning process. Idaho Power also strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve Idaho Power retail customers. Transmission projects are often regional resources and regional transmission planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG). Idaho Power coordinates local transmission planning with the regional forums as well as the Federal Energy Regulatory Commission (FERC). Idaho Power is obligated under FERC regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers[1] and Idaho Power retail customers.[2] The total transfer capacity of proposed transmission projects may be larger than the capacity identified in the Idaho Power IRP to accommodate the other ownership partners, third-party requests, and network customer obligations for transmission capacity.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Some earlier Idaho Power resource plans used a 10-year planning horizon. With the need for resources with long permitting and construction lead times, the requirement for a 20-year resource plan supporting independent power production contracts under the *Public Utility Regulatory Policies Act of 1978* (PURPA), and with support from the IRP Advisory Council, Idaho Power extended the planning horizon to 20 years.

The IRPs address Idaho Power long-term resource needs. Idaho Power plans for near term energy and capacity needs in accordance with the *Energy Risk Management Policy and Standards*. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC E-01-16). The *Energy Risk Management Policy and Standards* specifies an 18-month period, and Idaho Power assesses the resulting operations plan monthly.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council. The IRP Advisory Council generally meets monthly during the development of the resource plan, 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. Many members of the public participate even though they are not members of the IRP Advisory Council. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2013 IRP Advisory Council members can be found in *Appendix C—Technical Appendix*.

---

[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.

Idaho Power conducted 11 IRP Advisory Council meetings, including a resource portfolio design workshop. Idaho Power and members from the IRP Advisory Council also met in several small break-out sessions to discuss certain topics in greater detail.

The IRP Advisory Council visits the Hemingway Substation.

As part of the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and natural gas power generation. The IRP Advisory Council visited the Hemingway Substation and Langley Gulch Power Plant on the field trip.

The IRP Advisory Council actively participated throughout the resource planning process. Members of the IRP Advisory Council representing the Idaho Conservation League (ICL) and Boise State University (BSU) suggested a resource portfolio that was included and analyzed as part of the 2013 resource plan.

Idaho Power believes working with members of the IRP Advisory Council and the public improves the Idaho Power IRP. Idaho Power and the members of the IRP Advisory Council recognize that final decisions on the resource plan are made by Idaho Power. Idaho Power encourages IRP Advisory Council members and members of the public to submit comments expressing their views regarding the 2013 IRP and the resource planning process in general.

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

IRP Methodology

Preparation of the Idaho Power 2013 IRP began with the forecast of future customer demand. Existing generation resources and transmission import capacity are combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated demand response, new DSM programs, and the expansion of existing programs to revise any energy and capacity deficits. Finally, Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits.

Idaho Power evaluates resources and resource portfolios using a financial analysis. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), necessary transmission upgrades, and anticipated environmental control and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy credits (REC).

Idaho Power is part of the larger northwest and western regional energy markets, and market prices are an important component of evaluating energy purchases and sales. Idaho Power faces transmission import constraints and, at times of peak customer load, must rely on its own generation resources regardless of the regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds Idaho Power customer demand and the transmission export capacity, and Idaho Power must curtail generation on its system.

The 49 megawatt (MW) Shoshone Falls upgrade is the only committed resource in the Idaho Power 2013 IRP. The Shoshone Falls upgrade is expected to be in operation in July 2019. Committed supply-side resources are generation facilities that have been evaluated and selected in previous IRPs. Committed resources are assumed to be in Idaho Power's resource portfolio on the expected operational date of the facility. Committed resources are treated the same as existing resources in the IRP analysis.

An additional transmission connection to the Pacific Northwest has been part of the Idaho Power preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line and, since 2009, the addition has been called the Boardman to Hemingway transmission line. Idaho Power revaluated the Boardman to Hemingway transmission line in the 2013 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Idaho Power analyzed the resource portfolios over the entire 20-year planning period in the 2013 IRP. Idaho Power does not intend to add any resources until 2018, and Idaho Power determined it is practical to consider the 20-year planning period in total. For the 2011 IRP, the 20-year planning period was divided into two 10-year segments due to the anticipated near-term resource acquisition of the Langley Gulch combined-cycle combustion turbine (CCCT).

Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. The National Renewable Energy Laboratory (NREL) published the *Cost and Performance Data for Power Generation Technologies* in February 2012, and Idaho Power relied on the data from this publication to estimate the supply-side resource costs for the 2013 IRP.[3] Idaho Power used cost data from the company's Langley Gulch Power Plant to estimate the costs for natural gas CCCT.

The 2013 IRP forecasts load growth in the Idaho Power service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2013 IRP has identified periods of future capacity deficiencies. New resource costs are 30-year levelized estimates (based on expected annual generation) that include capital, fuel, non-fuel O&M, and the planning-case carbon adder. Figure 1.1 shows the 2013 capacity costs in dollars per kilowatt (kW) for various new supply-side resources considered in the 2013 IRP.

---

[3] National Renewable Energy Laboratory, *Cost and Performance Data for Power Generation Technologies*, February 2012, available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

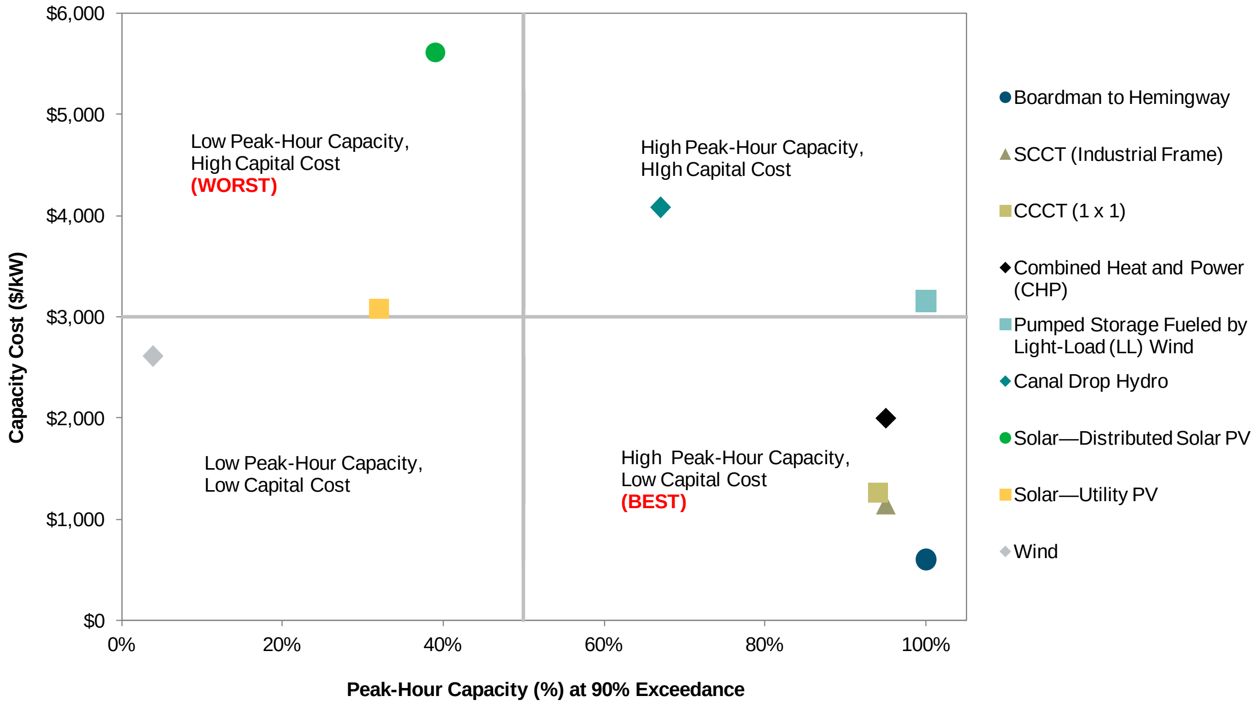


Figure 1.1 Capacity cost of new supply-side resources

Figure 1.1 shows the Boardman to Hemingway transmission line is the least-cost resource analyzed and provides the greatest level of peak-hour capacity. Simple-cycle combustion turbines (SCCT) and CCCTs are the second and third resources, respectively, in terms of capacity cost and provide slightly less peak-hour capacity than the Boardman to Hemingway line.

While it is important to evaluate the costs presented in Figure 1.1, the costs represent only part of the total resource cost (TRC). In preparing the IRP, Idaho Power also considers the value each resource provides in conjunction with the existing resources in the company's generation portfolio. A more complete analysis is presented in the Resource Alternatives Analysis section in Chapter 7. Supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 1.2 shows the 2013 cost of energy in dollars per megawatt-hour (MWh) for various new supply-side resources considered in the 2013 IRP. Figure 1.2 allows for resource alternatives to be compared based on the capacity cost and cost of production.

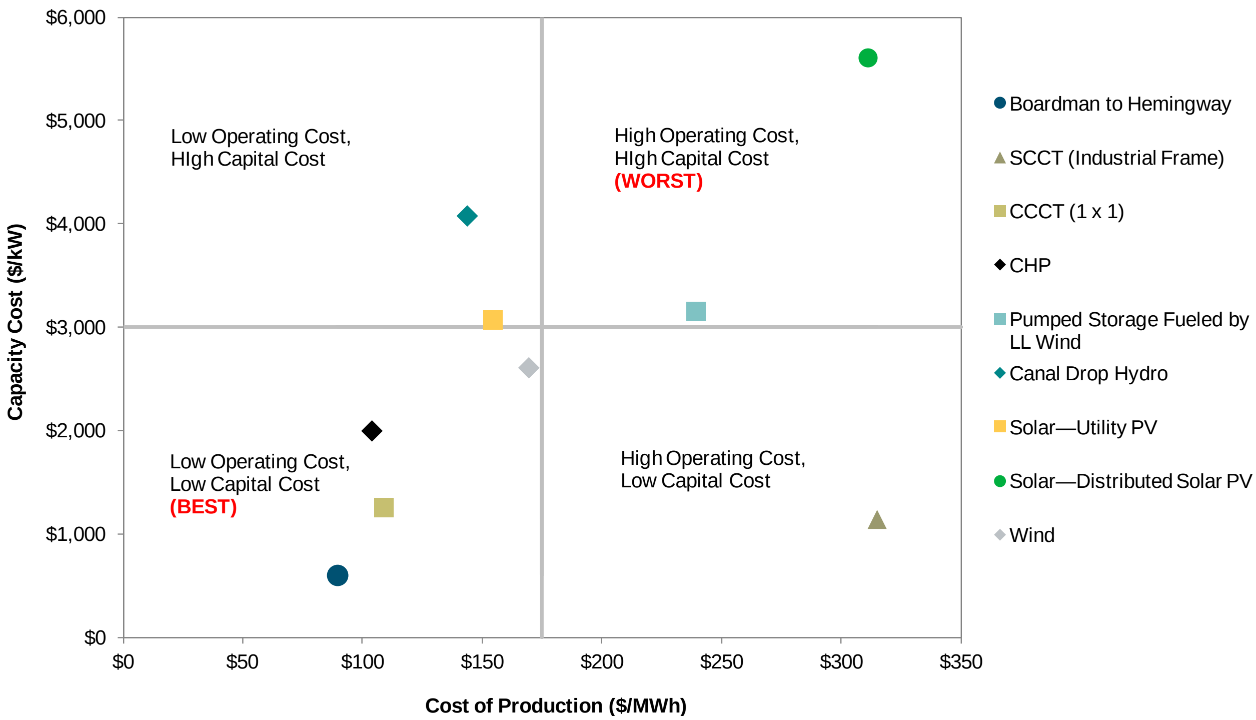


Figure 1.2 Energy cost of new supply-side resources

Figure 1.2 shows that the Boardman to Hemingway transmission line has the lowest capacity cost and the lowest cost of production. Natural gas-fueled resources are the next resources in terms of low capacity cost. CCCTs have a lower cost of energy production than SCCTs. Figures 1.1 and 1.2 show that a SCCT, with a relatively low cost of capacity, is a good resource to meet capacity deficiencies. Conversely, a SCCT is less efficient at meeting long periods of energy deficiencies. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2013 IRP is presented in Chapter 5.

Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel powered plant, and shares ownership in 3 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 (US), both in terms of total CO_2 emissions (tons) and CO_2 emissions intensity (pounds per MWh). In 2010, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 37th lowest emitter of CO_2 per MWh produced and the 35th lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, Entergy, Exelon, Bank of America, Tenaska, and by grants from the Energy Foundation and the Surdna Foundation using publicly reported 2010 generation and emissions data. Figures 1.3 and 1.4 show Idaho Power's relative position to other utilities in terms of CO_2 emissions intensity and the overall quantity of CO_2 emissions. According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 58th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

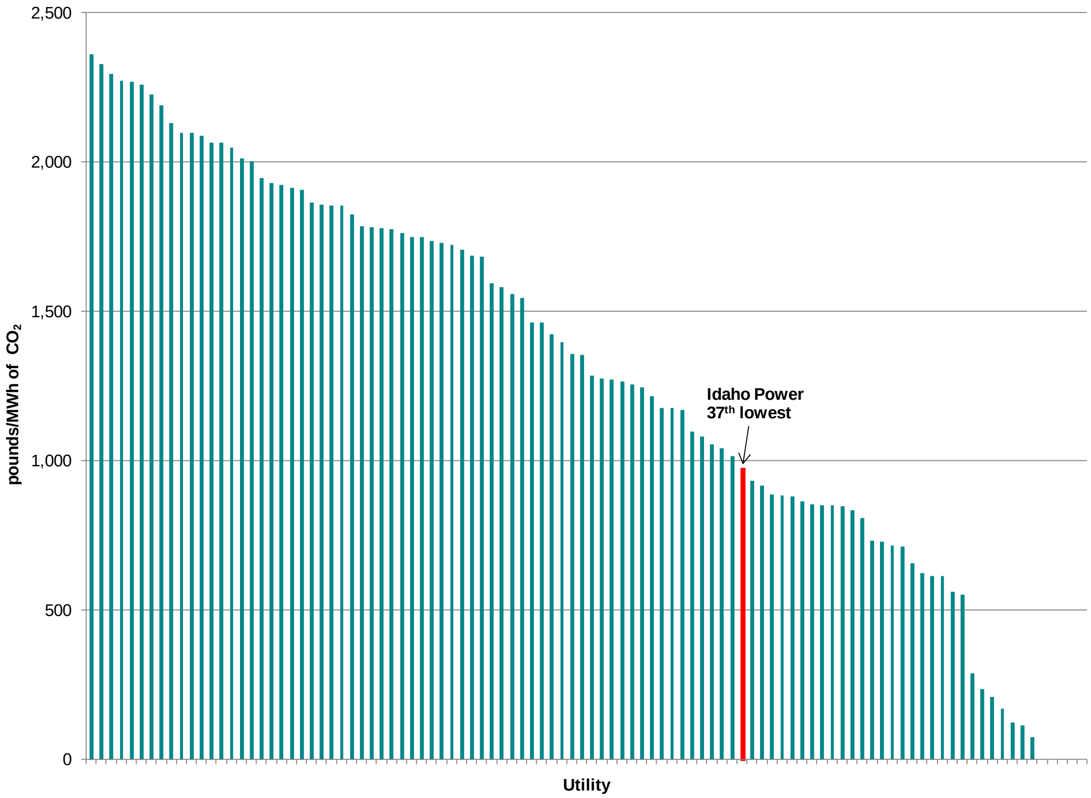


Figure 1.3 CO_2 emissions intensity of the largest 100 utilities

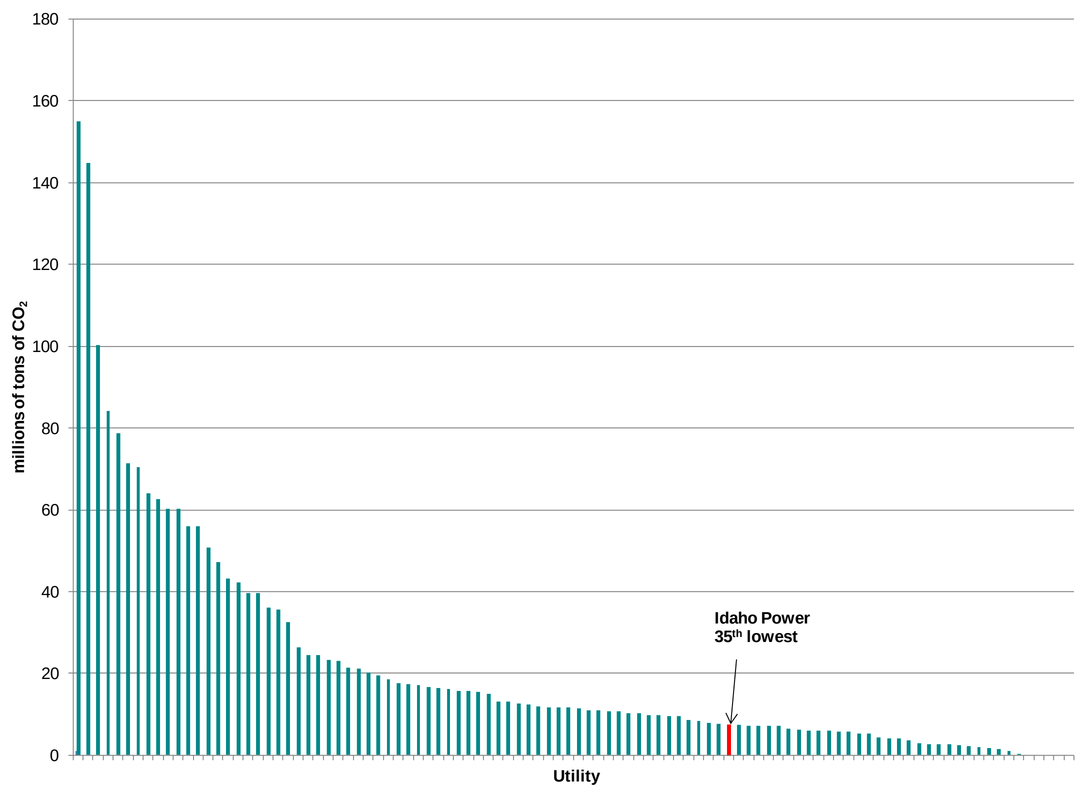


Figure 1.4 CO_2 emissions of the largest 100 utilities

In September 2009, Idaho Power's Board of Directors approved guidelines to reduce Idaho Power's resource portfolio average CO_2 emissions intensity from 2010 through 2013 to 10 to 15 percent below the company's 2005 CO_2 emissions intensity of 1,194 pounds per MWh. Because Idaho Power's CO_2 emissions intensity fluctuates with streamflows and production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

Currently, generation and emissions from company-owned resources are included in the CO_2 intensity calculation. The company's progress toward achieving this intensity reduction goal and additional information on Idaho Power's CO_2 emissions are reported on the company's website:

http://www.idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm.

Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at www.cdproject.net. In November 2012, the Board of Directors approved the extension of the company's 2010 to 2013 goal for reducing CO_2 emission intensity. The goal is to achieve CO_2 emission intensity 10 to 15 percent below the 2005 CO_2 emission intensity from 2010 to 2015.

The 2013 IRP quantifies the cost and longer term effects of carbon regulations by including a carbon adder applied to all resources that emit CO_2. Additional details regarding the assumptions and analysis are presented in Chapter 5 and Chapter 9.

Idaho Power included a more complete discussion of climate change and the regulation of greenhouse gas emissions on pages 65 through 67 of the IDACORP, Inc., 2012 Annual Report. This climate change section is also included in *Appendix C—Technical Appendix*.

Preferred Resource Portfolio

The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was first mentioned in the 2000 IRP, and the upgrade was specifically identified in the 2006 Idaho Power resource plan. Idaho Power continues the efforts to acquire the necessary regulatory approvals and permits to begin construction. The construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018.

Idaho Power's demand response programs will be used throughout the planning period to meet resource needs. Idaho Power expects to use up to approximately 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission. The preferred resource portfolio assumes a demand response capacity of 50 MW is available beginning in 2024 and steps up to approximately 370 MW by 2032. The level of demand response capacity available will be based on the deficits identified through the IRP process or operational needs identified between IRP cycles.

The preferred resource portfolio includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to the installation and operation of the additional emission-control systems. The approximate financial commitment dates are identified in the action plan. The commitment dates are derived from the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (coal study) that Idaho Power filed in February 2013 as part of the 2011 IRP Update.

Idaho Power prepares an IRP every two years and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

Action Plan

Table 1.1 identifies the actions Idaho Power will take over the next 20 years to meet the projected capacity deficits. The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission line project has outperformed the other resource portfolios in the 2013 resource plan. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.

Idaho Power treated the Boardman to Hemingway transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

Table 1.1 Action plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings.
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings.
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology.
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology.
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW.
2018	Boardman to Hemingway	Transmission line complete and in service.
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 370 MW.

This page left blank intentionally.

2. Political, Regulatory, and Operational Issues

Idaho Energy Plan

In 2007, the Idaho Legislature's Interim Committee on Energy, Environment and Technology prepared, and the Idaho Legislature approved, a new Idaho Energy Plan for the first time in 25 years. With rapid changes in energy resources and policies, the committee recommended the legislature revisit the Idaho Energy Plan every five years to properly reflect the interests of Idaho citizens and businesses. In keeping with this recommendation, the plan was reviewed and updated by the Interim Committee and approved by the legislature in 2012. The Idaho Office of Energy Resources (IOER) and the Idaho Strategic Energy Alliance provided assistance to the Interim Committee during the update of the energy plan.

The 2012 update finds that Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy, despite the potential economic and political vulnerability caused by Idaho's reliance on energy imports. Idaho currently lacks significant commercial natural gas and oil wells and only generates about half the electricity it uses. Yet the state has abundant hydropower, wind, biomass, and other renewable energy sources.

Ongoing changes in energy generation and consumption provide an opportunity for economic growth within the state. While the Idaho Energy Plan acknowledges the risks attributed to advances in energy generation, transmission, and end-use technologies, it also recognizes the prospective benefits. With this recognition, the 2012 Idaho Energy Plan emphasizes five core objectives:

1. Ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho.
2. Maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans.
3. Protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources.
4. Promote sustainable economic growth, job creation, and rural economic development.
5. Provide the means for Idaho's energy policies and actions to adapt to changing circumstances.

Idaho Strategic Energy Alliance

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

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

- Energy efficiency and conservation
- 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 the 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 cabinet members assigned responsibility by executive order to review suggestions from the board and interact directly with the governor. The council is led by the administrator of the IOER.

FERC Relicensing

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

Idaho Power filed a final license application (FLA) for the Swan Falls Hydroelectric Project (Swan Falls Project) with FERC in June 2008, and the new license for the Swan Falls Project was issued by FERC on September 8, 2012, for a 30-year term expiring September 1, 2042.

Idaho Power's remaining and most significant ongoing relicensing effort is the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 34 percent of the company's total generating capacity. The current license for the HCC 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 HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1978* (ESA); and other applicable federal laws.

Administrative work on relicensing the HCC is expected to continue until a new license is issued. After a new license is issued, further costs will be incurred to comply with the terms of the new license. Because the new license for the HCC has not been issued, and discussions on the protection, mitigation, and enhancement (PM&E) packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include the following:

1. Coordinating the relicensing process
2. Consulting with regulatory agencies, tribes, and interested parties
3. Preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites
4. Preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
5. Studying and analyzing data
6. Preparing all necessary reports, exhibits, and filings responding to requests for additional information from FERC
7. Consulting on legal matters

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental PM&E measures imposed as a condition of 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 has been assumed in the 2013 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 and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues is expected to affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

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

The Snake River at the Murphy gage below Swan Falls.

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

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

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

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

Idaho Power actively participated in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between the ESPA and Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River. The company had hoped implementation of the ESPA CAMP would improve aquifer levels and tributary spring flows to the Snake River. However, some of the Phase I recommendations, outlined in Table 2.1, have been slow to fully develop.

One major issue not fully resolved through the CAMP process was funding for proposed management practices. Several funding alternatives were discussed, but no long-term funding mechanisms have been established. While there have been two practices—recharge and weather modification—that have received adequate funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program and, through the cooperative effort, has greatly expanded the existing weather modification program as well as added additional forecasting and meteorological data support. The company has also established a long-term plan to continue the expansion of this program.

Table 2.1 Phase I measures included in the ESPA CAMP

Measure	Target (acre-feet)	Estimated to Date (acre-feet)
Groundwater to surface-water conversions	100,000	19,156
Managed aquifer recharge	100,000	115,000*
Demand reduction	–	–
Surface-water conservation	50,000	26,000
Crop mix modification	5,000	0
Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP)	40,000	33,368
Weather modification	50,000	124,000

*Average annual recharge from 2009 – 2012. Includes estimated for 2012

For the 2013 IRP, Idaho Power forecasted flows similar to those in the 2011 IRP; however, the declines in reach gains are extended through 2027. Based on modeling under the 90-percent exceedance forecast, declining flows reach the Swan Falls 3,900-cfs minimum in 2027. At that time, Idaho Power assumes the State of Idaho will provide appropriate management and water-rights administration under the Swan Falls Agreement to prevent further declines in surface-water flows. Figure 2.1 provides the yearly inflow to Brownlee Reservoir as forecasted for the 2013 IRP.

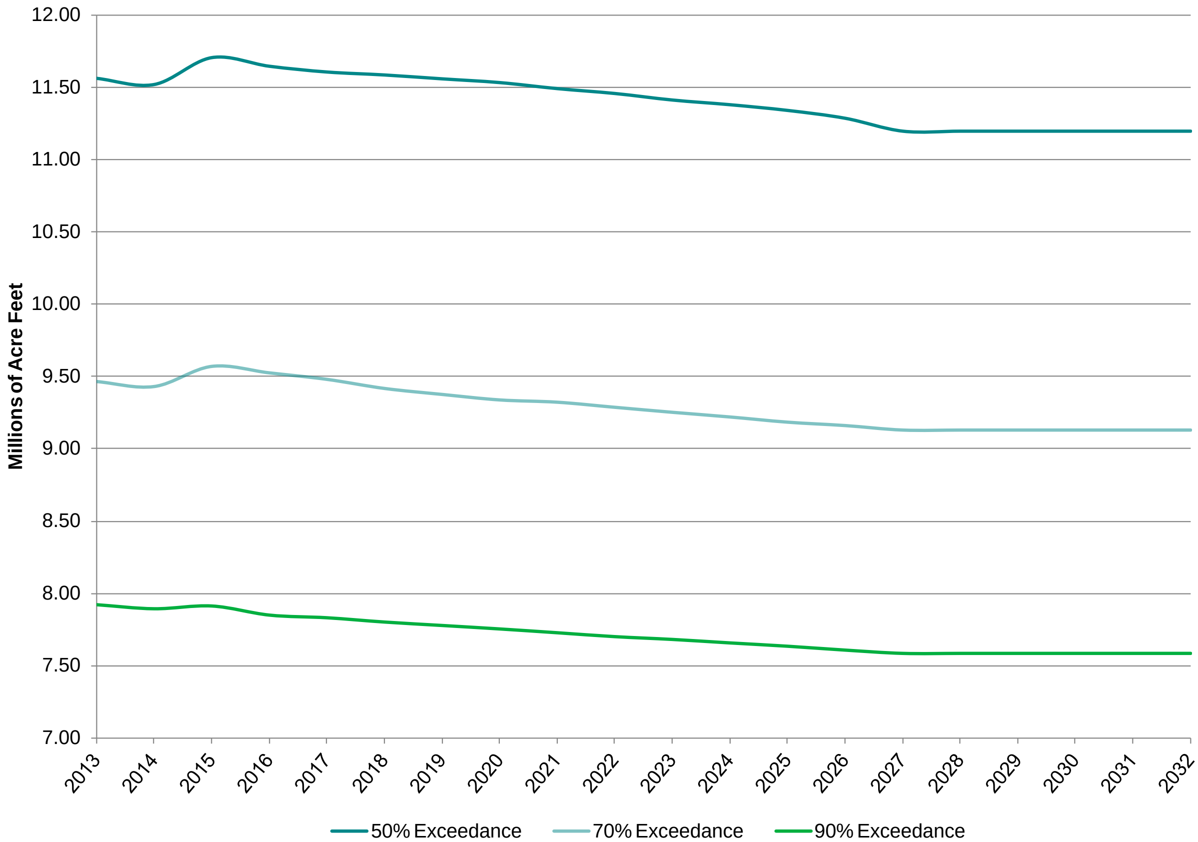


Figure 2.1 Brownlee total annual inflow—forecasted flows, 2013–2032

Wind Integration Study

Because wind generators require Idaho Power to modify the power system operations to successfully integrate wind energy, wind is a variable and uncertain generating resource. Idaho Power must adjust the generation schedule to include additional operating reserves that allow Idaho Power dispatchable generators to respond to wind variability and uncertainty.

The wind integration study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources, transmission interconnections, and customer load may be unable to provide the incremental balancing reserves to successfully integrate wind. Under low demand circumstances, the curtailment of wind generation may be necessary to balance generation with customer load. The wind integration study demonstrates that the frequency of curtailment is expected to increase when the installed wind generation capacity exceeds 800 MW. The study results indicate that wind development beyond 800 MW may lead to a considerable curtailment risk.

Idaho Power prepared the wind integration study and filed the study as part of the 2011 IRP Update. The *Wind Integration Study Report* is available at:

http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

Northwest Power Pool Energy Imbalance Market

In May 2012, the Northwest Power Pool (NWPP) initiated a study of an energy imbalance market (EIM) for the NWPP region. The 2012 study extended earlier work by WECC and various utility commissions. The NWPP study focused on issues related to hydroelectric resources in the Northwest. The NWPP analyzed the dispatch costs of the region to capture the diversity of load and wind variations that occur during the operating hour. In addition to the analysis, the NWPP study considered a mathematical simulation of the Northwest EIM. Idaho Power was 1 of over 20 entities supporting the study. The study found that an EIM would reduce the dispatch costs for the NWPP by about 3 percent when applied to the observed annual thermal dispatch cost of about $3 billion and resulted in savings between $40 and $120 million depending on the specific study assumptions. While the NWPP study found a positive benefit to cost ratio, many institutional issues remain before an EIM can be implemented in the Pacific Northwest.

For Idaho Power, there are several principle benefits to an EIM:

1. The market would provide greater access to balancing energy to accommodate intermittent generation variations within Idaho Power's balancing area.

2. There would be a slight improvement in real-time dispatch costs.

3. The market would provide better real-time pricing for power imbalances that occur in real-time for wholesale power customers. Idaho Power supports, and will continue to participate in, the NWPP discussions; however, participation by a majority of the NWPP members will be required to realize the benefits of an EIM.

Renewable Energy Certificates

RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The RECs and the electricity produced by a certified renewable resource can either be sold together (bundled) or separately (unbundled). The purchase of a REC buys the "greenness" of that energy.

In states with REC programs, a renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hour (kWh), or 1 MWh, of electricity produced. An average residential Idaho Power customer uses about 1,025 kWh a month.

A certifying tracking system gives each REC a unique identification number to ensure the REC is used only once. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used, held, or traded.

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- Whether there is a tight supply/demand situation
- Whether the REC is used for renewable portfolio standards (RPS) compliance
- The type of power
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds from the REC sales are returned to Idaho Power customers through the power cost adjustment (PCA) as directed by the IPUC in Order No. 32002 and by the OPUC in Order No. 11-086. Because the RECs were sold, Idaho Power cannot claim the renewable electricity associated with those RECs was delivered to retail customers. The new REC owner has purchased the rights to claim the renewable attributes, or “greenness,” of that energy.

If Idaho Power retains and retires its RECs, the company can claim electricity delivered to customers was generated by renewable resources.

Renewable Portfolio Standard

Some states have an RPS, a state policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy. In the future, there may be similar federal standards. Idaho Power anticipates that existing hydroelectric facilities will not be included in RPS calculations. However, hydroelectric upgrades on existing facilities, such as the Shoshone Falls upgrade, will likely be included in RPS calculations.

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

While the State of Idaho does not have an RPS, a federal Renewable Energy Standard (RES) is a possibility. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to position the company’s resource and REC portfolio to minimize the potential effect on customers if a federal RES is implemented.

Renewable Energy Credit Management Plan

In December 2009, Idaho Power filed a REC management plan with the IPUC that detailed the company’s plans to continue acquiring long-term rights to RECs in anticipation of a federal RES but to sell RECs in the near term and return their share of the proceeds to customers through the PCA mechanism. Public comments regarding the plan mirrored the positions expressed by IRP Advisory Council members, many of whom filed comments with the IPUC. In June 2010, the IPUC accepted Idaho Power’s REC management plan.

Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local environmental laws and regulations. Current and pending environmental legislation relates to climate change, greenhouse gas emissions and air quality, mercury (Hg) and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species. The legislation includes the *Clean Air Act of 1970* (CAA), the *Clean Water Act of 1972* (CWA); the *Resource Conservation and Recovery Act of 1976* (RCRA); the *Toxic Substances Control Act of 1976* (TSCA); the *Comprehensive Environmental Response, Compensation and Liability Act of 1980* (CERCLA); and the ESA.

While the utility industry will continue to respond to changes in environmental legislation associated with utility operations, including emissions regulations associated with the operation of coal- and natural gas-fired generating facilities, the introduction or passage of federal energy legislation resulting in a comprehensive shift in national energy policy does not appear to be imminent. However, with atmospheric CO_2 reaching 400 parts per million (ppm), grass roots and local activities related to energy policy have increased in some parts of the country, which may lead to renewed interest in advancing comprehensive federal energy legislation.

In February 2013, Senators Bernie Sanders and Barbara Boxer introduced comprehensive legislation on climate change. The legislation has been introduced as two separate measures, cited as the following:

1. *Climate Protection Act of 2013*
2. *Sustainable Energy Act of 2013*

The package of legislation would, among other things, set a long-term emissions reduction goal of 80 percent or more by 2050; establish a carbon fee of $20 per ton of CO_2 content (or CO_2 equivalent content of methane), rising at 5.6 percent per year over a 10-year period; create a Family Clean Energy Rebate program; create a Sustainable Technologies Finance Program; and require disclosure of the chemicals used in the fracking process. Both bills are in committee.

The utility industry will continue to respond to, and be shaped by, changes in state and federal regulations, especially the changes affecting coal-fired generating facilities, the permitting of transmission facilities, PURPA regulations and implementation, and renewable energy incentives (production tax credits, cash grants, bonus depreciation, etc.). As noted previously, local activities related to climate change and energy policy may create sufficient interest to introduce climate change or comprehensive energy policy legislation that would affect the utility industry. Absent comprehensive federal energy legislation, a utility's resource portfolios will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes.

This page left blank intentionally.

3. Idaho Power Today

Customer Load and Growth

An Idaho Power employee installs a Smart Meter.

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 500,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW. In July 2012, the peak-hour load reached 3,245 MW—the system peak-hour record. Idaho Power's successful demand-reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand from 2009 through 2011.

Average firm load increased from 1,200 aMW in 1990 to 1,745 aMW in 2012 (load calculations exclude the load from the former special-contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,595 MW. The 960-MW increase in capacity represents enough generation to serve approximately 150,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 318-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is located in the western Treasure Valley in Payette County, Idaho. Construction of the plant began in August 2010, and the plant became commercially available in June 2012.

The data in Table 3.1 suggests each new customer adds approximately 5.5 kW to the peak-hour load and about 2.5 average kilowatts (akW) to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to the average load; industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 210,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 210,000 customers require approximately 1,150 MW of additional peak-hour capacity and about 525 aMW of energy.

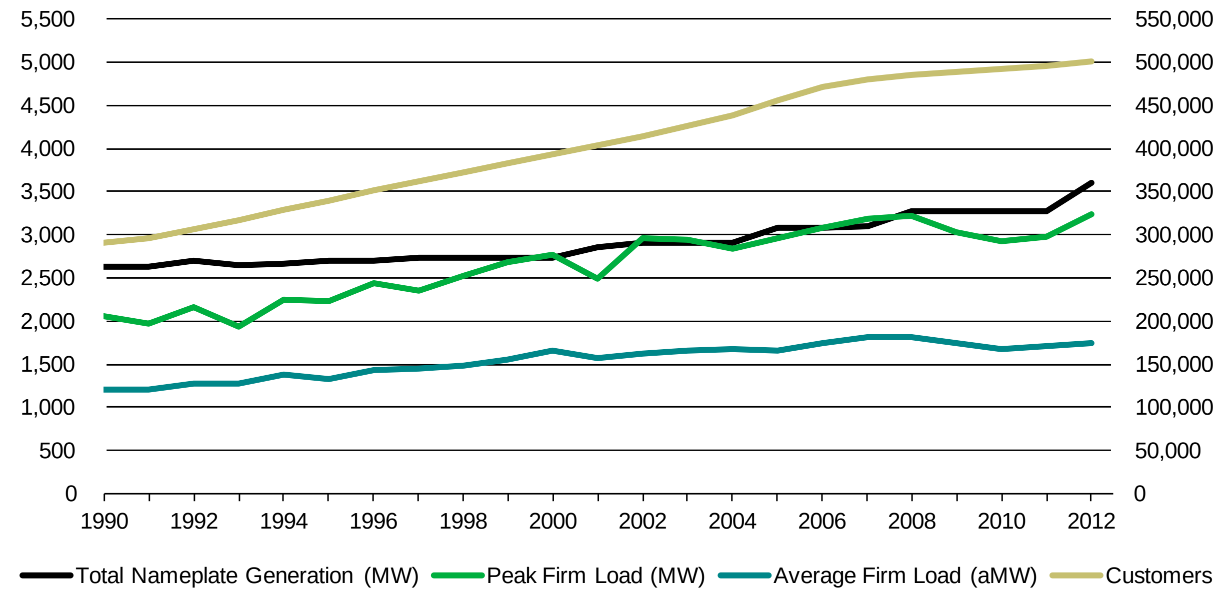


Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
1990	2,635	2,052	1,205	290,492
1991	2,635	1,972	1,206	296,584
1992	2,694	2,164	1,281	306,292
1993	2,644	1,935	1,274	316,564
1994	2,661	2,245	1,375	329,094
1995	2,703	2,224	1,324	339,450
1996	2,703	2,437	1,438	351,261
1997	2,728	2,352	1,457	361,838
1998	2,738	2,535	1,491	372,464
1999	2,738	2,675	1,552	383,354
2000	2,738	2,765	1,653	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,622	414,062
2003	2,912	2,944	1,657	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,660	456,104
2006	3,085	3,084	1,745	470,950
2007	3,093	3,193	1,808	480,523
2008	3,276	3,214	1,815	486,048
2009	3,276	3,031	1,742	488,813
2010	3,276	2,930	1,679	491,368
2011	3,276	2,973	1,711	495,122
2012	3,595	3,245	1,745	500,731

[1] Year-end residential, commercial, and industrial count plus the maximum number of active irrigation customers

Idaho Power anticipates adding approximately 8,400 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 55 MW per year, and the average-energy requirement is forecast to grow at 21 aMW per year. More detailed customer and load forecast information is presented in Chapter 5 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 318-MW Langley Gulch CCCT plant every six years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The plan to meet the requirements of Idaho Power's load growth is discussed in Chapter 10.

The generation costs per kW included in Chapter 5 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch Power Plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs are in 2013 US dollars and do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,400 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

2012 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and thermal generation facilities and long-term power purchase agreements (PPA) to supply the energy to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year.

In 2012, 79 percent of Idaho Power's supply of electricity came from company-owned generation resources as shown in Figure 3.2. Idaho Power purchased 11 percent of its energy from PURPA resources in 2012, and the remainder of the energy was purchased on the market or from PPAs (the four PPAs are described later in this section).

In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.3 shows Idaho Power's electricity sources for 2012, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

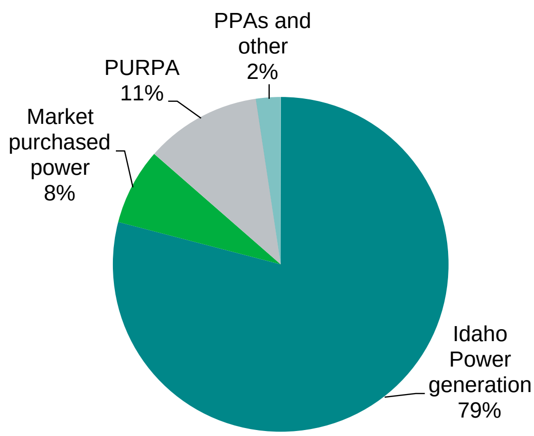


Figure 3.2 2012 energy sources by type

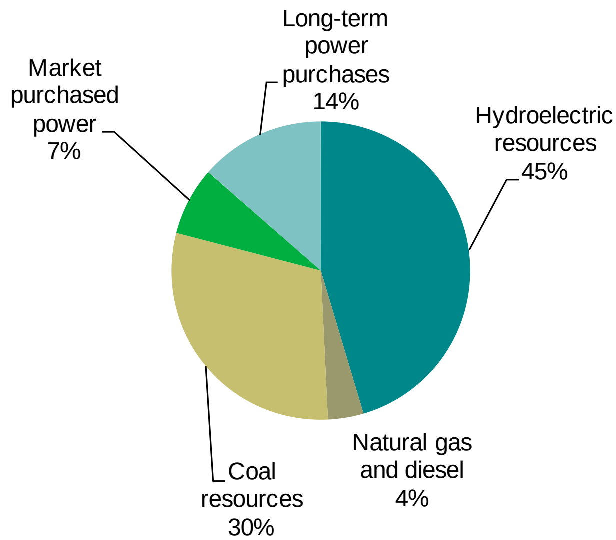


Figure 3.3 2012 energy sources

Figure 3.4 identifies the generation source by nameplate MW for Idaho Power generation in 2012. Figure 3.4 includes generation owned by Idaho Power and generation Idaho Power purchases through PPAs.

In 2012, Idaho Power purchased 2,374,795 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.5. Long-term power purchases that cannot be identified by resource type are shown as Other.

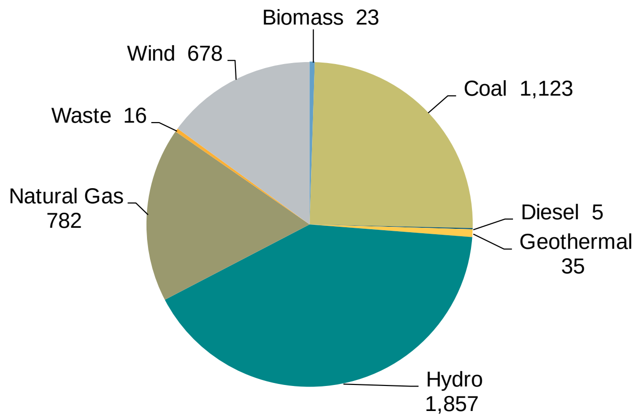


Figure 3.4 2012 Idaho Power system nameplate (MW) (owned resources plus PPAs)

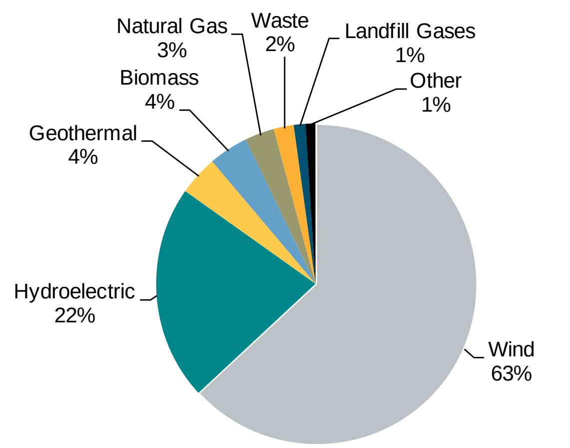


Figure 3.5 2012 long-term power purchases by resource type

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. RECs, also known as Renewable Energy Credits or green tags, represent the green or renewable attributes of energy produced by certified renewable resources. The Idaho Power REC policy is described in Chapter 2 of this IRP.

Table 3.2 shows that the Idaho Power Green Power Program delivered 18,593 RECs to Idaho Power retail customers in 2012. The energy from the Green Power Program is reported as renewable energy delivered to Idaho Power customers.

Table 3.2 shows that no hydroelectric, wind, geothermal, or solar generation is represented as being delivered to Idaho Power retail customers in 2012 because the RECs associated with such generation were sold to other parties who purchased the right to claim that the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with the renewable generation rather than sell the RECs, the company would have been able to claim that the renewable energy had been delivered to customers. The proceeds from REC sales are returned to Idaho Power customers through the PCA as directed by the Idaho Commission in Order No. 32002 and by the Oregon Commission in Order No. 11-086.

Idaho Power generates energy at several hydroelectric projects that qualify under the State of Nevada RPS, and some of the RECs from the hydroelectric projects were sold to NV Energy in 2012. The 222,854 unsold RECs from hydroelectric projects are RECs that can only be used in Nevada, and a buyer for the RECs has not been found.

Table 3.2 2012 REC Accounting

Resource by Type	RECs Generated or Acquired	RECs Sold Off-System[1]	RECs Delivered to Idaho Power Retail Customers	Unsold RECs
Hydroelectric	276,843	(53,989)	0	222,854
Solar (Oregon Solar)	238	(173)	0	65
Wind (Elkhorn)	314,145	(314,145)	0	0
Geothermal (Neal Hot Springs)	23,690	(23,690)	0	0
Purchased renewables (Green Power Program)	18,593	0	(18,593)	0
Total	**633,509**	**(391,997)**	**(18,593)**	**222,919**

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

Existing Supply-Side Resources

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

Table 3.3 Existing resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	585.4	Hells Canyon
C. J. Strike	Hydroelectric	82.8	Mid-Snake
Cascade	Hydroelectric	12.4	North Fork Payette
Clear Lake	Hydroelectric	2.5	South Central Idaho
Hells Canyon	Hydroelectric	391.5	Hells Canyon
Lower Malad	Hydroelectric	13.5	South Central Idaho
Lower Salmon	Hydroelectric	60.0	Mid-Snake
Milner	Hydroelectric	59.4	Upper Snake
Oxbow	Hydroelectric	190.0	Hells Canyon
Shoshone Falls	Hydroelectric	12.5	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	8.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
Valmy	Coal	283.5	North Central Nevada
Langley Gulch	Natural Gas—CCCT	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT	172.8	Southwest Idaho
Danskin	Natural Gas—SCCT	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,594.4**	

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

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 960 aMW, or 8.4 million MWh under median water conditions.

Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the HCC in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately

70 percent of Idaho Power's annual hydroelectric generation and approximately 30 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability.

Idaho Power operates the HCC 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 the spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the ESA.

Brownlee Reservoir is the only HCC reservoir—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1 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, navigation, recreation, and the benefit of fish and wildlife resources.

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

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

The US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake (mid-Snake) projects, with all of the flow augmentation eventually passing through the HCC 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.

Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C. J. Strike, Bliss, Lower Salmon, Upper Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, and C. J. Strike projects. The three projects are operated within the FERC license requirements to coincide with the daily system peak demand when the load-following capacity is available.

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

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

Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the water is needed are especially beneficial. Acquiring water through the water bank also helps the company to improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2012 with Water District 65 in the Payette River system to rent 10,000 acre-feet of storage water released in February 2012.

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

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

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River system above Milner Dam. Idaho Power is continuing to work with the stakeholders in the upper Snake River to expand the program.

Idaho Power seeds clouds by introducing silver iodide (AgI) into winter storms. Cloud seeding increases precipitation from passing winter storm systems. If a storm has the right combination of abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation.


An Idaho Power remote cloud-seeding generator.

Idaho Power uses two methods to seed clouds:

1. Remotely operated ground generators at high elevations
2. Modified aircraft burning flares containing AgI

Benefits of either method vary by storm, and the combination of the two methods provides the most flexibility to successfully place AgI into passing storms. Minute water particles within the clouds freeze on contact with the AgI particles and eventually grow and fall to the ground as snow.

AgI is a very efficient ice nucleus that allows it to be used in minute quantities. It has been used as a seeding agent in numerous western states for decades without any known harmful effects (http://weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 5 and 28 percent annually. Idaho Power estimates cloud seeding provides an additional 124,000 acre-feet from the upper Snake River, and 224,000 acre-feet from the Payette River. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2012 to 2013 winter season, the program included 17 remote-controlled, ground-based generators and 1 aircraft for operations in the Payette Basin. The Upper Snake River Basin program included 19 remote-controlled, ground-based generators operated by Idaho Power and

25 manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

Thermal Facilities

Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

North Valmy

Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

Boardman

Idaho Power owns 10 percent, or 64.2 MW (generator nameplate rating), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. Portland General Electric (PGE) has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative has 10 percent ownership. As the majority owner of the plant, PGE is the operator of the Boardman facility.

The 2013 IRP assumes Idaho Power's share of Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the Environmental Protection Agency (EPA) related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NO_x) emissions. At the end of 2012, the net-book value of Idaho Power's share of the Boardman facility was approximately $23.1 million. Additional emission controls are required to be installed to continue operating the Boardman plant through 2020.

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens STG-5000F4 combustion turbine and one 131.5-MW Siemens SST-700/SST-900 reheat steam turbine.

The Langley Gulch plant is located south of New Plymouth in Payette County, Idaho. Construction commenced in 2010, and the plant became commercially available in June 2012. The Langley Gulch project connects to existing 230-kilovolt (kV) transmission lines to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon.

Peaking Facilities

Danskin

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

Bennett Mountain

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

Salmon Diesel

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

Solar Facilities

In 1994, a 25-kW solar photovoltaic (PV) array with 90 panels was installed on the rooftop of Idaho Power's corporate headquarters (CHQ) in Boise, Idaho. The 25-kW solar array is still operational, and Idaho Power uses the hourly generation data from the solar array for resource planning.

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

Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. The majority of net metering customers use solar PV systems. As of June 1, 2013, there were 287 solar PV systems interconnected through the company's net metering service with a total capacity of 1.896 MW. At that time, the company had received completed applications for an additional 15 net metered solar PV systems representing an incremental capacity of 0.13 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.4.

Table 3.4 Net metering service customer count and generation capacity as of June 1, 2013

	Number of Customers			Generation Capacity (MW)		
Resource Type	**Active**	**Pending**	**Total**	**Active**	**Pending**	**Total**
Solar PV	287	15	**302**	1.896	0.130	**2.026**
Wind	71	3	**74**	0.577	0.010	**0.587**
Other/hydroelectric	10	0	**10**	0.147	0.000	**0.147**
Total	**368**	**18**	**386**	**2.620**	**0.140**	**2.760**

Oregon Solar Photovoltaic Pilot Program

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

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to customers in Oregon. Under the pilot program, Idaho Power will acquire up to 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW were allocated, and the remaining 200 kW were offered during an enrollment period in October 2011. However, because some PV systems were not completed from the last enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

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

Power Purchase Agreements

Elkhorn Valley Wind Project

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

Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. The Raft River geothermal project has not exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is not currently receiving RECs from the Raft River geothermal project. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of all RECs generated by the project.

Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project.

The Neal Hot Springs Geothermal 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 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Public Utility Regulatory Policies Act

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

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2013 IRP was completed in August 2012.

As of March 31, 2013, Idaho Power had 105 PURPA contracts with independent developers for approximately 789 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power projects. Of the 105 contracts, 103 were on-line as of March 31, 2013, with a cumulative nameplate rating of approximately 783 MW. Figure 3.6 shows the percentage of the total PURPA capacity of each resource type under contract.

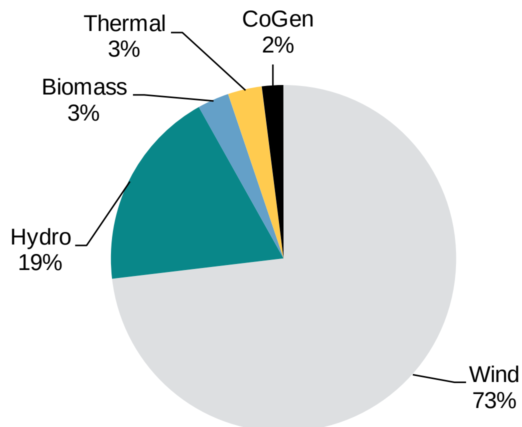


Figure 3.6 PURPA contracts by resource type

Published Avoided Cost Rates

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

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04, GNR-E-11-01, and GNR-E-11-03). The main issues in the cases included the disaggregation of larger, utility-scale projects to qualify for the published avoided cost rate and the methods used to calculate the published rate.

On December 18, 2012, the IPUC issued Order No. 32697. Order No. 32697 included new rules and regulations in regard to the numerous PURPA issues presented in the various cases that began in November 2010. Some highlights are as follows:

- The published avoided cost rate is available only for wind and solar projects with a nameplate rating of less than 100 kW.
- For all other resource types, the eligibility cap will remain at 10 aMW.
- Idaho Power's proposed incremental cost IRP method was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A different published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project retains the RECs associated with the project for QF contracts containing published avoided costs.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that are negotiated agreements.

On May 6, 2013, the IPUC issued Order No. 32802 concerning the reconsideration of Case No. GNR-E-11-03. Order No. 32802 affirms many of the commission rulings in Order No. 32697. PURPA contracting continues to be an issue in Idaho, and approximately 200 MW of various QF projects currently have some form of a filed dispute in regards to PURPA contracts with Idaho Power.

In April 2012, the OPUC issued Order No. 12-146, which opened OPUC Docket UM 1610. Docket UM 1610 addresses many of the same PURPA issues identified in the recent Idaho PURPA cases as well as unique PURPA issues associated with the Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013.

Wholesale Contracts

The fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative expired in 2011. The 83-MW contract with PPL EnergyPlus, LLC expired in 2012. Idaho Power imported the energy from PPL EnergyPlus using the Jefferson line, and Idaho Power continues to explore opportunities to use transfer capacity on the Jefferson line.

Idaho Power presently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts). The Elkhorn, Raft River Geothermal, Neal Hot Springs, and Clatskanie Exchange contracts were described previously in the Power Purchase Agreements section of this IRP.

Market Purchases and Sales

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

Committed Supply-Side Resources

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

Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric Project (Shoshone Falls project0 from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single 50-MW unit that will result in a net upgrade of 49 MW.

In July 2010, FERC issued a license amendment for the project. The license amendment allows two years to begin construction and five years to complete the project. The company requested and received a two-year extension from FERC on May 1, 2012, that requires construction to commence by July 1, 2014. A project team was assembled in 2012 and has started project preparations, including completing a geotechnical investigation and a survey of the construction site. Currently, Idaho Power intends to request an additional two-year extension from FERC regarding the major segments of the expansion project while progressing with the replacement of the existing gated spillway, which will occur during the next two years. Construction of the main expansion project will start in 2016 and finish in 2019.

For the 2013 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in 2019. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median and other projected water conditions, some uncertainty exists regarding future Snake River streamflows that would not only effect the Shoshone Falls project, but also all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls upgrade, it is included in the 2013 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the Idaho. Prior to filing for a Certificate of Public Convenience and Necessity (CPCN) with the IPUC, Idaho Power plans to update the economic analysis of the Shoshone Falls upgrade, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

4. Demand-Side Resources

DSM programs are an essential component of Idaho Power's resource strategy, and its portfolio of programs consists of demand response and energy efficiency programs.

Interior view of the Micron Center for Professional Technical Education at the College of Western Idaho. Energy efficiency upgrades were made using incentives from Idaho Power's Building Efficiency program.

Demand response targets decreasing peak loads through either customer behavior or automations that respond during periods of extreme loads when all other resources, including market purchases, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side baseload resources. Energy efficiency, demand response, and energy efficiency education programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations and funded Northwest Energy Efficiency Alliance (NEEA) market transformation activities since 1997. Due to the indirect nature of savings from market transformation, NEEA effects are not forecasted or accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs of offering them, are published annually. The most recent analysis can be found in the *Demand-Side Management 2012 Annual Report Supplement 1: Cost Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their potential effect over the 20-year IRP planning horizon as part of the IRP process. For the 2013 IRP process, Idaho Power engaged in a comprehensive energy efficiency potential study that also analyzed potential energy-saving opportunities not currently offered as part of its portfolio of programs. The forecast of energy savings was developed from the potential study. The resulting forecast and program history were analyzed against the load forecast process to better understand the energy efficiency opportunities not accounted for in the load forecast.

Demand response was treated as a resource option during the 2013 IRP portfolio selection process. The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. Idaho Power's demand response programs have been available to meet that need. However, an analysis done for the 2013 IRP indicates no peak-hour shortages until 2016.

The anticipated lack of peak-hour capacity deficits from 2013 to 2015 is primarily due to a slower-than-expected economic recovery, causing slower customer growth than previously forecasted, as well as two previously anticipated large-load customers that did not materialize. Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program.

Cost-effectiveness analyses of DSM forecasts for the 2013 IRP are presented in more detail in the *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2012 Annual Report* contains a detailed description of Idaho Power's 2012 energy efficiency program portfolio along with historical program performance (appendices B and C are filed as part of this IRP). A complete review of the energy efficiency potential study and report can be found in the 2012 annual report filing supplement, *Demand-Side Management 2012 Annual Report Supplement 2: Evaluation*, which is available on the Idaho Power website at:

http://www.idahopower.com/EnergyEfficiency/reports.cfm

DSM Program Performance

While the IRP planning process primarily looks forward, it also important to review the past DSM investments to understand their effects on system sales and loads. Accumulated annual savings from energy efficiency investments grow over time as loads decrease based on measure lives of the more efficient equipment and measures adopted and maintained by customers each year. Additionally, past performance of demand response programs provides a good indication of future potential for reducing peak summer loads and affecting IRP resource portfolios.

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in an annual load reduction of over 111 aMW or over 960,000 MWh of reduced supply-side energy production to customers through 2012. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 11-year period from 2002 through 2012. Over two-thirds (67%) of savings since 2002 from energy efficiency have come from programs available to commercial and industrial customers, with the other third of savings coming from residential and irrigation customer programs.

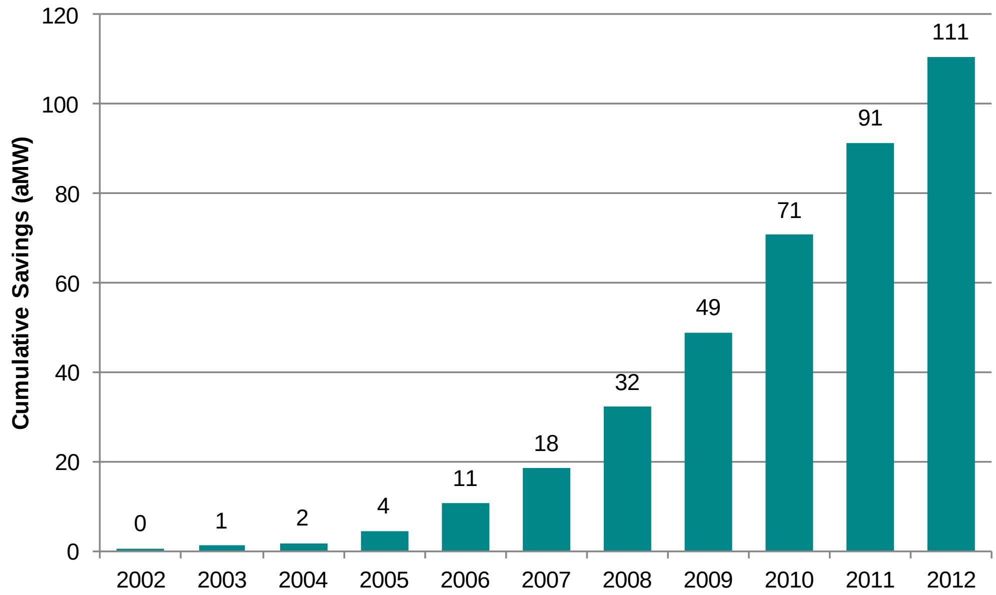


Figure 4.1 Cumulative energy efficiency savings, 2002–2012 (aMW)

Energy efficiency has proven a reliable, low-cost resource for Idaho Power, as the annual performance targets set for resource planning as part of IRPs from 2004 to 2011 have consistently been met or exceeded. Figure 4.2 shows the annual or incremental savings from energy efficiency and its associated planning targets starting with the 2004 IRP, when DSM programs were first fully implemented in the IRP process.

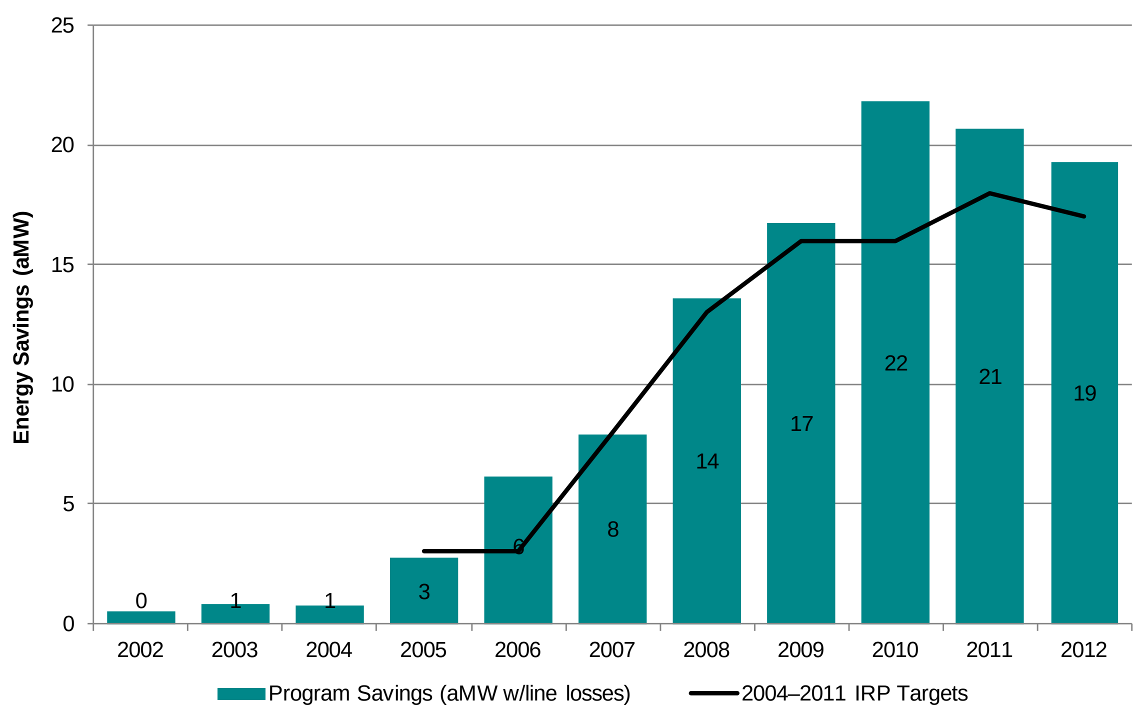


Figure 4.2 Annual energy efficiency savings and IRP targets, 2002–2012 (aMW)

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP and have provided a low-cost capacity resource. Three distinct programs, each targeting different customer classes, have made up the demand response portfolio:

- *A/C Cool Credit*—The A/C Cool Credit program cycles residential air conditioners on and off. A/C Cool Credit has provided 11 percent of the demand response portfolio, or an average of 37 MW, since 2009.

- *Irrigation Peak Rewards*—Irrigation Peak Rewards is a direct load-control program allowing irrigation pumps to be turned off during called events. Irrigation Peak Rewards contributes the largest load reduction, with 76 percent of demand response capacity, or an average of 268 MW.

- *FlexPeak Management*—Commercial and industrial customers can participate in the FlexPeak Management program, where customers commit to reduce demand at their facilities during called events. The FlexPeak Management program has averaged 45 MW of program capacity, or 12 percent of demand response reduction potential, since 2009.

Figure 4.3 shows the annual demand response program capacity between 2004 and 2012. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards program to a dispatch program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity from the Irrigation Peak Rewards program, respectively, which was not used based on the lack of need and the cost to dispatch.

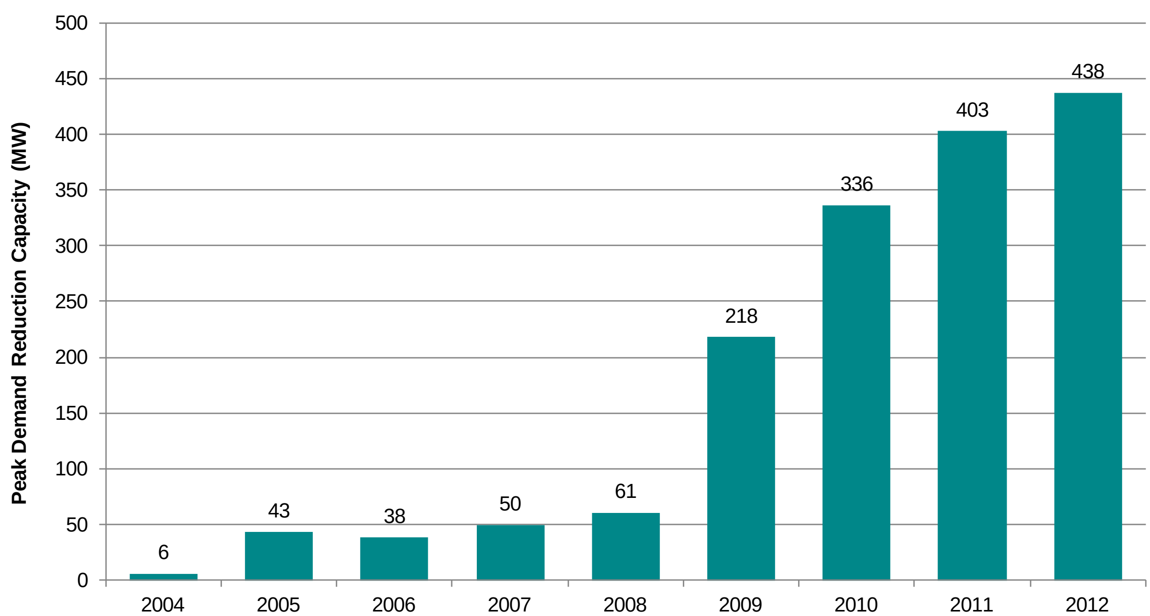


Figure 4.3 Demand response peak reduction capacity, 2004–2012 (MW)

Demand response programs have been a low-cost and reliable capacity resource for helping meet extreme summer peak loads. Programs have traditionally cost between $35 and $50/kW over a 20-year horizon to build, maintain, and manage—less than the cost of other peak capacity resources available for meeting capacity deficits. Figure 4.4 shows the annual program reduction capacity along with the committed demand reductions for the 2004 to 2011 IRPs.

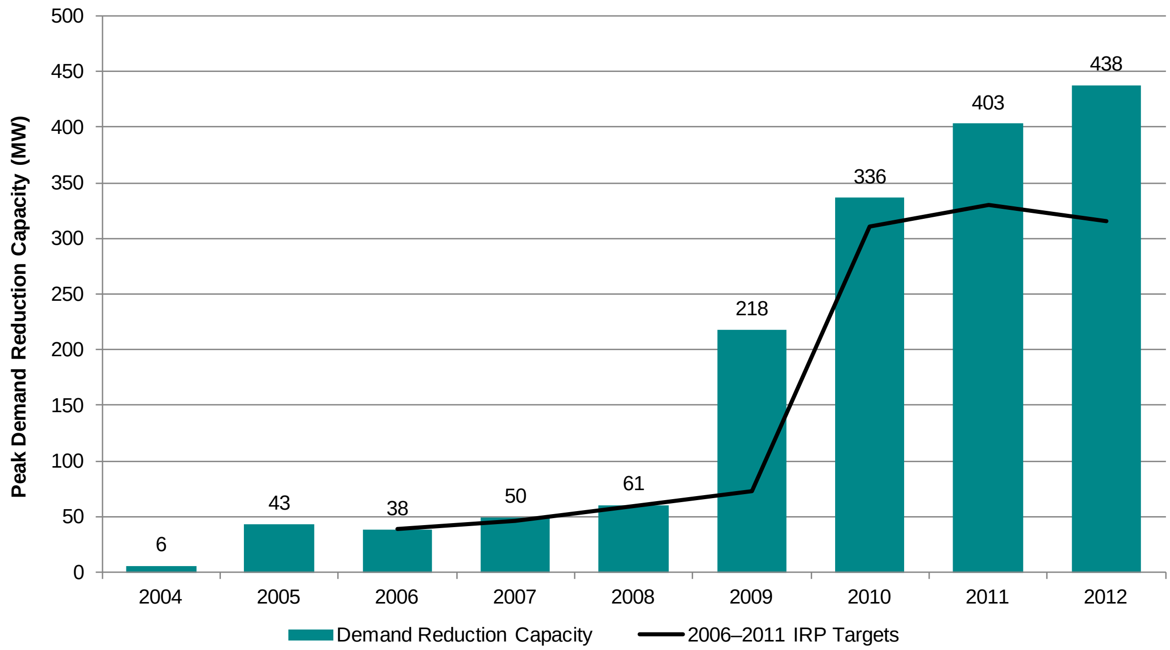


Figure 4.4 Demand response peak reduction capacity with IRP targets, 2004–2012 (MW)

New Energy Efficiency Resources

For the 2013 IRP, EnerNOC, Inc., was retained to develop a 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the potential study were as follows:

- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 21 years (2012–2032) within the Idaho Power service area.
- Assess potential energy savings associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide an executable dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Review and update load profiles by sector, program, and end use.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2012 through 2032.

Because the market characterization process bundles industries and building types into homogenous groupings, special contract customers were treated outside of the potential study model. Forecasts for these unique customers, who tend to be very active in efficiency, were based on the individual customer's efficiency goals and prior history of participation along with projects that are known and projected to occur in the future.

There were three levels of potential considered as part of the study:

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every available other measure, where applicable. The retrofit measures are phased in over a number of years, which is greater for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the TRC test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market adoption factors to the economic potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The potential study followed a typical approach in developing the achievable potential. First, the market was characterized by customer class. The classification phase included segmenting the market by housing type for residential and understanding the various industries and building types within the commercial and industrial customer classes. Saturations of end-use technologies within customer segments are assessed to help determine which technologies are available for efficient upgrades. The next step was screening measures and technologies for cost-effectiveness, then assessing the adoption rates of technologies to determine the forecast of achievable potential. More detailed information about cost-effectiveness methodologies and approaches can be found in *Appendix C—Technical Appendix*.

The annual savings potential forecast is measured in MWh, but to convert the savings to average annual or monthly demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are divided by either 8,760 hours (hours in a year) or a corresponding number of monthly hours subject to a load shape. All forecasts are prepared in terms of generation equivalency and therefore include line losses of 10.9 percent that account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the customer.

Table 4.1 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2013 to 2032 in five-year blocks, in terms of average demand reduction (aMW) by customer class. In 2017, the forecast reduction for 2013-to-2017 programs will be 69 aMW; by the year 2022, the reduction across all customer classes increases to 129 aMW. By the end of the IRP planning horizon in 2032, 261 aMW of reduction are forecast to come from the energy efficiency portfolio, with 60 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C—Technical Appendix*.

Table 4.1 Total energy efficiency current portfolio forecasted effects (2013–2032) (aMW)

	2017	2022	2027	2032
Industrial/Commercial	45	86	125	157
Residential	18	30	50	76
Irrigation	6	13	21	28
Total	**69**	**129**	**196**	**261**

Table 4.2 shows the cost-effectiveness summary from the potential study. The table shows the net present value (NPV) analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficiency technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing resources, the 2011 IRP preferred portfolio of generation resources, and the 2013 IRP natural gas price forecast and carbon-adder assumptions.

Table 4.2 Total energy efficiency portfolio cost-effectiveness summary

	2032 Load Reduction (aMW)	Resource Costs (20-Year NPV)	Alternate Energy Benefits (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs ($/kWh)
Industrial/Commercial	157	$188,245,928	$467,521,430	2.5	0.028
Residential	76	$123,886,346	$190,935,664	1.5	0.046
Irrigation	28	$52,623,496	$76,220,052	1.4	0.049
Total	**261**	**$364,755,770**	**$734,677,146**	**2.0**	**0.035**

The value of avoided energy over the 20-year investment in the energy efficiency measures was twice the TRC when comparing benefits and costs resulting in an overall benefit to cost ratio of 2. The levelized cost to reduce energy demand by 261 aMW is 43.5 cents per kWh from a TRC perspective. Figure 5.7 in Chapter 5 compares the energy costs of the energy efficiency programs with the other supply-side resource options.

Once the energy efficiency forecast is complete, the forecasted energy efficiency is included in the IRP planning horizon and the load and resource balance analysis. Planning assumptions in the energy efficiency potential forecast include new programs, technology, known codes and standards changes, customer adoption behavior, and cost-effectiveness that are explicitly incorporated into the potential study and reflect differences between the energy efficiency forecast and the amount of efficiency accounted for in the load forecast. A key difference between the two views of efficiency is that the load forecast accounts for energy efficiency effects based on previous years' program performance while the forecast from the potential study is more prospective in its approach. The amount of energy efficiency not captured by the load forecast is accounted for in the load and resource balance analysis.

Table 4.3 shows the new energy efficiency potential portion of the total energy efficiency forecast included in the load and resource balance. In 2017, the incremental energy efficiency savings will reduce energy loads by 38 aMW; in 2022, average loads will be reduced by 76 aMW. The full 20-year capacity of the program additions and changes is 188 aMW of average-energy reduction.

Table 4.3 New energy efficiency resources (2017–2032) (aMW)

	2017	2022	2027	2032
Industrial/Commercial	30	59	90	116
Residential	4	9	26	51
Irrigation	4	8	15	21
Total	**38**	**76**	**131**	**188**

Demand Response Resources

In fall 2012, the company's IRP analysis demonstrated no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. The most recent analysis from the 2013 IRP indicates no peak-hour shortages until mid-2016. Based on the results of this analysis, Idaho Power requested and received approval from the IPUC and OPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013 and can provide approximately 35 MW of peak load reduction within the parameters of the program. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.

Typical irrigation pivot supplied by a pump participating in the Irrigation Peak Rewards demand response program.

In the preferred 2013 IRP portfolio, demand response is used to satisfy temporary deficits from 2016 to 2018 prior to the build out of Northwest transmission. Demand response from 2016 to 2017 would be built out to 150 MW capacity, then it would be built up to 370 MW to meet the deficits from 2024 through the end of the planning period.

Conservation Voltage Reduction

Conservation voltage reduction (CVR) regulates the feeder voltage within the lower half of the standard operation range. In acknowledging the 2011 IRP, the OPUC directed Idaho Power to assess available cost-effective CVR resource potential and propose a course of action. The OPUC also requested Idaho Power incorporate the energy savings and reduced peak demand from the CVR program in the load and resource balance forecast.

Idaho Power considers it prudent to validate the benefit of the CVR program before expanding it beyond the initial study area. New technologies and methods of measurement are available to validate energy savings and reduced peak demand. Idaho Power intends to analyze the CVR effects at two of the six substations—the Alameda and Meridian substations—where CVR has been implemented.

Idaho Power expects to complete the CVR analysis in 2016. If the analysis confirms energy savings and reduced peak demand, Idaho Power will evaluate extending CVR measures to other Idaho Power facilities.

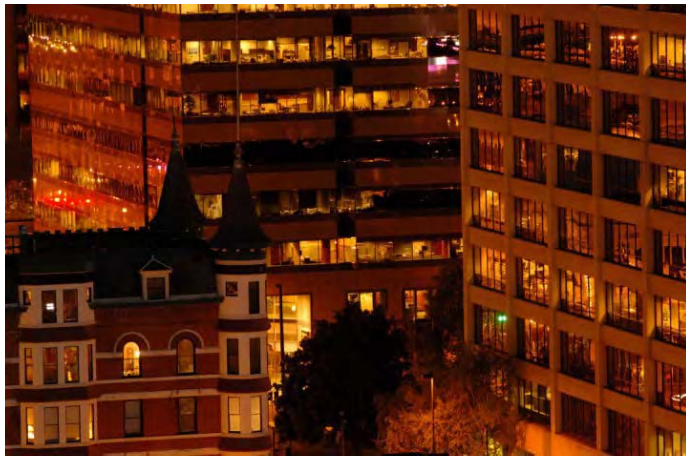
The actual savings from the current CVR implementation are not significant enough to be incorporated into the IRP load and resource balance forecast.

This page left blank intentionally.

5. Planning Period Forecasts

The IRP process requires Idaho Power to prepare numerous forecasts that can be grouped into four main categories:

1. Load forecasts
2. Generation forecasts
3. Fuel price forecasts
4. Financial assumptions



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

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2013 IRP.

Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning (A/C) in the months of June, July, and August. For a number of years, the growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. However, both measures are important in planning future resources and are part of the load forecast prepared for the 2013 IRP.

The expected case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not precisely follow the path suggested by the expected case forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with abnormal weather. The 70th-percentile and 90th-percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced the 2013 IRP load forecast results. The national, state, metropolitan statistical area (MSA) and county economic projections are tailored to Idaho Power's service area using an in-house economic database. 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

2013 IRP load forecast. The forecasts of households, population, employment, output, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

Weather Effects

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50-percent chance 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 the load will be greater than the forecast.

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

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal time horizon. Over the longer-term horizon, economic and demographic conditions influence the load forecast.

Economic Effects

The national recession that began in 2008 affected the local economy and energy use in the Idaho Power service area. The severity of the recession resulted in a significant decline in new customers. Idaho Power added less than 2,500 new residential customers in 2011. Recently, the number of new residential customers added each year has increased to approximately 4,000.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by 0.9 percent in 2010 and a slight decline in 2011. The 2009 through 2011 time period was the first time overall energy use had declined since the energy crisis of 2001. In 2012, system electricity sales increased by 1.8 percent over 2011. The 2012 sales increase was due to economic recovery in the service area and higher irrigation sales.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period, and the population increase is included in the load forecast models. Idaho Power also continues to receive requests from prospective large-load customers attracted to southern Idaho due to the positive business climate and 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 1.1 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 applying Idaho Power's share to county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with an expected declining consumption per household, results in a 1.1-percent average residential load-growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.5 percent annually from 416,000 at the end of 2012 to nearly 555,000 by the end of the planning period in 2032.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*. For example, the expected annual average system load growth of 1.1 percent (over the period 2013 through 2032) is comprised of a residential load growth of 1.1 percent, a commercial load growth of 1.1 percent, an irrigation load growth of 0 percent, an industrial load growth of 1.7 percent, and an additional firm load growth of 1.2 percent.

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery in the economic forecast used in the 2011 IRP was too optimistic, particularly in the near term. The updated economic forecast variables used as drivers in the 2013 IRP forecast reflect a lower near-term recovery relative to the 2011 IRP economic forecast drivers but are nonetheless conveying sustained and increased economic recovery. The stalled recovery in the national- and service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series. Longer term, the effect of economic recovery is tempered in the forecast by higher retail electricity price assumptions that incorporate estimates of assumed carbon legislation, which decreases the average load forecast. The decrease is especially evident in the second 10 years of the forecast period.

Additional significant factors that put downward pressure on load growth relative to the 2011 IRP forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected.

For the 2013 IRP, Idaho Power has assumed this “Special” contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from the sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power’s service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power’s service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. 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*.

- The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

Peak-Hour Load Forecast

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts. Idaho Power uses the 95th-percentile forecast as the basis for peak-hour planning in the IRP. The 95th-percentile forecast is based on the 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,245 MW—was recorded on July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on June 30, 2008, at 3:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011, the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also had a significant effect on reducing peak demand. The 2013 IRP load forecast projects peak-hour load to grow by approximately 55 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 as a supply-side resource.

Figure 5.1 and Table 5.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th-percentile, and 95th-percentile weather effects on the expected (median) peak forecast. The 95th-percentile forecast uses the 95th-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity.

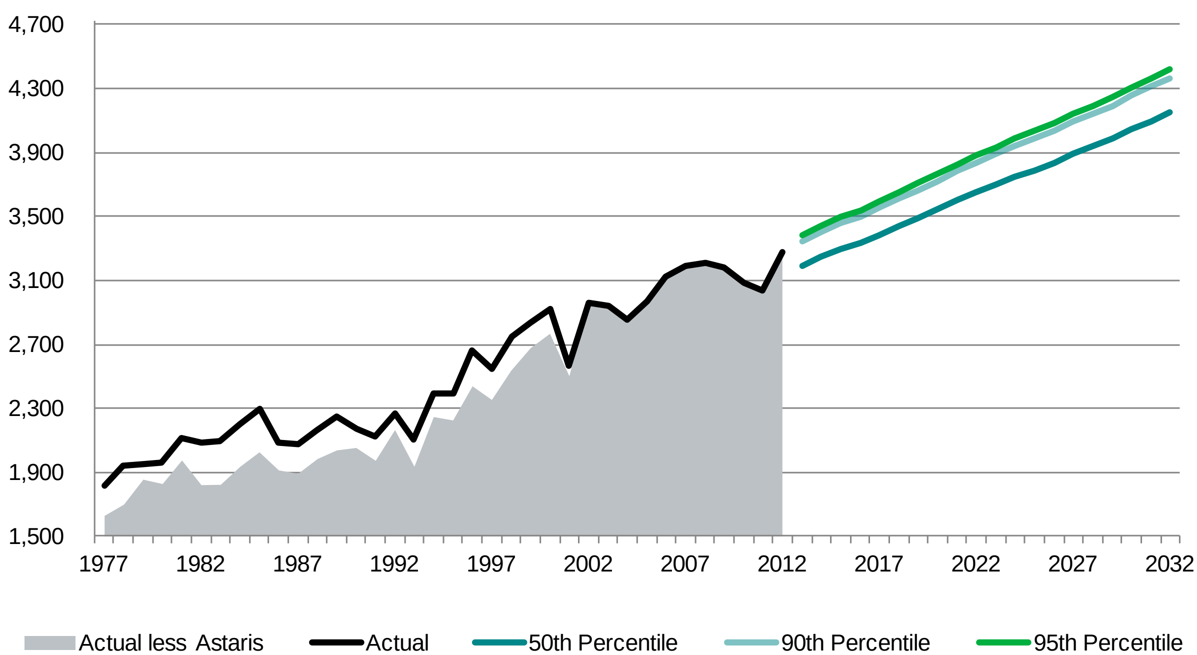


Figure 5.1 Peak-hour load-growth forecast (MW)

Table 5.1 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2012 (Actual)	3,245	3,245	3,245
2013	3,189	3,344	3,382
2014	3,245	3,403	3,442
2015	3,294	3,456	3,495
2016	3,335	3,500	3,541
2017	3,387	3,555	3,596
2018	3,437	3,609	3,651
2019	3,489	3,664	3,707
2020	3,544	3,722	3,766
2021	3,601	3,782	3,827
2022	3,651	3,835	3,881
2023	3,701	3,889	3,935
2024	3,748	3,939	3,987
2025	3,790	3,985	4,033
2026	3,836	4,034	4,083
2027	3,888	4,090	4,139
2028	3,936	4,141	4,191
2029	3,984	4,192	4,244
2030	4,045	4,256	4,308
2031	4,097	4,312	4,365
2032	4,147	4,365	4,418
Growth rate (2013–2032)	**1.4%**	**1.4%**	**1.4%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,189 MW in 2013 to 4,147 MW in 2032—an average annual compound growth rate of 1.4 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.4 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on 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 peak-day temperature variability 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 two load forecasts that reflect load uncertainty resulting from differing weather-related assumptions. Figure 5.2 and Table 5.2 show the results of the two forecasts used in the 2013 IRP reported as annual system load growth over the planning period. There is approximately a 50-percent probability Idaho Power's load growth will exceed the expected-case forecast and a 30-percent probability of load growth exceeding the 70th-percentile forecast. The projected 20-year average annual compound growth rate in the expected load forecast is 1.1 percent.

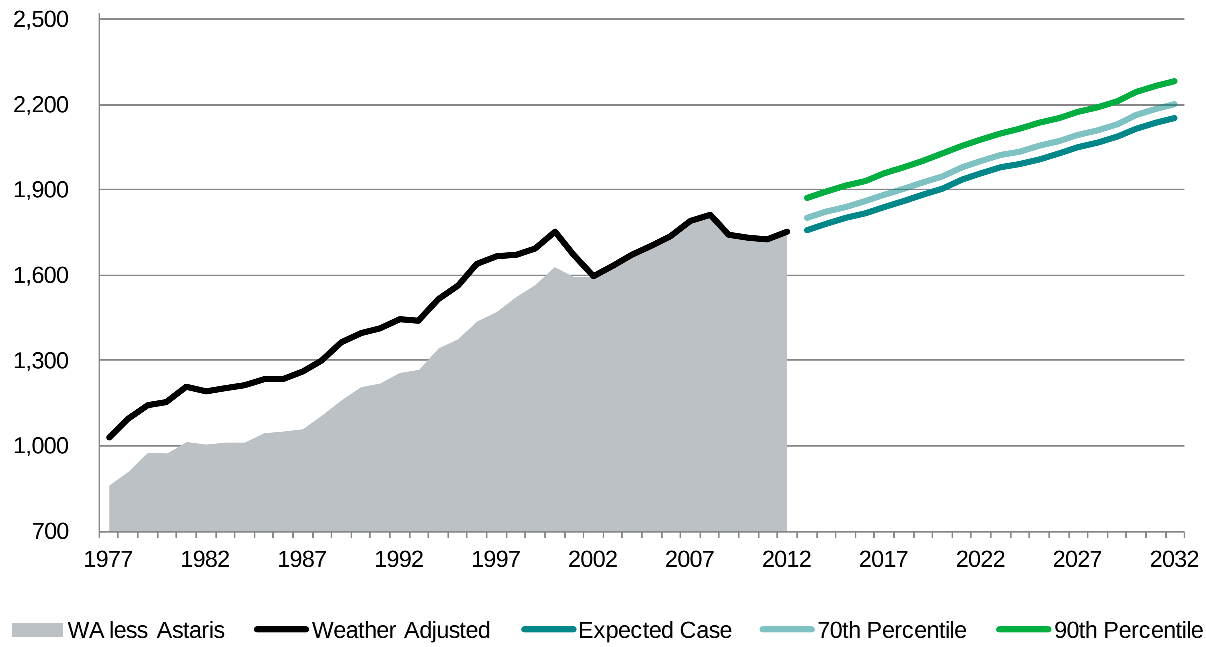


Figure 5.2 Average monthly load-growth forecast (aMW)

Table 5.2 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2013	1,759	1,800	1,872
2014	1,782	1,823	1,895
2015	1,800	1,841	1,914
2016	1,818	1,859	1,933
2017	1,842	1,884	1,959
2018	1,862	1,904	1,980
2019	1,883	1,926	2,002
2020	1,906	1,949	2,026
2021	1,934	1,977	2,055
2022	1,956	2,000	2,078
2023	1,977	2,021	2,100
2024	1,992	2,036	2,116
2025	2,009	2,054	2,134
2026	2,028	2,073	2,153
2027	2,049	2,094	2,176
2028	2,065	2,110	2,192
2029	2,087	2,132	2,214
2030	2,116	2,162	2,244
2031	2,137	2,183	2,265
2032	2,154	2,201	2,284
Growth rate (2013–2032)	**1.1%**	**1.1%**	**1.1%**

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

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), and Hoku Materials. The special-contract customers are described briefly as follows.

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance (Q/A), systems integration, and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly in 2013 and 2014, then stay flat throughout the remainder of the planning period.

Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated have not been included in this sales and load forecast.

"Special" Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm-load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared in August 2010, several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined at that time there was a real possibility of the new large load materializing. However, no customer signed a contract. The IPUC and OPUC directed Idaho Power not to include new large-load customers in the forecast until a contract is signed. Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are not included in the 2013 IRP sales and load forecast.

Existing Resources

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

Brownlee Dam is part of the HCC.

Hydroelectric Resources

For the 2013 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 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 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 50^{th}-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50^{th}-, 70^{th}-, and 90^{th}-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2013 IRP is included in *Appendix C—Technical Appendix*.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70^{th}-percentile year in 2010 is identical to a 70^{th}-percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the Eastern Snake River Plain Aquifer (ESPA) is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA Comprehensive Aquifer Management Plan (CAMP) includes demand reduction and weather-modification measures that will add new water to the basin water budget. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years are expected to continue and result in a return to declining basin outflows assumed to persist well into the 2020s. The declining basin outflows for this IRP are assumed to continue through 2027, when Swan Falls flows of the 90^{th}-percentile forecast drop to the irrigation season minimum of 3,900 cfs. Idaho Power assumes the decline of flows to the Swan Falls minimum would cause the State of Idaho to take remedial action to prevent further decline. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on trends in Snake River Basin hydrologic conditions as a standard part of forecasting hydroelectric generation for future IRPs.

The Snake River canyon above Swan Falls.

A water-management practice affecting Snake River streamflows involves the release of water to augment flows during salmon outmigration. Various federal agencies involved in salmon migration studies have, in recent years, supported efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years. During 2013—a year with markedly worse-than-median water conditions—flow augmentation water from the Upper Snake River and Boise River basins was delivered during May.

Because worse-than-median water is assumed in the IRP, and because of the importance of July as a resource-constrained month, Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2013 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. 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 HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 5.3 shows historical April-to-July Brownlee inflow as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability but do include reductions related to declining base flows in the Snake River. As noted previously in this section, these declines are assumed to equilibrate beyond 2027.

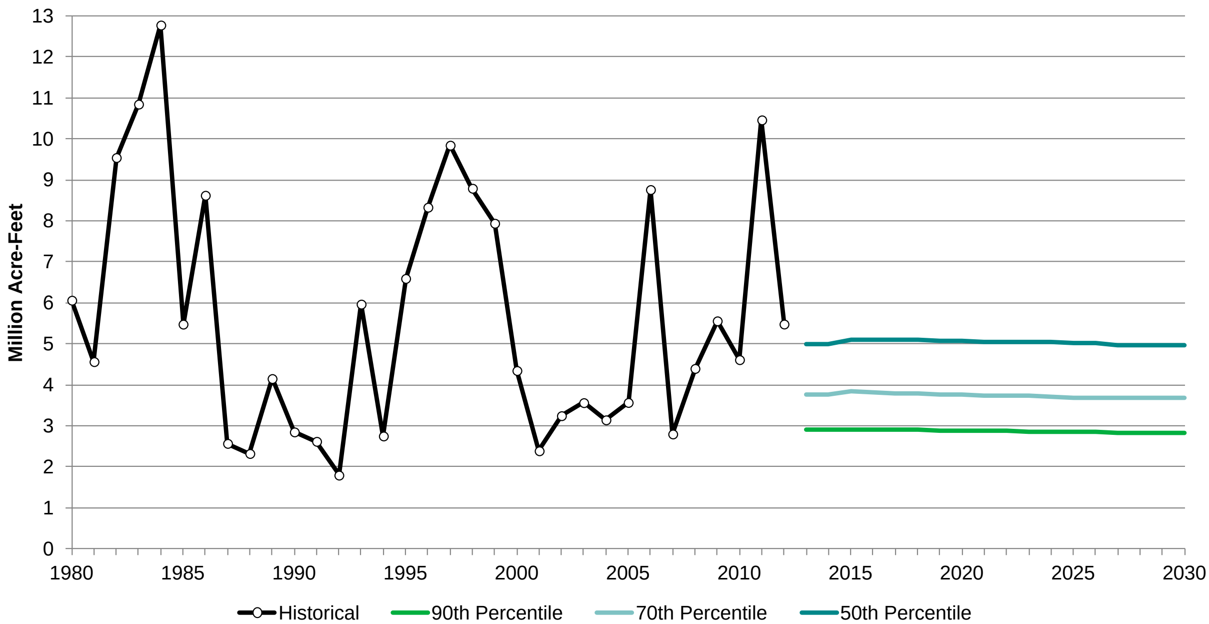


Figure 5.3 Brownlee historical and forecast inflows

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes 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 2013 IRP. A discussion of climate change, including expectations of possible effects on the Snake River water supply, is included in the *Appendix C—Technical Appendix*.

Coal Resources

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

Plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Boardman plant in 2014 and 2018, the North Valmy plant in 2015, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The EPA signed the proposed requirements and deadlines for the installation of pollution-control equipment for compliance with RH BART at the Jim Bridger plant on May 23, 2013. The EPA is planning to sign a notice of final rulemaking for RH BART for the Jim Bridger plant on November 21, 2013. The total generation loss for the air-quality modifications at all three plants is less than 1 percent.

The 2013 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The assumed date is the result of an agreement reached between the ODEQ and PGE related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. The EPA formally approved the agreement, and the agreement was published in the Federal Register on July 5, 2011.

Idaho Power prepared the coal study as part of the 2011 IRP Update. The report was filed with the IPUC and OPUC in February 2013.

Planned Upgrades at Jim Bridger

In addition to the selective catalytic reduction (SCR) emission-control upgrade mentioned previously, turbine upgrades are continuing at the Jim Bridger plant, and the replacement of the high-pressure/intermediate-pressure and low-pressure turbines on Unit 2 were completed in spring 2013. Upgrades of the high-pressure/intermediate-pressure and low-pressure turbines on Units 3 and 4 and upgrades to the low-pressure turbines on the remaining units are currently being evaluated.

Natural Gas Resources

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

Idaho Power's CCCT, Langley Gulch, became commercially available in June 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. Langley Gulch is forecast to contribute approximately 165 aMW with an on-demand peaking capacity of 318 MW in the 2013 IRP.

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 a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having a sufficient generating reserve capacity to meet daily operating reserve requirements.

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

Average Monthly Energy Planning

Average-energy surpluses and deficits are determined using 70th-percentile water and 70th-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using a reserved network capacity. Figure 5.4 shows the monthly average-energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 5.4 also include the forecast effect of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade when it is available. Figure 5.4 illustrates there are no energy deficits through the planning period.

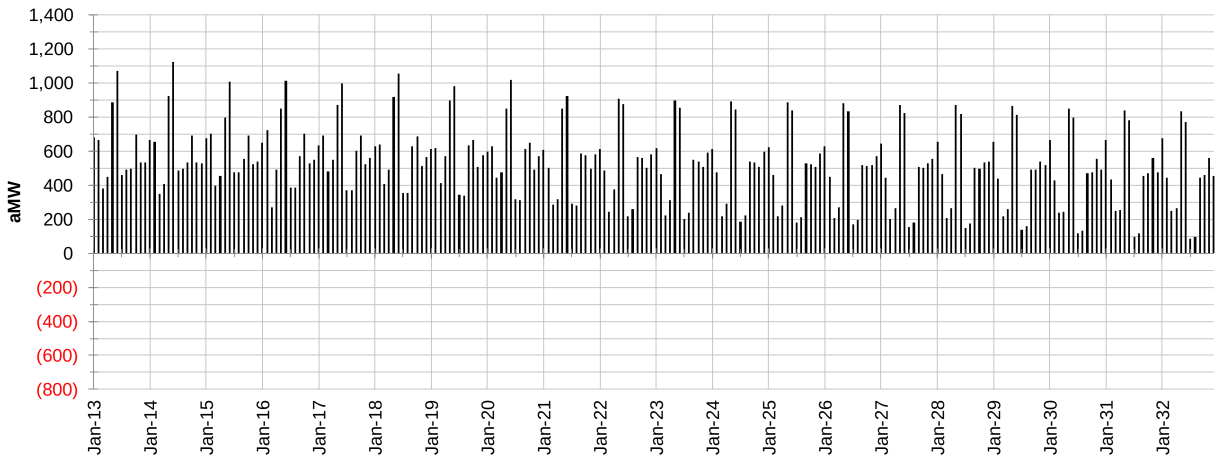


Figure 5.4 Monthly average-energy surpluses and deficits with existing and committed resources and existing DSM (70th-percentile water and 70th-percentile load)

Energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy. Peak-hour capacity continues to be the resource need in the 2013 IRP.

Peak-Hour Planning

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

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

At times of peak summer load, Idaho Power is using all available transmission capacity (ATC) from the Pacific Northwest. If Idaho Power was 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 was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Figure 5.5 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 5.5 also include the forecast effect of existing energy efficiency programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including the Shoshone Falls upgrade once it is available. Idaho Power assumes the existing PURPA projects will continue to deliver energy throughout the planning period unless the project developer has notified Idaho Power that the PURPA project intends to cease energy deliveries. Idaho Power assumes the existing PURPA projects will develop new contracts consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. The import capacity from the Boardman to Hemingway transmission line and the demand reduction due to the demand response programs are not included in Figure 5.5.

The first capacity deficit begins in July 2016, and monthly peak-hour deficit positions grow steadily in magnitude and the number of months affected. By July 2032, these capacity deficits are approximately 870 MW.

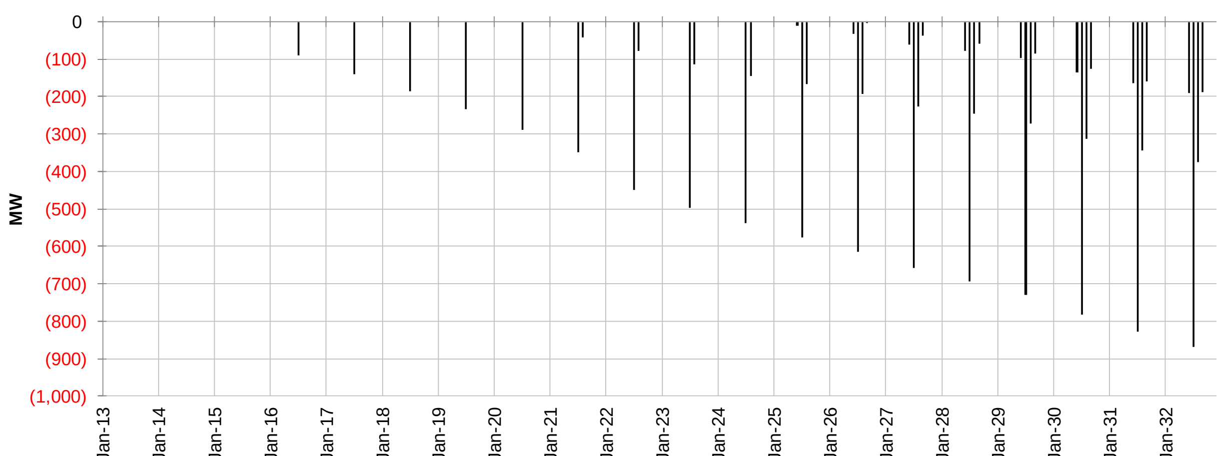


Figure 5.5 Monthly peak-hour deficits without existing and committed resources and existing DSM (90th-percentile water and 95th-percentile load)

Capacity and energy deficits are eliminated by designing portfolios containing new resources analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 5.5 were used to design the portfolios analyzed in the 2013 IRP.

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 IPUC has recently ruled on avoided cost rate methodologies (Case No. GNR-E-11-03, Order No. 32697; December 18, 2012). In the order, the IPUC stated the following (page 16):

> *We further find that, in order to remain flexible and responsive to the fluctuations in gas prices, it is appropriate to annually update the SAR model with the most recent gas forecasts provided by EIA's Annual Energy Outlook.*

Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast for IRP and avoided-cost calculations. The *Annual Energy Outlook 2012* Reference case was published by the EIA in June 2012, and Idaho Power used the *Annual Energy Outlook 2012* forecast for the 2013 IRP. A graph of the forecasted Henry Hub natural gas prices is shown in Figure 5.6. Idaho Power computed a high and low natural gas price forecast by adjusting the EIA natural gas price forecast upward and downward by 30 percent. The high and low forecasts are also shown in Figure 5.6. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city-gate price. The Idaho city-gate price is representative of the gas price delivered to the Idaho Power gas plants.

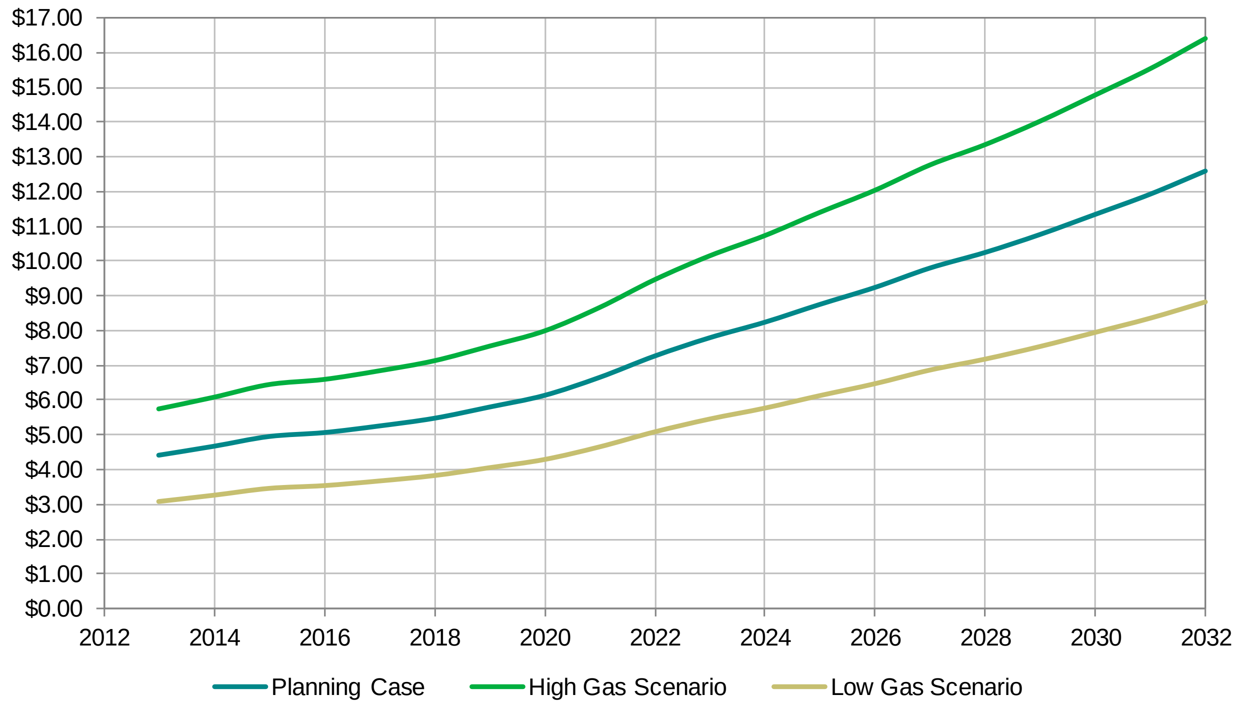


Figure 5.6 Henry Hub Price Forecast—EIA *Annual Energy Outlook 2012* (nominal dollars)

Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2013 IRP. Cost inputs and operating data used to develop the resource cost analysis are primarily derived from NREL's *Cost and Performance Data for Power Generation Report* from February 2012. Idaho Power engineering studies and plant operating experience were also utilized. Resource costs are presented as follows:

- *30-year levelized capacity (fixed) costs*—Levelized fixed cost per kW of installed (nameplate) capacity per month
- *30-year levelized cost of production (at stated capacity factors)*—Total levelized cost per MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

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

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, an annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial effects resulting from the load reduction programs.

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

Emissions Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil-fuel based generating resources are particularly sensitive to certain environmental and social costs. It is likely that additional emissions regulations will be implemented during the period covered in the 2013 IRP.

In the levelized resource cost analysis, Idaho Power incorporated an estimate for the future cost of CO_2 emissions in the overall cost of the various fossil fuel-based resources beginning in 2018. Additional information regarding the cost of carbon emissions is provided in the next section. Table 5.3 provides the emissions intensity rates assumed in the resource cost analysis and the portfolio analysis. Idaho Power assumed that new fossil fuel-based resources will be designed and built to comply with NO_x, Hg, and SO_2 regulations, and therefore emissions adders for these emission types would not be applicable.

In addition to including a CO_2 emissions adder in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for CO_2, NO_x, Hg, and SO_2 emissions for each portfolio in the 20-year planning period. For CO_2 emissions, Idaho Power assumed a CO_2 adder beginning in 2018, which affects the variable operating cost. Instead of assuming NO_x, Hg, and SO_2 emissions adders, the 2013 IRP used the Idaho Power coal study to calculate the variable and fixed environmental compliance costs attributed to each emission type. The Idaho Power coal study also performed various sensitivity analyses on NO_x, Hg, and SO_2 environmental compliance.

Table 5.3 Emissions intensity rates (pound/MWh)

			2013 Emission Rate[1] (pound/MWh)			
Plant	**Nameplate (MW)**	**Fuel**	**CO_2**	**NO_x**	**SO_2**	**Hg**
Bennett Mountain	173	Natural Gas	1,265	0.79	0.006	–
Danskin 1	179	Natural Gas	1,252	0.42	0.006	–
Danskin 2	46	Natural Gas	1,627	1.26	0.008	–
Danskin 3	46	Natural Gas	1,653	1.28	0.008	–
Langley Gulch	318	Natural Gas	799	0.06	0.004	–
Boardman	64	Coal	2,063	2.56	7.923	0.00001
Jim Bridger	771	Coal	2,182	2.03	1.529	0.00004
North Valmy	284	Coal	2,293	3.33	4.518	0.00001
IRP CCCT	300	Natural Gas	799	0.06	0.004	–
IRP SCCT	170	Natural Gas	1,265	0.79	0.006	–

[1] Approximate

Resource Cost Analysis II—Resource Stack

Levelized Capacity (Fixed) Cost

The annual fixed-revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars per kW of plant nameplate capacity per month. Included in these costs are the cost of capital and fixed O&M estimates. Figure 5.7 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 have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours per year to meet peak-hour demand.

Levelized Cost of Production

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

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 5.8. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

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

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

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

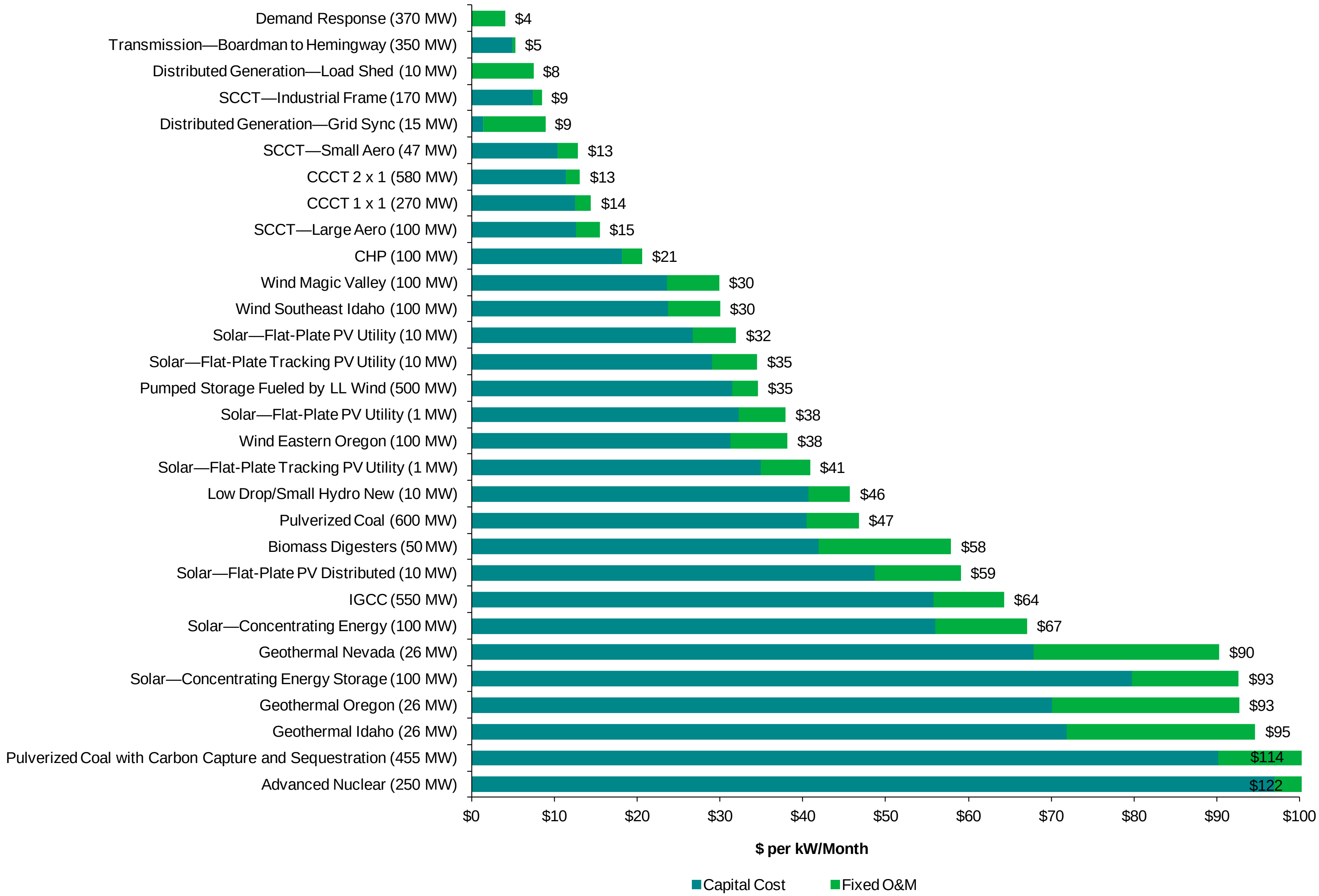


Figure 5.7 30-year levelized capacity (fixed) costs

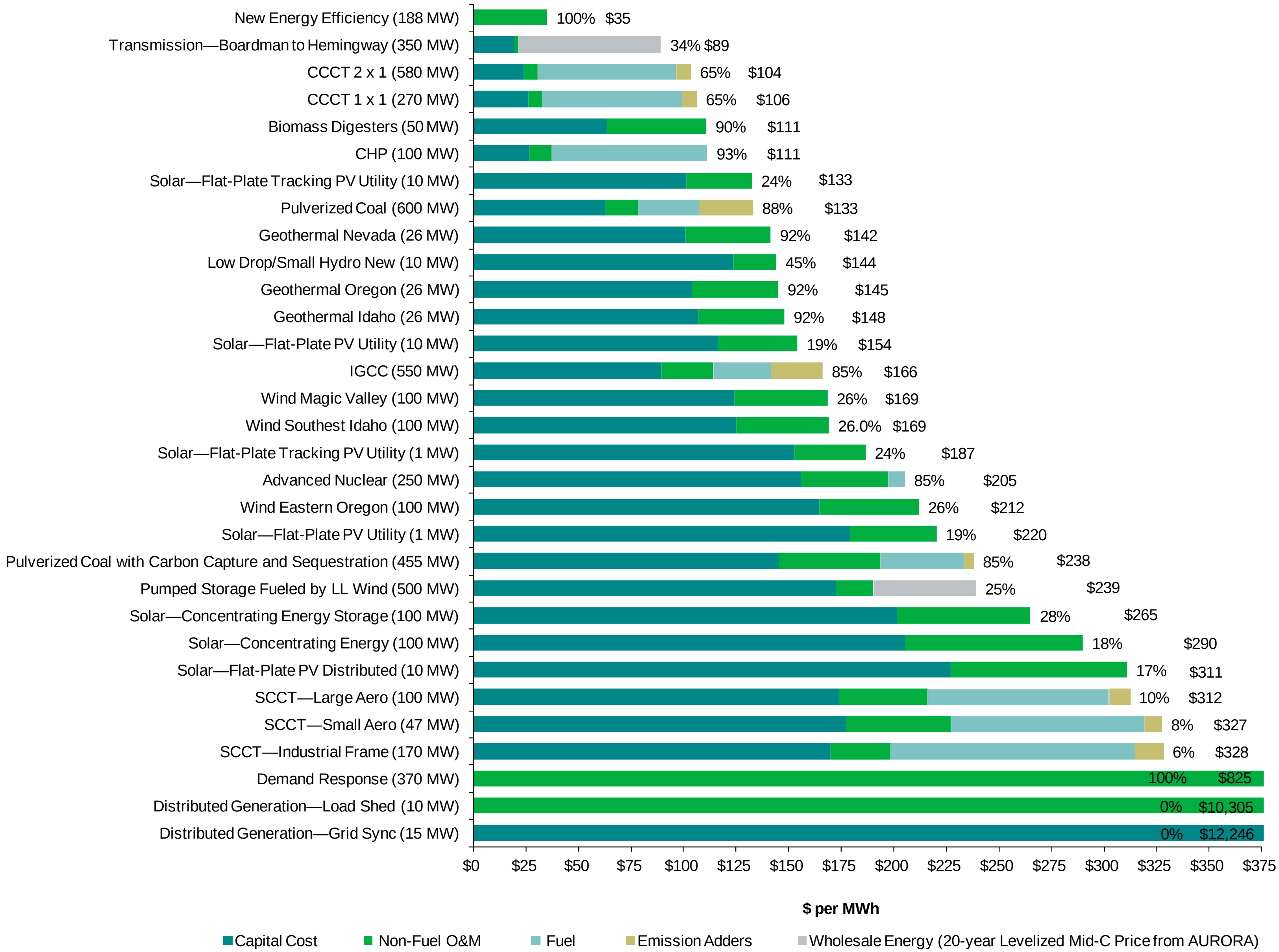


Figure 5.8 30-year levelized cost of production (at stated capacity factors)

Carbon Adder

Regulatory requirements suggest a carbon analysis be performed using a carbon adder or carbon tax. Idaho Power applied a carbon adder in the 2013 IRP. The purpose of a carbon adder is to estimate the carbon costs in the price of energy produced by carbon-emitting resources.

Three carbon-adder scenarios were analyzed as part of the 2013 IRP (in nominal dollars):

1. *Planning case*—The planning case starting at $14.64 per ton in 2018 and escalating at 3 percent annually
2. *High carbon*—The upper case starting at $35 per ton in 2018 and escalating at 9 percent annually
3. *Low carbon*—The zero-cost case where no future cost is associated with carbon emissions

Idaho Power applies a 3-percent annual escalation rate to change nominal dollars to constant-year dollars. The carbon-adder planning case is selected to be consistent with the $16-per-ton value in 2021 used in the coal study that was part of the Idaho Power 2011 IRP Update filed with the IPUC and OPUC in February 2013.

Idaho Power worked with the IRP Advisory Council to determine the three carbon scenarios. The high scenario is based in part on data from the *2011 Carbon Dioxide Price Forecast* and the *2012 Carbon Dioxide Price Forecast* published by Synapse Energy Economics, Inc., of Cambridge, Massachusetts.

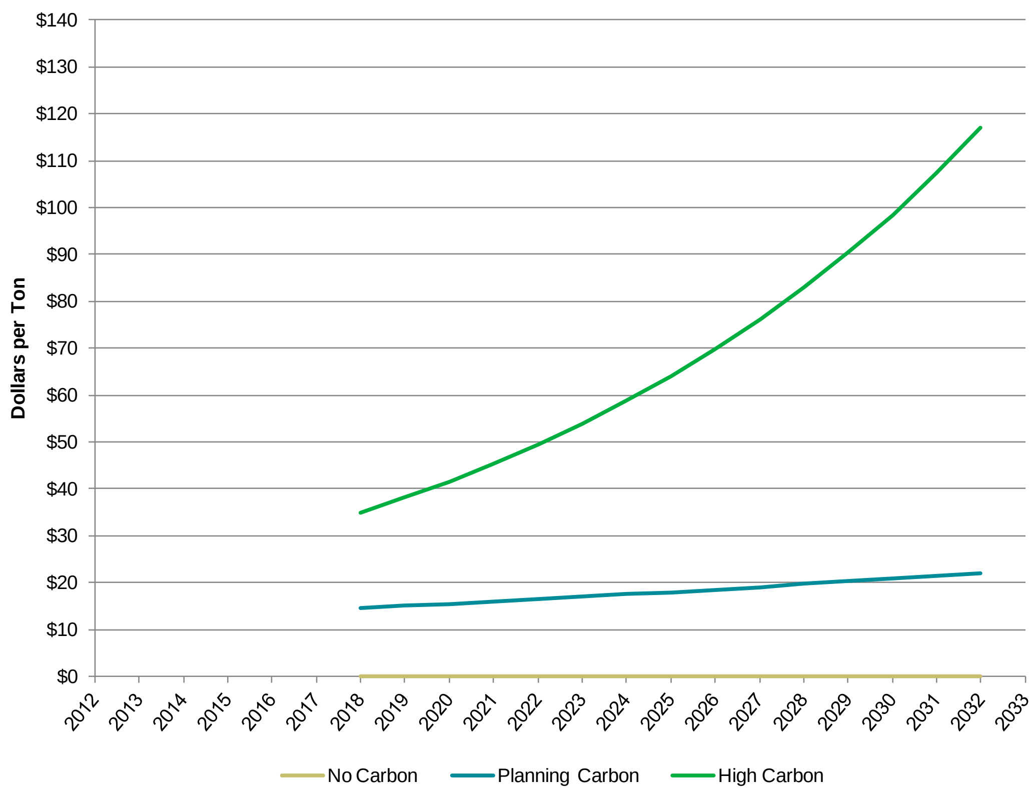


Figure 5.9 2013 IRP carbon adder

Table 5.4 Carbon-adder scenarios

	Nominal Dollars			2012 Dollars		
Year	No Carbon	Planning	Upper	No Carbon	Planning	Upper
2013	–	–	–	–	–	–
2014	–	–	–	–	–	–
2015	–	–	–	–	–	–
2016	–	–	–	–	–	–
2017	–	–	–	–	–	–
2018	$0.00	$14.64	$35.00	$0.00	$12.26	$29.31
2019	$0.00	$15.08	$38.15	$0.00	$12.26	$31.02
2020	$0.00	$15.53	$41.58	$0.00	$12.26	$32.83
2021	$0.00	$16.00	$45.33	$0.00	$12.26	$34.74
2022	$0.00	$16.48	$49.41	$0.00	$12.26	$36.76
2023	$0.00	$16.97	$53.85	$0.00	$12.26	$38.90
2024	$0.00	$17.48	$58.70	$0.00	$12.26	$41.17
2025	$0.00	$18.01	$63.98	$0.00	$12.26	$43.57
2026	$0.00	$18.55	$69.74	$0.00	$12.26	$46.11
2027	$0.00	$19.10	$76.02	$0.00	$12.26	$48.79
2028	$0.00	$19.68	$82.86	$0.00	$12.26	$51.63
2029	$0.00	$20.27	$90.31	$0.00	$12.26	$54.64
2030	$0.00	$20.88	$98.44	$0.00	$12.26	$57.83
2031	$0.00	$21.50	$107.30	$0.00	$12.26	$61.19
2032	$0.00	$22.15	$116.96	$0.00	$12.26	$64.76

Carbon-Adder Generation Dispatch Analysis

Both the 2009 and the 2011 Idaho Power IRPs indicated it would take a large carbon adder before it would be cost effective for Idaho Power to replace high CO_2-emitting resources with new generating resources that emit less CO_2. Assuming Idaho Power has already made prudent long-term resource acquisition decisions, the short-term generation dispatch decisions may vary daily resource use under certain conditions. For example, during times of the year when Idaho Power is not facing peak load and the company does not need the capacity from all generation resources, a relatively small carbon adder may affect resource dispatch decisions. A relatively small carbon adder can affect daily dispatch decisions because short-term operation decisions are primarily based on the variable costs to operate resources, whereas long-term resource acquisition decisions consider both the fixed and variable costs of the resources.

Idaho Power simulated resource dispatch conditions in 2020 as part of the 2013 IRP carbon analysis. Figure 5.10 shows that a carbon adder of approximately $5 per ton can affect the Idaho Power dispatch stack. Using 2020 planning values for fuel prices, a carbon adder over $5 per ton in 2020 may lead Idaho Power to dispatch Langley Gulch prior to dispatching the North Valmy coal plant. Figure 5.10 shows it would take a significantly higher carbon adder—over $25 per ton in 2020—before Langley Gulch has a lower dispatch cost than the Jim Bridger coal plant. Idaho Power assumed carbon adder values in 2020 of $0, $15.53, and $41.58 per ton in the 2013 IRP.

Displacing generation resources will only occur at times of low customer load. During peak seasons, it is very likely that Idaho Power will need all resources—supply side, demand side, and transmission—to meet customer load. The dispatch analysis does not suggest it is prudent or cost effective for Idaho Power to replace the coal-fired generation, but the dispatch analysis does indicate that a carbon adder may affect daily dispatch decisions under certain conditions.

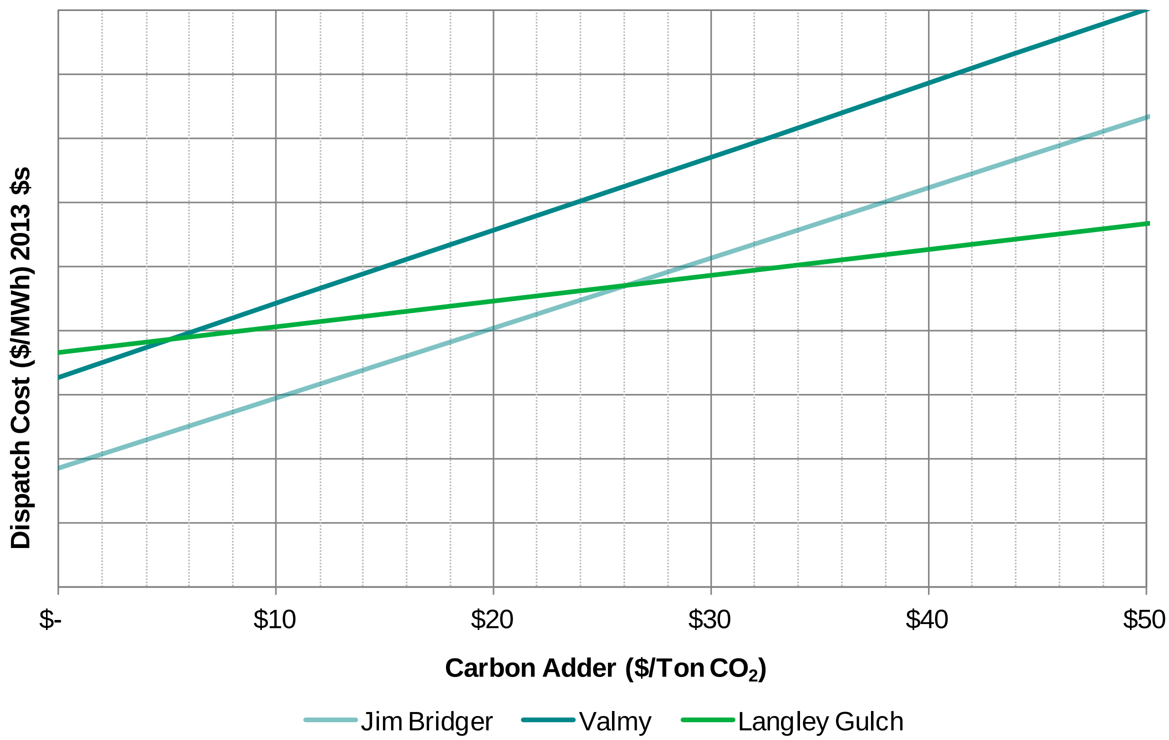


Figure 5.10 Dispatch costs, 2020

6. Transmission Planning

Past and Present Transmission

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

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

Idaho Power's regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of the difference in peak seasons, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load, and Idaho Power sells excess energy to Pacific Northwest utilities during the winter and spring. New regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers through the following:

- The construction of additional peaking resources to serve summer peak load is delayed or avoided.
- Revenue from off-system sales during the winter and spring is credited to customers through the PCA.
- Revenue from others' use of the transmission system is credited to Idaho Power customers.
- In general, regional transmission allows the region to share regulation and provides capacity to help integrate intermittent resources, such as wind and solar.

Transmission Planning Process

In recent years, FERC has mandated several aspects of the transmission planning process. FERC Order No. 1000 requires Idaho Power to participate in transmission planning on a local, regional, and interregional basis, as described in Attachment K of the Idaho Power Open-Access Transmission Tariff (OATT) and summarized in the following sections.

Local Transmission Planning Process

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

Local-Area Transmission Advisory Process

Idaho Power develops long-term, local-area transmission plans with community advisory committees. The community advisory committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for the full development of the area limited by the land-use plan and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for four load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Treasure Valley

Recently, the *Treasure Valley Electric Plan* was divided into two plans:

1. *Western Treasure Valley Electrical Plan*—The western plan was completed in 2011 and encompasses Malheur County in Oregon and Canyon, Gem, Owyhee, Payette and Washington counties in Idaho.
2. *Eastern Treasure Valley Electric Plan*—The eastern plan was completed in 2012 and encompasses all or portions of Ada, Elmore, and Owyhee counties in Idaho.

Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the planned supply-side resources identified in the IRP process, the transmission upgrades identified in the local-area transmission advisory process, the forecasted network customer load (e.g., Bonneville Power Administration [BPA] customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and point-to-point transmission customer requirements. By identifying potential resources, potential resource locations, and load-center growth, the required transmission system capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

Regional Transmission Planning

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

Interconnection-Wide Transmission Planning

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three distinct functions:

1. Oversee data management for the western interconnection.
2. Provide policy and management of the planning process.
3. Guide the analyses and modeling for Western Interconnection economic transmission expansion planning.

In addition to providing the means to model the transmission implications of various load and resource scenarios at an interconnection-wide level, the TEPPC coordinates planning between transmission owners, transmission operators, and regional planning entities.

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

Existing Transmission System

Idaho Power's transmission system traverses from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

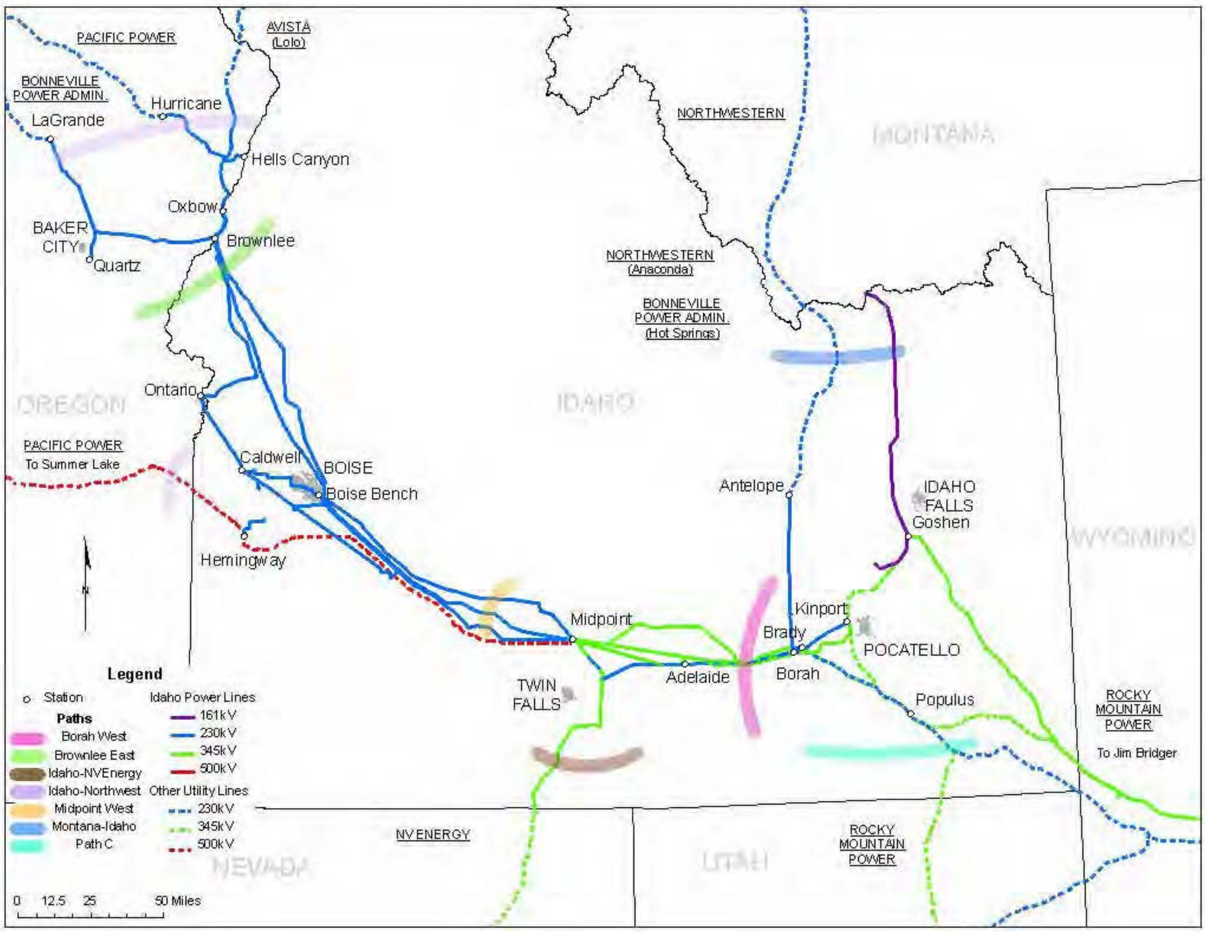


Figure 6.1 Idaho Power transmission system map

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

Idaho–Northwest Path

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

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the

HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the Brownlee East Total path. The capacity limitation on the Brownlee East transmission path occurs between Brownlee and the Treasure Valley.

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA eastern Oregon and southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the HCC as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

Idaho–Montana Path

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

Borah West Path

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

Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. The Midpoint West path is capacity-limited due to east-side Idaho Power resources, PURPA resources, and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

Idaho–Nevada Path

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

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns one of the lines and is allocated 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the other two lines and is allocated the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

Idaho–Utah Path

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

Table 6.1 Available transmission import capacity

	Total Transmission Capacity*		
Transmission Path	**Import Direction**	**Capacity (MW)**	**ATC (MW)****
Idaho–Northwest	West to East	1,200	0
Idaho–Nevada	South to North	262	0
Idaho–Montana	North to South	166	0
Brownlee East	West to East	1,915	0
Midpoint West	East to West	1,027	0
Borah West	East to West	2,557	0
Idaho–Wyoming (Bridger West)	East to West	2,400	60
Idaho–Utah (Path C)	South to North	1,250	0***

*Total transmission capacity and ATC as of April 1, 2013.

**The ATC of a specific path may change based on changes in the transmission service and generation interconnection request queue (i.e., the end of a transmission service, granting of transmission service, or cancelation of generation projects that have granted future transmission capacity).

***Idaho Power estimated value, actual ATC managed by PacifiCorp.

Boardman to Hemingway

Idaho Power's IRP process has identified a transmission line to the Pacific Northwest electric market dating back to 2006. At that time, a line interconnecting at the McNary Substation to the greater Boise, Idaho, area was included in IRP portfolios. Since its initial identification, the project has been refined and developed over the years, including different terminus locations and the concept of "right sizing", or building the project to an appropriate potential. The project identified in 2006 has evolved into what is currently the Boardman to Hemingway project. The project involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and reduced capacity limitations on the regional transmission system as demand for energy grows
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon

The Boardman to Hemingway project was identified as part of the preferred portfolio in Idaho Power's 2011 IRP. Since 2011, significant progress has been made on the Boardman to Hemingway project. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the Boardman to Hemingway project. Table 6.2 shows each party's Boardman to Hemingway capacity and permitting cost allocation.

Table 6.2 Boardman to Hemingway capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350 200 winter/500 summer	400 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two Boardman to Hemingway options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the Boardman to Hemingway project.

Considerable progress has also been made in regard to the federal and state permitting processes. The federal permitting process is established by NEPA. The Bureau of Land Management (BLM) is the lead agency in administering the NEPA process for the Boardman to Hemingway project. On May 3, 2013, the BLM announced their preliminary environmentally preferred route to the public. Figure 6.2 shows the proposed transmission line routes with the preliminary environmentally preferred route.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the Oregon Department of Energy (ODOE) as part of the state siting process. The final application is scheduled to be filed in spring 2014. As a result of the current federal and Oregon state permitting process, Idaho Power estimates that a project in-service date prior to 2018 is unlikely.

Additional project information is available at http://www.boardmantohemingway.com.

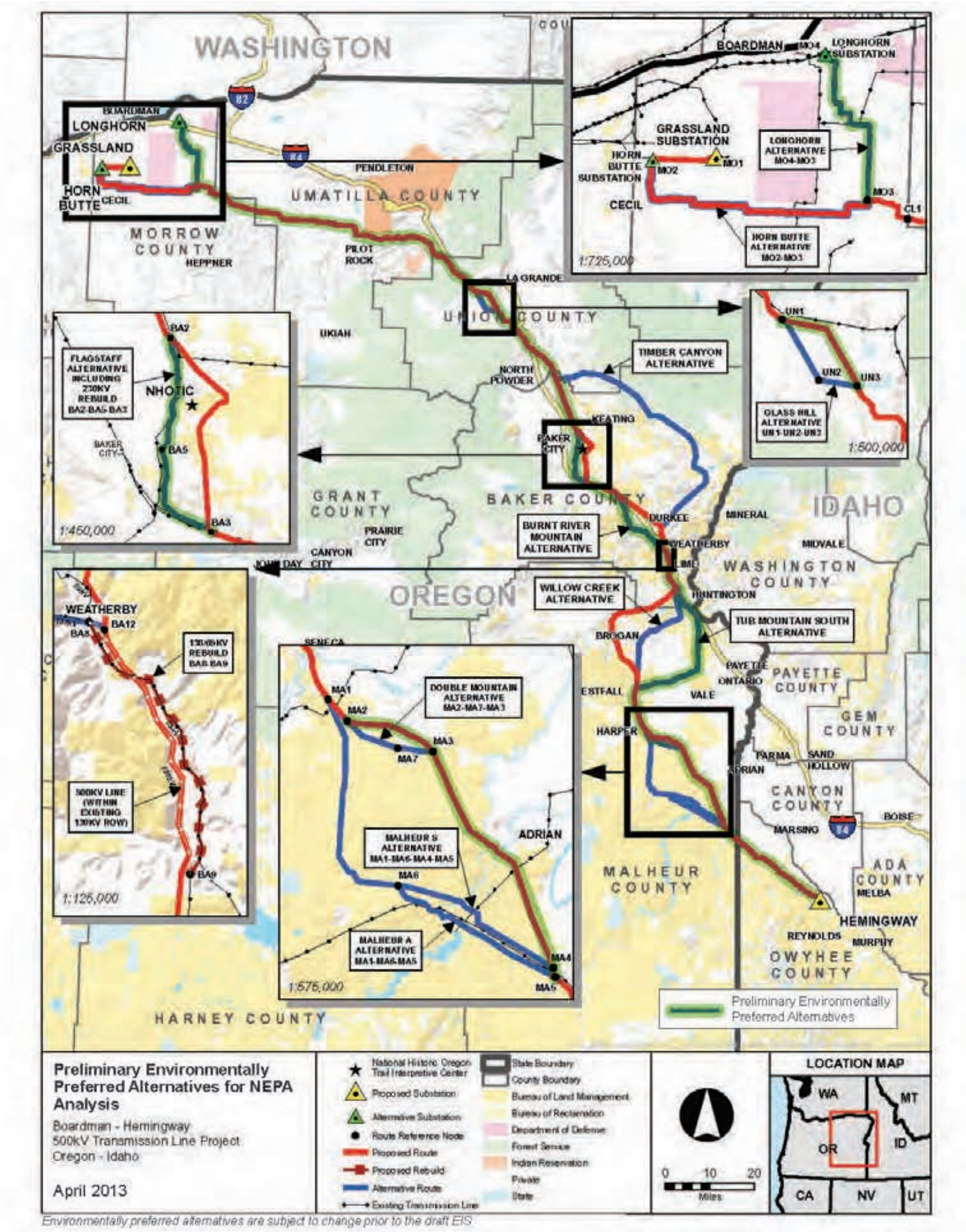


Figure 6.2 Boardman to Hemingway routes with the BLM preliminary environmentally preferred route

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho. Rocky Mountain Power has been designated as the permitting project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 6.3 shows a map of the project identifying the routes studied in the federal permitting process and depicts the BLM's preferred route. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint, which is constructed as a 500 kV-line presently operating at 345 kV. The 345-kV line will be converted to 500-kV operation in the future.

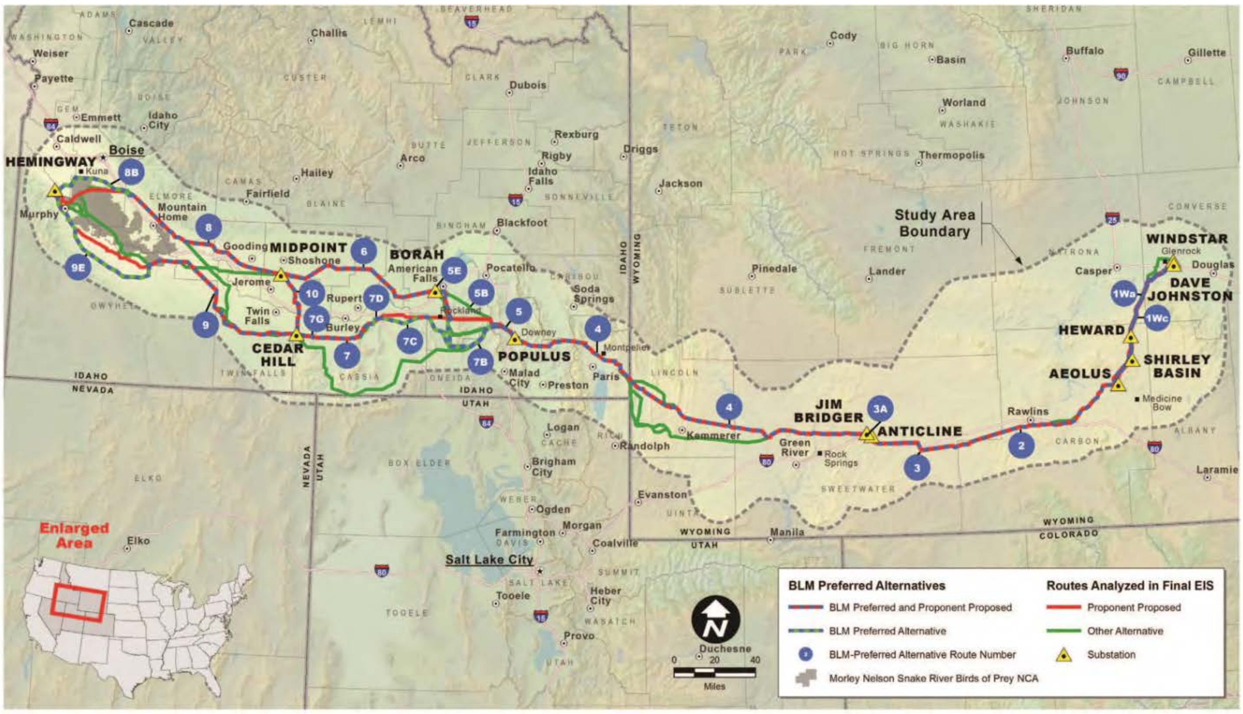


Figure 6.3 Gateway West Map

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. The new line will provide many benefits to Idaho Power customers, including the following:

- Relieve transmission constraints on the Borah West and Midpoint West paths, allowing Idaho Power to move additional energy between the east and west sides of the system.

- Provide the option to locate future generation resources east of the Treasure Valley load center.
- Provide future load service to the Magic Valley from the Cedar Hill Substation.

Phase 1 of the project is expected to provide up to 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide a total of 3,000 MW of additional transfer capacity.

The Gateway West project is currently undergoing the federal permitting process established by NEPA. The BLM is the lead agency administering the NEPA permitting process. On April 26, 2013, the BLM publically released the Final Environmental Impact Statement (FEIS) for comment. Releasing the FEIS for comment is a significant milestone in the NEPA process. A Record of Decision (ROD) is anticipated before the end of the 2013 calendar year.

The project is scheduled for line segments to be in service between 2019 and 2023. Multiple construction phases are planned to develop the transmission project by segment. The line segments from the Windstar Substation near Glenrock, Wyoming, to the Populus Substation near Downey, Idaho, are a priority for Rocky Mountain Power and are planned to be in service between 2019 and 2021.

Additional information about the Gateway West project can be found at http://www.gatewaywestproject.com.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine the transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 6.3.

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

Table 6.3 Transmission assumptions

Resource Type	Geographic Area	Resource Levels (per portfolio)	Additional Transmission Requirements
Boardman to Hemingway Line	Hemingway Substation	500 MW	New 230-kV line from Hemingway into the Treasure Valley.
Gas Turbines[1]	Payette County	0 MW–170 MW	Upgrade of approximately 9 miles of existing transmission into the Treasure Valley.
	Payette County	170 MW–300 MW	Rebuild an existing 230-kV line.
	Elmore County	>300 MW	Additional 230-kV line(s) into the Treasure Valley, possibly requiring different geographic locations for the resources.
Combined heat and power (CHP)	Canyon County	0 MW–100 MW	No transmission upgrades required.

[1] Coal replacement resources are assumed at or near the existing coal generation facilities.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. An analysis of the transmission capacity required from the new resources to the growing Treasure Valley load center was conducted for each portfolio. The analysis assumed that CCCT gas turbines identified to replace coal resources are located at or near the existing coal generation facilities. The transmission capacity analysis of the portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

This page left blank intentionally.

7. Resource Alternatives Analysis

Idaho Power conducted a resource portfolio design workshop with the IRP Advisory Council on November 30, 2012. At the portfolio design workshop, members of the IRP Advisory Council suggested Idaho Power explore a variety of resource alternatives. Members of the IRP Advisory Council commented that the method to compare resources used in earlier resource plans often paired resources, making it difficult to isolate the characteristics of a single resource alternative.

Based on the comments of the IRP Advisory Council at the portfolio design workshop, Idaho Power decided to perform a preliminary resource analysis to isolate the effects of each resource. Idaho Power performed an analysis of the following eight resources:

1. Northwest transmission
2. SCCT
3. CCCT
4. CHP
5. Pumped storage fueled by LL Wind
6. Canal drop hydroelectric
8. Utility solar PV
9. Distributed solar PV

Idaho Power assumed the same time period—2013 through 2022—the same set of existing resources, the same load forecast, the same set of planning criteria, and added the same quantity of 200 MW of on-peak capacity of each resource type. Idaho Power then conducted eight Aurora simulations of the Idaho Power system to isolate the characteristics of each resource type.

Even though the on-peak capacity of 200 MW was selected for the test, 200 MW may not be a feasible generation quantity. The alternative resource portfolios were designed only as a comparison test and were not designed to either meet load or be constructed. For example, the transmission distance to the Northwest energy market requires a greater transfer capacity than 200 MW. In each resource case, the resource costs were scaled using a linear function to estimate the costs of 200 MW of on-peak capacity for the resource alternatives analysis.

Idaho Power uses a 90-percent exceedance value to calculate the nameplate generation necessary to achieve the on-peak capacity contribution. The 90-percent exceedance value means the resource is expected to deliver the on-peak contribution during the peak hours 9 times out of 10. The 90-percent exceedance method was first applied to hydroelectric generation in the 2002 Idaho Power IRP, and it has been the standard since. The nameplate capacity of many of the resource types must exceed 200 MW to achieve 200 MW of on-peak capacity. A summary of the costs is shown in Table 7.1. Figure 7.1 shows the relative costs per delivered on-peak kW; the most cost-effective resource is Northwest transmission, followed closely by natural gas combustion turbines.

Table 7.1 Resource alternatives to achieve 200 MW of peak-hour contribution in 2018 (NPV years 2013–2022, 2013 dollars, 000s)

Resource Alternative	Peak-Hour Capacity (90% exceedance)	2018 Peak-Hour Deficit Target (MW)	Installed Nameplate Needed to Meet 200 MW Peak	Variable Costs (Aurora)	RECs Sold (reflected in variable costs)	Fixed Costs (plant, transmission, fixed O&M, & rate of return)	New Natural Gas Pipeline Capacity Charge	Total	Lowest Cost Rank	Lowest Cost Relative Difference
1—Northwest transmission	100%	(200)	200	$2,674,610	N/A	$33,039	–	$2,707,650	1	$0
2—SCCT	95%	(200)	211	$2,677,067	N/A	$79,331	$7,152	$2,763,549	2	$55,900
3—CCCT	95%	(200)	211	$2,646,794	N/A	$134,786	$38,377	$2,819,957	3	$112,308
4—CHP	95%	(200)	211	$2,644,909	$5,964	$192,212	$34,461	$2,871,582	4	$163,932
5—Pumped storage fueled by LL wind	100%	(200)	200	$2,677,703	$10,332	$311,842	–	$2,989,545	5	$281,895
6—Canal drop hydroelectric	67%	(200)	299	$2,513,007	$21,104	$603,920	–	$3,116,927	6	$409,277
7—Utility solar PV	32%	(200)	625	$2,514,873	$17,589	$882,286	–	$3,397,159	7	$689,510
8—Distributed solar PV	39%	(200)	513	$2,542,702	$14,550	$1,338,597	–	$3,881,298	8	$1,173,649

Note: Variable costs reflect the existing system plus the resource alternative. Fixed costs are representative of the resource alternative only.

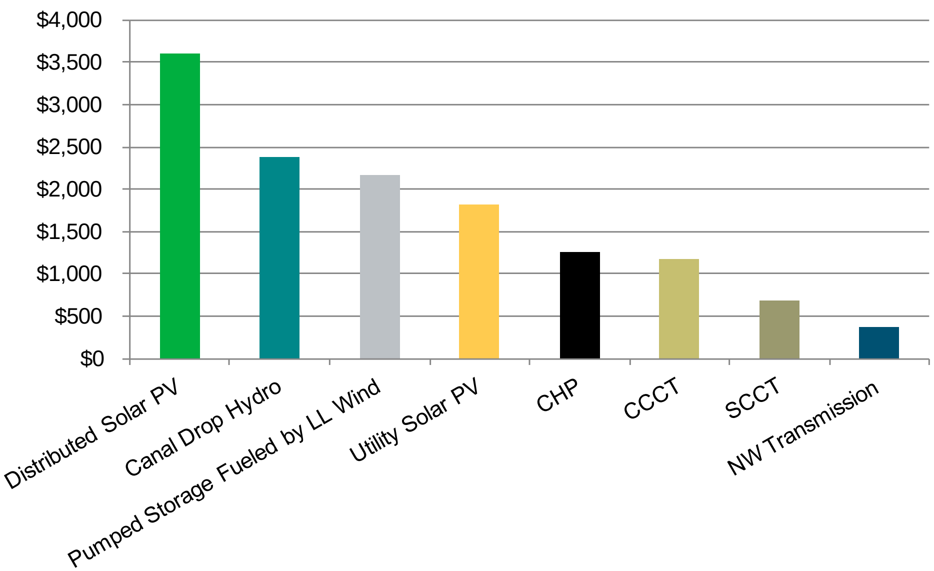


Figure 7.1 Relative costs per delivered on-peak kW

The high costs of the solar PV resources require some explanation. The Idaho Power system peak commonly occurs in the late afternoon and early evening on hot July days when A/C and agricultural pumping are near maximum use. Solar gain reaches a maximum at solar noon on the summer solstice in June. By the late afternoon and early evening hours in mid-July when Idaho Power experiences peak demand, solar gain in Idaho is considerably less—especially in the evening hours. The solar characteristics combined with the 90-percent exceedance criteria require a considerable quantity of solar generation to meet peak customer demand.

Distributed solar PV was the subject of several spirited discussions at the IRP Advisory Council meetings. Idaho Power performed a supplemental analysis of distributed PV to determine the time necessary to recover the capital investment from the perspective of an Idaho Power residential customer. Idaho Power estimated the investment recovery time period using a residential energy rate of $0.0855 per kWh, a 3-percent escalation rate, and an annual solar capacity factor of approximately 15 percent (the solar capacity factor is based on solar data from the NREL PVWatts website). The results of the analysis are shown in Figure 7.2. The figure shows the cost recovery with no tax incentives as well as the recovery with federal and state incentives. Until the installed cost with incentives drops below approximately $2 per watt, investment recovery periods exceed 10 years for residential solar PV.

The same general conclusions can be applied to utility solar PV installations. Until annual average wholesale energy prices exceed $85.50 per MWh and until the installed cost with incentives drops below $2,000 per kW, utility solar investment recovery periods are likely to exceed 10 years.

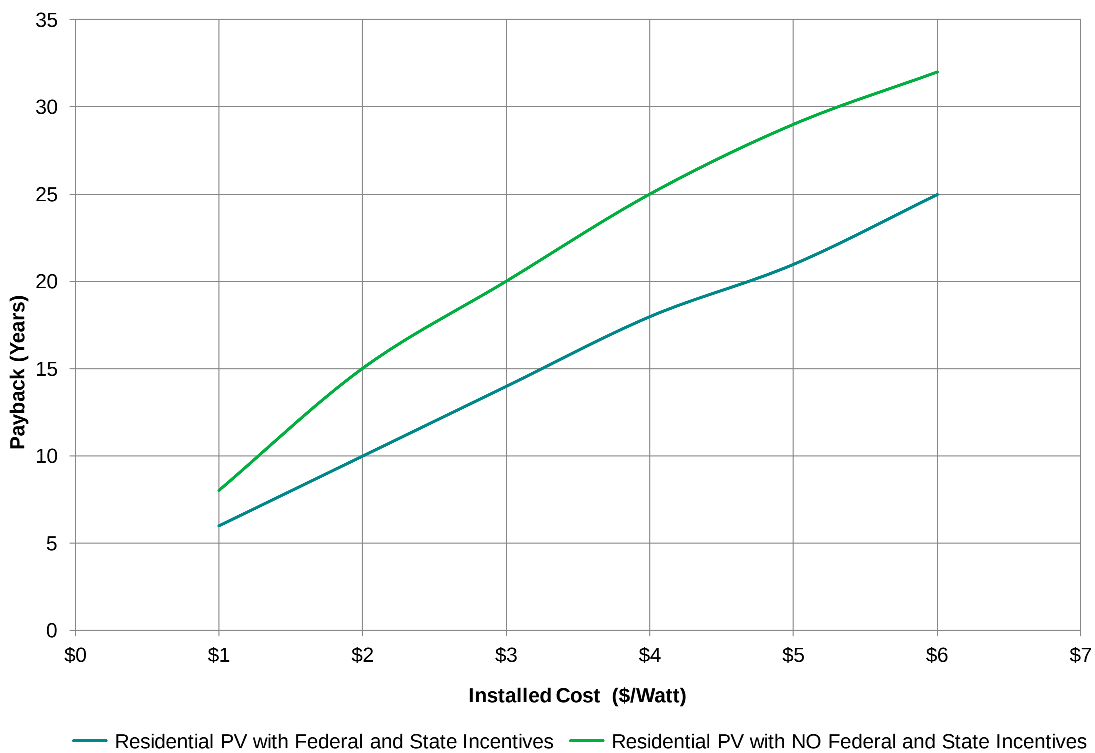


Figure 7.2 Solar generation recovery period

Idaho Power proposed a solar demonstration project as part of the 2011 IRP. The proposed project had a nameplate capacity between 0.5 and 1 MW and was initially expected to be on-line by the end of 2013.

Idaho Power is still interested in developing a solar demonstration project. With the recent issues surrounding PURPA in Idaho, the timing has not been suitable for Idaho Power to pursue the construction of a small-scale solar project. Idaho Power is required to comply with the requirements identified in the Oregon Solar Incentive Program, which include building a 500-kW, utility-scale solar facility by 2020 (Oregon House Bill 3039). Idaho Power will continue to evaluate the solar demonstration project and the benefits of receiving double RECs in the Oregon if the project is completed by the end of 2016.

Solar Parking Lot Lighting Demonstration Project

Idaho Power and Boise-based Inovus Solar have recently entered into an agreement under which Inovus will install a Solar-Enhanced Lighting™ System in the south parking lot of Idaho Power's CHQ (the parking lot is bound by Main Street, Grove Street, 12th Street, and 13th Street). The system is designed to be a grid connected net-zero system, meaning it will generate as much energy during the day as the lights consume at night while illuminating the parking lot. An example of the light is shown in Figure 7.3.

The project provides Idaho Power with insight into the performance, technology, and potential applications of the Inovus state-of-the-art Solar-Enhanced Lighting System. Additionally, the Idaho Power project provides Inovus a local installation to evaluate the performance of individual components, test enhancements, and monitor and evaluate overall system performance.

The system will generate approximately 4 kW, and the new lights are scheduled to be in service by late July 2013.

Figure 7.3 Inovus solar light

Risk Analysis and Results

Idaho Power also performed a risk analysis on the eight resource alternatives. The risk analysis is a quantitative scenario analysis. Idaho Power identified four variables for the risk analysis—the natural gas price, customer load, hydroelectric conditions, and carbon adder. In total, using the four risk variables, the following seven risk scenarios were tested:

1. High carbon adder
2. Low carbon adder
3. High gas prices

4. Low gas prices
5. Low water conditions
6. High gas prices plus low water conditions
7. High gas prices plus low water conditions and a high carbon adder

Scenarios six and seven are combinations of the risk variables designed to test more severe conditions.

The ranking of the resource alternatives under each of the seven scenarios is presented in Table 7.2 (the full costs for the different scenarios are reported in *Appendix C—Technical Appendix*).

Table 7.2 Risk scenario results

	Risk Scenario						
	Carbon		Natural Gas Price				
Resource Alternative	High	Low	High	Low	Low Water	Scenario 6	Scenario 7
Northwest transmission	1	1	1	1	1	1	1
SCCT	2	2	2	2	2	2	2
CCCT	3	3	3	3	3	3	3
CHP	4	4	4	4	4	4	4
Pumped storage fueled by LL wind	5	5	5	5	5	5	5
Canal drop hydroelectric	6	6	6	6	6	6	6
Utility solar PV	7	7	7	7	7	7	7
Distributed solar PV	8	8	8	8	8	8	8

Northwest transmission was the lowest-cost resource alternative in all scenarios, and the ranking of the resource alternatives did not change in any scenario; the low cost resources were low cost in all seven risk scenarios, and the high cost resources were high cost in all seven risk scenarios.

Based on the suggestions of the IRP Advisory Council and the results of the resource alternatives analysis, Idaho Power designed resource portfolios using the lowest-cost resource alternatives—Northwest transmission and generation fired by natural gas. The specific resource portfolios are described in the following chapter.

This page left blank intentionally.

8. Planning Criteria and Portfolio Selection

Planning Scenarios and Criteria

Idaho Power conducted a systematic analysis to select the preferred resource portfolio. The planning scenarios can be grouped into three main categories:

1. *Boardman to Hemingway resource portfolios*—Two resource portfolios rely primarily on the Boardman to Hemingway transmission line to meet future resource needs. The two resource portfolios contain the existing and committed Idaho Power generation resources.

2. *Alternative to Boardman to Hemingway resource portfolios*—Three resource portfolios explore alternatives to the Boardman to Hemingway transmission line to meet future resource needs. The Boardman to Hemingway transmission line is not included in the three resource portfolios. The three resource portfolios contain the existing and committed Idaho Power generation resources.

3. *Coal alternative resource portfolios*—Four resource portfolios explore options to reduce coal-fired generation in the Idaho Power resource portfolio. The options to reduce the reliance on coal include replacement with natural gas-fired generation; increased demand-side measures, including demand response; changing the fuel at the North Valmy plant to natural gas; and the Boardman to Hemingway transmission line. The alternatives to coal resource portfolios are an extension of the coal study Idaho Power included with the 2011 IRP Update.

Demand response is included in many of the resource portfolios. Idaho Power applied demand response in 50 MW increments in the resource portfolios. The lines shown on the resource portfolio graphs identify the maximum level of demand response. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The demand response 2016 level was estimated to be 100 MW and the 2017 level was estimated to be 150 MW.

The four resource portfolios that explore options for reducing coal-fired generation at Idaho Power are the first IRP portfolios in which Idaho Power has considered the early retirement of a generating resource in an IRP. Resource retirement raises a few issues unique to the 2013 IRP. Specifically, resource retirement portfolios require Idaho Power to consider the remaining asset value of the resource and to include recovering the asset value in the resource portfolio. In addition, resource retirement also requires Idaho Power to account for any retirement and termination costs when estimating the resource portfolio costs.

Resource retirement also requires Idaho Power to estimate the ongoing capital requirements of the coal-fired resources and to include the ongoing capital requirements in the resource portfolios containing the existing resources. Treatment of the fixed-cost accounting is summarized in Table 8.1.

Table 8.1 Coal resource fixed-cost accounting

Capital Description	Existing Coal Resource Portfolios	Coal Replacement Resource Portfolios
Coal Emission-Control Equipment	Included	Excluded
Existing Coal Resources	Included	Excluded
Replacement Resources	Excluded	Included
Accelerated Recovery of Existing Coal Plant Investment	Excluded	Included
Decommissioning Coal Asset	Excluded	Included

The word *included* indicates costs must be added to the resource portfolio costs, and *excluded* indicates no additional costs. For example, the cost of the emission-control equipment must be added to the resource portfolios that use the existing coal plants, whereas the resource portfolios that replace coal will not incur the emission-control equipment costs. Each of the nine detailed resource portfolios analyzed are described in the next section.

Portfolio Design and Selection

The following resource portfolios are described in tables 8.2 through 8.10, which list the resource types, implementation dates, and on-peak capacity. Figures 8.1 through 8.9 show monthly peak-hour deficits under 90th-percentile water and 95th-percentile load with existing and committed resources and existing energy efficiency programs. When a new resource is added, a horizontal line on the chart shows the capacity contribution of the new resource.

Boardman to Hemingway Resource Portfolios

Resource Portfolio 1—Boardman to Hemingway plus Demand Response and an SCCT

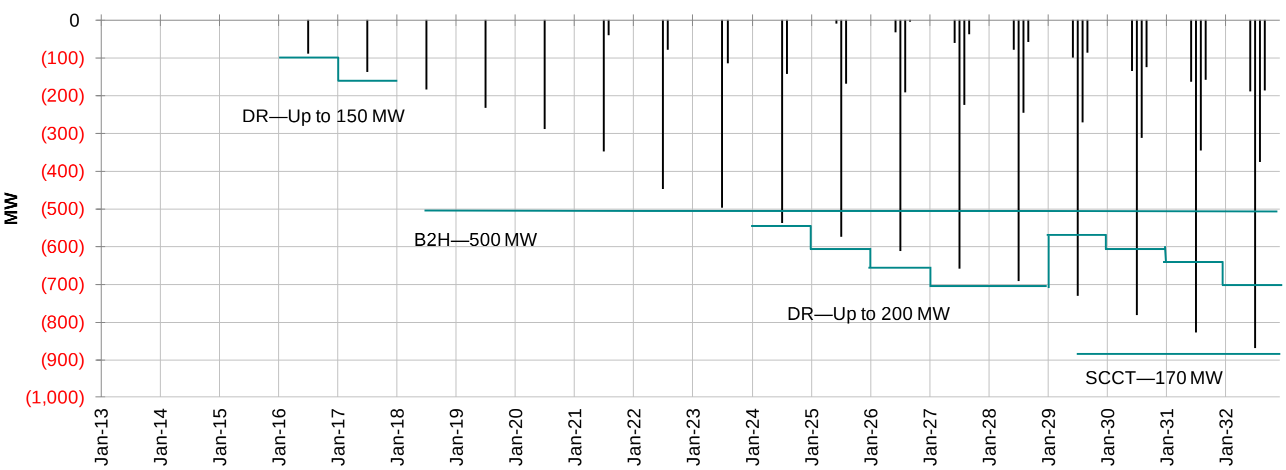


Figure 8.1 Resource portfolio 1

Table 8.2 Resource portfolio 1

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Summer 2024	Demand response	Up to 200 MW in 50-MW increments
Summer 2029	SCCT	170 MW

Resource Portfolio 2—Boardman to Hemingway plus Demand Response

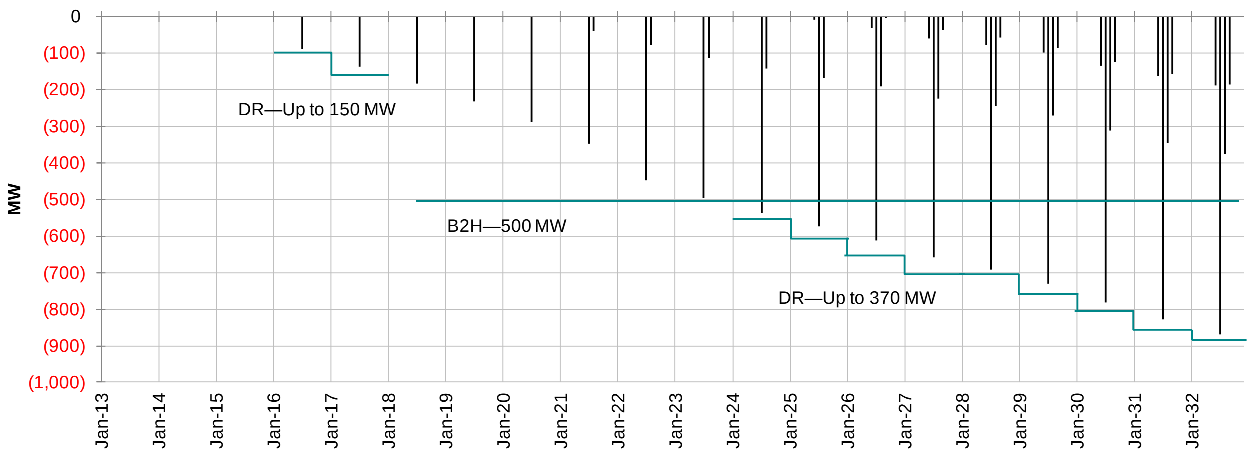


Figure 8.2 Resource portfolio 2

Table 8.3 Resource portfolio 2

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Summer 2024	Demand response	Up to 370 MW in 50-MW increments

Alternative to Boardman to Hemingway Resource Portfolios

Resource Portfolio 3—Demand Response plus a CCCT and an SCCT

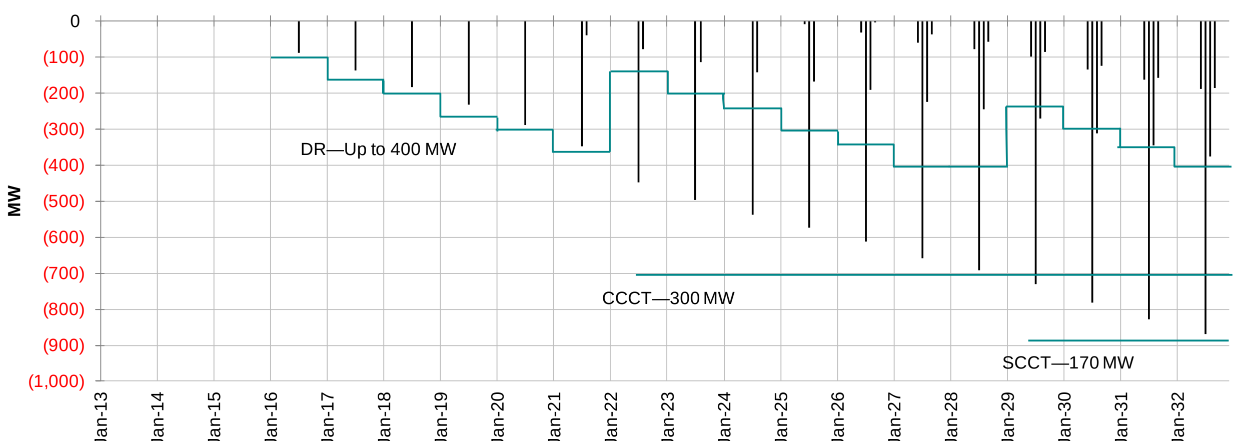


Figure 8.3 Resource portfolio 3

Table 8.4 Resource portfolio 3

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	Demand response	Increasing to 400 MW in 50-MW increments
Summer 2022	CCCT	300 MW
Summer 2029	SCCT	170 MW

Resource Portfolio 4—Demand Response plus Two CCCTs

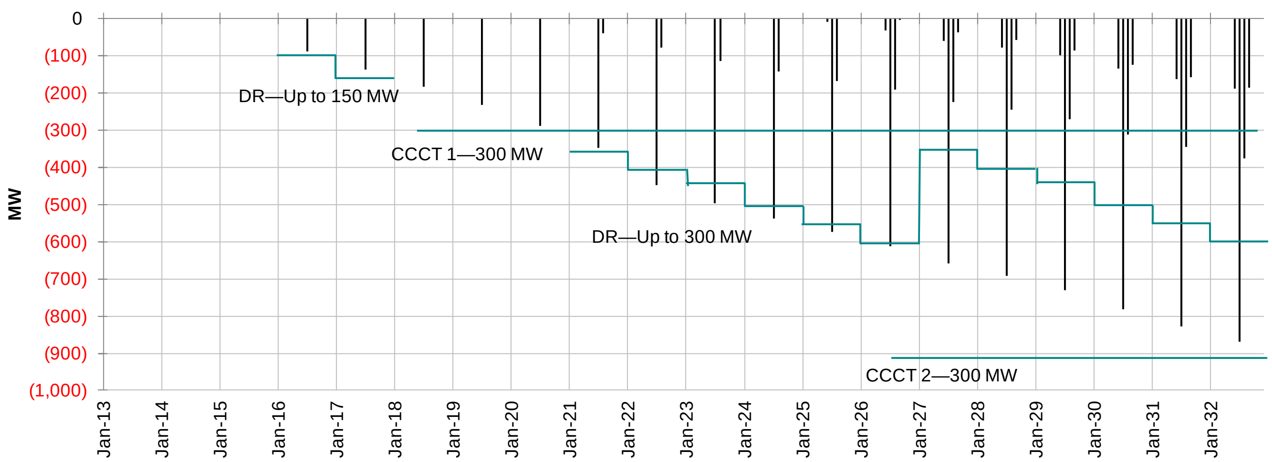


Figure 8.4 Resource portfolio 4

Table 8.5 Resource portfolio 4

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	CCCT	300 MW
Summer 2021	Demand response	Additional 300 MW in 50-MW increments
Summer 2026	CCCT	300 MW

Resource Portfolio 5—Demand Response plus Two Consecutive CCCTs

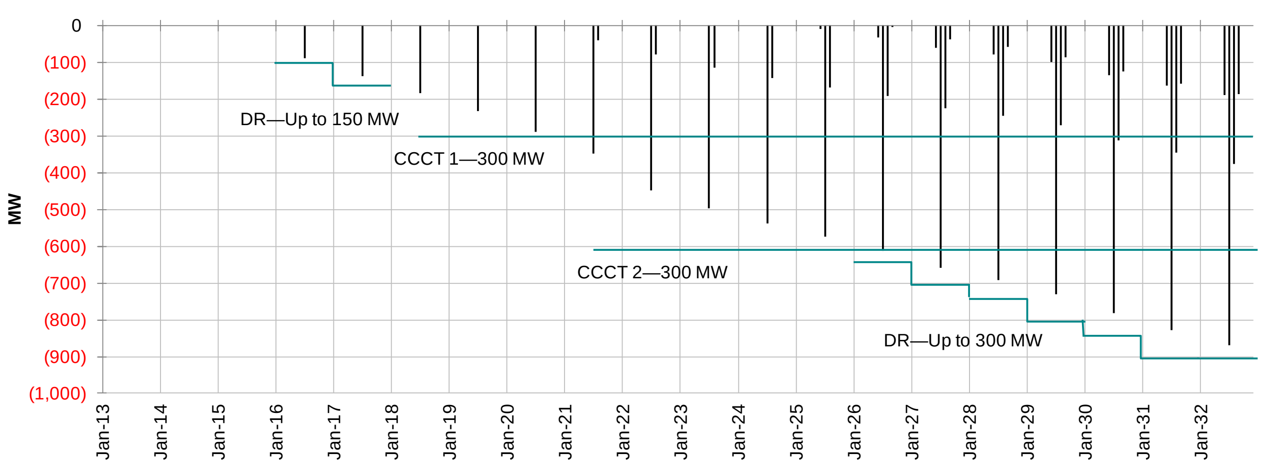


Figure 8.5 Resource portfolio 5

Table 8.6 Resource portfolio 5

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
Summer 2018	CCCT	300 MW
Summer 2021	CCCT	300 MW
Summer 2026	Demand response	Additional 300 MW in 50-MW increments

Coal Alternative Resource Portfolios

The coal alternative resource portfolios are shown with a different monthly peak-hour load and resource balance. Figures 8.6 through 8.9 show the anticipated monthly peak-hour resource deficits in black, similar to resource portfolios 1 through 5. However, removing existing generation resources increases the monthly peak-hour capacity deficits, and figures 8.6 through 8.9 show the increased deficits created by removing coal generation in red. Resource portfolios 6 through 9 are designed to meet the increased deficits shown in red. The deficit scale in the coal alternative resource portfolios is different than the scale shown in the resource portfolios containing the existing coal resources. The monthly peak-hour deficits are under 90th-percentile water and 95th-percentile load with existing and committed resources and existing energy efficiency programs.

Resource Portfolio 6—ICL–BSU

Resource portfolio 6 was suggested by members of the Idaho Power IRP Advisory Council representing the ICL and BSU. Idaho Power worked with the two IRP Advisory Council members representing the ICL and BSU to refine the resource portfolio.

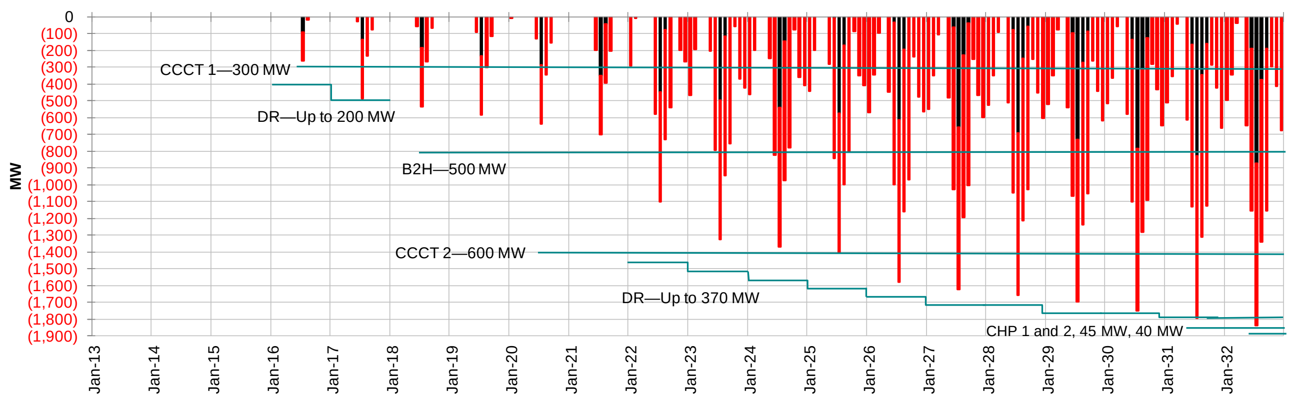


Figure 8.6 Resource portfolio 6

Table 8.7 Resource portfolio 6

Date	Resource	Capacity
Year-end 2015	Exit Bridger Unit 3 and Valmy Unit 1	Minus approximately 300 MW
Summer 2016	CCCT	300 MW
Year-end 2016	Exit Bridger Unit 4	Minus approximately 170 MW
2016–2017	Demand Response	Up to 200 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2020	Exit Bridger Units 1 and 2, Valmy Unit 2	Minus approximately 370 MW
Year-end 2020	CCCT	600 MW
Summer 2031	CHP	45 MW
Summer 2032	CHP	40 MW

Resource Portfolio 7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response

Resource portfolio 7 is based on the Idaho Power coal study presented with the 2011 IRP Update. Resource portfolio 7 replaces coal-fired generation resources with natural gas-fired generation. Specifically, the North Valmy coal plant is modified to burn natural gas and the Jim Bridger plant is replaced with CCCTs fired by natural gas.

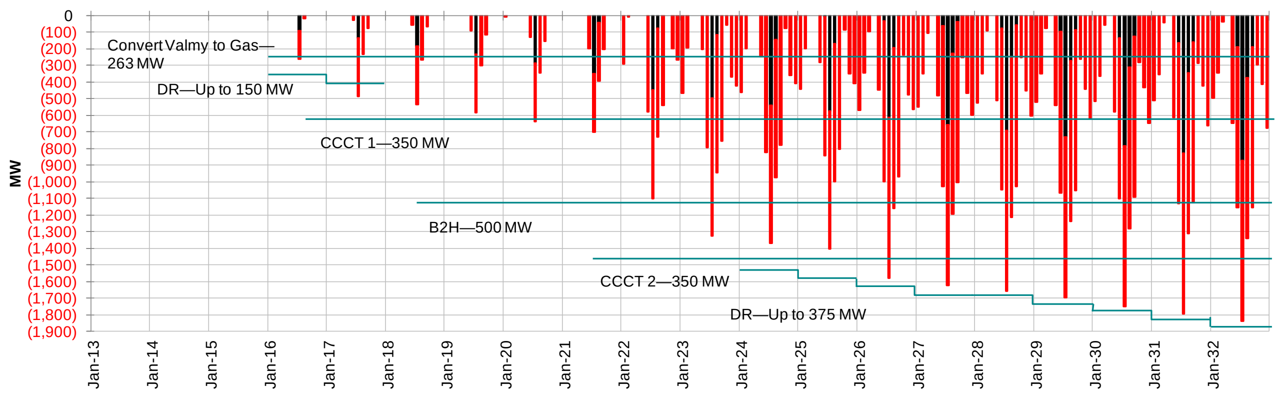


Figure 8.7 Resource portfolio 7

Table 8.8 Resource portfolio 7

Date	Resource	Capacity
January 2015	Convert Valmy Units 1 and 2 to be fueled by natural gas	No Change
Year-end 2015	Cease coal-fired operation of Bridger Units 3 and 4	Minus approximately 340 MW
Summer 2016	CCCT	350 MW
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2020	Cease coal-fired operation of Bridger Units 1 and 2	Minus approximately 340 MW
Summer 2021	CCCT	350 MW
2021–2032	Demand response	Up to 375 MW

Resource Portfolio 8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT

In April 2013, NV Energy announced a schedule to retire the North Valmy Coal Plant. Idaho Power is a one-half owner of the North Valmy coal plant, and NV Energy is the operating partner. Idaho Power has not agreed to the North Valmy plant retirement schedule announced by NV Energy. Resource Portfolio 8 is designed to estimate the effects of retiring North Valmy Units 1 and 2 according to the NV Energy schedule and replacing the lost generation with demand response, Boardman to Hemingway, and a CCCT (North Valmy Unit 1 is retired at year-end 2020 and North Valmy unit 2 is retired at year-end 2025).

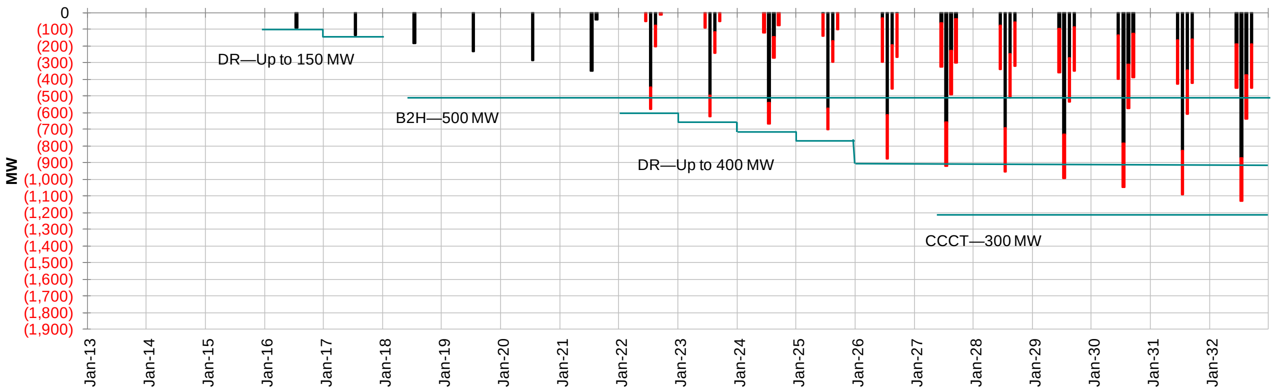


Figure 8.8 Resource portfolio 8

Table 8.9 Resource portfolio 8

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Boardman to Hemingway	500-MW transfer capacity
Year-end 2021	Valmy 1 retired	Minus approximately 130 MW
Summer 2022	Demand response	Up to 400 MW
Year-end 2025	Valmy 2 retired	Minus approximately 130 MW
Summer 2027	CCCT	300 MW

Resource Portfolio 9—North Valmy Closure, Boardman to Hemingway Alternative

Like resource portfolio 8, resource portfolio 9 is designed to estimate the effects of retiring North Valmy on the schedule announced by NV Energy. Resource Portfolio 9 replaces the lost generation with alternatives to Boardman to Hemingway, including demand response, two CCCTs, and one SCCT.

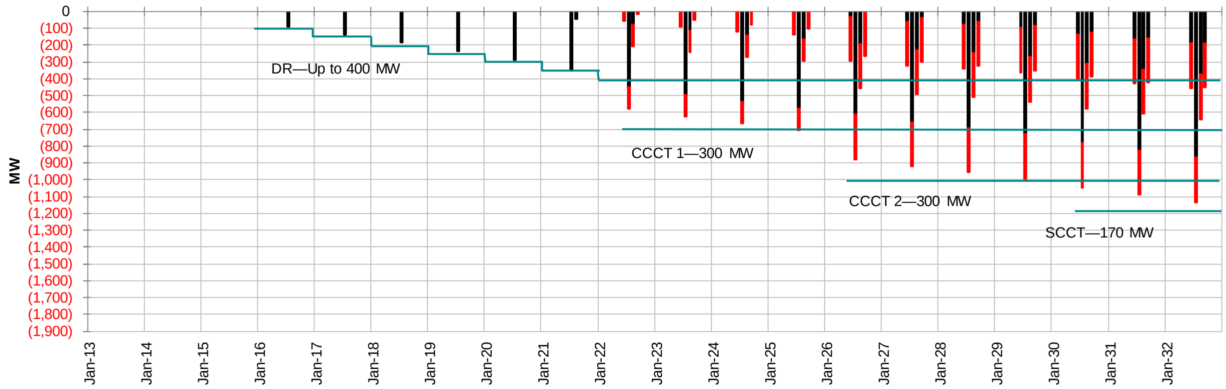


Figure 8.9 Resource portfolio 9

Table 8.10 Resource portfolio 9

Date	Resource	Capacity
2016–2017	Demand response	Up to 150 MW
2018	Expanded demand response	Up to 400 MW
Year-end 2021	Valmy 1 closure	Minus approximately 130 MW
Summer 2022	CCCT	300 MW
Year-end 2025	Valmy 2 closure	Minus approximately 130 MW
Summer 2026	CCCT	300 MW
Summer 2030	SCCT	170 MW

9. Modeling Analysis and Results

Portfolio Costs

Idaho Power evaluated the costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to meet the customer load using all resources in the portfolio. Resource portfolios 1 through 5 assume the continued operation of the Jim Bridger and North Valmy coal facilities. (The Boardman coal plant ceases coal-fired operations at year-end 2020 in all resource portfolios.) Idaho Power ceases coal-fired operations at the North Valmy and Jim Bridger plants in resource portfolios 6 and 7. Resource portfolios 8 and 9 retire the North Valmy plant on the schedule identified by NV Energy in April 2013. (North Valmy Unit 1 is retired at year-end 2021, and North Valmy Unit 2 is retired at year-end 2025.)

The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 9.1 Financial assumptions

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

Table 9.2 reports the total cost of each resource portfolio for the 20-year planning horizon. The total cost is the NPV of the variable operating costs plus the fixed cost of the existing, new, and replacement resources. The variable operating costs include the fuel cost, purchased-power cost, O&M, and other costs.

Table 9.2 2013 IRP portfolios, NPV years 2013–2032 (2013 dollars, 000s)

	Variable Costs	Fixed Costs				Summary		
Portfolio (1)	Operating[1] (Aurora) (2)	New Resources[2] (3)	New Natural Gas Pipeline Capacity Charge (4)	Demand Response (5)	Total (6) (3)+(4)+(5)	Total Portfolio Costs (7) (2)+(6)	Lowest Cost Rank (8)	Lowest Cost Relative Difference (9)
2—Boardman to Hemingway plus Demand Response	$4,987,003	$185,028	$0	$48,547	$233,575	$5,220,578	1	$0
1—Boardman to Hemingway plus Demand Response and an SCCT	$4,987,143	$221,699	$2,300	$34,818	$258,817	$5,245,960	2	$25,382
3—Demand Response plus a CCCT and an SCCT	$4,940,835	$351,762	$80,973	$105,933	$538,668	$5,479,503	3	$258,925
4—Demand Response plus Two CCCTs	$4,872,870	$638,016	$166,043	$52,744	$856,803	$5,729,673	4	$509,095
8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT	$5,056,695	$598,447	$38,902	$73,927	$711,276	$5,767,971	5	$547,394
5—Demand Response plus Two Consecutive CCCTs	$4,843,988	$796,666	$211,320	$35,067	$1,043,052	$5,887,040	6	$666,463
9—North Valmy Closure, Boardman to Hemingway Alternative	$4,991,277	$744,041	$139,722	$127,677	$1,011,439	$6,002,716	7	$782,138
6—ICL–BSU	$5,688,123	$650,693	$336,164	$57,771	$1,044,628	$6,732,751	8	$1,512,173
7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response	$5,789,525	$654,534	$516,133	$45,965	$1,216,632	$7,006,156	9	$1,785,578

[1] Variable operating costs reflect the existing system with coal plant shutdowns (when applicable) plus the new portfolio resources, REC sales, and carbon adder.

[2] New plant capital, new plant transmission, stranded asset value, environmental compliance upgrade (when applicable), accelerated recovery of existing coal plant investment, and decommissioning coal asset.

The resource portfolios are sorted from lowest cost to highest cost in Table 9.2. Resource portfolio 2 is the least-cost resource portfolio.

The general ranking of resource portfolios shows resource portfolios that include Boardman to Hemingway cost less than comparable resource portfolios that rely on alternatives to Boardman to Hemingway. The resource portfolios that replace resources—resource portfolios 6 through 9—are generally the most expensive options. However, resource portfolio 8, which replaces North Valmy, costs less because it includes the Boardman to Hemingway transmission line. Figure 9.1 shows the resource portfolio costs.

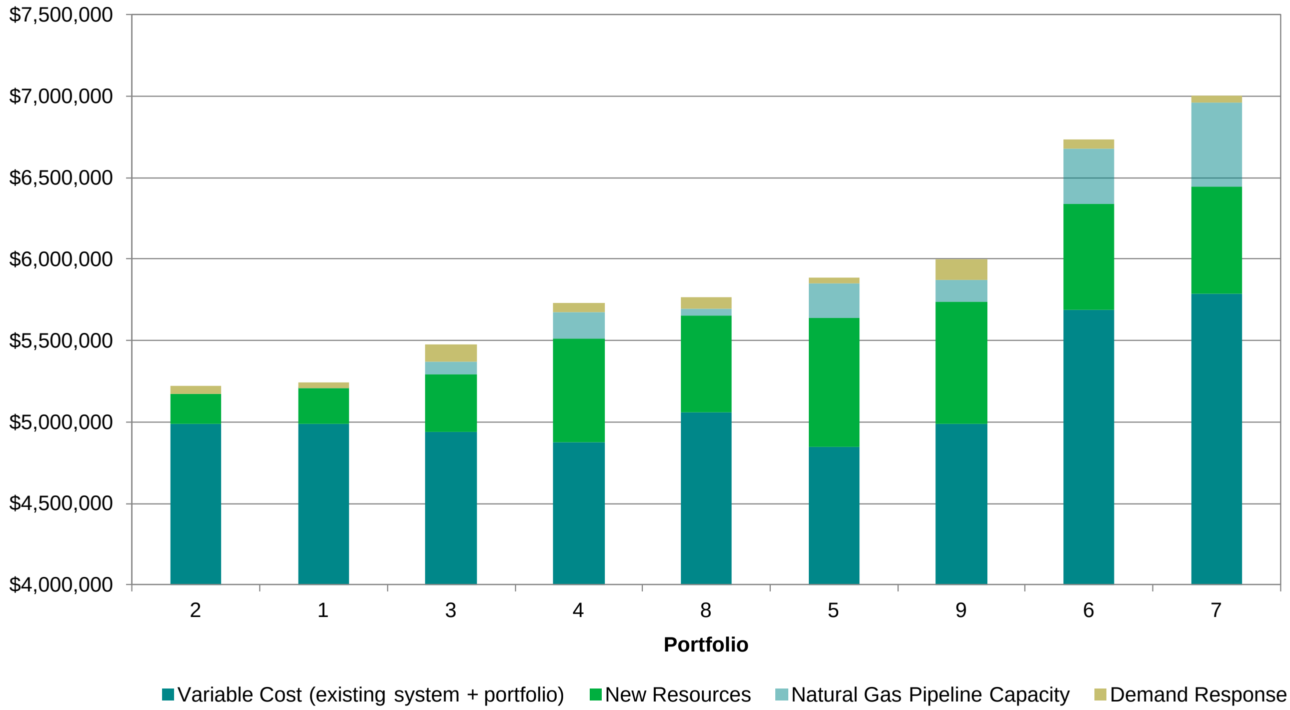


Figure 9.1 Total portfolio costs, NPV 2013–2032 (2013 dollars, 000s)

Portfolio Emissions

For the 2013 IRP, Idaho Power analyzed the total portfolio emissions for the 20-year planning period by the following four emission types:

1. CO_2—A greenhouse gas associated with climate change
2. NO_x—Contributes to regional haze
3. SO_2—Contributes to acid rain formation
4. Hg—A toxic element found in coal deposits

Total emissions by type were calculated using Aurora emissions modeling. All portfolios comply with all known environmental regulations. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing and committed resources.

CO_2 Emissions

Figure 9.2 shows the total CO_2 emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced CO_2 emissions. The reduced emissions are because a CCCT resource emits approximately 37 percent of the CO_2 per MWh that Idaho Power coal-fired generation resources emit on average.

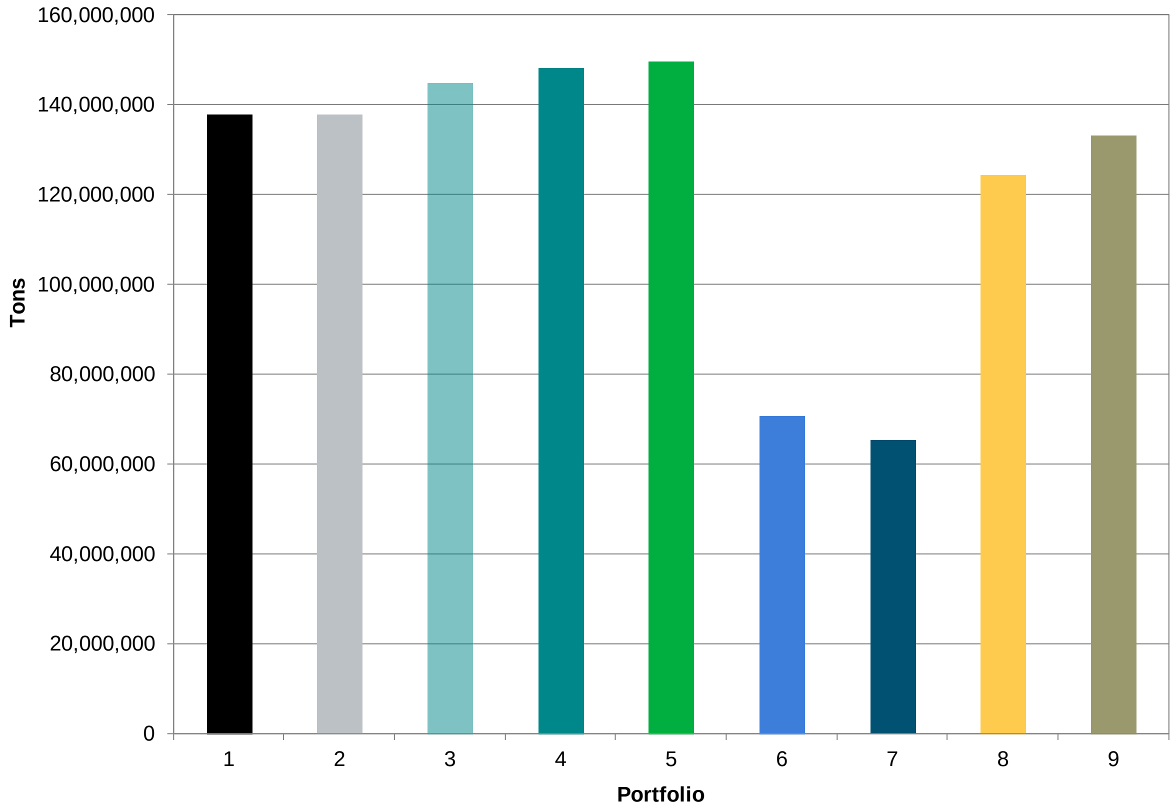


Figure 9.2 Total CO_2 emissions for 2013–2032

NO_x Emissions

Figure 9.3 shows the total NO_x emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced NO_x emissions. The reduced emissions are because a CCCT resource emits approximately 2 percent of the NO_x per MWh that Idaho Power coal-fired generation resources emit on average.

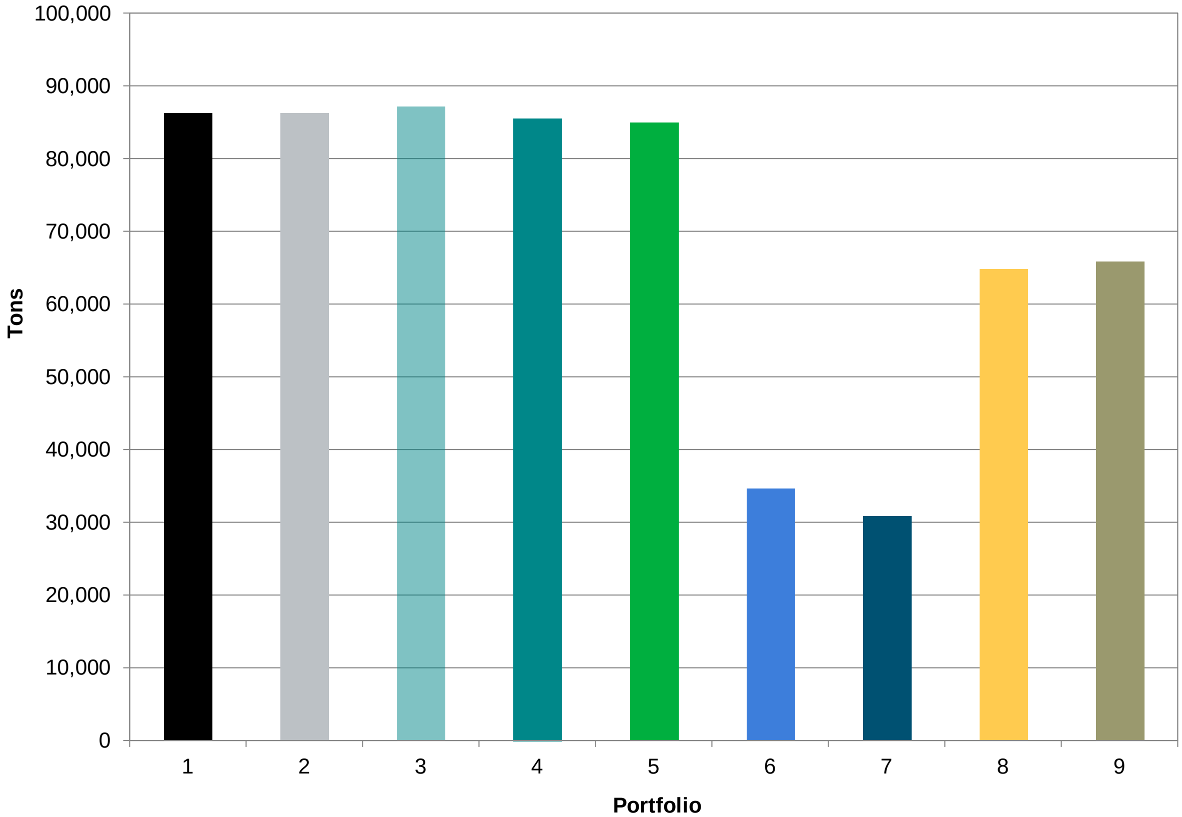


Figure 9.3 Total NO_x emissions for 2013–2032

SO_2 Emissions

Figure 9.4 shows the total SO_2 emissions for each portfolio analyzed for the 20-year planning period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced SO_2 emissions. The reduced emissions are because a CCCT resource emits approximately 1 percent of the SO_2 per MWh that Idaho Power coal-fired generation resources emit on average.

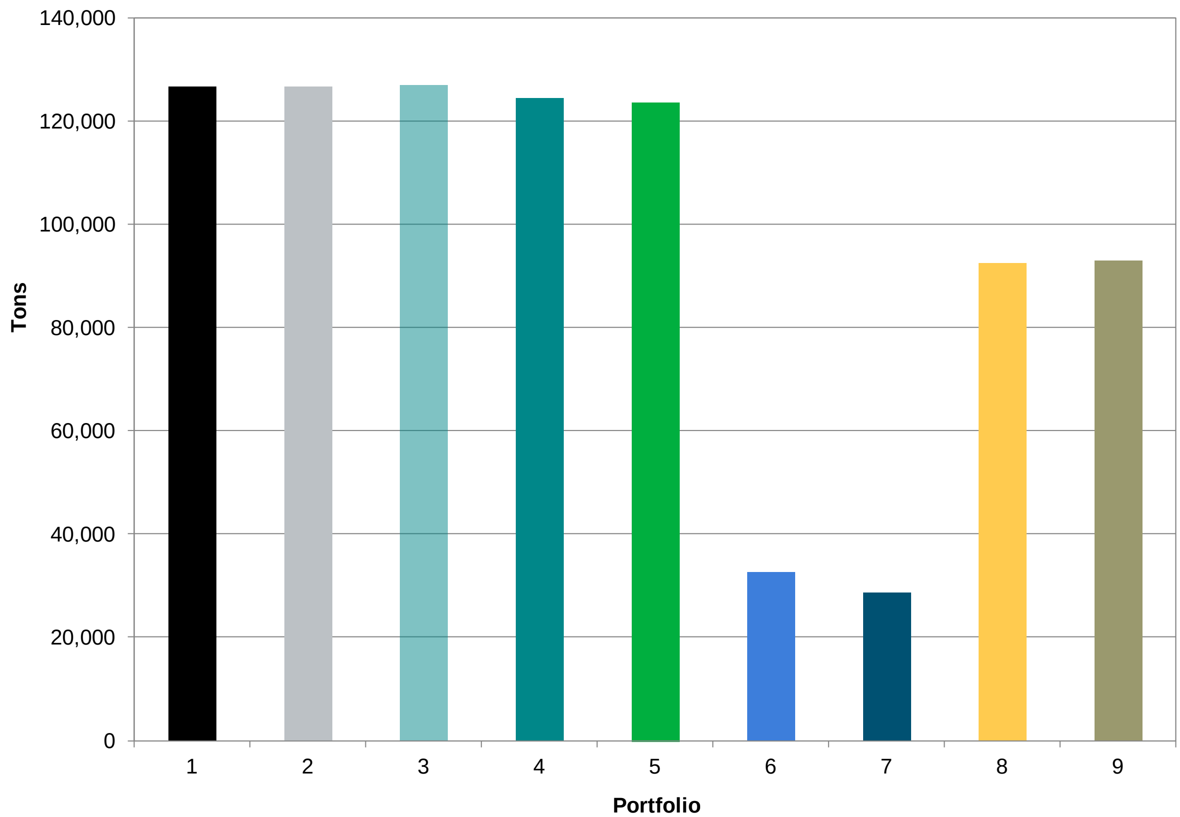


Figure 9.4 Total SO_2 emissions for 2013–2032

Hg Emissions

Figure 9.5 shows the total Hg emissions for each portfolio analyzed for the 20-year period. The portfolios that replace the coal resources and the portfolios that convert coal-fired generation to natural gas-fired generation have reduced Hg emissions. The reduced emissions are because CCCT resources do not have Hg emissions. Coal fuel contains traces of Hg.

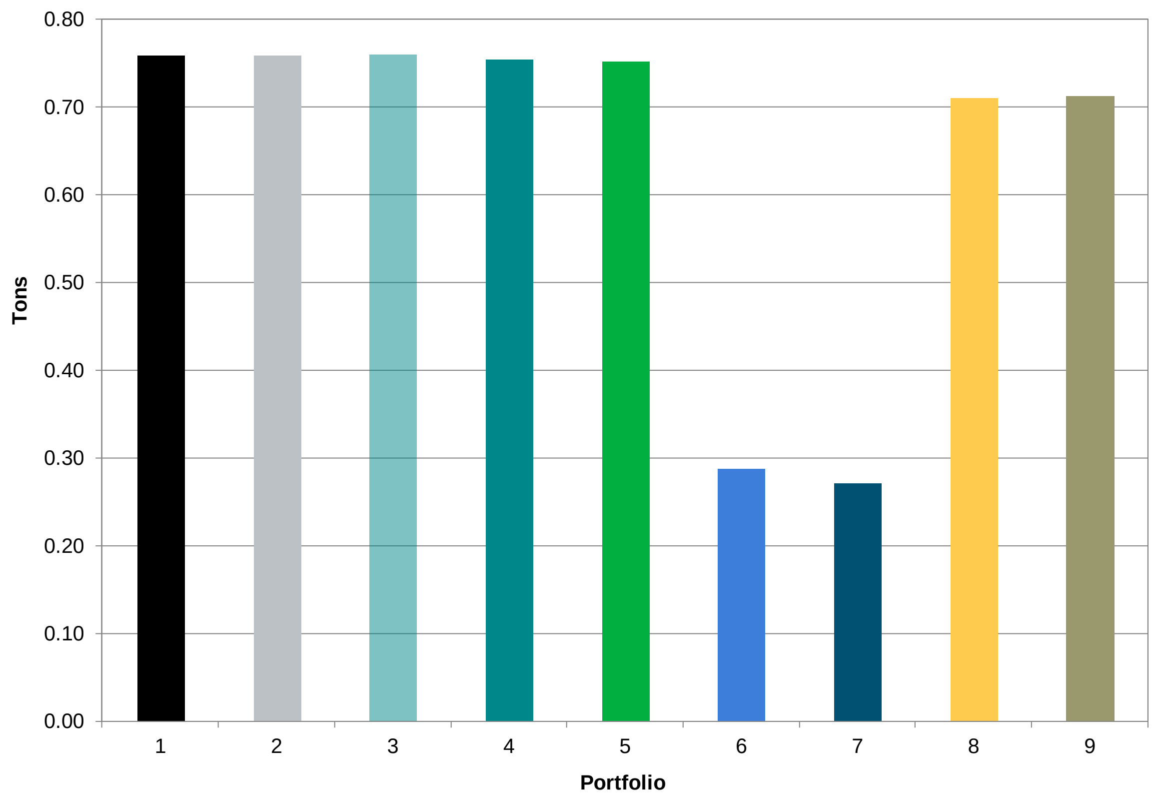


Figure 9.5 Total Hg emissions for 2013–2032

Stochastic Analysis

The stochastic analysis is an extension of the risk analysis of the resource alternatives presented in Chapter 7. The stochastic analysis simulates a variety of possible futures and calculates the resource portfolio performance in each of the futures.

Idaho Power identified the following four variables for the stochastic simulation:

1. *Natural gas price*—The natural gas price follows a log-normal distribution centered on the planning period forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2012. The serial correlation factor is 0.65.

2. *Customer load*—The customer load follows a normal distribution and is correlated with the Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

3. *Hydroelectric variability*—The hydroelectric variability follows a normal distribution. The Idaho Power-owned hydroelectric generation is serial correlated with the Pacific Northwest regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from the 1928 through 2009.

4. *Carbon adder*—Idaho Power and the IRP Advisory Council identified three carbon-adder scenarios: low, planning, and high. Idaho Power stratified the stochastic simulation, and one-third of the stochastic simulations were drawn from each of the three carbon-adder scenarios.

Idaho Power created a set of 102 simulations based on the four stochastic variables. Idaho Power then calculated the TRC of each of the nine resource portfolios for each of the 102 simulations using the Aurora model. Each simulation was reduced to one numerical value—the NPV of the total cost to meet the customer load over the 20-year planning period. Figure 9.6 shows the stochastic simulations.

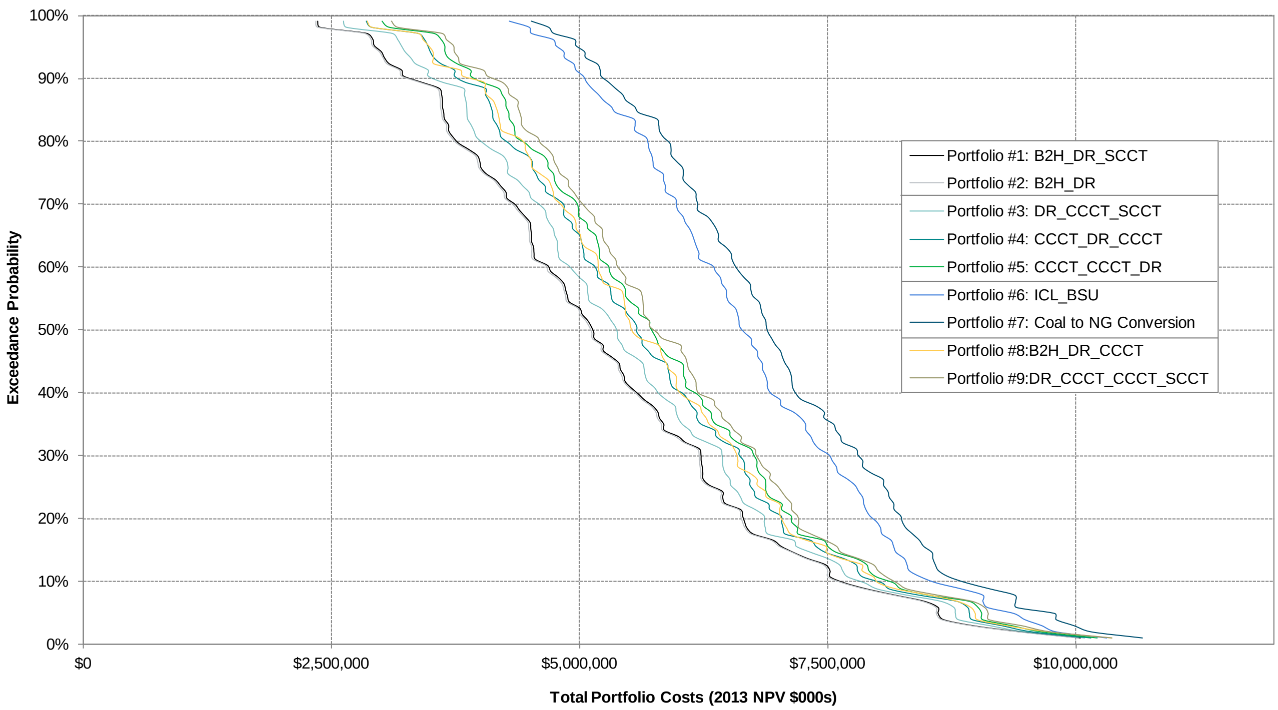


Figure 9.6 Portfolio stochastic analysis

Figure 9.6 shows the NPV of the portfolio cost on the horizontal axis and the exceedance probability on the vertical axis. The exceedance probability is the likelihood a resource portfolio will cost more than a certain amount. For example, in 50 percent of the simulations, resource portfolio 2 cost more than approximately $5.2 billion.

Resource portfolio 2, which relies on Boardman to Hemingway and Idaho Power's demand response programs to meet customer load, is the lowest-cost resource portfolio in all the simulations. The resource alternative analysis presented in Chapter 7 indicated that Northwest transmission, such as the Boardman to Hemingway transmission line, is the lowest-cost resource addition. The stochastic analysis confirms the cost-effectiveness of the Boardman to Hemingway line. In general, resource portfolios that contain the Boardman to Hemingway transmission line are less costly than the resource portfolios with alternatives to the Boardman to Hemingway line.

As expected, resource portfolios that replace generation resources cost more than resource portfolios that continue operations at the existing Idaho Power generation facilities. The resource portfolios replacing all of the coal generation have the highest cost and are represented by the two lines on the right side of the graph.

Carbon-Adder Analysis

During the IRP Advisory Council meetings in April and May, several IRP Advisory Council members questioned the effect of carbon-adder prices on Idaho Power's resource acquisition decisions. As described previously, the stochastic results demonstrated that resource portfolio 2 is the preferred resource portfolio. The IRP Advisory Council members' question was, "At what carbon adder does Idaho Power choose a different resource portfolio than resource portfolio 2?"

Idaho Power analyzed the IRP Advisory Council's question by increasing the price of the carbon adder beyond the values selected for the high-carbon scenario and extrapolated the trends in resource portfolio costs. The supplemental carbon analysis focuses on two of the resource portfolios: the preferred resource portfolio—resource portfolio 2—and the lowest-cost coal-retirement resource portfolio—resource portfolio 6. (Resource portfolio 6 was suggested by IRP Advisory Council members representing the ICL and BSU.) The results of the analysis are shown in Figure 9.7.

Figure 9.7 shows that at a carbon adder of approximately $45 per ton in 2018, the preferred resource portfolio would change from resource portfolio 2 to resource portfolio 6. (In 2018, the IRP high-carbon scenario has a value of $35 per ton.) The supplemental carbon analysis shows that sufficiently high carbon prices can affect Idaho Power resource acquisition decisions. Much lower carbon-adder values can affect the daily resource dispatch decisions under certain conditions as described previously in the Carbon Adder section.

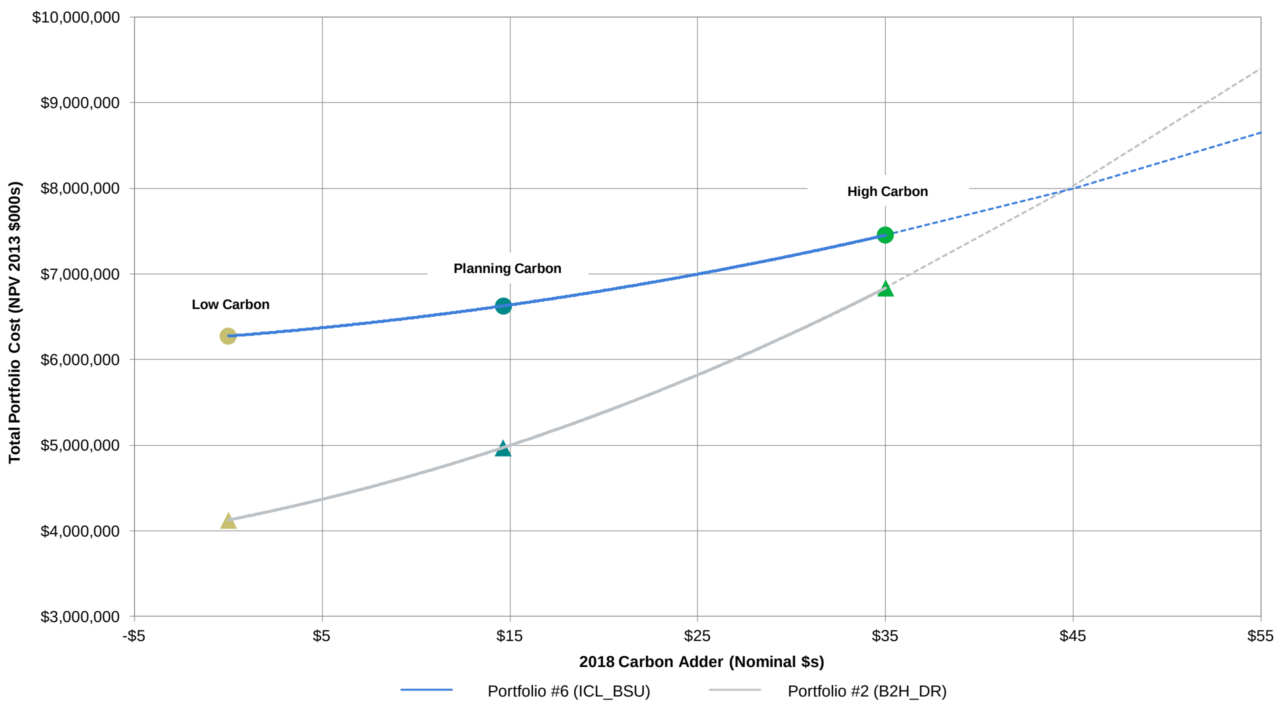


Figure 9.7 Stochastic-based carbon-adder tipping point

Capacity Planning Margin

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

As part of preparing the 2013 IRP, Idaho Power 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 the expected-case (50^{th}-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin is also roughly equivalent to a loss-of-load expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.3.

Table 9.3 Capacity planning margin

	July 13	July 14	July 15	July 16	July 17	July 18	July 19	July 20	July 21	July 22	July 23	July 24	July 25	July 26	July 27	July 28	July 29	July 30	July 31	July 32
Load and Resource Balance																				
Peak-Hour Forecast (50th%)	(3,189)	(3,245)	(3,294)	(3,335)	(3,387)	(3,437)	(3,489)	(3,544)	(3,601)	(3,651)	(3,701)	(3,748)	(3,790)	(3,836)	(3,888)	(3,936)	(3,984)	(4,045)	(4,097)	(4,147)
Existing Resources																				
Coal																				
Jim Bridger	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703
North Valmy	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263	263
Boardman	58	58	58	58	58	58	58	58	–	–	–	–	–	–	–	–	–	–	–	–
Coal Total	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**1,024**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**	**966**
Gas																				
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Gas Total	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Hydroelectric																				
Hydroelectric (50th%)—HCC	1,170	1,168	1,168	1,165	1,162	1,160	1,157	1,154	1,151	1,148	1,145	1,142	1,139	1,136	1,133	1,133	1,133	1,133	1,133	1,133
Hydroelectric (50th%)—Other	311	311	311	311	310	310	309	309	308	307	307	306	306	305	304	304	304	304	304	304
Shoshone Falls Upgrade (50th%)	–	–	–	–	–	–	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Shoshone–Bannock Water Lease	48	48	48	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hydroelectric Total (50th%)	**1,529**	**1,526**	**1,527**	**1,476**	**1,473**	**1,470**	**1,468**	**1,465**	**1,461**	**1,458**	**1,454**	**1,450**	**1,447**	**1,443**	**1,440**	**1,440**	**1,440**	**1,440**	**1,440**	**1,440**
CSPP (PURPA) Total	**177**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**	**189**
PPAs																				
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Clatskanie Exchange—Take	6	6	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Clatskanie Exchange—Return	0	0	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PPAs Total	**41**	**41**	**41**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**	**35**

Table 9.3 Capacity planning margin (continued)

	July 13	July 14	July 15	July 16	July 17	July 18	July 19	July 20	July 21	July 22	July 23	July 24	July 25	July 26	July 27	July 28	July 29	July 30	July 31	July 32
Firm Pacific Northwest Import Capability Total	**194**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**290**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**	**237**
Gas Peakers Total	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**	**416**
Existing Resource Subtotal	**3,681**	**3,733**	**3,733**	**3,676**	**3,673**	**3,670**	**3,669**	**3,665**	**3,657**	**3,601**	**3,597**	**3,593**	**3,590**	**3,586**	**3,582**	**3,582**	**3,582**	**3,582**	**3,582**	**3,582**
Monthly Surplus/Deficit	**492**	**488**	**439**	**341**	**286**	**233**	**180**	**122**	**56**	**(50)**	**(104)**	**(155)**	**(201)**	**(250)**	**(306)**	**(354)**	**(402)**	**(462)**	**(515)**	**(564)**
2013 IRP DSM (Energy Efficiency)																				
Irrigation	3	6	8	10	11	13	15	17	20	22	26	29	33	38	43	48	54	56	58	61
Commercial	7	13	20	25	30	36	41	47	53	60	67	74	80	86	92	98	104	109	114	119
Residential	0	0	1	2	3	6	9	8	8	8	9	11	14	18	23	29	33	38	42	46
Total New DSM Peak Reduction	**10**	**20**	**29**	**37**	**45**	**55**	**65**	**72**	**80**	**91**	**101**	**114**	**127**	**142**	**158**	**175**	**191**	**202**	**214**	**226**
Remaining Monthly Surplus/Deficit	**502**	**507**	**468**	**377**	**331**	**288**	**244**	**193**	**137**	**41**	**(3)**	**(41)**	**(73)**	**(108)**	**(148)**	**(179)**	**(211)**	**(260)**	**(300)**	**(338)**
2013 IRP Resources																				
2016 Demand Response	–	–	–	150	150	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2018 Boardman to Hemingway	–	–	–	–	–	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2024 Demand Response	–	–	–	–	–	–	–	–	–	–	–	370	370	370	370	370	370	370	370	370
New Resource Subtotal	**0**	**0**	**0**	**150**	**150**	**500**	**500**	**500**	**500**	**500**	**500**	**870**	**870**	**870**	**870**	**870**	**870**	**870**	**870**	**870**
Remaining Monthly Surplus/Deficit	**502**	**507**	**468**	**527**	**481**	**788**	**744**	**693**	**637**	**541**	**497**	**829**	**797**	**762**	**722**	**691**	**659**	**610**	**570**	**532**
Planning Margin	**16%**	**16%**	**14%**	**16%**	**14%**	**23%**	**21%**	**20%**	**18%**	**15%**	**13%**	**22%**	**21%**	**20%**	**19%**	**18%**	**17%**	**15%**	**14%**	**13%**

Flexible Resource Needs Assessment

In Order No. 12-013 issued on January 19, 2012, as part of Docket No. UM 1461 on the "Investigation of Matters related to Electric Vehicle Charging," the OPUC adopted the following staff-proposed guidelines:

1. *Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.*

2. *Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.*

3. *Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.*

Idaho Power relies primarily on its hydroelectric system to meet reserve requirements. Increases in Idaho Power's reserve requirements due to load-growth projections can be adequately handled with the existing hydroelectric generation.

Changes in intermittent resources, such as wind generation, will be the primary driver of future reserve requirements. Idaho Power's *Wind Integration Study Report*[4] details the effects of adding additional wind capacity to the Idaho Power system. The balancing requirements for various levels of wind integration are documented along with an estimated cost for integration at those levels.

Idaho Power has reviewed the guidelines and the preferred resource portfolio—resource portfolio 2. Specifically, resource portfolio 2 proposed to add no new intermittent renewable generation over the 20-year planning horizon. Idaho Power does not forecast a significant increase in intermittent generation from PURPA or a significant increase in intermittent renewable generation from the customer programs. Idaho Power does not forecast a need to increase flexible capacity associated with implementing resource portfolio 2.

Resource portfolio 2 adds two resources—the Boardman to Hemingway transmission line and demand response programs. Resource portfolio 2 is not expected to increase the supply of flexible resources over the 20-year planning horizon.

[4] The *Wind Integration Study Report* can be found on Idaho Power's website at: http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf

Idaho Power does not project a gap between demand and the supply of flexible capacity. Electric vehicles are not expected to significantly affect the Idaho Power load and resource balance over the 20-year planning horizon. The effect of electric vehicles over the 20-year planning period is described in *Appendix A—Sales and Load Forecast*.

Loss of Load Expectation

Idaho Power used a spreadsheet model[5] to calculate the LOLE for the nine portfolios identified in the 2013 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred portfolio. As mentioned in the previous section, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require the use of the transmission capacity. The 2013 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 and purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load for the 10 peak hours in a given year. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a 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 chose to calculate a LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5 to 1 hour per year.

The results of the LOLE probability analysis are shown in Figure 9.8. Several portfolios result in a LOLE greater than two, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The LOLE in 2031 is high for many portfolios due to the number of high load days and the assumptions made for demand response (only available for 10 peak days). The results indicate that resource portfolios 1 and 2 perform well over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

[5] Based on Roy Billinton's *Power System Reliability Evaluation*, chapters 2 and 3. 1970.

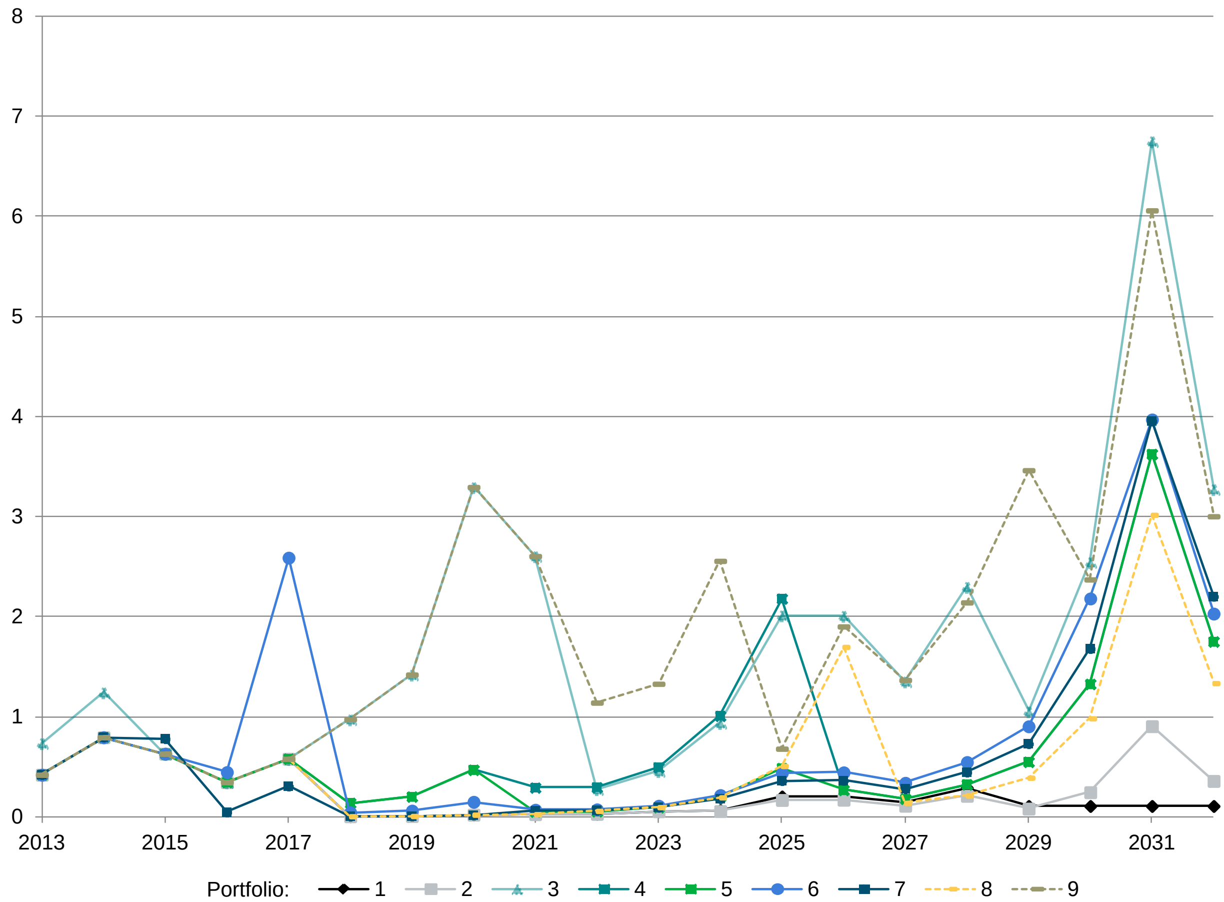


Figure 9.8 LOLE (hours per year)

Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In 2005, the NWPCC and the BPA created the Resource Adequacy Forum and asked the forum develop an adequacy standard for the Pacific Northwest regional power supply (Idaho Power participates as a member of the Resource Adequacy Forum). The purpose of the resource adequacy standard is to provide an early warning should resource development fail to keep pace with demand growth. The analytical information generated with each resource adequacy assessment assists the regional utilities when preparing their individual IRPs.

The NWPCC assesses the adequacy of the regional power supply annually. The latest assessment assumes the existing resources and conservation levels identified in the NWPCC 6th power plan, and the resource assessment shows the regional power supply to be slightly inadequate by 2017 (NWPCC document no. 2012-12). The adequacy assessment notes that adding 350 MW of dispatchable resource capacity brings the Pacific Northwest resource adequacy back within the 5 percent adequacy standard. The adequacy assessment indicates that the majority of potential problems are short-term capacity deficits. The regional resource assessment is available from the NWPCC at:

http://www.nwcouncil.org/energy/resource/2012-12/

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2013 IRP analysis indicates Idaho Power resource deficits occur in the summer months of June, July, August, and September. July is the most critical month for Idaho Power. The Northwest Regional Adequacy Assessment indicates that January, February, and, to a lesser extent, August are the most critical months for the overall Pacific Northwest region. The Boardman to Hemingway transmission line is a regional resource that will assist Idaho Power and the larger Pacific Northwest in addressing their opposing seasonal capacity deficits.

The Idaho Power resource planning process is consistent with the NWPCC resource adequacy studies. The Idaho Power stochastic analysis indicates that even under high load, high electricity prices, and low water conditions, resource portfolio 2 (containing the Boardman to Hemingway transmission project) is the lowest-cost resource alternative.

10. Action Plan

Action Plan (2013–2032)

Resource portfolio 2 is the preferred resource portfolio. The Boardman to Hemingway transmission line with associated market purchases is the major resource addition identified in the preferred resource portfolio. A new transmission line connecting Idaho Power to the Pacific Northwest was mentioned as early as the 2000 IRP, and the upgrade was specifically identified in the 2006 IRP. Idaho Power continues efforts to acquire the necessary regulatory approvals and permits to begin construction. Construction of the Boardman to Hemingway transmission line is expected to be substantially complete, and the line is expected to be operational, in 2018. The action plan to implement resource portfolio 2 is shown in Table 10.1.

Table 10.1 Portfolio 2 action plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings.
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings.
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology.
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology.
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW.
2018	Boardman to Hemingway	Transmission line complete and in service.
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031.

Idaho Power continues efforts to acquire the necessary regulatory approvals and permits for the Gateway West project. As discussed in Chapter 6, Gateway West will relieve transmission constraints and provide the option to locate future generation resources east of the Treasure Valley load center.

For the purpose of this resource plan, the company's demand response programs are assumed to be used throughout the planning period to meet resource needs. Idaho Power expects to use up to 150 MW of demand response prior to the completion of the Boardman to Hemingway transmission line in 2018. Idaho Power applied demand response in approximate 50-MW steps for the 2013 IRP. In the analysis, Idaho Power tailored the level of demand response to the identified deficit. For example, the projected deficit in 2016 is 89 MW, and the projected deficit in 2017 is 137 MW. The level of demand response projected for 2016 was approximately 100 MW and approximately 150 MW in 2017. Idaho Power plans to have a demand response capacity available beginning in 2024 of up to approximately 370 MW by 2031. Like the 2016 to 2017 time period, demand response for later time periods was applied in 50-MW increments for the resource portfolio analysis. The level of demand response capacity available will be based on the deficits identified through the IRP process or based on operational needs identified between IRP cycles.

The Boardman to Hemingway transmission line is a significant interstate construction project with federal, state, and local permitting and line routing issues. In addition, the project has multiple business partners, which further complicates project management and scheduling. Idaho Power intends to use the demand response programs to adapt to schedule variations that may occur on the Boardman to Hemingway project.

Resource portfolio 2—the preferred resource portfolio—includes continued operations at the Jim Bridger and North Valmy coal facilities. Idaho Power intends to operate its facilities, including the coal-fired generation plants, in full compliance with environmental regulations. Continued coal operations at the Jim Bridger and North Valmy plants are expected to require the installation of additional emission-control systems. Idaho Power expects that the financial commitment to install the emission-control systems at the Jim Bridger and North Valmy coal-fired generation stations will be required approximately two years prior to their installation and operation. The approximate financial commitment dates are identified in the action plan.

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

Conclusion

The Boardman to Hemingway transmission line with associated market purchases is the primary resource addition in the preferred resource portfolio. The Boardman to Hemingway transmission project has outperformed the other resource portfolios in the 2013 IRP. Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction.

Wild horses near the Hemingway Substation.

The 2013 IRP confirms that the Boardman to Hemingway transmission line is a very cost-effective resource. The Resource Alternatives Analysis section of the 2013 IRP indicates that the Boardman to Hemingway line is more cost effective than the other supply-side resources studied. Chapter 9 of the 2013 IRP indicates that resource portfolios containing the Boardman to

Hemingway line are more cost effective than resource portfolios containing alternatives to the Boardman to Hemingway line.

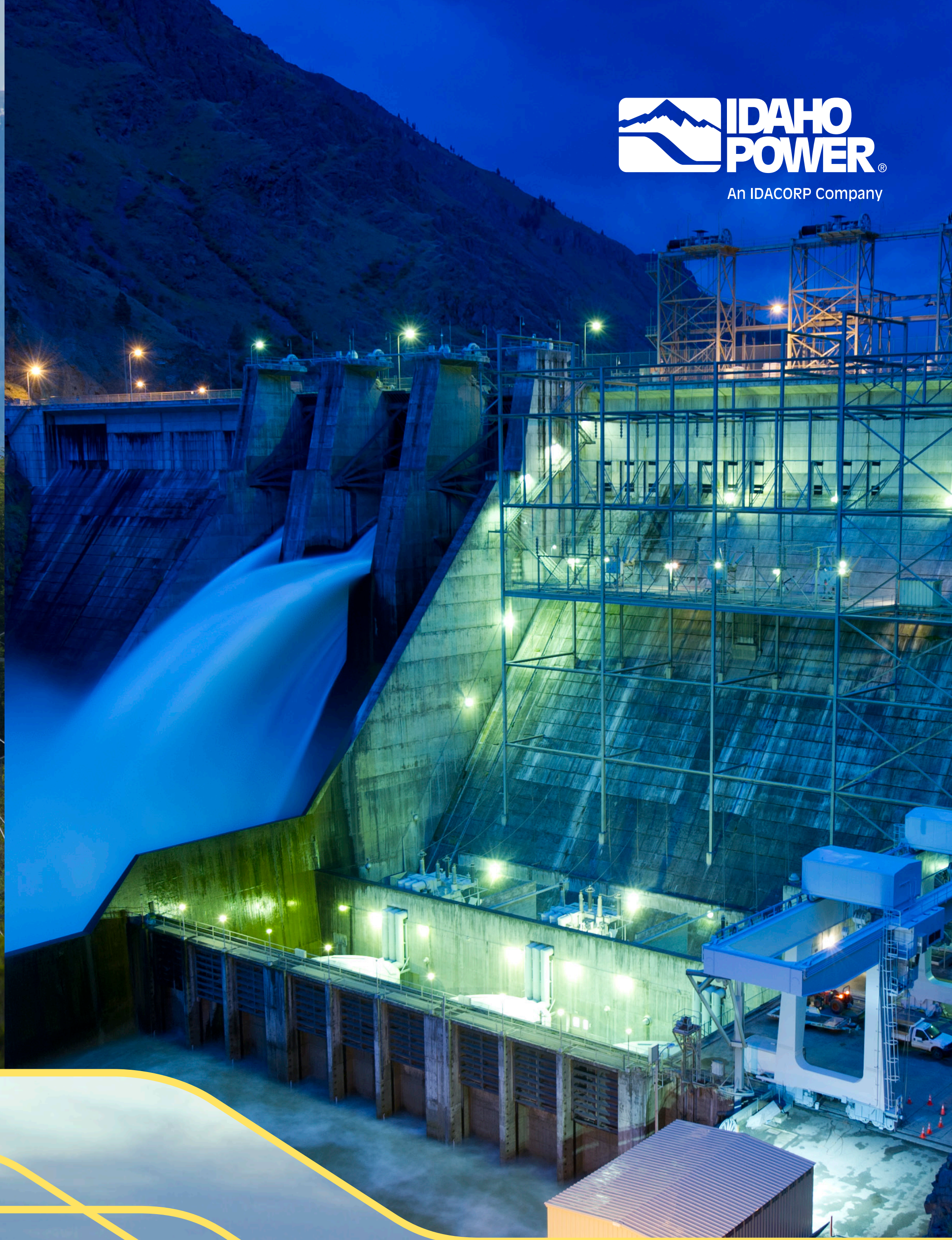
Idaho Power treated the Boardman to Hemingway Transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates that it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the Boardman to Hemingway transmission line.

The company's demand response programs will be used throughout the planning period to meet resource needs. The level of demand response capacity available will be based on the deficits identified through the IRP process or on operational needs identified between IRP cycles. The demand response programs may also be used to adapt to schedule variations that may occur on the Boardman to Hemingway transmission project.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRP Advisory Council members and the public for their contributions to the 2013 IRP. The IRP Advisory Council discussed many technical aspects of the 2013 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to Idaho Power facilities. Idaho Power's resource plan is better because of the contributions from the IRP Advisory Council members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2015. In addition, Idaho Power updates the IRP approximately one year after the resource plan is acknowledged by the OPUC. The regional utility market is constantly changing, and Idaho Power anticipates that the 2013 IRP action plan may be adjusted in the next IRP filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC.

This page left blank intentionally.



IDAHO POWER
An IDACORP Company

2013 Integrated Resource Plan

APPENDIX A

Sales and Load Forecast

June 2013

2013

Integrated Resource Plan

APPENDIX A

Sales and Load Forecast

June 2013

IDAHO POWER®
An IDACORP Company

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

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

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

SAFE HARBOR STATEMENT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

This page left blank intentionally.

INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as an appendix to its *2013 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2013 through 2032.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load 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. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70th-percentile and 90th-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Because actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered: a 70th-percentile average load forecast and 90th-percentile average load forecast. The 70th-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90th-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,154 average megawatts (aMW) in the year 2032 from the 2013 forecast load of 1,759 aMW. The expected-case forecast system load growth rate averages 1.1 percent per year over the 20-year planning period (2013–2032). In the more critical 70th-percentile load forecast used for resource planning, the system load is forecast to reach 2,201 aMW by 2032. The Idaho Power system peak load (95th percentile) is forecast to grow to 4,418 megawatts (MW) in the year 2032 from the actual system summer peak of 3,245 MW that occurred on Thursday, July 12, 2012, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2013–2032). The number of Idaho Power active retail customers is expected to increase from the December 2012 level of 500,000 customers to over 667,000 customers at year-end 2032.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics June 2012 macroeconomic forecast strongly influenced *Appendix A—Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated into the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A—Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2012 Annual Report*. This report is Appendix B to the 2013 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon regulations and subsequent higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high- and low-load growth scenarios previously described. The impact of carbon legislation on the load forecast is reflected in retail electricity prices, which are a driver in the major sector sales forecasting model. The alternative sales and load scenarios of *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for the sales and load forecast is presented in Appendix A1 of this report.

2013 IRP Sales and Load Forecast

Average Load

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. The expected recovery reflected in the economic forecast used for the 2011 IRP was determined too optimistic in terms of a rapid recovery from the recession. The updated variables driving the 2013 forecast reflect this recent performance. The stalled recovery in the national and, to a lesser extent, service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic series to date. Longer-term, higher-retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2013 IRP load forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 74 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The 2011 IRP sales and load forecast included a high-probability new customer referred to as "Special". At the time the forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. At that time, it was determined that the likelihood of the load materializing was sufficient to warrant its inclusion in the IRP. Ultimately, the contract was not completed and the load did not materialize as expected. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy originally anticipated are excluded from this sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, in 2011 and 2012, residential and commercial customer growth, along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yields higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. 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*.

- The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop patterns. Farmers have taken advantage of the commodities market by planting greater acreage than in the recent past. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices. The continued conversion of irrigation systems from labor-intensive hand-lines to electrically operated pivot sprinklers continues to impact increased irrigation energy consumption.

Peak-Hour Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed Hoku Materials will not come on-line, and the 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

- As referenced previously, the 2011 IRP sales and load forecast included a new customer referred to as "Special" that failed to materialize. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 60 MW of peak demand originally anticipated is excluded from this sales and load forecast.

- The 2013 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2013 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts to effectively plan for demand response and supply-side resources in meeting peak demand. Demand response programs impacts are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the 50^{th}, 90^{th}, and 95^{th} percentiles of occurrence for each month of the year.

- Historical peak-demand data is considered in the peak-model regressions. Based on a historical comparison of percentiles, the July 2002, July 2003, June 2005, and July 2005 peak-day temperatures were near the 100^{th} percentile, and their addition to the regression models impacted forecast results. More recently, all-time system peaks were reached in July 2007, June 2008, and July 2012 and were incorporated into the peak forecast model regressions.

- Idaho Power continues to use a median peak-day temperature driver in lieu of an average peak-day temperature driver. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1982 to 2011 time period (the most recent 30 years).

This page left blank intentionally.

OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); the Idaho National Laboratory (INL); and Hoku Materials. These four special-contract customers are combined into a single forecast category labeled additional firm load. Last, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2013 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space-heating demand that normally occurs in December, January, or February; and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning (A/C) use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic 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.

Fuel Prices

Fuel prices, in combination with service-area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

Table 1. Residential fuel-price escalation (2013–2032) (average annual percent change)

	Nominal	Real*
Electricity—2013 IRP	3.2%	1.3%
Electricity—2011 IRP	1.5%	(0.1%)
Natural Gas	3.2%	1.3%

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1972 to 2012 and over the forecast period 2013 to 2032. Both nominal and real prices are shown. In the 2013 IRP, nominal electricity prices are expected to climb to nearly 17 cents per kilowatt-hour (kWh) by the end of the forecast period in 2032. Real electricity prices (inflation adjusted) are expected to increase over the forecast period at an average rate of 1.3 percent annually. In the 2011 IRP, nominal electricity prices were assumed to slowly climb to nearly 13 cents per kWh by 2032, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of -0.1 percent annually. The impact of the higher real electricity price forecast on the 2013 IRP load forecast serves to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast yielded higher future prices. The retail prices are mostly higher in the second 10 years of the planning period and impact the sales forecast negatively, a consequence of the inverse relationship between electricity prices and electricity demand.

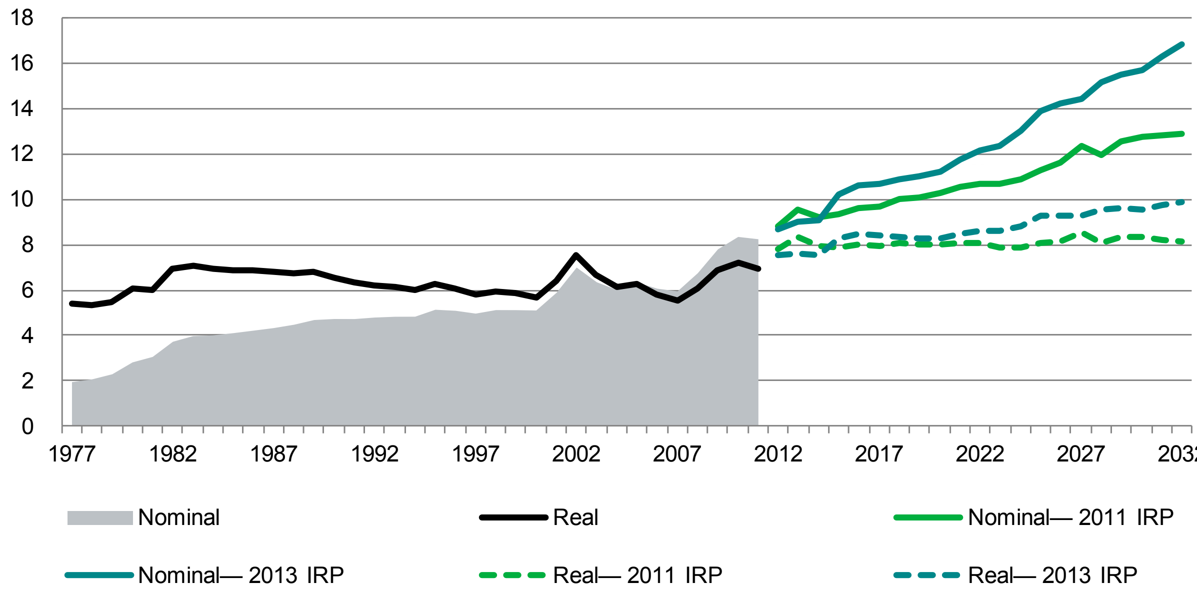


Figure 1. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970 to 2011 and forecast prices from 2012 to 2032. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. The collapse in natural gas prices that began in 2009 led to much lower prices in 2010 and 2011. Nominal natural gas prices are expected to rise slowly through 2014, then more rapidly throughout the remainder of the forecast period until nearly doubling at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

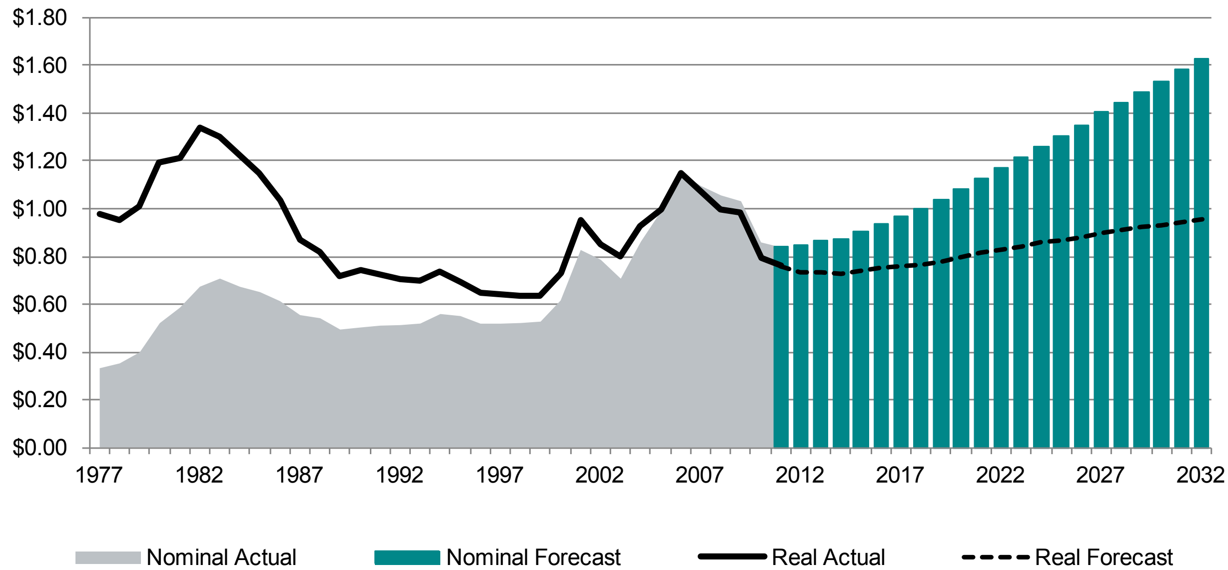


Figure 2. Forecast residential natural gas prices (dollars per therm)

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2013 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles on the system load. The 2011 IRP forecast model relied heavily on the forecast methodologies of the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory. At the time, these models did not have actual consumer adoption data or most recent domestic fuel supply impacts of advanced technologies in crude oil production. The 2013 IRP electric-vehicle forecast update integrates service area vehicle registration data with updated technological and economic variables impacting adoption, as well as vehicle charging behavior. This update also integrates the fuel and technology forecasts of the Department of Energy’s (DOE) National Energy Model (NEM).

The Idaho Power vehicle share forecast is based on a Bass diffusion model of adoption as informed by actual vehicle registration. Load impacts from adoption are derived from assumptions of battery-only and hybrid plug-in shares evident from historical registration data and informed by NEM forecasts. The combined vehicle forecast represents just over 4 percent of new vehicle sales in the service area at the end of the planning period. Battery-only vehicles represent 15 percent of the total, and the updated forecast model reflects a much slower adoption rate than anticipated in the 2011 forecast. The all-electric share is consistent with the DOE Annual Energy Outlook (AEO) 2013 update that forecasts all-electric vehicles at less than 1 percent of sales in 2040.

The resulting impact on the load forecast is about 1 aMW in 2020, reaching approximately 4 aMW at the end of the forecast period in 2032. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, respectively.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption to improve the forecasting model in future forecasts.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation (i.e., there is a 50-percent chance loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1982 to 2011 (the most recent 30 years) was 1,039. The 70th-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90th-percentile HDD is 1,291 and would be exceeded in 1 out of 10 years. The 100th-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70th-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th-percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile, reflecting drier-than-median weather. The 90th-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70^{th}-percentile or 90^{th}-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70^{th}-percentile or 90^{th}-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2013 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

Table 2. Average load and peak-demand forecast scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90^{th} Percentile	90%	1-in-10 years	HDD, CDD, GDD, precipitation
70^{th} Percentile	70%	3-in-10 years	HDD, CDD, GDD, precipitation
Expected Case	50%	1-in-2 years	HDD, CDD, GDD, precipitation
Forecasts of Peak Demand			
95^{th} Percentile	95%	1-in-20 years	Peak-day temperatures
90^{th} Percentile	90%	1-in-10 years	Peak-day temperatures
50^{th} Percentile	50%	1-in-2 years	Peak-day temperatures

The analysis of resource requirements is based on the 70^{th}-percentile average load forecast coupled with the 95^{th}-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50^{th} percentile) average-load forecast and the 90^{th}-percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2013 to 2032 planning period due to high and low economic and demographic conditions. The high- and low-economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1987–2011).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1987–2011). The high- and low-case load forecasts also reflect the integration of existing energy efficiency DSM program effects as a reduction to the average load wintertime forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

Table 3. Forecast probabilities

Probability of Exceeding				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	90%	90%	90%	90%
Expected Case	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser).

Idaho Power system load projections are reported in Table 4 and pictured in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.5 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Low	1,738	1,760	1,826	1,949	0.6%
Expected	1,759	1,842	1,956	2,154	1.1%
High	1,829	1,972	2,145	2,447	1.5%

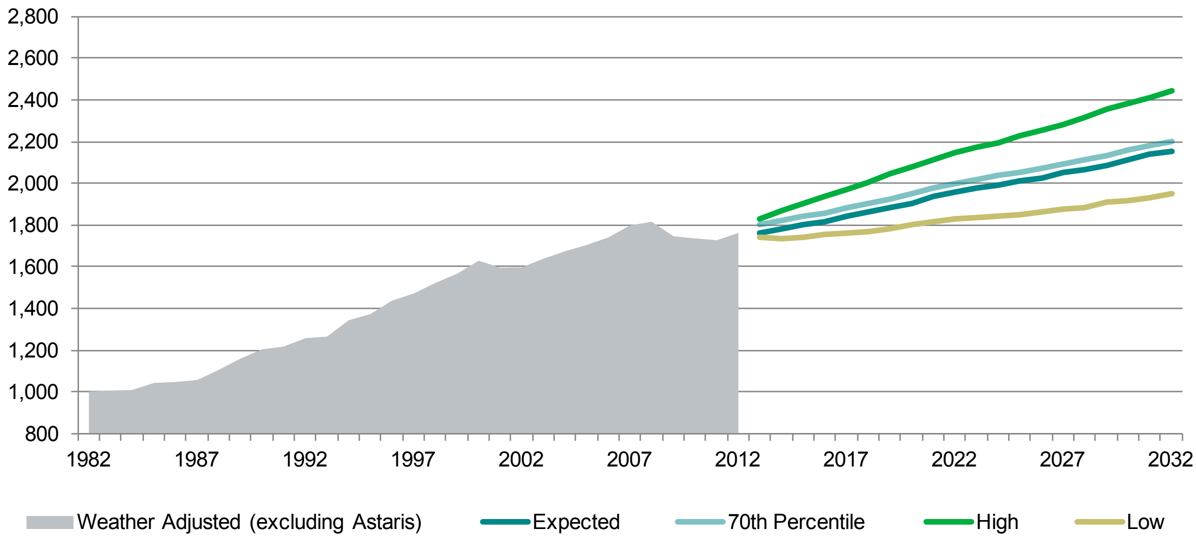


Figure 3. Forecast system load (aMW)

Residential

The expected-case residential load is forecast to increase from 574 aMW in 2013 to 704 aMW in 2032, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 590 aMW in 2013 to 724 aMW in 2032, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

Table 5. Residential load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	623	649	687	763	1.1%
70th Percentile	590	614	650	724	1.1%
Expected Case	574	597	632	704	1.1%

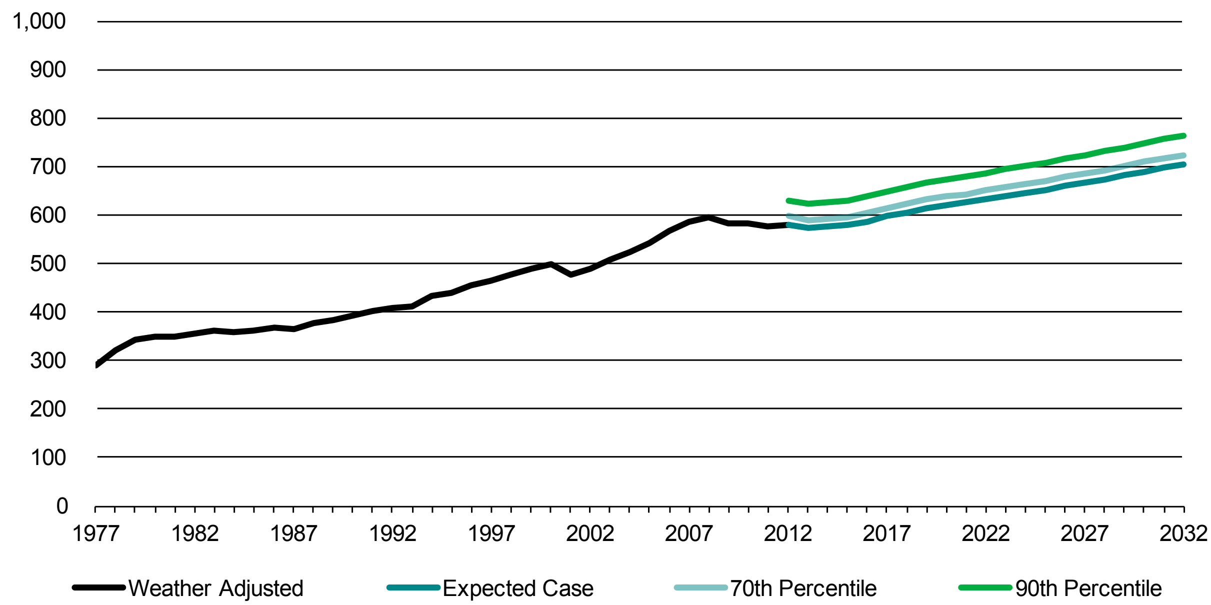


Figure 4. Forecast residential load (aMW)

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1982 and 36 percent of system sales in 2012. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2032. There were 416,000 residential customers as of December 2012. The number of residential customers is projected to increase to approximately 554,000 by December 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average sales per residential customer were 13,700 kWh in 1977. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use served to slow the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2032. Average annual sales per residential customer are shown in Figure 5.

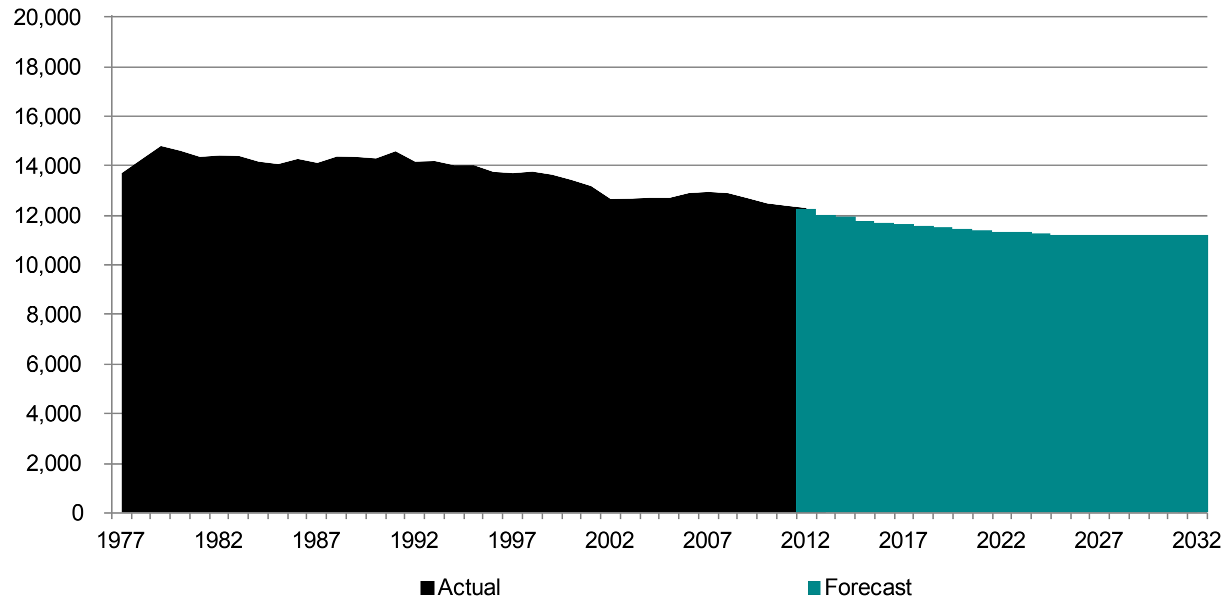


Figure 5. Forecast residential use per customer (weather-adjusted kWh)

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 forecast of county housing stock and demographic data. The residential-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.5 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

Commercial

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other schedules considered part of the commercial category are unmetered general-service, street-lighting service, traffic-control signal-lighting service, and dusk-to-dawn customer lighting.

In the expected-case scenario, the commercial load is projected to increase from 446 aMW in 2013 to 549 aMW in 2032. The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. As referred to previously, the forecast does not include an assumption for growth from new customers that deviate from historical business failure and startup parameters. As summarized in Table 6, the commercial load in the 70th-percentile scenario is projected to increase from 451 aMW in 2013 to 556 aMW in 2032. The commercial load forecasts are illustrated in Figure 6.

Table 6. Commercial load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	463	485	510	572	1.1%
70th Percentile	451	472	496	556	1.1%
Expected Case	446	466	490	549	1.1%

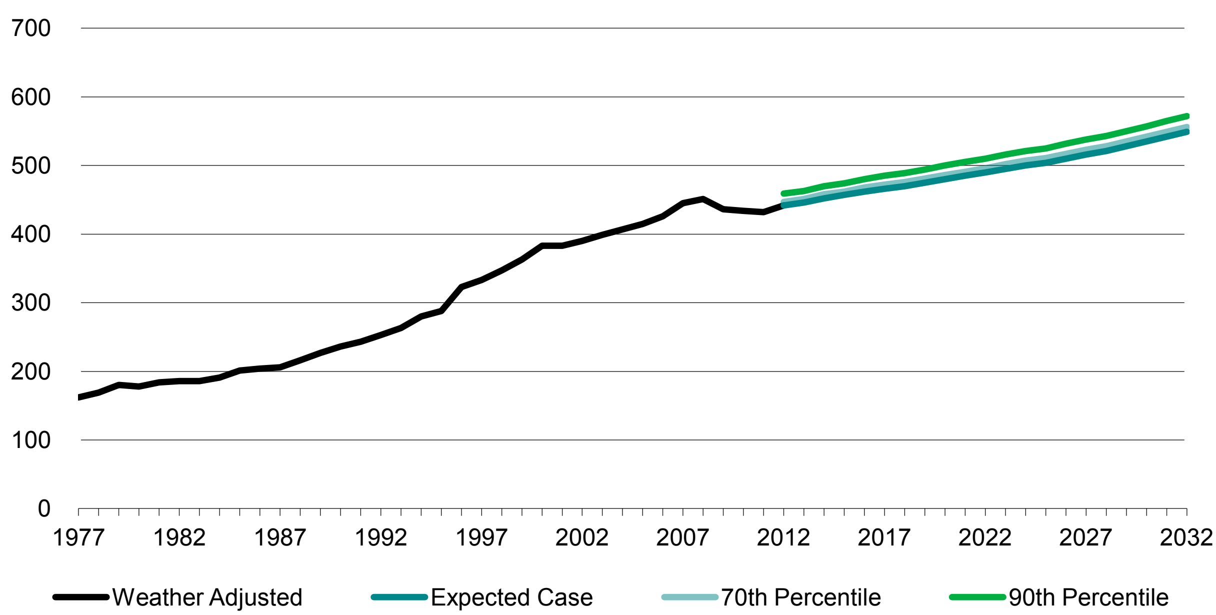


Figure 6. Forecast commercial load (aMW)

As of December 2012, Idaho Power had 66,000 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 1.6 percent, reaching 90,200 customers by 2032. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1982 and nearly 28 percent of system sales in 2012.

The commercial customer proportion of system sales is projected to remain at 28 percent of system sales by 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average consumption per commercial customer increased to a record 67,300 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial use per customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial use per customer through 2007. However, a severe recession in 2008 and 2009 caused commercial use per customer to drop considerably. After flattening out from 2010 to 2012, commercial use per customer is projected to rise slowly through 2014 as the economy recovers, then continue its downward trend. The primary reasons for the long-term decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 53,500 kWh in 2032. The forecast average annual use per commercial customer is shown in Figure 7.

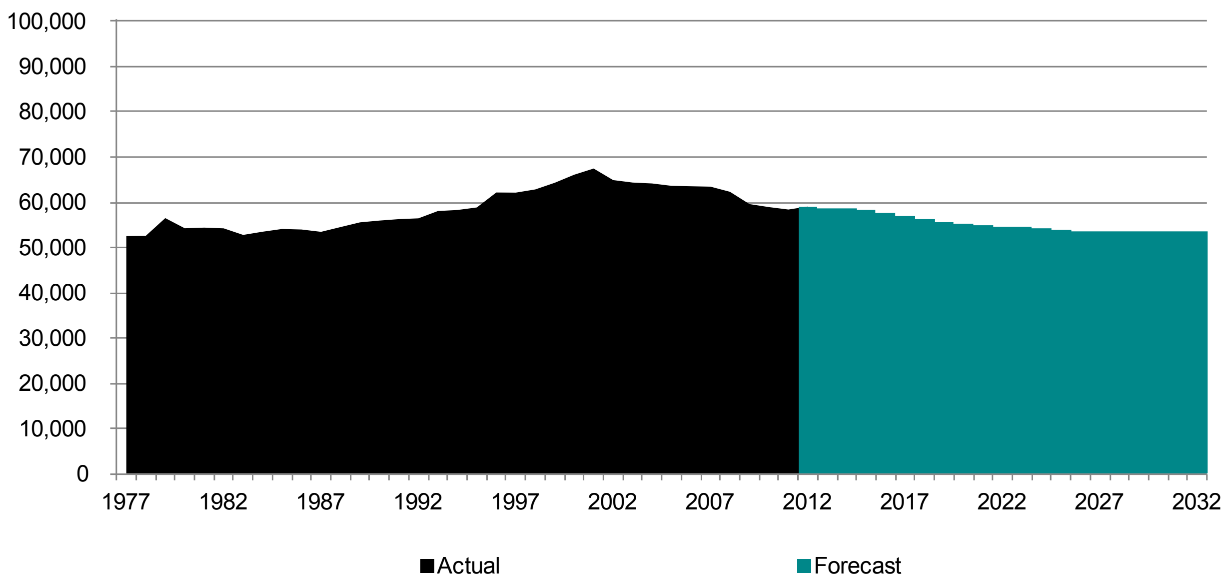


Figure 7. Forecast commercial use per customer (weather-adjusted kWh)

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial-sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.6 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households and service-area employment as derived from

Moody's Analytics forecasts; and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecast DSM, by the commercial-customer forecast.

This page left blank intentionally.

IRRIGATION

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecast period, the expected-case irrigation load is forecast to remain flat at 200 aMW from 2013 to 2032, an average annual compound growth rate of 0 percent. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast no growth in irrigation load from 2013 to 2032. In the 70th-percentile scenario, irrigation load is projected to be 215 aMW in 2013 and 215 aMW in 2032. The individual irrigation load forecasts are reported in Table 7 and Figure 8, which illustrates the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

Table 7. Irrigation load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	235	235	236	235	0.0%
70th Percentile	215	215	216	215	0.0%
Expected Case	200	200	202	200	0.0%

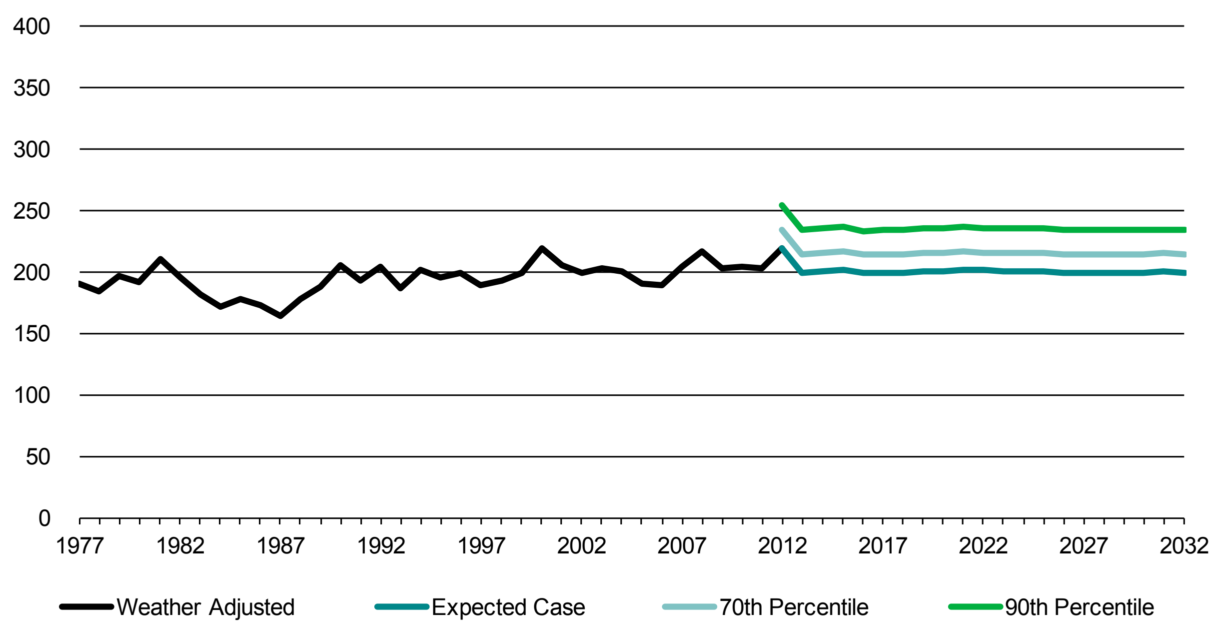


Figure 8. Forecast irrigation load (aMW)

It is important to understand that the annual average loads in Table 7 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 800 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

The 2013 irrigation sales forecast is slightly higher than the 2011 IRP forecast through 2015, likely due to recent high commodity prices and changing crop planting patterns. Farmers have taken advantage of the commodities market by planting increasing levels of acreage. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices influencing demand. The conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2013 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1982 and reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2012, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2032, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 15.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2012, the number of active irrigation accounts had increased to 18,675 and is projected to be nearly 23,000 at the end of the planning period in 2032.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh annually.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

This page left blank intentionally.

INDUSTRIAL

The industrial category is made up of Idaho Power's large power service (Schedule 19) customers with monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2012, the number of industrial customers had risen to 116, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 267 aMW in 2013 to 367 aMW in 2032, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th-percentile scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 9.

Table 8. Industrial load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Expected Case	267	294	319	367	1.7%

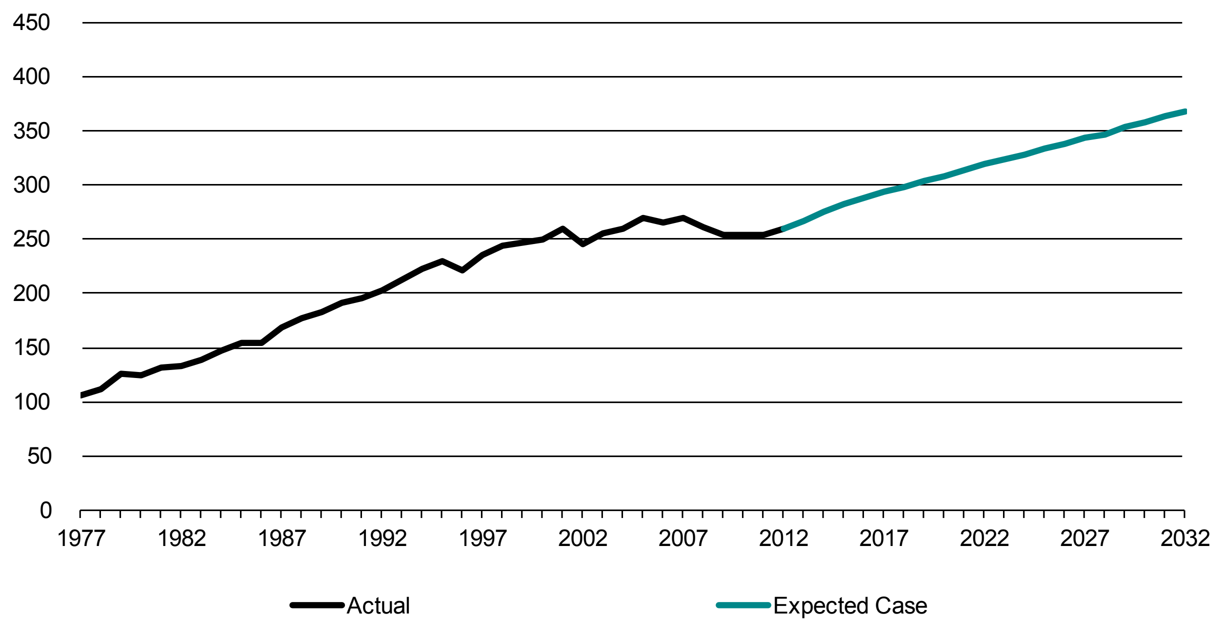


Figure 9. Forecast industrial load (aMW)

The industrial energy forecast is based on the most recent (June 2012) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 primary and transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial-sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 16 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2012 industrial electricity consumption by industry group. By far, the largest share of electricity was consumed by the food manufacturing sector (47%); followed by other industry groups (17%); health care (7%); and computer and electronic product manufacturing, education, and other manufacturing (each representing 6%). As Figure 10 shows, several other industry groups make up the remaining share of the 2012 industrial electricity consumption.

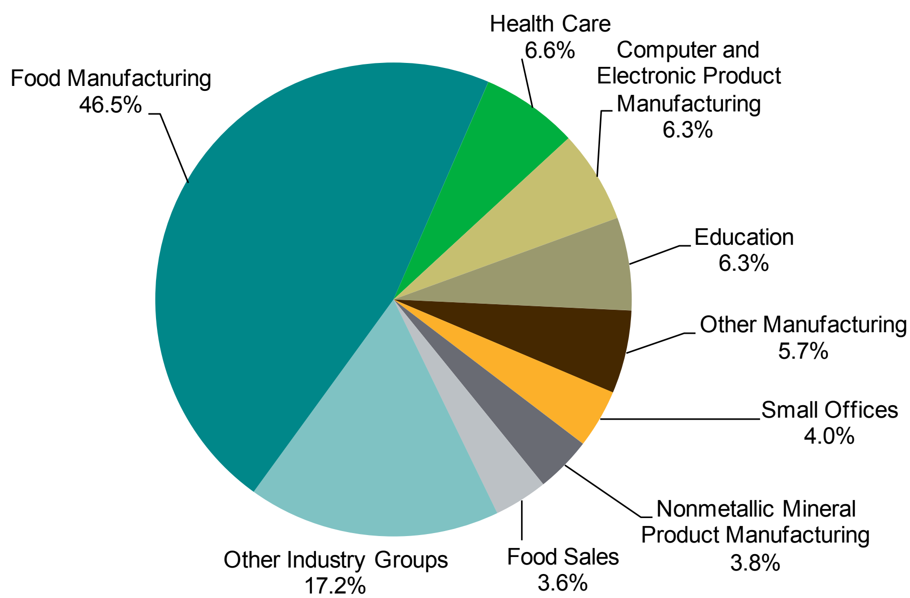


Figure 10. Industrial electricity consumption by industry group (based on 2012 figures)

ADDITIONAL FIRM LOAD

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

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, the INL, and Hoku Materials. The contract with Raft River expired on September 30, 2011.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2013 to 143 aMW in 2032, an average growth rate of 1.1 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70th and 90th-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

Table 9. Additional firm load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
Expected Case	115	121	140	143	1.1%

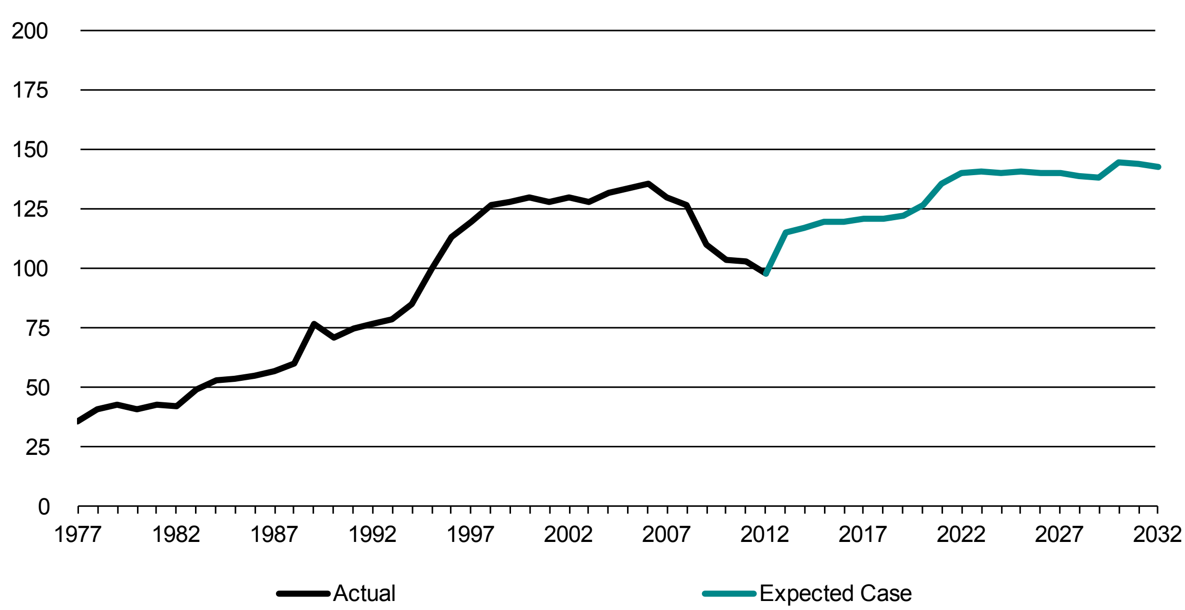


Figure 11. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly in 2013 and 2014, then stay flat throughout the remainder of the planning. The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2032 for the INL. The forecast calls for loads to slowly rise through 2015, remain flat for five years, rise dramatically through 2022, and stay at the higher level throughout the remainder of the forecast period.

Hoku Materials

The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. However, since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed that Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

"Special" Contract

In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm load category (special contracts) even though no long-term contract had been fully executed. When that forecast was prepared (August 2010), several interested parties had taken significant steps toward the development and location of their businesses within Idaho Power's service area. It was determined at that time there was a real possibility of the new large load materializing. However, since the 2011 IRP, the likelihood of the new large load diminished. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 54 aMW of energy and 60 MW of peak demand originally anticipated are excluded from this sales and load forecast.

COMPANY SYSTEM PEAK

System peak load includes the sum of individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

The all-time system summer peak demand was 3,245 MW, recorded on Thursday, July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,344 MW in 2013 to 4,365 MW in the year 2032, an average growth rate of 1.4 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. The three scenarios of projected system summer peak load are illustrated in Figure 12. The 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

Table 10. System summer peak load growth (MW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
95th Percentile	3,382	3,596	3,881	4,418	1.4%
90th Percentile	3,344	3,555	3,835	4,365	1.4%
50th Percentile	3,189	3,387	3,651	4,147	1.4%

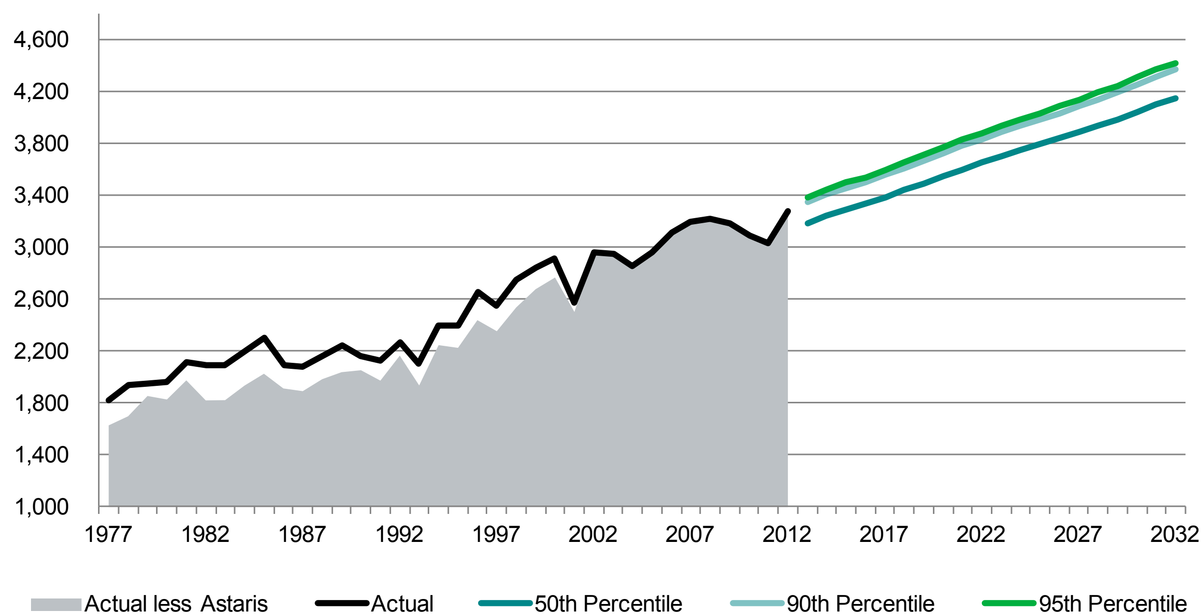


Figure 12. Forecast system summer peak (MW)

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is far greater than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,585 MW in 2013 to 3,020 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,683 MW in 2013 to 3,118 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

Table 11. System winter peak load growth (MW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
95th Percentile	2,683	2,765	2,901	3,118	0.8%
90th Percentile	2,585	2,668	2,803	3,020	0.8%
50th Percentile	2,301	2,384	2,520	2,737	0.9%

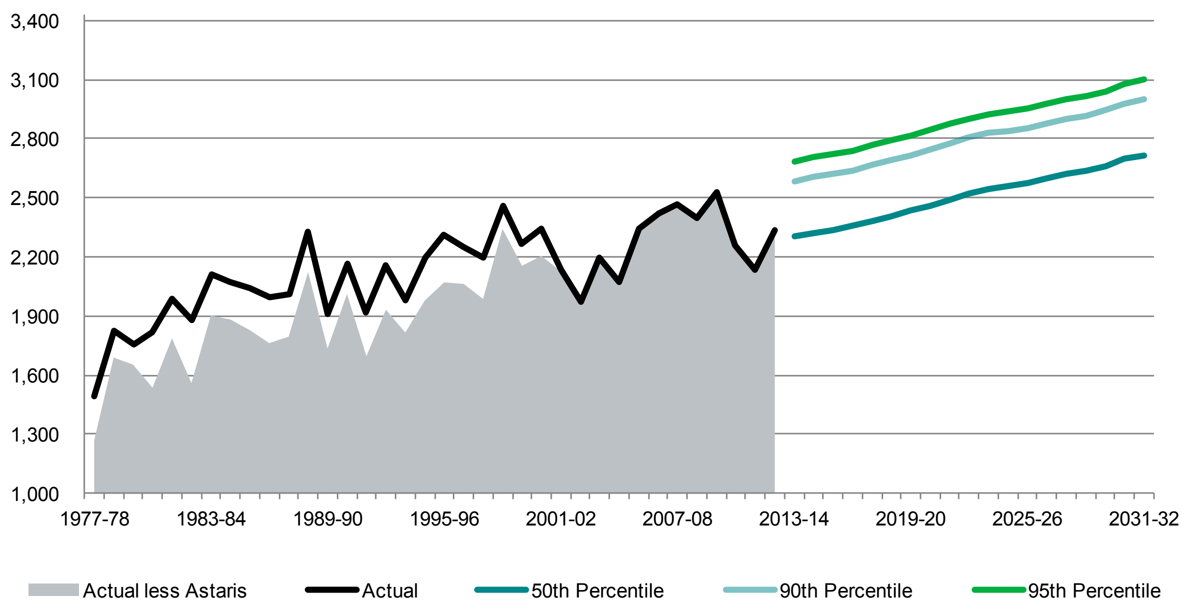


Figure 13. Forecast system winter peak (MW)

Company System Load

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation, state, MSAs, and counties in the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.1 percent per year from 2013 to 2032. Company system load projections are reported in Table 12 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,759 aMW in 2013 to 2,154 aMW in 2032. In the 70th-percentile forecast, the company system load is expected to increase from 1,800 aMW in 2013 to 2,201 aMW by 2032, an average growth rate of 1.1 percent per year over the planning period (Table 12).

Table 12. System load growth (aMW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
90th Percentile	1,872	1,959	2,078	2,284	1.1%
70th Percentile	1,800	1,884	2,000	2,201	1.1%
Expected Case	1,759	1,842	1,956	2,154	1.1%

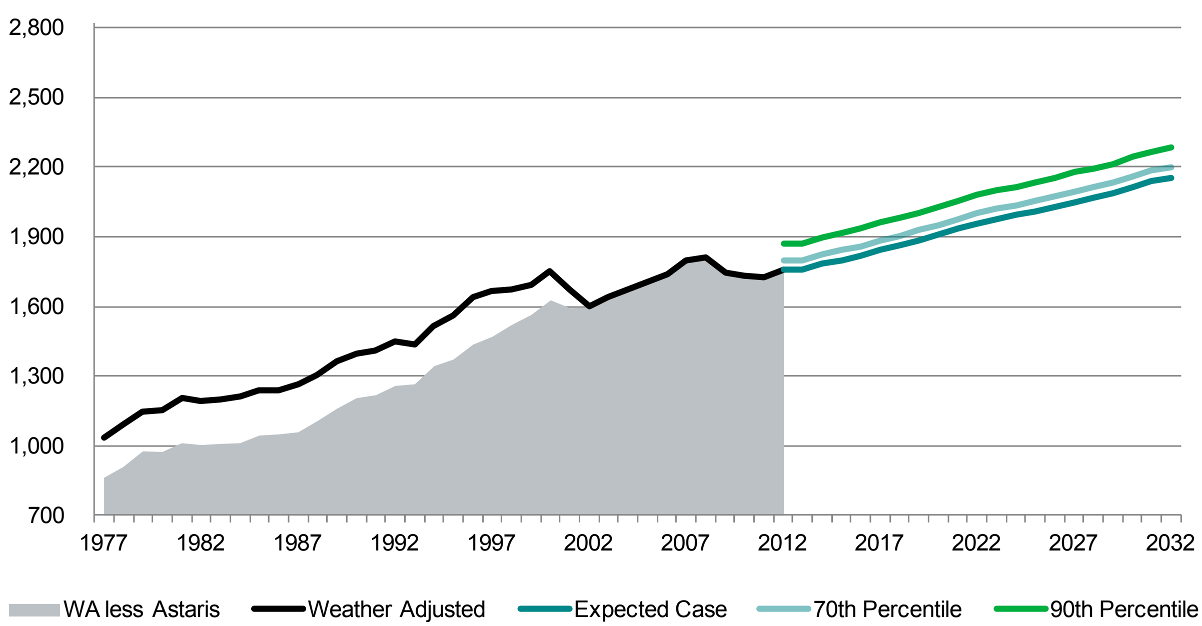


Figure 14. Forecast system load (aMW)

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load more accurately portrays the underlying general business growth trend within the service area.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A—Sales and Load Forecast* projects continued growth in Idaho Power's system load. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 23 percent higher in 2032, gaining 1.1 million MWh over 2013. Commercial sales are also expected to be 23 percent higher or 0.9 million MWh above 2013 followed by industrial (38 percent higher or 0.9 million additional MWh) and irrigation (only 0.2 percent higher in 2032 than 2013). Electricity sales to Astaris ended in April 2002.

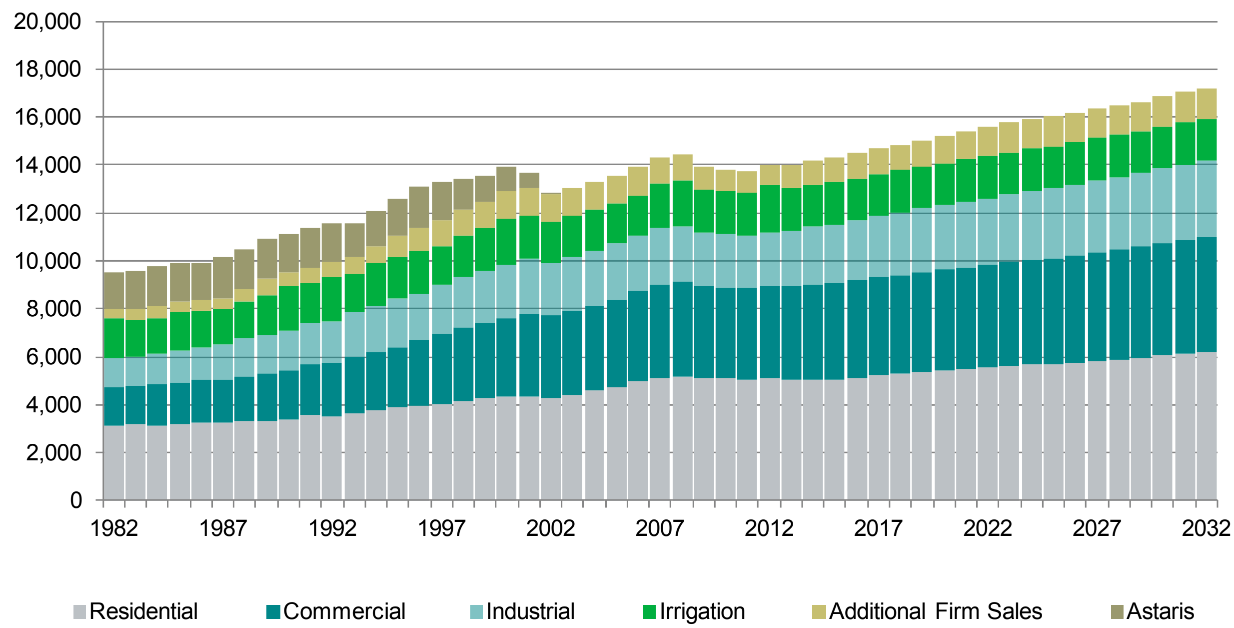


Figure 15. Composition of system company electricity sales (thousands of MWh)

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2013 to 2032.

CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

This page left blank intentionally.

ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for industrial and irrigation customers is not directly surveyed and collected by the DOE; therefore, the models for efficiency impacts have been developed using a methodology established in Itron's white paper, "Incorporating DSM into the Load Forecast".[1] This approach develops statistical methods to recognize efficiency trends from historical utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serves as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical actual energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to sister utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

---

[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of the new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

Demand Response

Beginning with the 2009 IRP, demand response programs have been accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries, are detailed in *Appendix C—Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2013 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction integrated into the sales and load forecast. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2012 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1972–2012 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	145,208	–	10,959	1,591	–	184
1973	152,957	5.3%	11,537	1,765	10.9%	203
1974	160,151	4.7%	12,066	1,932	9.5%	223
1975	167,622	4.7%	12,955	2,172	12.4%	250
1976	175,720	4.8%	13,455	2,364	8.9%	271
1977	184,561	5.0%	13,686	2,526	6.8%	290
1978	194,650	5.5%	14,235	2,771	9.7%	321
1979	202,982	4.3%	14,779	3,000	8.3%	342
1980	209,629	3.3%	14,585	3,057	1.9%	348
1981	213,579	1.9%	14,339	3,063	0.2%	349
1982	216,696	1.5%	14,395	3,119	1.9%	356
1983	219,849	1.5%	14,375	3,160	1.3%	363
1984	222,695	1.3%	14,146	3,150	(0.3%)	357
1985	225,185	1.1%	14,049	3,164	0.4%	363
1986	227,081	0.8%	14,256	3,237	2.3%	368
1987	228,868	0.8%	14,097	3,226	(0.3%)	366
1988	230,771	0.8%	14,352	3,312	2.7%	378
1989	233,370	1.1%	14,336	3,346	1.0%	383
1990	238,117	2.0%	14,277	3,400	1.6%	393
1991	243,207	2.1%	14,566	3,542	4.2%	402
1992	249,767	2.7%	14,146	3,533	(0.3%)	408
1993	258,271	3.4%	14,172	3,660	3.6%	412
1994	267,854	3.7%	14,002	3,750	2.5%	434
1995	277,131	3.5%	14,004	3,881	3.5%	438
1996	286,227	3.3%	13,734	3,931	1.3%	455
1997	294,674	3.0%	13,682	4,032	2.6%	463
1998	303,300	2.9%	13,744	4,169	3.4%	476
1999	312,901	3.2%	13,620	4,262	2.2%	488
2000	322,402	3.0%	13,407	4,322	1.4%	500
2001	331,009	2.7%	13,160	4,356	0.8%	476
2002	339,764	2.6%	12,637	4,294	(1.4%)	488
2003	349,219	2.8%	12,653	4,419	2.9%	507
2004	360,462	3.2%	12,686	4,573	3.5%	524
2005	373,602	3.6%	12,684	4,739	3.6%	543
2006	387,707	3.8%	12,878	4,993	5.4%	568
2007	397,286	2.5%	12,924	5,135	2.8%	585
2008	402,520	1.3%	12,875	5,182	0.9%	594
2009	405,144	0.7%	12,672	5,134	(0.9%)	584
2010	407,551	0.6%	12,461	5,078	(1.1%)	582
2011	409,786	0.5%	12,363	5,066	(0.2%)	577
2012	413,610	0.9%	12,274	5,077	0.2%	581

Residential Load

Projected Residential Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	417,852	1.0%	12,025	5,025	(1.0%)	574
2014	422,850	1.2%	11,954	5,055	0.6%	577
2015	429,685	1.6%	11,783	5,063	0.2%	579
2016	438,746	2.1%	11,695	5,131	1.3%	587
2017	448,379	2.2%	11,644	5,221	1.8%	597
2018	457,313	2.0%	11,588	5,299	1.5%	606
2019	465,250	1.7%	11,545	5,371	1.4%	614
2020	472,652	1.6%	11,480	5,426	1.0%	620
2021	479,844	1.5%	11,412	5,476	0.9%	626
2022	486,853	1.5%	11,363	5,532	1.0%	632
2023	493,741	1.4%	11,342	5,600	1.2%	640
2024	500,509	1.4%	11,294	5,653	0.9%	646
2025	507,171	1.3%	11,235	5,698	0.8%	651
2026	513,749	1.3%	11,230	5,769	1.2%	659
2027	520,202	1.3%	11,230	5,842	1.3%	667
2028	526,553	1.2%	11,199	5,897	0.9%	674
2029	532,781	1.2%	11,197	5,966	1.2%	682
2030	538,901	1.1%	11,211	6,042	1.3%	690
2031	544,944	1.1%	11,203	6,105	1.0%	697
2032	550,883	1.1%	11,189	6,164	1.0%	704

Commercial Load

Historical Commercial Sales and Load, 1972–2012 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	22,585	–	46,141	1,042	–	120
1973	23,286	3.1%	48,145	1,121	7.6%	128
1974	24,096	3.5%	49,028	1,181	5.4%	136
1975	25,045	3.9%	51,217	1,283	8.6%	147
1976	26,034	3.9%	52,513	1,367	6.6%	157
1977	27,112	4.1%	52,416	1,421	3.9%	162
1978	27,831	2.7%	52,476	1,460	2.8%	169
1979	28,087	0.9%	56,389	1,584	8.4%	180
1980	28,797	2.5%	54,145	1,559	(1.6%)	178
1981	29,567	2.7%	54,286	1,605	2.9%	184
1982	30,167	2.0%	54,127	1,633	1.7%	186
1983	30,776	2.0%	52,676	1,621	(0.7%)	186
1984	31,554	2.5%	53,383	1,684	3.9%	191
1985	32,418	2.7%	53,989	1,750	3.9%	201
1986	33,208	2.4%	53,869	1,789	2.2%	204
1987	33,975	2.3%	53,357	1,813	1.3%	206
1988	34,723	2.2%	54,409	1,889	4.2%	216
1989	35,638	2.6%	55,451	1,976	4.6%	227
1990	36,785	3.2%	55,844	2,054	3.9%	236
1991	37,922	3.1%	56,164	2,130	3.7%	243
1992	39,022	2.9%	56,339	2,198	3.2%	253
1993	40,047	2.6%	57,951	2,321	5.6%	263
1994	41,629	4.0%	58,181	2,422	4.4%	280
1995	43,165	3.7%	58,742	2,536	4.7%	288
1996	44,995	4.2%	62,048	2,792	10.1%	323
1997	46,819	4.1%	62,019	2,904	4.0%	333
1998	48,404	3.4%	62,722	3,036	4.6%	347
1999	49,430	2.1%	64,191	3,173	4.5%	363
2000	50,117	1.4%	65,975	3,306	4.2%	383
2001	51,501	2.8%	67,339	3,468	4.9%	383
2002	52,915	2.7%	64,788	3,428	(1.1%)	390
2003	54,194	2.4%	64,243	3,482	1.6%	399
2004	55,577	2.6%	64,042	3,559	2.2%	407
2005	57,145	2.8%	63,517	3,630	2.0%	415
2006	59,050	3.3%	63,425	3,745	3.2%	426
2007	61,640	4.4%	63,336	3,904	4.2%	445
2008	63,492	3.0%	62,200	3,949	1.2%	451
2009	64,151	1.0%	59,488	3,816	(3.4%)	436
2010	64,421	0.4%	58,820	3,789	(0.7%)	434
2011	64,921	0.8%	58,285	3,784	(0.1%)	432
2012	65,599	1.0%	58,941	3,866	2.2%	442

Commercial Load

Projected Commercial Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	66,489	1.4%	58,657	3,900	0.9%	446
2014	67,430	1.4%	58,737	3,961	1.6%	452
2015	68,612	1.8%	58,249	3,997	0.9%	457
2016	70,122	2.2%	57,661	4,043	1.2%	462
2017	71,686	2.2%	56,953	4,083	1.0%	466
2018	73,199	2.1%	56,250	4,117	0.9%	470
2019	74,579	1.9%	55,754	4,158	1.0%	475
2020	75,873	1.7%	55,392	4,203	1.1%	480
2021	77,131	1.7%	55,025	4,244	1.0%	485
2022	78,357	1.6%	54,730	4,288	1.0%	490
2023	79,565	1.5%	54,520	4,338	1.2%	495
2024	80,754	1.5%	54,202	4,377	0.9%	500
2025	81,925	1.4%	53,864	4,413	0.8%	504
2026	83,082	1.4%	53,741	4,465	1.2%	510
2027	84,220	1.4%	53,642	4,518	1.2%	516
2028	85,343	1.3%	53,466	4,563	1.0%	521
2029	86,450	1.3%	53,429	4,619	1.2%	528
2030	87,540	1.3%	53,470	4,681	1.3%	535
2031	88,619	1.2%	53,491	4,740	1.3%	542
2032	89,685	1.2%	53,547	4,802	1.3%	549

Irrigation Load

Historical Irrigation Sales and Load, 1972–2012 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	7,815	–	132,292	1,034	–	118
1973	8,341	6.7%	141,030	1,176	13.8%	134
1974	8,971	7.6%	147,698	1,325	12.6%	151
1975	9,480	5.7%	153,957	1,460	10.2%	167
1976	9,936	4.8%	155,406	1,544	5.8%	176
1977	10,238	3.0%	163,266	1,672	8.3%	191
1978	10,476	2.3%	154,006	1,613	(3.5%)	184
1979	10,711	2.2%	161,705	1,732	7.4%	197
1980	10,854	1.3%	155,740	1,690	(2.4%)	192
1981	11,248	3.6%	164,533	1,851	9.5%	211
1982	11,312	0.6%	151,369	1,712	(7.5%)	196
1983	11,133	(1.6%)	142,865	1,591	(7.1%)	182
1984	11,375	2.2%	132,933	1,512	(4.9%)	172
1985	11,576	1.8%	134,849	1,561	3.2%	178
1986	11,308	(2.3%)	134,121	1,517	(2.8%)	173
1987	11,254	(0.5%)	128,532	1,446	(4.6%)	165
1988	11,378	1.1%	137,237	1,561	7.9%	178
1989	11,957	5.1%	137,982	1,650	5.7%	188
1990	12,340	3.2%	146,128	1,803	9.3%	206
1991	12,484	1.2%	135,557	1,692	(6.2%)	193
1992	12,809	2.6%	140,744	1,803	6.5%	205
1993	13,078	2.1%	125,294	1,639	(9.1%)	187
1994	13,559	3.7%	130,325	1,767	7.8%	202
1995	13,679	0.9%	125,349	1,715	(3.0%)	196
1996	14,074	2.9%	123,944	1,744	1.7%	199
1997	14,383	2.2%	115,552	1,662	(4.7%)	190
1998	14,695	2.2%	114,918	1,689	1.6%	193
1999	14,912	1.5%	117,715	1,755	3.9%	200
2000	15,253	2.3%	126,625	1,931	10.0%	220
2001	15,522	1.8%	116,328	1,806	(6.5%)	206
2002	15,840	2.0%	110,674	1,753	(2.9%)	200
2003	16,020	1.1%	110,784	1,775	1.2%	203
2004	16,297	1.7%	108,574	1,769	(0.3%)	201
2005	16,936	3.9%	98,823	1,674	(5.4%)	191
2006	17,062	0.7%	97,105	1,657	(1.0%)	189
2007	17,001	(0.4%)	105,867	1,800	8.6%	205
2008	17,428	2.5%	109,360	1,906	5.9%	217
2009	17,708	1.6%	100,337	1,777	(6.8%)	203
2010	17,846	0.8%	99,895	1,783	0.3%	204
2011	18,292	2.5%	97,124	1,777	(0.3%)	203
2012	18,675	2.1%	103,703	1,937	9.0%	220

Irrigation Load

Projected Irrigation Sales and Load, 2013–2032

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	18,890	1.2%	92,719	1,751	(9.6%)	200
2014	19,142	1.3%	92,074	1,762	0.6%	201
2015	19,396	1.3%	91,204	1,769	0.4%	202
2016	19,645	1.3%	89,128	1,751	(1.0%)	199
2017	19,899	1.3%	87,928	1,750	(0.1%)	200
2018	20,152	1.3%	87,142	1,756	0.4%	200
2019	20,404	1.3%	86,281	1,760	0.2%	201
2020	20,655	1.2%	85,477	1,766	0.3%	201
2021	20,909	1.2%	84,582	1,769	0.2%	202
2022	21,160	1.2%	83,429	1,765	(0.2%)	202
2023	21,413	1.2%	82,407	1,765	0.0%	201
2024	21,664	1.2%	81,620	1,768	0.2%	201
2025	21,917	1.2%	80,447	1,763	(0.3%)	201
2026	22,172	1.2%	79,028	1,752	(0.6%)	200
2027	22,423	1.1%	78,263	1,755	0.2%	200
2028	22,675	1.1%	77,568	1,759	0.2%	200
2029	22,926	1.1%	76,458	1,753	(0.3%)	200
2030	23,180	1.1%	75,656	1,754	0.0%	200
2031	23,434	1.1%	75,013	1,758	0.2%	201
2032	23,684	1.1%	74,129	1,756	(0.1%)	200

Industrial Load

Historical Industrial Sales and Load, 1972–2012 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	56	–	10,944,714	615	–	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	91
1976	73	3.0%	11,681,540	858	9.3%	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	(0.3%)	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	(0.1%)	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	(1.0%)	11,660,183	1,546	4.9%	177
1989	132	(0.6%)	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	(15.9%)	16,793,437	2,021	3.7%	230
1996	103	(14.4%)	18,774,093	1,934	(4.3%)	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	(2.3%)	19,985,029	2,160	0.7%	247
2000	107	(0.8%)	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	(0.1%)	19,441,876	2,156	(5.8%)	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	(1.1%)	265
2007	123	(3.6%)	19,275,551	2,366	1.8%	270
2008	119	(3.1%)	19,412,391	2,308	(2.4%)	261
2009	124	4.0%	17,987,570	2,224	(3.6%)	254
2010	121	(2.0%)	18,404,875	2,232	0.3%	254
2011	120	(1.1%)	18,586,468	2,229	(0.1%)	254
2012	115	(4.2%)	19,746,525	2,269	1.8%	260

Industrial Load

Projected Industrial Sales and Load, 2013–2032

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	116	0.9%	20,123,969	2,334	2.9%	267
2014	117	0.9%	20,531,410	2,402	2.9%	275
2015	118	0.9%	20,904,644	2,467	2.7%	282
2016	121	2.5%	20,855,283	2,523	2.3%	288
2017	121	0.0%	21,229,207	2,569	1.8%	294
2018	123	1.7%	21,215,736	2,610	1.6%	298
2019	124	0.8%	21,400,507	2,654	1.7%	303
2020	125	0.8%	21,591,980	2,699	1.7%	308
2021	126	0.8%	21,777,074	2,744	1.7%	314
2022	128	1.6%	21,782,963	2,788	1.6%	319
2023	130	1.6%	21,787,965	2,832	1.6%	324
2024	131	0.8%	21,953,791	2,876	1.5%	328
2025	131	0.0%	22,268,240	2,917	1.4%	333
2026	133	1.5%	22,264,535	2,961	1.5%	338
2027	133	0.0%	22,596,372	3,005	1.5%	343
2028	135	1.5%	22,573,943	3,047	1.4%	347
2029	136	0.7%	22,727,071	3,091	1.4%	353
2030	138	1.5%	22,713,855	3,135	1.4%	358
2031	139	0.7%	22,862,159	3,178	1.4%	363
2032	140	0.7%	23,014,399	3,222	1.4%	367

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1972–2012

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	284	–	32
1973	291	2.3%	33
1974	282	(2.9%)	32
1975	314	11.2%	36
1976	289	(8.1%)	33
1977	311	7.8%	36
1978	357	14.8%	41
1979	373	4.4%	43
1980	360	(3.5%)	41
1981	376	4.6%	43
1982	368	(2.4%)	42
1983	425	15.6%	49
1984	466	9.6%	53
1985	471	1.1%	54
1986	482	2.4%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	(6.9%)	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,122	0.8%	128
2000	1,143	1.9%	130
2001	1,118	(2.1%)	128
2002	1,139	1.9%	130
2003	1,120	(1.7%)	128
2004	1,157	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	(4.0%)	130
2008	1,114	(2.4%)	127
2009	965	(13.4%)	110
2010	907	(6.0%)	104
2011	906	0.0%	103
2012	862	(4.8%)	98

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2013–2032

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	1,010	17.1%	115
2014	1,025	1.5%	117
2015	1,053	2.7%	120
2016	1,053	0.1%	120
2017	1,062	0.8%	121
2018	1,060	(0.3%)	121
2019	1,068	0.8%	122
2020	1,115	4.4%	127
2021	1,193	7.0%	136
2022	1,229	3.0%	140
2023	1,234	0.4%	141
2024	1,231	(0.2%)	140
2025	1,234	0.2%	141
2026	1,228	(0.5%)	140
2027	1,228	0.0%	140
2028	1,217	(0.9%)	139
2029	1,212	(0.5%)	138
2030	1,268	4.6%	145
2031	1,262	(0.5%)	144
2032	1,257	(0.4%)	143

*Includes Micron Technology, Simplot Fertilizer, and the INL

Company System Load (excluding Astaris)			
Historical Company System Sales and Load, 1972–2012 (weather adjusted)			
Year	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (aMW)**
1972	4,566	–	577
1973	5,040	10.4%	635
1974	5,461	8.4%	690
1975	6,012	10.1%	760
1976	6,422	6.8%	810
1977	6,858	6.8%	863
1978	7,174	4.6%	910
1979	7,776	8.4%	977
1980	7,773	0.0%	974
1981	8,043	3.5%	1,012
1982	7,994	(0.6%)	1,004
1983	7,991	0.0%	1,009
1984	8,095	1.3%	1,012
1985	8,303	2.6%	1,045
1986	8,382	0.9%	1,050
1987	8,462	1.0%	1,059
1988	8,839	4.5%	1,108
1989	9,237	4.5%	1,161
1990	9,544	3.3%	1,206
1991	9,744	2.1%	1,219
1992	9,985	2.5%	1,259
1993	10,163	1.8%	1,266
1994	10,628	4.6%	1,344
1995	11,030	3.8%	1,373
1996	11,390	3.3%	1,437
1997	11,688	2.6%	1,471
1998	12,151	4.0%	1,522
1999	12,472	2.6%	1,565
2000	12,895	3.4%	1,628
2001	13,037	1.1%	1,594
2002	12,771	(2.0%)	1,596
2003	13,030	2.0%	1,637
2004	13,327	2.3%	1,673
2005	13,568	1.8%	1,703
2006	13,909	2.5%	1,739
2007	14,346	3.1%	1,796
2008	14,460	0.8%	1,813
2009	13,917	(3.8%)	1,744
2010	13,789	(0.9%)	1,734
2011	13,762	(0.2%)	1,725
2012	14,011	1.8%	1,760

Company System Load (including Astaris)						
	Historical Company System Sales and Load, (1972–2012) (weather adjusted)			Astaris Sales and Load (1972–2002) (weather adjusted)		
Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)	Astaris Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1972	6,385	–	794	1,819	–	207
1973	6,685	4.7%	832	1,645	(9.6%)	188
1974	7,104	6.3%	887	1,643	(0.1%)	188
1975	7,569	6.6%	946	1,557	(5.3%)	178
1976	7,997	5.6%	998	1,575	1.2%	179
1977	8,276	3.5%	1,033	1,418	(10.0%)	162
1978	8,716	5.3%	1,094	1,542	8.8%	176
1979	9,170	5.2%	1,144	1,395	(9.6%)	159
1980	9,286	1.3%	1,155	1,513	8.5%	172
1981	9,677	4.2%	1,208	1,634	8.0%	186
1982	9,548	(1.3%)	1,191	1,554	(4.9%)	177
1983	9,600	0.5%	1,202	1,610	3.6%	184
1984	9,796	2.0%	1,215	1,701	5.7%	194
1985	9,917	1.2%	1,239	1,614	(5.1%)	184
1986	9,935	0.2%	1,236	1,554	(3.7%)	177
1987	10,154	2.2%	1,262	1,692	8.9%	193
1988	10,474	3.2%	1,303	1,635	(3.4%)	186
1989	10,940	4.4%	1,365	1,703	4.2%	194
1990	11,149	1.9%	1,398	1,604	(5.8%)	183
1991	11,353	1.8%	1,412	1,609	0.3%	184
1992	11,555	1.8%	1,446	1,570	(2.4%)	179
1993	11,600	0.4%	1,438	1,437	(8.4%)	164
1994	12,048	3.9%	1,514	1,420	(1.2%)	162
1995	12,597	4.6%	1,561	1,567	10.4%	179
1996	13,079	3.8%	1,639	1,689	7.8%	192
1997	13,315	1.8%	1,666	1,628	(3.6%)	186
1998	13,424	0.8%	1,674	1,273	(21.8%)	145
1999	13,523	0.7%	1,691	1,051	(17.4%)	120
2000	13,949	3.1%	1,754	1,054	0.3%	120
2001	13,695	(1.8%)	1,673	658	(37.5%)	75
2002	12,782	(6.7%)	1,597	11	(98.3%)	1
2003	13,030	1.9%	1,637	0	(100.0%)	0
2004	13,327	2.3%	1,673	0	0.0%	0
2005	13,568	1.8%	1,703	0	0.0%	0
2006	13,909	2.5%	1,739	0	0.0%	0
2007	14,346	3.1%	1,796	0	0.0%	0
2008	14,460	0.8%	1,813	0	0.0%	0
2009	13,917	(3.8%)	1,744	0	0.0%	0
2010	13,789	(0.9%)	1,734	0	0.0%	0
2011	13,762	(0.2%)	1,725	0	0.0%	0
2012	14,011	1.8%	1,760	0	0.0%	0

Company System Load

Projected Company System Sales and Load, 2013–2032

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	14,020	0.1%	1,759
2014	14,205	1.3%	1,782
2015	14,348	1.0%	1,800
2016	14,502	1.1%	1,818
2017	14,684	1.3%	1,842
2018	14,842	1.1%	1,862
2019	15,011	1.1%	1,883
2020	15,208	1.3%	1,906
2021	15,426	1.4%	1,934
2022	15,603	1.1%	1,956
2023	15,769	1.1%	1,977
2024	15,905	0.9%	1,992
2025	16,025	0.8%	2,009
2026	16,176	0.9%	2,028
2027	16,348	1.1%	2,049
2028	16,483	0.8%	2,065
2029	16,640	1.0%	2,087
2030	16,879	1.4%	2,116
2031	17,043	1.0%	2,137
2032	17,201	0.9%	2,154

This page left blank intentionally.

IDAHO POWER®
An IDACORP Company

2013 Integrated Resource Plan

APPENDIX B

Demand-Side Management

2012 ANNUAL REPORT

March 15, 2013

2013

Integrated Resource Plan

APPENDIX B

Demand-Side Management

2012 ANNUAL REPORT

March 15, 2013

IDAHO POWER®

An IDACORP Company

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

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

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

SAFE HARBOR STATEMENT

TABLE OF CONTENTS

LIST OF TABLES

List of Figures

List of Appendices

List of Supplements

GLOSSARY OF ACRONYMS

aMW—Average Megawatt

A/C—Air Conditioning/Air Conditioners

ACB, Inc.—Advertising Checking Bureau, Inc.

ADM—ADM Associates, Inc.

AMI—Advanced Metering Infrastructure

ARRA—*American Reinvestment and Recovery Act of 2008*

B/C—Benefit/Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BCW—Boise Center West

BOMA—Building Owners and Managers Association

BOP—Builder Option Package

BPA—Bonneville Power Administration

CAES—Center for Advanced Energy Studies

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CAIS—Certified Agricultural Irrigation Specialist

CBSA—Commercial Building Stock Assessment

CEERI—CAES Energy Efficiency Research Initiative

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CEU—Continuing Education Unit

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CIS—Customer Information System

COP—Coefficient of Performance

CR—Customer Representative (field staff)

CR&EE—Customer Research and Energy Efficiency Department

CSR—Customer Service Representative (call center)

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

DSR—Demand-Side Resource

EA4—EA4 Energy Audit Program

EA5—EA5 Energy Audit Program

EEAG—Energy Efficiency Advisory Group

EECBG—Energy Efficiency Conservation Block Grant

EISA—*Energy Independence and Security Act of 2007*

EM&V—Evaluation, Measurement, and Verification

EnerNOC Solutions—EnerNOC Utility Solutions Consulting

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

EUAT—Energy-Use Advisory Tool

FCA—Fixed-Cost Adjustment

ft^2—Square Feet

GMPG—Green Motors Practice Group

GWh—Gigawatt-hour

H&CE—Heating & Cooling Efficiency Program

HEM, LLC—Home Energy Management, LLC

hp—Horsepower

HPWH—Heat Pump Water Heater

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IDL—Integrated Design Lab (in Boise)

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IOER—Idaho Office of Energy Resources

IP—Internet Protocol

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

IRS—Internal Revenue Service

iSTEM—Idaho Science, Technology, Engineering and Mathematics

IT—Information Technology

JACO—JACO Environmental, Inc.

kW—Kilowatt

kWh—Kilowatt-hour

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

MEF—Modified Energy Factor

MOU—Memorandum of Understanding

MHAFB—Mountain Home Air Force Base

MPER—Market Progress Evaluation Report

MW—Megawatt

MWh—Megawatt-hour

MVBA—Magic Valley Builders Association

NEEM—Northwest Energy Efficient Manufactured

NEEA—Northwest Energy Efficiency Alliance

NEMA—National Electrical Manufacturers Association

NPCC—Northwest Power and Conservation Council

NWRRC—Northwest Regional Retail Collaborative

OPUC—Public Utility Commission of Oregon

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PECI—Portland Energy Conservation, Inc.

PLC—Power-Line Carrier

PSA—Public-Service Announcement

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAP—Resource Action Programs

R&D—Research and Development

RBSA—Residential Building Stock Assessment

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure Test

ROCEE—Refrigerator Operator Coaching for Energy Efficiency

RPAC—*Regional Portfolio Advisory Committee*

RTF—Regional Technical Forum

SCCT—Simple-Cycle Combustion Turbine

SCO—State-Certifying Organization

SEE—Students for Energy Efficiency

SEER—Seasonal Energy Efficiency Ratio

SEM—Strategic Energy Management

SGIS—Smart Grid Investment Grant

SIR—Savings-to-Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

T-5HO—T-5 High Output

TRC—Total Resource Cost

TVP—Time-Variant Pricing

VFD—Variable-Frequency Drive

UC—Utility Cost

UES—Unit Energy Savings

US—United States

USA—Utility Service Agreement

W—Watt

WAQC—Weatherization Assistance for Qualified Customers

Executive Summary

The pursuit of cost-effective energy efficiency is a primary objective for Idaho Power. Energy efficiency and demand response provide economic and operational benefits to the company and its customers. The enhancement of information and programs ensures customers' opportunities to learn about their energy use and participate in programs.

In 2012, Idaho Power focused energy efficiency activities on program analysis, energy savings, demand reductions, and improvements and expansion of its current programs. Idaho Power initiated several impact evaluations conducted by third-party consultants. The company also sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about the company's energy efficiency programs. To identify additional energy-savings measures, Idaho Power conducted a new energy efficiency potential study in conjunction with its *2013 Integrated Resource Plan* (IRP). Also in 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000th unit.

Total expenditures from all funding sources on demand-side management (DSM)-related activities increased about 7 percent, from almost $46.3 million in 2011 to $49.3 million in 2012. This funding now comes from several sources outside the Idaho and Oregon Energy Efficiency Riders. Idaho incentives from the company's demand response programs are recovered through the annual power cost adjustment (PCA), and Idaho incentives for its industrial energy efficiency program, Custom Efficiency, are capitalized similar to a supply-side resource.

Although on target for savings achieved for the IRP, Idaho Power's annual energy savings from its energy efficiency activities slightly decreased in 2012. Reduced energy savings in 2012 were caused partially by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities, which generally reduce savings estimates. The amount of energy saved was enough to power over 13,000 average homes served by Idaho Power. From Idaho Power's energy efficiency programs alone (excluding Northwest Energy Efficiency Alliance [NEEA] savings), the savings decreased 7 percent, from 163,315 megawatt-hours (MWh) in 2011 to 152,486 MWh in 2012. Annual energy savings for 2011, including the revised NEEA savings, were 183,862 MWh. In 2012, these savings decreased slightly to 170,228 MWh.

In 2012, Idaho Power celebrated 10 years of energy efficiency and demand response activity funded under the Idaho Energy Efficiency Rider (Idaho Rider). In those 10 years, the company realized a cumulative annual savings of over 1 million MWh savings. This is enough energy to power a city of 85,000 average residences. The demand-reduction capacity for Idaho Power's demand response programs in 2012 was over 438 megawatts (MW). This represents over 13 percent of Idaho Power's new record system peak of 3,245 MW set in 2012.

The *Demand-Side Management 2012 Annual Report* provides a review of the company's DSM activities and finances throughout 2012 and outlines Idaho Power's plans for DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419, as well as the Memorandum of Understanding (MOU) signed by IPUC staff and Idaho investor-owned utilities in January 2010.

This page left blank intentionally.

INTRODUCTION

Idaho Power's *Demand-Side Management 2012 Annual Report* provides a review of the financial and operational performance of Idaho Power's demand-side management (DSM) activities and initiatives for 2012. In 2012, Idaho Power offered energy efficiency and demand response programs to all customer sectors and sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about reducing their electricity consumption.

Idaho Power's main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. Idaho Power also strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

Customer participation in Idaho Power's energy efficiency and demand response programs continues to remain strong, provide substantial energy savings, and increase demand-reduction capacity. The energy savings exclusively from Idaho Power's energy efficiency programs in 2012 were 152,486 megawatt-hours (MWh). In 2012, the amount of energy saved from its programs was enough to power more than 13,000 average homes served by Idaho Power for one year.

Demand reduction available from the demand response programs increased in 2012. Combined, the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs resulted in an estimated summer peak reduction capacity of 438 megawatts (MW).

Idaho Power uses the same report structure each year in a continuing effort to fulfill the objectives of the Memorandum of Understanding (MOU) signed on January 25, 2010 by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities. The report consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows all of the standard cost-effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category (Table 2). In 2012, the company continued its commitment to third-party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2012 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. In 2012, all Idaho Power energy efficiency programs were cost effective, except the company's weatherization programs for income-qualified customers and 52 individual measures in various programs. The majority of these measures have been discontinued, and the remaining measures will be reviewed in 2013.

The cost-effectiveness analysis of Idaho Power's demand response programs showed all three demand response programs to be cost-effective over the life of each program. This analysis uses a program life of a 20-year planning period for the A/C Cool Credit and Irrigation Peak Rewards programs and a 10-year planning period for the FlexPeak Management program. For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in IPUC Case No. IPC-E-12-29, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The cost-effectiveness analysis for the FlexPeak Management program is still based on a 10-year life. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance.

DSM Programs

The programs within Idaho Power's energy efficiency and demand response portfolio are offered to all major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either sector.

Idaho Power groups its DSM activities in four categories: energy efficiency, demand response, market transformation, and other programs and activities. The other programs and activities are generally designed to provide customer outreach and education concerning the efficient use of electricity. All of these activities are coordinated to advance Idaho Power's continued commitment to pursue all cost-effective energy efficiency, all prudent demand response, and to enhance customer satisfaction.

Figures 1 through 3 show the demand-reduction capacity, historic energy savings, and DSM expenses.

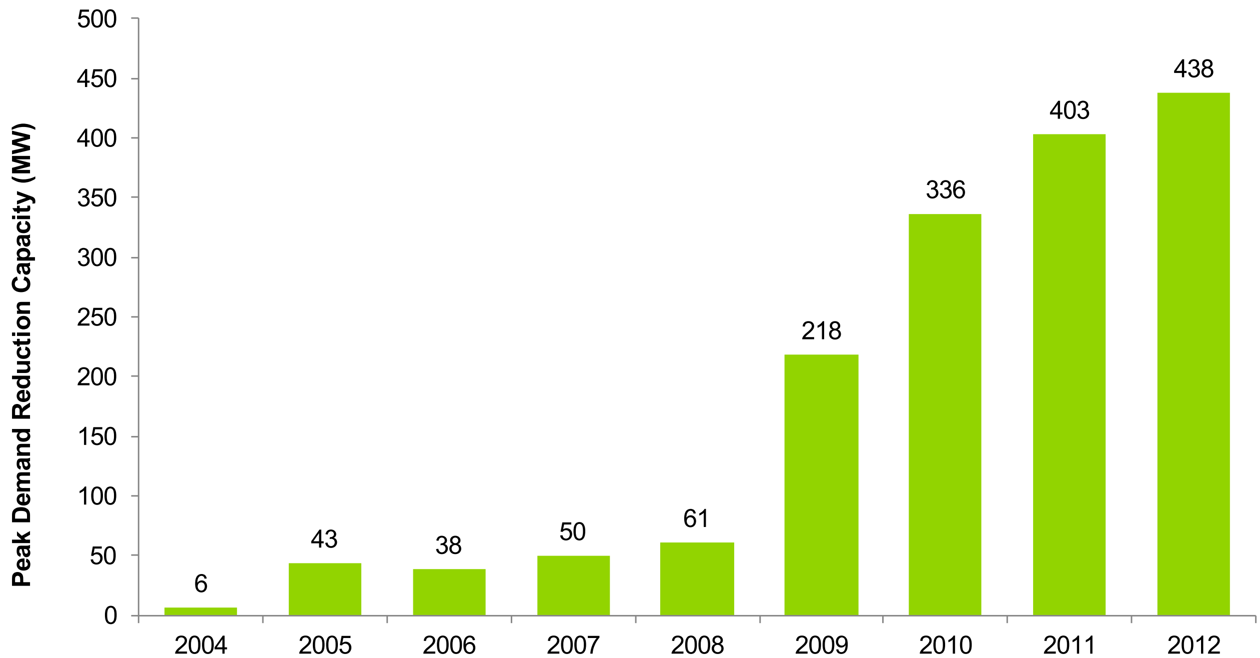


Figure 1. Peak demand-reduction capacity 2004–2012 (MW)

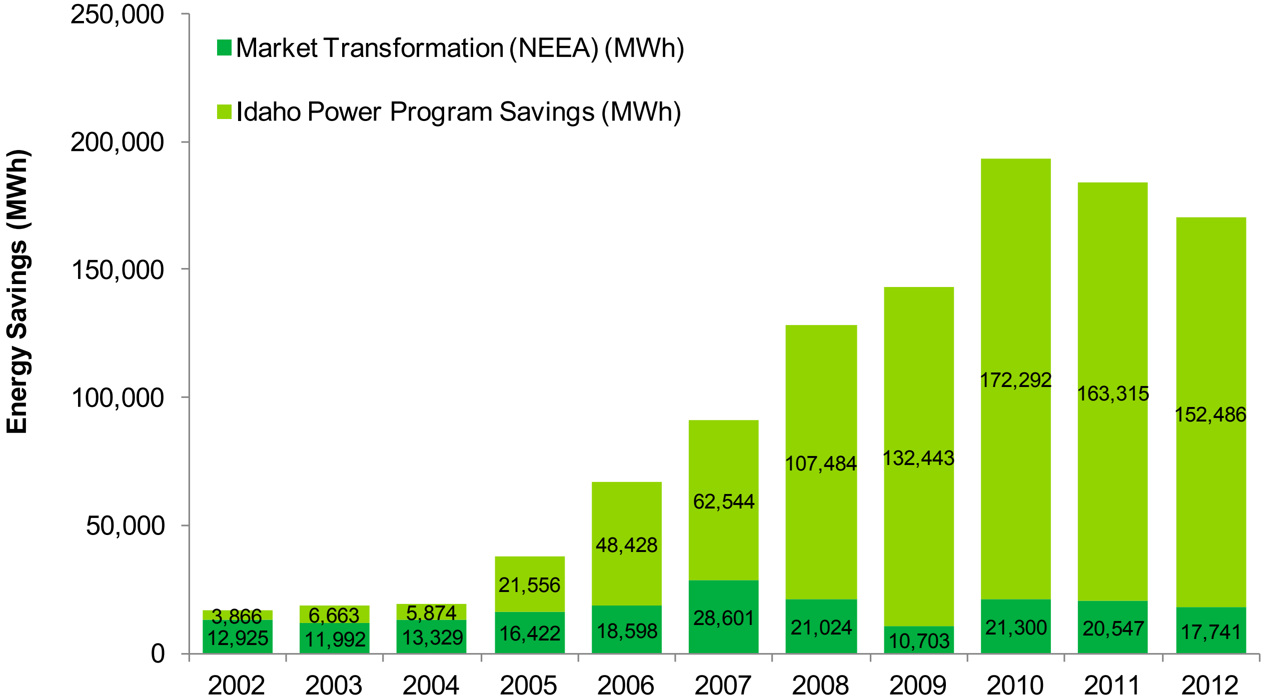


Figure 2. Annual energy savings 2002–2012 (MWh)

Note: 2012 market-transformation savings (NEEA) are preliminary.

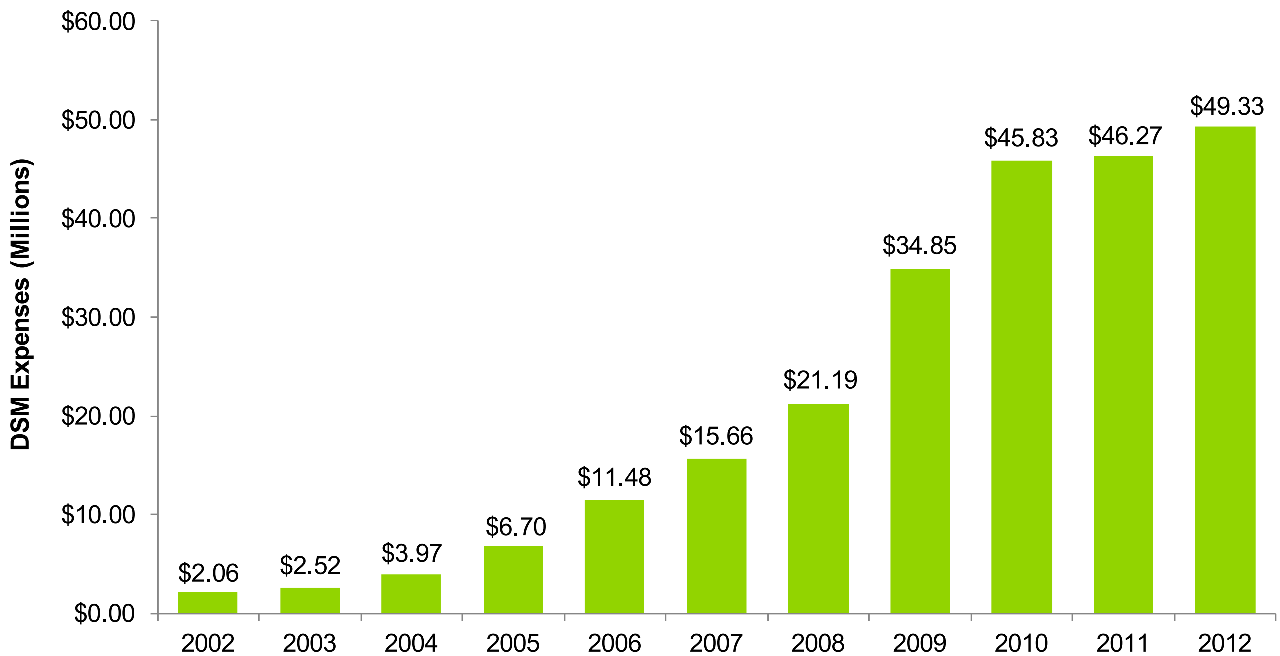


Figure 3. DSM expense history 2002–2012 from all sources (millions of dollars)

Demand Response Programs

The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side resources. The company estimates future capacity shortfalls through the IRP planning process, then plans programs to mitigate these shortfalls. Demand response programs are measured by the amount of demand reduction, in MW, available to the company during system peak periods. In 2012, Idaho Power operated three demand response programs: the A/C Cool Credit program for residential customers, the FlexPeak Management program for commercial/industrial customers, and the Irrigation Peak Rewards program for irrigation customers.

Research efforts in 2012 included a continued investigation into the need for demand response, as well as how to measure its value. Idaho Power also continued to examine and refine program dispatch criteria. Idaho Power contracted with Portland Energy Conservation, Inc. (PECI), to conduct a research project for the A/C Cool Credit program to optimize the use of this program by more accurately estimating the available demand reduction in advance of dispatching this program. In 2012, the company, based on PECI's research plan, used the A/C Cool Credit program 13 times, with a goal of capturing various cycling strategies at various temperature bins, allowing PECI to create a regression model to estimate demand reduction.

The FlexPeak Management program was used four times during summer 2012. These events did not incur any marginal costs for the company and were successful in keeping the participants familiar and engaged with the program while verifying the accuracy of EnerNOC, Inc.'s, weekly nominations. Although Idaho experienced fairly extreme weather conditions in summer 2012, there was no need to dispatch the Irrigation Peak Rewards program, which was not economical to operate considering the variable payment necessary to use this program. Idaho Power hit a new all-time system peak of 3,245 MW at 4:00 p.m. on July 12, 2012. Both the A/C Cool Credit and FlexPeak Management programs were dispatched at 4:00 p.m. on this day, successfully preventing the system peak from increasing after 4:00 p.m., as it would have otherwise done.

Idaho Power's IRP determines the company's forecasted need for energy resources while balancing reliability, cost, environmental concerns, and efficiency. The plan is developed with the assistance of the company's customers and other stakeholders and is reviewed and updated every two years. In 2012, Idaho Power began the analytical portion of the 2013 IRP and commenced its regular meetings with the Integrated Resource Plan Advisory Council (IRPAC).

In fall 2012, the company's IRP analysis demonstrated there were no capacity deficits in the near term. In past years, the IRP has forecasted a need for additional resources at times of peak electricity use. The Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management programs have been available to meet that need. However, the most recent analysis from the 2013 IRP indicates no peak-hour shortages until 2016. This is primarily due to a slower-than-expected economic recovery, causing slower customer growth than previously forecasted, as well as two previously anticipated large-load customers that did not materialize. Based on the results of this analysis, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC, requesting a temporary suspension of the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.

Energy Efficiency Programs

Energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components where an energy-efficient design, replacement, or repair can achieve energy savings. These programs are available to all customer sectors in Idaho Power's service area. Project measures range from entire residential or commercial building construction to appliance replacement. Savings from these programs are measured in terms of kilowatt-hour (kWh) or MWh savings. These programs usually supply energy savings throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improves their energy efficiency. Idaho Power achieves market-transformation savings primarily through its participation in the Northwest Energy Efficiency Alliance (NEEA).

Other Programs and Activities

Other programs and activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Educational Initiative, Local Energy Efficiency Funds (LEEF), Residential Economizer Project Study, and Boise City Home Audit Project. These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a list of the DSM programs and their respective sectors, operational category, the state each was available in 2012, and associated energy savings.

Table 1. 2012 DSM, sectors, programs, operational type, and energy savings/demand reduction

Program by Sector	Operational Type	State	Savings
Residential			
A/C Cool Credit	Demand Response	ID/OR	44.9 MW
Ductless Heat Pump Pilot	Energy Efficiency	ID/OR	445 MWh
Energy Efficient Lighting	Energy Efficiency	ID/OR	16,709 MWh
Energy House Calls	Energy Efficiency	ID/OR	1,192 MWh
ENERGY STAR® Homes Northwest	Energy Efficiency	ID/OR	537 MWh
Heating & Cooling Efficiency Program	Energy Efficiency	ID/OR	689 MWh
Home Improvement Program	Energy Efficiency	ID	457 MWh
Home Products Program	Energy Efficiency	ID/OR	887 MWh
Oregon Residential Weatherization	Energy Efficiency	OR	12 MWh
Rebate Advantage	Energy Efficiency	ID/OR	187 MWh
Residential Energy Efficiency Education Initiative	Other Programs and Activities	ID/OR	n/a
See ya later, refrigerator®	Energy Efficiency	ID/OR	1,576 MWh
Weatherization Assistance for Qualified Customers	Energy Efficiency	ID/OR	648 MWh
Weatherization Solutions for Eligible Customers	Energy Efficiency	ID	258 MWh
Commercial/Industrial			
Building Efficiency	Energy Efficiency	ID/OR	20,450 MWh
Commercial Education Initiative	Other Programs and Activities	ID/OR	n/a
Easy Upgrades	Energy Efficiency	ID/OR	41,569 MWh
FlexPeak Management	Demand Response	ID/OR	52.8 MW
Oregon Commercial Audits	Energy Efficiency	OR	n/a
Custom Efficiency	Energy Efficiency	ID/OR	54,253 MWh
Irrigation			
Irrigation Efficiency Rewards	Energy Efficiency	ID/OR	12,617 MWh
Irrigation Peak Rewards	Demand Response	ID/OR	339.9 MW
All Sectors			
Northwest Energy Efficiency Alliance	Market Transformation	ID/OR	17,741 MWh

Program Performance

In 2012, annual energy savings slightly decreased compared to 2011. The saving difference varied by sector. Energy savings for the residential sector decreased by 24 percent to 23,597 MWh. The commercial sector energy savings increased by 23 percent to 62,019 MWh, and the industrial sector energy savings decreased by 20 percent to 54,253 MWh. Energy savings for the irrigation sector decreased by 10 percent to 12,617 MWh. The reduction in savings in the residential sector was due, in part, to new lower deemed-savings amounts approved by the Regional Technical Forum (RTF) and Idaho Power making some programs available only for electrically heated homes. Some of the energy-savings reduction in the industrial sector and the increase in the commercial sector were due to programmatic changes. The overall reduced energy savings in 2012 may be caused, in part, by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities. Additional energy savings continue to be realized through market-transformation partnership activities with NEEA.

Customer participation remained strong in most of the existing programs during the year. The number of projects completed under the Building Efficiency and Easy Upgrades programs increased by 33 percent and 6 percent, respectively. Participation in Rebate Advantage increased by 40 percent, from 25 homes in 2011 to 35 homes in 2012. The number of homes completed under the ENERGY STAR® Homes Northwest program increase by 33 percent. The projects completed under the Irrigation Efficiency Rewards program increased slightly by 3 percent, from 880 projects in 2011 to 908 projects in 2012.

A few programs were big contributors to overall energy savings. Although the Custom Efficiency program had reduced savings compared to 2011, the program accounted for 32 percent of Idaho Power's energy savings from programs, resulting in an estimated 54,253 MWh of savings. The Easy Upgrades program in the commercial sector provided 24 percent, or 41,569 MWh, of estimated energy savings. In the residential sector, the Energy Efficient Lighting program saved 16,709 MWh, accounting for 10 percent of overall energy savings.

Table 2 shows the 2012 annual energy savings, percent of energy usage, number of customers, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2012 contribution of each sector in terms of energy usage and its respective size in the number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

Table 2. 2012 program sector summary and energy usage/savings/demand reduction

	Energy Efficiency Program Impacts[a]				Idaho Power System Sales		
	Program Expenses	Energy Savings (kWh)	Average Energy (aMW)	Peak Load Reduction (MW)[b]	Sector Total (MWh)	Percentage of Energy Usage	Number of Customers
Residential	$ 6,337,777	23,597,363	2.7	44.9	5,052,302	35.83%	416,020
Commercial	6,954,795	62,018,709	7.1	7.1	3,869,314	27.44%	65,920
Industrial	7,092,581	54,253,106	6.2	60.4	3,131,650	22.21%	116
Irrigation	2,373,201	12,617,164	1.4	343.0	2,048,435	14.53%	19,045
Market Transformation	3,379,756	17,741,430	2.0	n/a	n/a	n/a	n/a
Other Programs and Activities	692,062	n/a	n/a	n/a	n/a	n/a	n/a
Total Direct Program Expenses	**$26,830,172**	**170,227,773**	**19.0**	**455.0**	**14,101,701**	**100.00%**	**501,101**

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] This includes peak load reduction from both demand response and energy efficiency programs.

2012 Activities

In 2012, Idaho Power continued to expand its DSM programs to increase participation and energy savings. Many activities in 2012 revolved around evaluation and research to make DSM programs more effective and the savings gained from these programs more reliable. The company also completed a third-party energy efficiency potential study and a non-participant survey for the residential, commercial, and irrigation sectors.

Although not directly related to Idaho Power's DSM activities, the company has continued to install and configure its new Customer Information System (CIS), made possible under a matching grant from the Smart Grid Investment Grant (SGIG). This project should be complete with migration to the new CIS by mid-2013. This installation has and will affect some of the company's DSM program activities because any changes related to the company's billing system cannot occur until the system is implemented. Information technology (IT) resources for other projects have also been dramatically constrained during the conversion.

Idaho Power collaborated with the City of Boise to finalize the Boise City Home Audit Project. Additionally, the company continued to fund and collaborate with the Integrated Design Lab (in Boise) (IDL) and participate with NEEA's Ductless Heat Pump (DHP) Pilot.

During 2012, Idaho Power continued its contractual participation in NEEA under the 2011 to 2014 agreement. NEEA's efforts in the northwest impact Idaho Power's customers by encouraging regional market transformation. Idaho Power representatives participated in several NEEA committees and in several NEEA events.

Idaho Power also continued to help fund and participate in the RTF and used the results from the RTF's research in program development and cost-effectiveness analyses. Beginning in 2012, a representative from Idaho Power was a member of the RTF Policy Advisory Committee. This committee provides policy recommendations on how to best meet the needs of stakeholders while maintaining the independent technical model of the RTF. Additionally, Idaho Power staff participated in numerous sub-committees.

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15, a request for the IPUC to designate Idaho Power's expenditure of $35,623,321 in Idaho Energy Efficiency Rider (Idaho Rider) funds and $7,018,385 in Custom Efficiency incentive expenses as prudently incurred expenses in 2012. Through the discovery process, Idaho Power found that $345 had been inadvertently charged to the Idaho Rider that should have been charged to the Oregon Energy Efficiency Rider (Oregon Rider). The company subsequently modified its request for prudency to $35,622,976 in Idaho Rider expenses, for a total request of $42,641,361. The company included copies of the *Demand-Side Management 2011 Annual Report* along with *Supplement 1: Cost-Effectiveness* and *Supplement 2: Evaluation* in its filing. On October 22, 2012, the IPUC issued Order No. 32667. In this order, the IPUC found that the company had prudently incurred $41,942,123.50, including $34,923,738.50 in Rider expenses and $7,018,385 in Custom Efficiency incentive expenses in 2011. The commission declined to decide the reasonableness of $89,601 of Idaho Power labor-related expense increases for Rider funded employees and denied Rider funding for $82,855.50 in A/C Cool Credit incentive payments to customers. On November 13, 2012, Idaho Power filed a petition for reconsideration in Case No. IPC-E-12-15. In this filing and subsequent filings, the company asked for reconsideration on an accounting adjustment of $526,781 and $89,601 in labor-related expenses. On December 11, 2012, the commission issued Order No. 32690, in which they found it reasonable to grant the company reconsideration of the accounting-related adjustment but again declined to decide the reasonableness of the company's labor-related expense increase until the company provided evidence from which the commission might better assess the reasonableness of those expenses. As a result of these orders, the company has credited the Idaho Rider account 254201 by $82,855.50 and placed $89,601 in reserve account 253000 until prudency can be determined. These prudency filings and Idaho Power's DSM activities are designed to comply with the agreed principles set forth in the MOU for Prudency Determination of DSM Expenditures.

Energy Efficiency Advisory Group

Formed in 2002, the Energy Efficiency Advisory Group (EEAG) provides input on formulating and implementing energy efficiency and demand-reduction programs funded by the Rider. Currently, the EEAG consists of 14 members from Idaho Power's service area and the Pacific Northwest. Members represent a cross section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power.

The EEAG met three times in 2012: February 22, July 19, and November 6. Additionally, a webinar was held on December 5 and a conference call was held on December 14. During these meetings, Idaho Power discussed and requested recommendations on new program proposals, marketing methods, and specific measure details; provided a status of the Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues. Idaho Power relies on input from the EEAG to provide a customer and public interest review of energy efficiency and demand response programs and expenses. The minutes from the 2012 EEAG meetings, the webinar on December 5, and the December 14 conference call are included in *Supplement 2: Evaluation*.

During the July 19 EEAG meeting, EEAG members and Idaho Power staff engaged in an interactive session to review the structure and content of EEAG meetings. A summary of this discussion and suggestions was provided in a memo dated August 3, 2012, and sent to all members. In subsequent meetings, and after review of the original order by the IPUC that created EEAG, the members affirmed their desire to meet quarterly for all-day, in-person sessions to review DSM activities. Additional teleconferences and/or webinars may supplement the quarterly meetings. The members also requested that time be allocated for the audience to ask questions throughout the presentations and discussions and that guest speakers be used when appropriate to the subject matter. Finally, members will be given an opportunity to suggest agenda items and will receive presentation materials one week in advance of the meeting. The company has implemented many of the EEAG members' recommendations to increase the effectiveness of EEAG meetings. Additionally, Idaho Power continues to address recommendations from the IPUC received in Case No. IPC-E-12-15 and confirmed by Order No. 32667. A copy of the revised memo can be found in *Supplement 2: Evaluation*.

At the November 6 EEAG meeting, Idaho Power presented and discussed four residential initiatives: Home Energy Audits, Shade Tree Pilot, Student Energy Efficiency Kits, and Solar Thermal Hot Water measure. All initiatives except the Solar Thermal Hot Water measure received positive feedback and support from EEAG. Idaho Power plans on launching the following three initiatives in 2013.

The new Home Energy Audits program is based, in part, on the Boise City Home Audit Project that Idaho Power and the City of Boise undertook previously using *American Recovery and Reinvestment Act of 2008* (ARRA) funding. This new program will allow all-electric residential customers to select a home performance specialist (HPS) from a list of preferred providers and have the HPS perform an audit of their home. The audit will include a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Homeowners will receive a report with specific recommendations for their home and information on programs that may help with the cost of energy efficiency improvements. Preparations are underway for a program launch during third quarter 2013.

Idaho Power, along with local stakeholders, is exploring a shade-tree program for the Treasure Valley. Using results from a state-sponsored urban tree-canopy study and online planting resources developed by the Arbor Day Foundation, the Shade Tree Pilot will encourage strategic planting of trees to reduce residential energy use. Properly planted shade trees save energy in the summer by reducing cooling costs. Trees provide measureable economic and environmental benefits, including enhanced air quality, storm water quality, and property values. Utility shade-tree programs throughout the country report energy savings, high participant satisfaction, and enhanced public images related to environmental stewardship. The Shade Tree Pilot is being developed for implementation in fall 2013, and results will be reviewed for full program development in 2014.

Idaho Power plans to build on the success of its previous Students for Energy Efficiency (SEE) Program (2009–2011) by implementing a new Student Energy Efficiency Kits program. The new program will target elementary school students in grades four through six. The project plan includes the delivery of 2,500 kits to students attending schools in Idaho Power's service area during spring semester 2013 and another 2,500 kits in the fall. Participating classrooms will be identified by Idaho Power's community education representatives. Once enrolled, one of two vendors selected through a competitive request for proposal (RFP) process will facilitate the delivery of the curriculum, take-home energy kits, and feedback materials directly to the school. Spring kit delivery will begin on approximately April 1, 2013, and reporting for the spring enrollment will be complete in July 2013. Fall kit delivery will begin in September 2013, with reporting complete in early 2014. At the end of 2013, Idaho Power intends to gather feedback from all stakeholders to capture lessons learned and determine whether or not to continue the program in 2014.

In addition to EEAG, Idaho Power solicits further customer input through meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27, which was filed with the IPUC on October 22, 2010.

Since 2002, Idaho Power has recovered most DSM program costs through the Rider, with the intended result of providing a more timely recovery of DSM costs. To address the removal of financial disincentives, Idaho Power has tested the effects of a fixed-cost adjustment (FCA) mechanism in a five-year pilot initiative. In 2011, the FCA pilot completed year five and the company filed Case No. IPC-E-11-19 with the IPUC requesting to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC approved the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company filed its Compliance Filing in response to the IPUC's directive. On January 31, 2013, the IPUC issued Final Order No. 32731, directing that the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for customer incentives paid through the Custom Efficiency program as a regulatory asset beginning on January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in demand-side resources (DSR). As of December 31, 2012, proceedings relating to this case are ongoing.

DSM Expenditures

Funding for DSM programs in 2012 came from several sources. The Rider funds are collected directly from customers on their monthly bills. For 2012, the Idaho Rider was 4 percent of base-rate revenues. The 2012 Oregon Rider was 3 percent of base-rate revenues. Beginning in 2011, Idaho Power was allowed to account for incentives paid through the Custom Efficiency program as a regulatory asset in Idaho. Additionally beginning in 2012, Idaho related demand response program incentives were paid through the power cost adjustment (PCA) mechanism. Other energy efficiency and demand response-related expenses not funded through the Rider, including costs for administration and overhead, are included as part of Idaho Power's ongoing operation and maintenance costs.

Total DSM expenses funded from all sources were $49.3 million in 2012. At the beginning of 2012, the Idaho Rider negative balance was about $5.3 million, and by January 1, 2013, the positive balance was $4 million. This reduction in the Idaho Rider negative balance and accrual of a positive balance was accomplished through the filings described in the Regulatory Initiatives section. At the beginning of the year, the Oregon Rider negative balance was approximately $3.5 million, and by year-end, the negative balance was $3.9 million.

Table 3 shows the total expenditures funded by the Idaho Rider ($25,739,189); the Oregon Rider ($1,382,330); and Idaho Power base rates ($22,205,341). The Idaho Power base rates category includes Idaho Custom Efficiency program incentives, Idaho Power demand response incentives, and operation and maintenance costs, separated by expense category.

Table 3. 2012 funding source and energy impact

Funding Source	Expenses	MWh Savings
Idaho Rider	$ 25,739,188	164,781
Oregon Rider	1,382,330	4,771
Idaho Power Base Rates	22,205,341	676
Total	**$ 49,326,859**	**170,228**

Table 4 and Figure 4 indicate 2012 DSM program expenditures by category. The expenses in the Materials & Equipment category are primarily for A/C Cool Credit ($3,300,000). The Other Expense category includes marketing ($397,800), program evaluation ($214,000), and program training ($115,800). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs, such as M2M Communication Corp. for Irrigation Peak Rewards; EnerNOC for FlexPeak Management; JACO Environmental, Inc. (JACO), for See ya later, refrigerator®; Honeywell for A/C Cool Credit; Evergreen Consulting for Easy Upgrades; and contractors for Weatherization Assistance for Qualified Customers (WAQC) and Weatherization Solutions for Eligible Customers.

Table 4. 2012 DSM program expenditures by category

	Total	% of Total
Incentive Expense	$ 30,848,941	62%
Labor/Administrative Expense	3,490,392	7%
Materials & Equipment	3,308,304	7%
Other Expense	532,733	1%
Purchased Services	11,146,489	23%
Total 2012 DSM Program Expenditures by Category	**$ 49,326,859**	**100%**

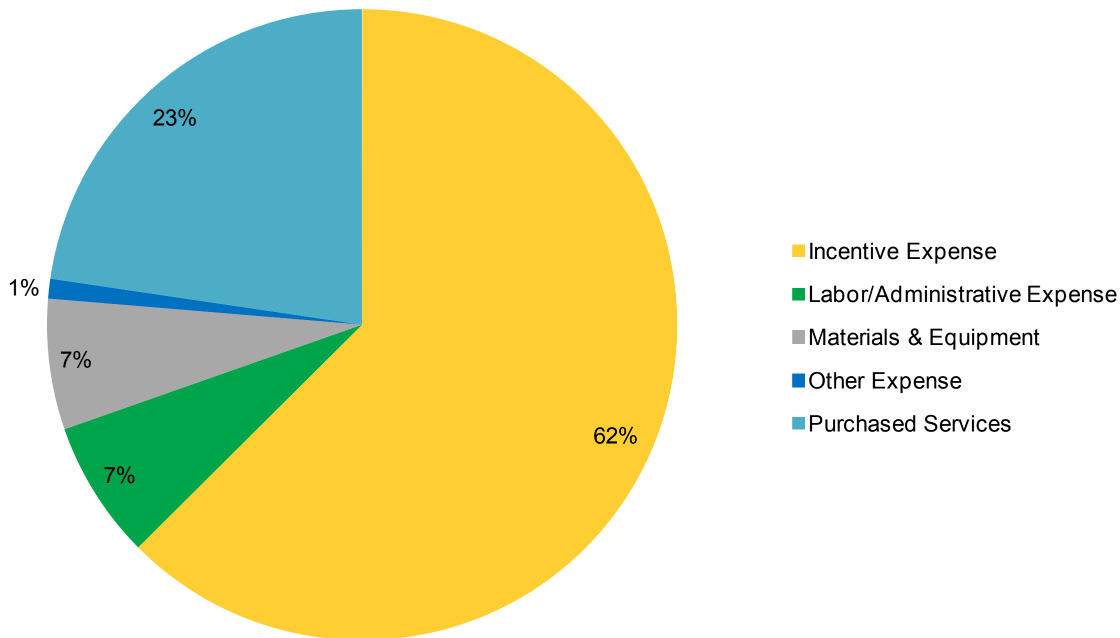


Figure 4. 2012 DSM program expenditures by category

Table 5 and Figure 5 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments—demand response (DR) and Energy Efficiency (EE)—and three sectors—Residential, Commercial/Industrial, and Irrigation. The incentives listed are funded by the Idaho Rider, Oregon Rider, the Custom Efficiency regulatory asset, the Idaho PCA mechanism, and Idaho Power base rates. Market transformation-related payments made to NEEA and payments made to third-party community action partners under the WAQC program are not included in the incentive amounts.

Table 5. 2012 DSM program incentives by segment and sector

	Sector Total	% of Total
DR—Residential	$ 759,544	2%
DR—Commercial/Industrial	2,905,642	9%
DR—Irrigation	11,011,193	36%
EE—Irrigation	2,043,829	7%
EE—Residential	2,143,235	7%
EE—Commercial/Industrial	11,985,498	39%
Total Incentive Expense	**$ 30,848,941**	**100%**

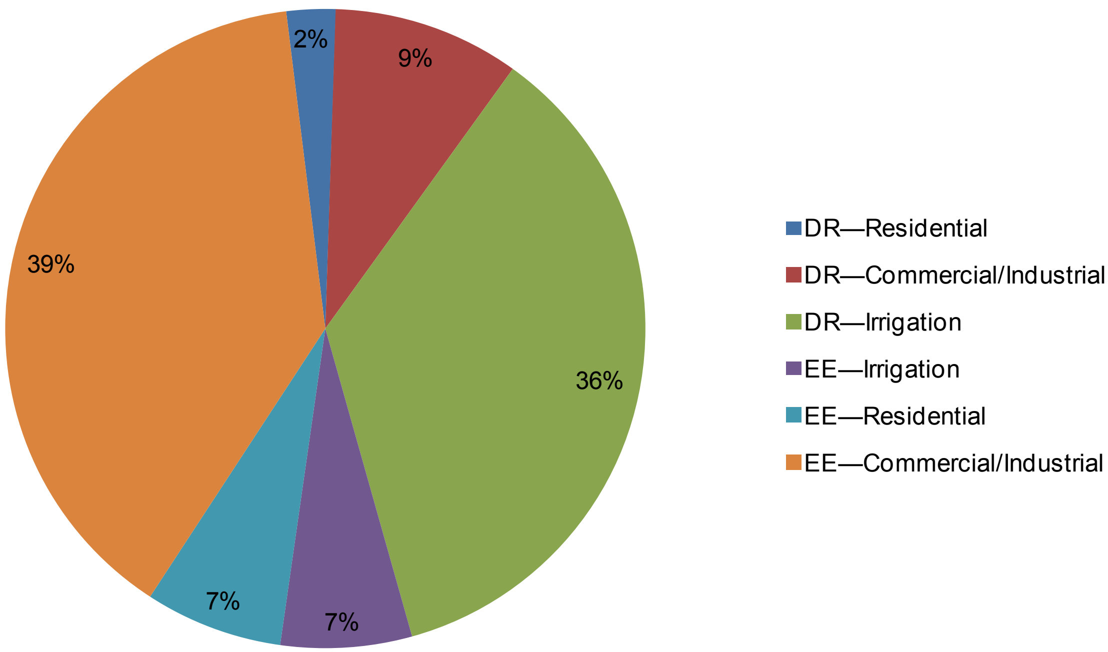


Figure 5. 2012 DSM program incentives by segment and sector

Marketing

With technology rapidly advancing, marketing choices are no longer as simple as placing a print advertisement or distributing a press release. Now marketing is a mosaic that also includes social media, multimedia, community events, online advertising, and owned media.

To meet the demands, a new marketing specialist was added to the energy efficiency team at Idaho Power in April 2012. Adding this position allowed for new marketing ideas and a more balanced workload for two specialists.

Idaho Power marketing staff continually research academic and industry best practices to stay current on marketing theory and tactics. Successful marketing approaches from inside and outside the utility industry are studied and evaluated to determine if they are appropriate for marketing Idaho Power's energy efficiency programs.

Below is a high-level summary of new marketing communication tactics developed and implemented during 2012.

To increase Idaho Power's communication with small and medium commercial customers, the company launched the first biannual *Energy at Work* commercial newsletter. The goal of this newsletter is to provide pertinent and useful information to a customer segment with limited time. The summer 2012 edition is available to download on Idaho Power's business energy efficiency web page. Topics in this edition include the following:

- Energy Efficiency: Good for Business and Your Health
- T-12 Lamps are So Yesterday

- 2011 Commercial Energy Efficiency Program Recap
- Planning for a Successful Energy Efficiency Project
- Four Steps to An Energy-Saving Business Strategy

A video about the DHP Pilot was produced in the first half of 2012 using customer testimonials to explain why people choose DHPs and the benefits for electrically-heated homes. This video is available on Idaho Power's DHP Pilot's web page http://www.idahopower.com/EnergyEfficiency/Residential/Programs/ductlessHeatPumps/default.cfm. The video also was uploaded to YouTube and received 5,200 views in approximately one year.

Planning for an Easy Upgrades program online advertising campaign began in the fall and winter of 2012 to increase participation in the program. An animated advertisement was developed to target commercial businesses, with a planned launch date of January 2, 2013. The advertisement targets specific professions and industries within Idaho Power's service area. Idaho Power staff will review weekly reports to monitor click-through rates (the number of times a user clicks on the advertisement, taking them to a corresponding web page) and make adjustments as needed over the course of the three-month campaign.

Two movie theater advertisements, one for the Home Improvement Program and one for both ducted and DHPs, were produced using in-house resources and shown at Regal Cinema theaters in Nampa and Boise. The advertisements ran for eight weeks during June and July 2012. The number of individual advertisements shown totaled 12,544, and the number of total projected impressions was 695,376; total projected impressions are the anticipated number of times an advertisement will be displayed or viewed, giving customers a certain number of potential exposures to a message or an "opportunity-to-see." The more times a message is viewed, particularly within a shorter time frame, the more likely customers will take action. To maximize the usability of the two movie theater advertisements, both advertisements were uploaded to YouTube and the Home Improvement Program advertisement was posted on the program's Idaho Power web page.

At the November 6 EEAG meeting, an Idaho Power Corporate Communications department representative solicited information from EEAG regarding changes to the company's monthly customer newsletter, *Connections*. Discussions covered reducing the number of energy efficiency bill inserts and instead creating energy efficiency-focused *Connections* editions. EEAG members offered suggestions and support for adding more energy efficiency information in the newsletter. In July 2013, *Connections* will specifically focus on the company's energy efficiency programs.

In January 2013, Idaho Power produced a print advertisement campaign featuring a New Year's theme and a number of Idaho Power's energy efficiency programs. The advertisement ran for two weeks in daily and weekly newspapers throughout Idaho Power's service area.

Facebook and Yahoo! behavioral-targeted advertisements are being used to expand Idaho Power's online presence. Idaho Power staff track these online marketing campaigns through reports that show the number of impressions (number of times a person is exposed to a message), click-through rates, and reach (geographic dispersion of the message). These reports will help inform subsequent marketing decisions.

The following additional metrics are used to determine if marketing tactics are successful.

- Trade ally/contractor feedback
- Customer comments via the Idaho Power call center, email, and customer representatives (CR)
- Qualitative and quantitative survey results
- Customer inquiries and customer awareness of programs
- Web Trends data reports

Program Evaluation

Evaluation of the company's DSM programs is integral in providing accurate and transparent program savings results and is a key component in Idaho Power's commitment to continuous program improvement.

Most program evaluations and primary research is contracted through third-party entities by means of a competitive bid process managed by Idaho Power's Procurement department. When appropriate, an internal analysis is conducted and managed by Idaho Power's Energy Efficiency Research and Analysis team.

In 2012, Idaho Power completed third-party impact evaluations on the following six programs: Heating & Cooling Efficiency (H&CE) Program; See ya later, refrigerator®; WAQC; Weatherization Solutions for Eligible Customers; Building Efficiency; and Easy Upgrades. Additionally, a third-party process evaluation of the A/C Cool Credit program and a 20-year all-sector energy efficiency potential study were completed.

Two third-party primary research projects were conducted in 2012. The A/C Cool Credit research project delivered a predictive model for future use in determining the value of curtailments at various temperatures and cycling strategies. The Irrigation Efficiency Rewards research project determined the estimated unit energy savings for measures deemed out of compliance by the RTF.

Internal program impact reports were completed by Customer Relations and Energy Efficiency staff for the FlexPeak Management and Irrigation Peak Rewards programs. The *Weatherization Assistance for Qualified Customers 2011 Annual Report* was completed in 2012 and filed with the IPUC on April 1, 2012.

Copies of the final reports from evaluations and research performed in 2012 and the *Weatherization Assistance for Qualified Customers 2011 Annual Report* are included in *Supplement 2: Evaluation*.

Customer Satisfaction

In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*. In 2013, based on surveys conducted in 2012, Idaho Power's satisfaction among business customers decreased by 6 percent overall.
Fifty-five percent of the business customer respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than the

customers who are unaware of the programs. The awareness of Idaho Power's energy efficiency programs not only affects the customer's overall satisfaction with the company but also his/her satisfaction with corporate citizenship.

Since 1995, Idaho Power has employed an independent third-party research vendor to conduct customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The survey measures the satisfaction of a number of aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, the intent of this survey is not to measure all aspects of any or all energy efficiency programs offered by Idaho Power.

The 2012 results of Idaho Power's quarterly customer relationship survey continued to show slight but steady improvement. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003, when energy efficiency-related questions were added to the survey, to 60 percent in late 2012. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for improvement. Figure 6 depicts quarterly growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

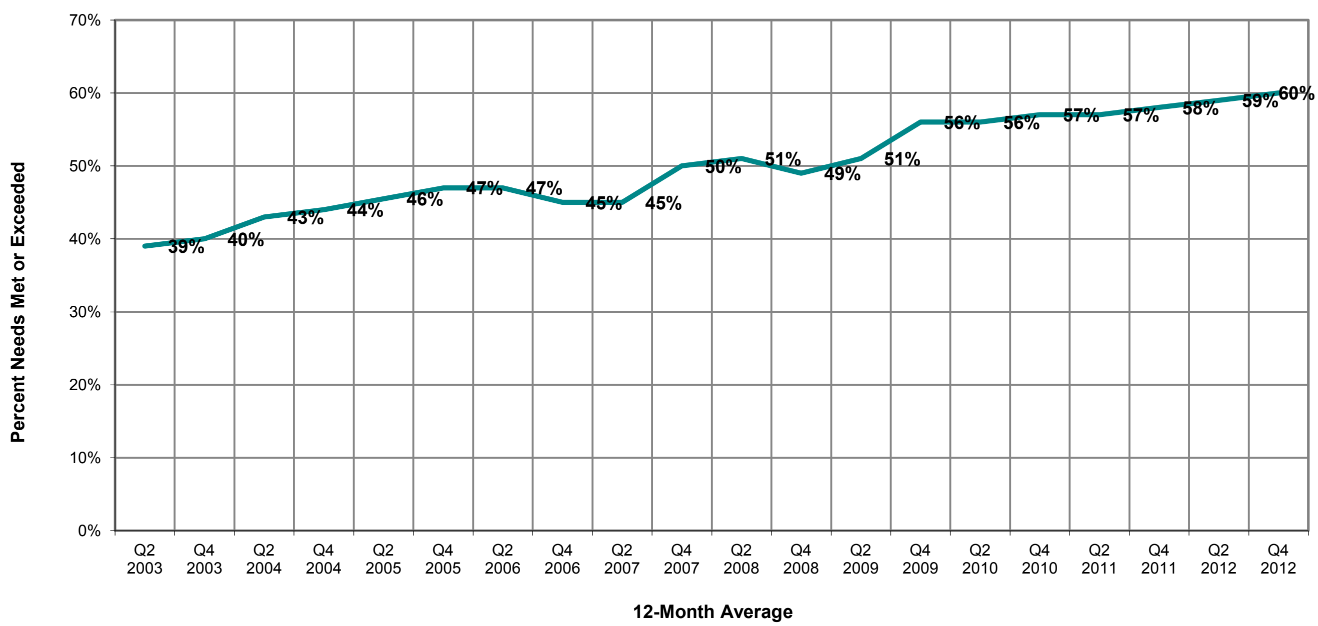


Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

Three questions related to energy efficiency programs in the general relationship survey were added in 2010 and continued in the 2012 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs?, 2) Which energy efficiency program did you participate in?, and 3) Overall, how satisfied are you with the energy efficiency program? In 2012, overall, 35 percent of the survey respondents across all sectors indicated they have participated in at least one Idaho Power energy efficiency program. Of survey respondents who have participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program.

Qualitative research in the form of focus groups and one-on-one customer interviews measured customer satisfaction with the Building Efficiency program in 2012. This research provided guidance for program modification and marketing. Results from this research are presented in the program descriptions in this report under Building Efficiency.

Due to a concern of over-surveying program participants or "survey fatigue," and because the measures and specifics of most program designs do not change annually, Idaho Power has determined it is in the best interest of customers and program operations not to survey most program participants annually. To ensure meaningful research in the future, Idaho Power has determined that program research will be done periodically (every two to three years), unless there have been major program changes. If aspects of the program change significantly, a satisfaction survey will likely be warranted subsequent to the change.

Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. In the past, most of Idaho Power's energy efficiency and demand response programs were preliminarily identified through the IRP process. Because of Idaho Power's diversified portfolio of programs, in the 2011 IRP, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to programs rather than new programs. The process in the IRP remains the same for determining if measures should be adopted as it was for program inclusion. Specific cost-effective programs or energy-saving measures are screened by sector to determine if the levelized cost of these programs or measures is less than supply-side resource alternatives. If they are shown to be less costly than supply side resources from a levelized-cost perspective, the hourly shaped energy savings is subsequently included in the IRP as a resource.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models are inputs from various sources in order to use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other utilities in the region or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than 1 for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program level and the measure level where appropriate. An exception to the measure level cost-effectiveness is when there is interaction between measures. Idaho Power may launch a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following the implementation of a program, cost-effectiveness analyses are reviewed as new inputs from the actual program activity become available, such as actual program expenses, savings, or participation levels. If measures or programs are determined not to be cost effective after implementation, the program or measures are reexamined, including input provided from the company's EEAG.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2012. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. As done in 2011, the actual historic savings and expenses were not discounted; only the value of the ongoing savings going forward are discounted to reflect today's dollars. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

In 2012, all three of the company's demand response programs were cost effective from a long-term perspective. Since this report is focused on cost-effectiveness for 2012 and with the final order pending on IPC-E-12-29, Idaho Power did not change the forecast of future expenses and program performance of its demand response programs. The Irrigation Peak Rewards and FlexPeak Management programs were shown to be cost effective from the one-year perspective for 2012. The A/C Cool Credit program was determined not to be cost-effective on a one-year perspective for 2012 because of the additional expense of replacing the paging switches with Advanced Metering Infrastructure (AMI)-compatible switches. All but two of Idaho Power's energy efficiency programs were cost effective from the UC, TRC, and PCT perspectives. WAQC and Weatherization Solutions for Eligible Customers programs are shown to be not cost-effective from the TRC and UC perspective. This was due to the lower estimated savings per home that resulted from the impact evaluation conducted by D&R International, Ltd. Fifty-two measures within programs were not cost effective from the UC or TRC perspective. Of those 52 measures, 40 were measures that were removed from the program offerings in 2012. Eleven measures will be reviewed and possibly modified in 2013. One measure will be removed in 2013. The specific cost-effectiveness ratios are included in *Supplement 1: Cost-Effectiveness*.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found that 10 incentives out of 410 were paid to builders who submitted applications for ENERGY STAR gas-heated homes that were initiated in 2011. Since non-electrically heated ENERGY STAR Homes Northwest applicants with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The total incentives paid for the 10 homes were $4,000. Gas-heated homes were excluded from the program because, as shown in *Supplement 1: Cost-Effectiveness*, gas-heated ENERGY STAR homes are not cost effective from the TRC perspective; however, they are cost-effective from the UC perspective, and the program remains cost-effective with the inclusion of the costs and savings from the gas-heated homes. In 2013, the fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. The code was changed on the incentive field to reflect electrically heated homes. These changes will prevent gas-heated homes from being given incentives in the future. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

Future Plans

Many of Idaho Power's DSM programs are selected for implementation through Idaho Power's biennial IRP planning process. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency in developing a preferred portfolio of future resources that meets the specific energy needs of Idaho Power's customers. In 2013, Idaho Power plans to increase participation in, and energy savings from, existing energy efficiency programs and initiatives. The company will continue to explore new potential, such as efficient measures for multiple-family dwellings. The company will continue to modify programs and measures and update energy savings and cost data to ensure all of its programs remain cost effective. With the filing and acknowledgement of the 2013 IRP, Idaho Power will have a new set of commission-acknowledged DSM alternative costs with which to analyze its energy efficiency programs. The company will conduct research and analysis to determine the effects of these new costs on the cost-effectiveness of its programs. Additionally, the company will continue to expand and enhance its research and EM&V projects included in the evaluation plan in *Supplement 2: Evaluation*.

DSM Annual Report Structure

The structure of Idaho Power's *Demand-Side Management 2012 Annual Report* remains mostly unchanged from the 2011 report. It aligns with the reporting requirements included in the MOU with the IPUC staff and Idaho's other investor-owned utilities.

This main *Demand-Side Management 2012 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a chart containing 2012 and 2011 program metrics in tabular format, followed by a general description, 2012 activities, cost-effectiveness, customer satisfaction/evaluation, and 2013 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. Appendices 1 through 5 following the written sections contain tabular information on 2012 expenses and savings and supply historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions: 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams, Valley, and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot, and Salmon areas.

Idaho Power currently divides its service area into three geographic regions: 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the five historical regions are often referred to throughout this report.

Appendices 1 through 5 remain generally unchanged in form and contain financial, energy savings, demand reduction, levelized costs, and program life B/C ratios from the UC and the TRC perspectives. Appendix 5 contains detailed financial and energy-savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Included again this year are two supplements and an attached CD. *Supplement 1: Cost Effectiveness* contains detailed annual cost-effectiveness information by program and energy-saving measures, as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, ratepayer impact measure test (RIM), and PCT perspectives. As of 2011, Idaho Power is using the alternate DSM costs and other financial inputs from Idaho Power's 2011 IRP. These inputs are used in cost-effective analyses for 2011 and forward.

Supplement 2: Evaluation contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) and other reports provided by NEEA is attached to Supplement 2.

This page left blank intentionally.

RESIDENTIAL SECTOR OVERVIEW

Description

Idaho Power serves a population of slightly over one million people. Of this overall population, at the end of 2012 the company was serving 416,020 residential customers in its Idaho and Oregon service areas. During 2012, Idaho Power added 4,533 residential customers, a significant increase of residential customers compared to 2,733 in 2011. The growth in residential customers is the largest increase of residential customers over the past five years. This positive trend points towards a decrease in economic uncertainty, with more housing starts occurring in the company's service area. However, it is important to keep this growth rate in perspective from the standpoint that at its highest growth rate, Idaho Power was adding over 15,000 residential customers per year. In 2012, the residential segment represented 35.8 percent of Idaho Power's total electricity usage.

During 2012, after three consecutive years without hitting a system peak, Idaho Power hit its new system peak of 3,245 MW on July 12 at 4:00 p.m. The previous system peak of 3,214 MW was on Monday, June 30, 2008, at 3:00 p.m. In 2012, the Idaho Power service area experienced higher than normal summer temperatures and a summer high temperature of 108 degrees on July 12, 2012. A/C Cool Credit and FlexPeak Management demand response programs were dispatched on July 12, helping reduce what would have been a higher system peak. The company also had a low system winter peak during 2012. The all-time winter peak for Idaho Power of 2,528 MW occurred on Thursday, December 10, 2009, at 8:00 a.m. The winter system peak during 2012 was only 2,133 MW on Wednesday, December 19, at 8:00 a.m. All of these factors contributed to a of 1.4-percent decrease in residential system sales from 2011 to 2012. However, when the system sales data is weather adjusted, this decrease is only 0.2 percent. Idaho Power continued its education and promotion of energy efficiency programs and information to all residential customers. These tasks and activities contributed to increased program participation and continued strong customer satisfaction results.

Programs

Table 6. 2012 residential program summary

Program	Participants		Total Cost Utility	Total Cost Resource	Savings Annual Energy (kWh)	Savings Peak Demand (MW)
Demand Response						
A/C Cool Credit	36,454	homes	$ 5,727,994	$ 5,727,994	n/a	44.9
Total			**$ 5,727,994**	**$ 5,727,994**		**44.9**
Energy Efficiency						
Ductless Heat Pump Pilot	127	homes	$ 159,867	$ 617,833	444,500	
Energy Efficient Lighting	925,460	bulbs	1,126,836	2,407,355	16,708,659	
Energy House Calls	668	homes	275,884	275,884	1,192,039	
ENERGY STAR® Homes Northwest	410	homes	453,186	871,310	537,447	
Heating & Cooling Efficiency Program	141	projects	182,281	676,530	688,855	
Home Improvement Program	840	homes	385,091	812,827	457,353	
Home Products Program	16,675	appliances/fixtures	659,032	817,924	887,222	
Oregon Residential Weatherization	5	homes	4,516	11,657	11,985	
Rebate Advantage	35	homes	37,241	71,911	187,108	
See ya later, refrigerator®	3,176	refrigerators/freezers	613,146	613,146	1,576,426	
Weatherization Assistance for Qualified Customers	238	homes/non-profits	1,370,141	1,819,945	648,304	
Weatherization Solutions for Eligible Customers	141	homes	1,070,556	1,070,556	257,466	
Total			**$ 6,337,777**	**$10,066,879**	**23,597,363**	

Notes:
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.

Programs available to residential customers include 1 demand response program, 12 energy efficiency programs, and 1 energy efficiency educational initiative. Residential efficiency programs include Energy House Calls; Rebate Advantage; ENERGY STAR® Homes Northwest; Home Products Program; Home Improvement Program; Energy Efficient Lighting; WAQC; Weatherization Solutions for Eligible Customers; DHP Pilot; Oregon Residential Weatherization; H&CE Program; and See ya later, refrigerator®.

Idaho Power markets its residential energy efficiency programs through many promotional methods including, but not limited to, bill inserts, bill messages, print advertisements, radio and television commercials, billboards, retail events, customer visits, and participation in home and garden shows as well as fairs.

Presentations to community groups and businesses continued to be a major emphasis during 2012. Idaho Power customer and community education representatives made hundreds of presentations in communities served by the company.

Idaho Power conducts the Burke Customer Relationship survey each year. This survey showed 53 percent of residential survey respondents in 2012 indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill.

Sixty-one percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 45 percent of Idaho Power residential customers surveyed in 2012 indicated Idaho Power is meeting or exceeding their needs in offering energy efficiency programs, while 26 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 83 percent are “very” or “somewhat” satisfied with the program.

A/C Cool Credit

		2012	2011
Participation and Savings			
	Participants (participants)	36,454	37,728
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	44.9	24.0
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$4,804,566	$2,781,553
	Oregon Energy Efficiency Rider	$92,810	$114,989
	Idaho Power Funds	$830,618	$0
	Total Program Costs—All Sources	$5,727,994	$2,896,542
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.33	
	Total Resource Benefit/Cost Ratio	1.33	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2003	

Description

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners (A/C) or heat pumps off and on via a direct-load control device installed on the A/C unit. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high. Idaho Power may cycle participants' A/C for up to 40 hours each month in June, July, and August. In return, participants receive a $7 per-month credit on their Idaho Power bill during July, August, and September.

Customers' A/Cs are controlled using two types of switches that communicate either by power-line carrier (PLC) or radio paging signals. A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C during a cycling event. AMI switches use PLC communication, which provides the communication backbone for these switches. Since the implementation of Idaho Power's AMI project, the company installed the AMI switches wherever possible on new A/C Cool credit participants' A/C units in an effort to eliminate the use of radio paging signal switches.

In 2012, Idaho Power decided to replace existing radio-controlled paging switches with AMI switches due to declining radio paging coverage. There were approximately 23,500 paging switches in the field at the start of 2012. The company successfully negotiated with its third-party installation vendor to reduce the cost to replace the switches and worked with the switch supplier, Aclara®, to reduce the lead time to secure the necessary switches. This switch replacement project began in spring 2012. The project was originally planned to take approximately 18 months beginning in March 2012 and finishing in

June 2013. Switches in areas where paging coverage had been discontinued were replaced first and were replaced by June 15, 2012. Due to Idaho Power's filing of IPUC Case No. IPC-E-12-29 to temporarily suspend the program, the switch replacement project was discontinued in December 2012. At the end of 2012, approximately 7,640 radio-controlled paging switches were still on the system and 28,539 AMI switches were in the program.

2012 Activities

In 2012, Idaho Power contracted with PECI to conduct a research project for the A/C Cool Credit program. PECI's goals were to: 1) verify that savings can be estimated using AMI data, 2) verify that the adaptive algorithm embedded in the switches was working as designed, 3) create a predictive model for planning purposes, 4) estimate the kW reduction at various temperature and cycling strategies, and 5) test customer comfort impacts of higher cycling strategies to find optimum curtailment strategies that maximize kW results while minimizing customer comfort impacts.

To obtain the necessary data to complete this research and develop a predictive model, PECI needed observations of different curtailment strategies at different temperatures with corresponding baseline days where no curtailments occurred. The baseline days provided comparative information to ensure the impact on a curtailment day was fully attributed to the program. Overall, this curtailment research approach was a departure from previous years, where resources were called based on the perceived system need and value.

Based on PECI's research strategy and available days where the temperature matched the research design, there were 13 cycling events in 2012. One cycling event was in June, six events were in July, and six events were in August. Most events lasted from 4:00 p.m. to 7:00 p.m. For two events, participants were divided into two groups, with one group cycling from 4:00 p.m. to 7:00 p.m. and the second group cycling from 5:00 p.m. to 8:00 p.m. One hundred percent cycling, where the paging switches completely turn off the A/C units, was tested twice for one hour each time from 5:00 p.m. to 6:00 p.m.

Prior to the 2012 cycling season, the program specialist convened a working group to manage the complex nature of the cycling events required by the study. This working group included leaders and staff from the Customer Research & Energy Efficiency (CR&EE) department and representatives of Idaho Power's Metering department, who are responsible for configuring the dispatch software used by the AMI switches. The variables that needed configuration included three geographic areas, eight cycling percentages, and four time intervals that needed to be developed for two types of AMI switches.

This working group monitored the events and acted to address cycling issues as they occurred throughout the summer. After the cycling season, this group updated program process flow charts and provided input to PECI's Start-Up Checklist provided in their process evaluation report.

In 2012, due to the low switch inventory and the lead-time necessary to obtain switches, the company determined it would be best to use the available switches to replace paging switches and reduce marketing activities. The limited marketing methods used included a bill insert, follow-up letters for a cause-related effort, and a few small direct-mail campaigns.

The cause-related marketing approach used the last few years, consisting of partnering with the Idaho Foodbank and the Oregon Food Bank–Southeast Oregon Services, was updated and expanded to offer more choices for potential participants. The promotion started in mid-October 2011 and continued through February 2012. Customers enrolling during this limited-time offer and having a switch installed chose between a $20 contribution made to the participant's local food bank and a $20 gift card to a retailer or restaurant of their choice. For 2012, this marketing approach yielded 315 new A/C Cool Credit enrollments. Gift card fulfillment was administered by a third party.

The criteria used for creating new participant solicitation lists were further refined in 2012 as part of a continuing endeavor to focus targeting efforts. Previous criteria included July energy use over 500 kWh; July use 15 percent or greater than April use; Idaho and Oregon residential customers in Ada, Bannock, Bingham, Canyon, Elmore, Gem, Gooding, Jerome, Malheur, Payette, Power, Twin Falls, and Washington counties; an active Utility Service Agreement (USA); "receive marketing" indicator yes; not an existing program participant; premise type is a house; no known landlord; and no duplicates. In 2012, a criterion was added to include 5 kW of demand, or more, for July. The mailing list was further refined to remove any miscellaneous accounts that met the above criteria but did not make sense to include, such as outbuildings, wells, religious facilities, estate accounts, or those managed by a third party.

Since the paging provider discontinued paging service to the Mountain Home Air Force Base (MHAFB), the company could not cycle the switches located in this area in 2012. The financial incentives previously paid to the MHAFB were discontinued. The company explored the option of partnering with the MHAFB to add additional paging equipment at the MHAFB; however, it was not possible to complete the contracts in time for the 2012 cycling season. As of the date of this publishing, a solution to use the paging switches on the MHAFB has not been determined.

Cost-Effectiveness

The B/C analysis for the A/C Cool Credit program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW simple-cycle combustion turbine (SCCT) is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation agreed to in that settlement workshop was filed on February 14, 2013. Idaho Power will meet with stakeholders and interested parties in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in the IPC-E-12-29 case, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit program for its cost-effective analysis. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance. Under these assumptions, the A/C Cool Credit program had a lifecycle TRC ratio of 1.33 and a one-year TRC ratio of 0.68. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

Customer Satisfaction and Evaluations

As mentioned earlier, in 2012, Idaho Power contracted with PECI to conduct research on the A/C Cool Credit program to determine optimal curtailment strategies to meet cost-effectiveness targets and develop a predictive model that correlates weather forecasts with achievable kW load shifts from curtailment events. The results of this research showed that: 1) AMI data for evaluation is more reliable, accurate, and cost-effective than data loggers; 2) the embedded adaptive algorithm is operating as intended, although was only used once during the research period; 3) customer comfort is only minimally affected by higher cycling strategies and indoor temperature increase during events within the range expected for load control programs; and 4) the data from this research enabled PECI to create a predictive model that can be used for planning purposes.

The PECI research also demonstrated that the A/C Cool Credit program can achieve 1.09 kW per participant demand reduction when the weather is sufficiently hot and the cycling strategy is set appropriately. The research noted that on the July 2 event, one set of switches did not respond as expected. The event was intended to be a one-hour curtailment at 100 percent at a temperature of less than 90 degrees. The temperature rose above 90 degrees, which was outside the parameters recommended by PECI, thus the event was canceled. The paging switches and one set of the AMI switches responded; however, the other set of the AMI switches did not stop cycling when the event was cancelled. A change had been made to the scheduling software on Friday, June 29, and the Monday, July 2 event was the first event that occurred after this change was made. Upon investigating and working with the vendor, a coding error was found in the third-party software. Idaho Power developed an interim solution for future use. The vendor is aware of the situation and is working to develop a more permanent solution. The report also makes note that for the event on July 11, only one set of the AMI switches received the signal to dispatch. Idaho Power investigated and found a configuration setting that needed to be changed. This setting was corrected and tested before the event on the following day, July 12. All the switches responded correctly for that event.

Idaho Power also contracted with PECI to provide a process evaluation and program readiness plan. The objective of this evaluation was to document and evaluate the current program processes, identify best practices, and provide recommendations for improvement where applicable. The readiness plan was created to ensure interdepartmental coordination and program readiness prior to the 2012 curtailment season.

The process evaluation report indicated that the program has a high customer satisfaction rate, low churn rate, and a successful relationship with the delivery partner, Honeywell, Inc. PECI also noted that the program has operated successfully due to the continuity in program knowledge from the program specialist and the diligence of internal stakeholders.

PECI recommends: 1) determine appropriate metrics for measuring response rates to marketing campaigns; 2) more focus on customer retention; 3) clearly define roles, responsibilities, and accountability to increase collaboration between marketing and program staff; 4) incorporate pre-season testing of field equipment; and 5) more consistent messaging regarding program guidelines. Copies of both of these reports are included in *Supplement 2: Evaluation*.

2013 Strategies

The 2013 activities for this program hinge on the results of the company's proposal in IPC-E-12-29 to temporarily suspend the A/C Cool Credit program for the 2013 season and upcoming workshops on how to proceed with demand response programs for 2014 and beyond. The proposed suspension will provide Idaho Power an opportunity to work with stakeholders to determine how this program might best serve customers and the company in the future. The company believes the filing is a prudent step to avoid expenses associated with the program until the company's planning process determines the future of the A/C Cool Credit program and the demand response programs in general. Because of this pending proposal, switch replacements were discontinued in December 2012. Approximately 15,564 paging switches have been replaced, and approximately 7,640 remain in the field.

Ductless Heat Pump Pilot

	2012	2011
Participation and Savings		
Participants (homes)	127	131
Energy Savings (kWh)	444,500	458,500
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$153,017	$183,260
Oregon Energy Efficiency Rider	$6,850	$7,923
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$159,867	$191,183
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.024	$0.028
Total Resource Benefit/Cost Ratio	$0.094	$0.081
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.22	
Total Resource Benefit/Cost Ratio	1.44	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2009	

Description

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area. The company extended the project as an Idaho Power DHP pilot through 2012. A main goal of the Northwest DHP Pilot project is to promote DHP technology as an energy-saving alternative for customers who primarily heat their homes with electricity. In 2012, Idaho Power offered customers a $750 incentive payment to participate.

The program targets homes heated with electric zonal systems. Typically, these homes do not have air ducting and therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboards, ceiling cables, and wall-mounted units. Homes heated with fossil fuel forced-air systems or electric forced-air systems do not qualify. Qualifications include having one DHP indoor unit installed in the main living area of the home, since this is where most occupants spend the majority of their time.

Other Northwest DHP Pilot goals are to identify how much energy this technology saves to determine an RTF deemed-savings amount and to obtain customer satisfaction and behavior patterns regarding the units.

Field monitoring of selected homes throughout the Pacific Northwest, an analysis of billing data, and other evaluations occurred from 2009 through mid-2011. Data was analyzed during the second half of 2011 and continued through 2012. An impact and process evaluation field metering report was published in 2012 by NEEA. NEEA will complete a billing analysis report, cost-effectiveness report, and the final summary report in early 2013. Details about the regional DHP effort can be found at the project website at www.goingductless.com and www.neea.org.

2012 Activities

Idaho Power used several marketing methods during 2012 to promote the pilot. Examples include participating in trade shows with a working demo unit, advertising in 10 newspapers, sending direct-mail letters, and adding bill inserts. The use of social-media websites continued in 2012 to increase DHP Pilot awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on the Idaho Power website. Copies of the two DHP Pilot 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Expanding the network of participating contractors remained a key growth strategy for the DHP Pilot. The goal was to support contractors currently in the DHP Pilot while adding new contractors. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation training sessions to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22 percent increase over 2011.

To hasten the residential adoption of the DHP technology in the Idaho Power service area, a key strategy was to communicate with other tiers of the supply chain. In the Idaho Power service area, there are several wholesalers supplying DHPs to the contractors. The program specialist met with several of these wholesalers to provide them the ability to promote DHPs to their contracting customers and to share helpful information. NEEA provided additional marketing and contractor training support for the DHP Pilot.

Idaho Power and other northwestern utilities participated in a 2012 NEEA-sponsored marketing campaign for DHPs conducted from September through December. Residents in the Idaho Power service area were targeted for the campaign using radio, television, and social-media website advertisements.

Cost-Effectiveness

In 2012, the RTF reaffirmed support for a provisional annual-savings estimate based on the installation of one indoor-unit installation until the full pilot analysis is completed in early 2013. The qualifying unit should be installed consistent with the pilot guidelines, including at least one ton of heating capacity and using an inverted driven compressor. The deemed savings per unit is estimated at 3,500 annual kWh until the pilot analysis is completed. Regardless of prior cooling, the type of electric-resistance heat the DHP was displacing, or the climate zone in which the unit is located, the RTF has only deemed one savings amount. Participant costs for the TRC estimate were calculated by averaging one-unit installations that occurred in Idaho Power's service area in 2012. The average installation cost was $4,358, which was an increase over the 2011 average cost of $3,407. Using the RTF-deemed savings, this program is shown to be cost effective. For details see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

As part of the DHP Pilot, Idaho Power conducted on-site verifications (OSV) at completed installations in Idaho Power's service area to ensure the installations complied with program requirements. The OSVs were beneficial for customers and the contractors. The inspector provided information to customers regarding maximizing the benefits of their DHP. The contractors received feedback from the inspector and reviewed the installation requirements of the DHP Pilot. Ten percent of the installations received on-site verifications in 2012.

In 2012, NEEA provided two reports to update the DHP pilot. The following are report highlights. These reports are included on the CD accompanying *Supplement 2: Evaluation*.

Report E12-237, released May 2012

This report focuses on the detailed metering portion of the evaluation. Ecotope, Inc., installed metering equipment on a total of 95 homes selected from the participants in the DHP Pilot project. The metered sites were analyzed to develop the determinants of energy savings of the DHP systems as they operated across a variety of climates and occupants. The results of this report contribute to a more comprehensive understanding of DHP performance and its applicability as an energy efficiency measure in the Northwest. The metering results indicate supplemental heat from other fuels has less overall impact on savings than originally expected. The analysis also strongly indicates that increased indoor temperatures result in lower savings. The use of a DHP in place of baseboard heaters is far less sensitive to the characteristics of the home than would be expected in a conventional heating system. Other findings suggest the occupant's acceptance of this equipment is good and their satisfaction is uniform. The amount of DHP cooling energy measured in the study was about 7 percent of the total value of heating savings. The cooling energy value was considered insignificant when compared to the heating savings value. Therefore, the cooling energy usage was not factored into the net impact of the equipment.

Report E12-245, released October 2012

This report is the second MPER of NEEA's Northwest DHP Initiative. The report presents evaluation findings based on 1) telephone surveys of households that purchased DHPs through the initiative, 2) telephone surveys of other general-population households, and 3) in-depth interviews with Northwest utilities that support the initiative, DHP manufacturers/distributors, and installers. The report includes current data on the DHP market in the Northwest. The report findings suggest that multimedia marketing should be continued. Word-of-mouth marketing is a tactic that should be incented as well. The distributors should also be encouraged to promote DHPs that can perform well in extremely low outdoor temperatures. The report also suggests that banks and financial institutions be encouraged to offer financing for DHPs.

2013 Strategies

Idaho Power will sponsor and provide training sessions and orientations to the DHP Pilot program for new and existing contractors to assist them in meeting program requirements and further their product knowledge.

Expanding the network of participating contractors remains a key strategy for the DHP Pilot. The goal is to support contractors currently in the DHP Pilot while adding new contractors. Performance of the DHP Pilot is substantially dependent on the success of the contractor's ability to promote and leverage the DHP Pilot. Frequent individual contractor meetings will be held in 2013. The program specialist, along with Idaho Power CRs, will arrange these meetings.

To promote the residential adoption of the DHP technology in Idaho Power's service area, the strategy includes communicating with the complete supply chain. To accelerate the wholesaler's ability to increase contractor awareness of DHPs and the DHP Pilot, the program specialist will meet with the wholesalers and share helpful information.

Traditional and new marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the DHP Pilot program, as well as the H&CE Program. Specifically, Idaho Power will discuss the helpfulness and usability of a contractor portal housed on Idaho Power's website. The portal will provide contractors with access to predesigned and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their specific business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces targeted to customers who have high electric winter usage, as well as customers who have moved into a new home, which research has shown have a higher likelihood to make home upgrades. Behavioral advertisements refer to advertisements posted on websites based on an individual's recent web behavior. For example, if someone views a major automobile company's website, automobile advertisements will pop up on other unrelated websites viewed because the Internet Protocol (IP) address of the viewer's searches is tracked.

Energy Efficient Lighting

		2012	2011
Participation and Savings			
	Participants (bulbs)	925,460	1,039,755
	Energy Savings (kWh)	16,708,659	19,694,381
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,110,329	$1,668,328
	Oregon Energy Efficiency Rider	$16,507	$50,805
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$1,126,836	$1,719,133
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.012	$0.015
	Total Resource Benefit/Cost Ratio	$0.025	$0.024
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.47	
	Total Resource Benefit/Cost Ratio	3.05	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2002	

Description

The Energy Efficient Lighting program strives for residential energy savings through the replacement of less-efficient lighting with more-efficient technology. According to the *NEEA 2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study, the average Idaho home has 63 bulb sockets. The *2010 Idaho Power End Use* study shows 88 percent of customers have less than 20 compact fluorescent bulbs installed, indicating there is still potential to install more energy-efficient bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR® qualified compact fluorescent lamps (CFL) are an alternative to standard incandescent light bulbs that result in saved money, energy, and time. Bulbs come in a variety of wattages, colors, and styles, including bulbs for three-way lights and dimmable fixtures. ENERGY STAR bulbs use up to 75 percent less energy and last up to 10 times longer than incandescent bulbs.

2012 Activities

In 2012, the Energy Efficient Lighting program provided more than two-thirds of all energy savings derived from residential energy efficiency customer programs. This contribution is expected to decline in future years as CFL penetration rates increase and more efficient lighting standards are enforced.

The Energy Efficiency Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers with savings passed onto the customer at the point of purchase. The benefits of this model are low administration costs, the availability of products to the customer, and the ability to provide an incentive for specific products.

In 2012, Idaho Power again participated in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings™ promotion focusing on ENERGY STAR specialty and spiral bulbs. Fluid Market Strategies managed the promotion. Fluid Market Strategies is responsible for retailer and manufacturer contracts, marketing materials at the point of purchase, and for providing support and training to retailers. Additional marketing by Idaho Power included the utility website, events, and presentations to customers.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power dropped light fixtures from the Home Products Program and added them as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales of fixtures were reported in 2012 under this promotion.

Additional 2012 program activities included direct distribution and retailer education events. Idaho Power has a small, direct-distribution program where bulbs are given directly to customers at appropriate venues. The idea is, if given a free bulb, customers might try CFLs for the first time or be encouraged to replace additional lamps. Guidelines for approved venues and the direct distribution effort have been developed to ensure customer fairness.

During 2012, Idaho Power participated in six retailer events with large national retailers. Retailer events were designed to communicate directly to customers at the point of sale. Idaho Power staff set up tables with light displays at the entrances of stores and answered questions about CFLs.

The Energy Efficient Lighting program was one of three Idaho Power programs that sponsored the local, semi-professional basketball team, the Idaho Stampede, at the team's Green Week games in April. As part of the promotion, Idaho Power ran a 30-second public-service announcement (PSA) on energy-efficient lighting that aired at two Idaho Stampede home games. The announcement was posted to Idaho Power's website and to YouTube. At the two Idaho Stampede games, the promotion included a light bulb demonstration using a bicycle to power incandescent and CFL bulbs. Sixty-eight people rode the bike at the games and learned firsthand how much less electricity CFL blubs use compared to incandescent bulbs.

Three presentations were developed for use by Idaho Power staff focusing on lighting basics, outdoor lighting, and holiday lighting. A lighting-basics presentation was given at the Ada County Extension office and the Idaho Green Expo.

In 2012, Idaho Power began participating in the Northwest Regional Retail Collaborative (NWRRC) facilitated by NEEA and following work by the Western Regional Utility Network. Both the NWRRC and the Network seek to develop collaborative approaches to working with manufactures and retailers to increase the uptake of energy-efficient products in the retail market.

In 2012, Idaho Power began researching the transition of the Energy Efficient Lighting program to a more comprehensive retailer markdown program that would include additional product categories. Barriers include retailer point-of-sale system limitations. Groups like the NWRRC provide a forum to identify and work toward addressing these types of barriers.

Cost-Effectiveness

In 2012, the RTF updated several assumptions for specialty CFL bulbs. The change to baseline and efficient wattage assumptions, though minimal, did contribute to the decrease in savings. The RTF reviewed studies and took into consideration the changes in bulb efficiency standards from the

Energy Independence and Security Act of 2007 (EISA), as well as regional sales data. Additionally, there was a change to the hours-of-use assumptions for various lamp types and storage rates that further contributed to the decrease in savings. Despite the change, the measures still remain cost effective. The savings for spiral bulbs remained unchanged. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

2013 Strategies

Idaho Power will continue to participate in Simple Steps, Smart Savings through 2013. Marketing for this program will continue to include point-of-purchase signs at the retailer managed by Fluid Market Strategies. Idaho Power will also promote the program through its website, events, and presentations.

Idaho Power will continue to distribute limited quantities of bulbs directly to customers at appropriate public energy efficiency events and continue to participate in retailer educational events. An evaluation will be made based on the cost to put CFLs in new-customer welcome packets. Customer education regarding savings of time and energy from these improved products will continue.

The company will monitor the market and emerging technologies. Light-emitting diode (LED) light bulbs are on display at many major retailers. As of December 2012, there were over 1,300 products on the ENERGY STAR criteria list for LED replacement bulbs. Seventy-five percent are reflectors. Market prices for LED products are significantly higher than CFLs and EISA-compliant halogens.[1] Idaho Power will continue to evaluate the price, availability, savings, and technology of LED lighting to determine if it should be included in the future.

Idaho Power will also participate in the NWRRC. Participation in the NWRRC will help facilitate research into transitioning the Energy Efficient Lighting program to a more comprehensive retailer-markdown program with additional product categories.

In 2013, Idaho Power plans to do a third-party process evaluation of the Energy Efficient Lighting program.

[1] Example: An ENERGY STAR qualified, 60-watt (W) equivalent A-lamp LED equivalent by Phillips retails between $25.45 and $38.50 according to Consumer Reports at http://www.consumerreports.org/cro/home-garden/home-improvement/lightbulbs/lightbulb-ratings/models/overview/philips-ambientled-12-5w-12e26a60-60w-409904-99040398.htm.

Energy House Calls

	2012	2011
Participation and Savings		
Participants (homes)	668	881
Energy Savings (kWh)	1,192,039	1,214,004
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$272,666	$447,229
Oregon Energy Efficiency Rider	$3,217	$36,146
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$275,884	$483,375
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.016	$0.027
Total Resource Benefit/Cost Ratio	$0.016	$0.027
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.05	
Total Resource Benefit/Cost Ratio	3.05	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2002	

Description

The Energy House Calls program helps manufactured and mobile homeowners with electric heating reduce electricity use by improving the home's efficiency. This program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing a CFL bulb; providing two furnace filters, along with replacement instructions; testing water heater temperatures for the proper setting; and distributing energy efficiency educational materials for manufactured home occupants. The value of the service to the customer is dependent on the complexity of the repair, although services are provided free to participants. The typical cost range of the average service call is $325 to $550. Idaho Power provides the customer with the sub-contractor contact information. Customers access the service and schedule an appointment by directly calling one of the recognized, certified sub-contractors specially trained to provide these services in their region.

2012 Activities

Energy House Calls serviced 592 manufactured homes during 2012, resulting in 1,192,039 kWh savings. Seventy-six percent of the homes serviced were located in the Treasure Valley. Twenty-four percent were outside the Treasure Valley, with 11 percent in Eastern Idaho and 13 percent in Southern Idaho. Quality-assurance (QA) checks were conducted on 5 percent of the homes serviced in the program. Idaho Power coordinates the sub-contractors performing local weatherization and energy efficiency services, processes sub-contractor paperwork, and pays sub-contractors directly for work performed.

Marketing campaigns included a bill insert sent to all Idaho Power residential customers, a program brochure used by Idaho Power representatives in the field and at Idaho Power-sponsored events, and a direct-mail postcard. The direct-mail postcards were sent to all customers identified as living in a manufactured home. Feedback from Idaho Power sub-contractors indicated the direct-mail postcards yielded the most amount of interest in the program. This was the most effective form of marketing.

During summer 2012, Idaho Power employees marketed the Energy House Calls program to managers and residents of mobile home parks in Twin Falls, Pocatello, and Chubbuck. Marketing efforts included distributing marketing material, leaving door hangers, and answering customer questions and inquiries. Marketing materials informed customers their inquiries would be forwarded to the appropriate contractor.

Idaho Power field staff CRs and call-center customer service representatives (CSR) are educated about the program and will continue to promote it to qualified customers.

Cost-Effectiveness

Duct-sealing deemed savings for manufactured homes were revised in spring 2012 by the RTF to bring the measure into compliance with current guidelines. The measure definition was also updated to reflect different manufactured home styles.

The baseline pre- and post-supply duct leakage were analyzed by the RTF as part of the comprehensive measure review during 2012, and the results were reported at the October 2012 RTF meeting. The baseline duct leakage increased from a previous 15 percent to 20 percent, which corresponds to more duct leakage being found in existing homes, resulting in increased savings from duct sealing. The increased baseline leakage is consistent with data collected from Idaho Power projects. The updated savings were provided along with new measure definitions splitting out savings by either single-wide manufactured homes and double-wide or triple-wide manufactured homes. Annual savings reported for 2012 were assigned by the home's heat source, the existence of central A/C (electric furnace with and without A/C) or a heat pump, and the home's climate zone. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

To monitor QA in 2012, third-party verifications were conducted by Momentum, LLC on approximately 5 percent of the participant homes, resulting in 33 home inspections. The final round of QA results is being analyzed during first quarter 2013 and appears to be consistent with those conducted earlier in the year, which were very positive. Verifications were selected at random. The verification included a visual review of the reported information, as well as a blower door test to verify the results submitted by the sub-contractor.

2013 Strategies

Plans for the upcoming year include continuing the direct-mail campaign throughout the Idaho Power service area to increase market penetration. Based off low response rates in the Eastern and Southern regions, there are concerns the market may be reaching saturation. Possible reasons for the lack of participation include an imperfect mailing list and the difficulty in identifying manufactured homes on the Idaho Power billing system. Idaho Power updated the mailing list used for the direct-mail letters in

2012 and plans to do the same in 2013. The list is generated from homes designated as manufactured or mobile on Idaho Power's CIS and is analyzed for homes that appear to use electric heat, based on kWh use during winter and summer months. The company will also continue to explore low-cost and effective methods of marketing this program to all residential customers believed to have electrically heated manufactured homes. This form of marketing may yield additional word-of-mouth promotion to potential program participants. Less broad-based outreach efforts will continue via CRs and limited-income outreach entities.

ENERGY STAR® Homes Northwest

		2012	2011
Participation and Savings			
	Participants (homes)	410	308
	Energy Savings (kWh)	537,447	728,030
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$450,727	$255,405
	Oregon Energy Efficiency Rider	$2,458	$4,357
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$453,186	$259,762
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.046	$0.020
	Total Resource Benefit/Cost Ratio	$0.089	$0.051
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.77	
	Total Resource Benefit/Cost Ratio	2.51	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2003	

Description

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA to improve and promote the construction of energy-efficient homes using guidelines set forth by the United States (US) Environmental Protection Agency (EPA). This program targets the lost-opportunity energy savings and summer-demand reduction that results by increasing the efficiency of the residential-building envelope and air delivery system above current building codes and building practices. An ENERGY STAR certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR rater to meet the stringent ENERGY STAR requirements. This third-party rater is hired by the builder to perform these duties.

The ENERGY STAR Homes Northwest residential construction program promotes homes that are electrically heated and are at least 15 percent more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes Northwest are verified by independent, third-party HPS and are certified by the Washington State University Extension Energy Program, an organization that conducts the certification inspections throughout the state of Idaho and for the EPA. The homes are more efficient, comfortable, and durable than standard homes constructed according to Idaho building codes.

Homes that earn the ENERGY STAR label include six required specifications. The specifications found in all ENERGY STAR certified homes are 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

In 2012, builders involved in ENERGY STAR Homes Northwest received a $1,000 incentive per home built to the Northwest Builder Option Package (BOP) electrically heated homes standard. Builders who entered their homes in a Parade of Homes received the standard $1,000 incentive plus an additional $500 incentive to encourage builders to construct ENERGY STAR homes.

The Idaho Power program collaborates with many local entities for program promotion, including ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2012 was to provide marketing materials and conduct education and training activities for residential new construction industry partners.

2012 Activities

As the housing market slowly started to improve throughout the Idaho Power service area in 2012, the ENERGY STAR Homes Northwest program showed an increase in ENERGY STAR Homes certified from 308 in 2011 to 410 in 2012.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2012. The company presented energy efficiency awards at the Building Contractors Association of Southwestern Idaho (BCASWI) Parade of Homes awards banquet. In addition, the company maintained a presence in the building industry by supporting many of the building contractors associations (BCA) throughout Idaho Power's service area. Specifically, the company participated in the BCASWI Builder's Expo, the Snake River Valley Building Contractors Association (SRVBCA) Builder's Expo, the Magic Valley Builders Association Parade of Homes (MVBA), the BCASWI Parade of Homes, SRVBCA Parade of Homes, the Building Contractors Association of Southeast Idaho (BCASEI) Parade of Homes, and the Idaho BCA Convention. Idaho Power joined with Northwest ENERGY STAR for a minor sponsorship of the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home. Northwest ENERGY STAR secured the donation of the heat pump. Idaho Power produced a bill insert, sent to all residential customers in the Idaho Power service area, promoting ENERGY STAR homes and highlighting the 2012 Dream Home.

Other marketing projects involved adding a message about this program to residential customers' electric bills. These bill messages encouraged Idaho Power customers to visit ENERGY STAR certified homes in their local Parade of Homes events.

Cost-Effectiveness

There were no changes to RTF deemed-savings values for single family ENERGY STAR homes during 2012. In fall 2012, the RTF produced deemed annual savings for multi-family ENERGY STAR homes using a blended prototype of low-rise, multi-family dwelling types that included a townhome design. The modeled multi-family ENERGY STAR home prototype included a range of homes sizes between 950 to 1,500 square feet (ft^2). The average size of a townhome in the program in 2012 was 925 ft^2, which falls within the RTF-modeled prototype range. The annual deemed savings for the townhome are approximately one-third the annual savings of a traditional detached single-family home and vary depending on the climate zone between 599 and 770 kWh annual savings. Since 396 out of 410 ENERGY STAR homes given incentives by Idaho Power in 2012 were townhome style homes and did not fit the traditional single-family home, the company applied the new updated savings to all townhomes.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found 10 incentives, out of a total of 410, that were inadvertently paid to builders who submitted applications for ENERGY STAR gas-heated homes. Since non-electrically heated ENERGY STAR Homes Northwest homes with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The costs and savings are included in the cost-effectiveness analysis, and although the company has determined that gas-heated homes are not cost-effective, the program remains cost-effective. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

The HPS works with builders to ensure the ENERGY STAR homes are compliant with the Northwest electric-only BOP. Along with verifying the installation of building components and equipment through on-site inspections, prior to being certified, the home must pass a blower door test, air-duct leakage test, and combustion back-draft tests.

The state-certifying organization (SCO) performs QA. The Washington State University Energy Extension Program is under contract with NEEA to perform QA and technical assistance duties within Idaho. For QA purposes, 10 percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed by the Washington State University Energy Extension Program. This is a technical verification of the homes. All of the homes randomly chosen for QA in Idaho Power's service area passed the QA inspection process.

2013 Strategies

As in 2012, builders involved in ENERGY STAR Homes Northwest during 2013 will receive a $1,000 incentive per home built to the Northwest BOP, electric-only standards in Idaho Power's service area. Builders showcasing their electric-only home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive.

Idaho Power plans to continue marketing efforts to help sell ENERGY STAR homes, including educating consumers, Realtors, and appraisers about the benefits and features of ENERGY STAR homes. Results will be influenced by the housing market's potential improvements. These marketing efforts include Parade of Homes advertisements in parade magazines for the BCASWI, SRVBCA, MVBA, and the Building Contractor Association of Eastern Idaho. Bill inserts will be sent to all residential customers in April and May. In addition, bill messaging is planned in June, July, and August to support the various BCA Parade of Homes events throughout Idaho Power's service area.

In 2013, changes were made in Idaho Power's database and payment review process to prevent incentives to be paid for gas-heated ENERGY STAR homes. The fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. Also, the code was changed on the incentive field to reflect electrically heated homes. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the ENERGY STAR Homes Northwest program.

Heating & Cooling Efficiency Program

	2012	2011
Participation and Savings		
Participants (projects)	141	130
Energy Savings (kWh)	688,855	733,405
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$175,483	$188,876
Oregon Energy Efficiency Rider	$6,798	$6,894
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$182,281	$195,770
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.018	$0.018
Total Resource Benefit/Cost Ratio	$0.066	$0.056
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.49	
Total Resource Benefit/Cost Ratio	1.78	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2007	

Description

The H&CE Program provides incentives for the purchase and proper installation of qualified heating and cooling equipment to residential customers.

The objective of the program is to acquire energy savings by providing customers with energy-efficient alternatives for electric space heating. Incentive payments are provided to residential customers and heating, ventilation, and air conditioning (HVAC) participating contractors who install eligible equipment. The eligible measures in 2012 included air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Heating and A/C companies authorized by Idaho Power as participating contractors for the program are required to perform all installations, with the exception of evaporative coolers, which can be self-installed. The program continued through 2012 with the same portfolio of incentives as in 2011.

2012 Activities

The H&CE Program's list of measures and incentives during 2012 included the following:

- Air-source heat pump customer incentives for replacing an existing air-source heat pump with a new air-source heat pump were $200 for minimum efficiency 8.2 heating seasonal performance factor (HSPF) and $250 for minimum efficiency 8.5 HSPF.
- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump were $300 for minimum efficiency 8.2 HSPF and $400 for minimum

efficiency 8.5 HSPF. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.

- Incentives for customers or builders of new construction installing an air-source heat pump in a new home were $300 for minimum efficiency 8.2 HSPF and $400 for minimum efficiency 8.5 HSPF.
- The open-loop water-source heat pump customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump was $500 for minimum efficiency 3.5 coefficient of performance (COP).
- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump was $1,000 for minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.
- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home was $1,000 for minimum efficiency 3.5 COP.
- The evaporative-cooler customer incentive was $150.

The expanding of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal was to support contractors currently in the program, while adding new contractors. The company held meetings with several prospective contractors to support this strategy. Six companies were added in 2012 to Idaho Power's list of participating contractors, doubling the number added from 2011.

Idaho Power held training sessions for contractors in September that provided general instructions on heat pumps and program guidelines. For a company to be eligible to join the program as a participating contractor, they must have attended this training. Fourteen technicians from eight companies attended the sessions in 2012. These training sessions remain an important part of the program because the training creates opportunities to invite additional contractors into the program.

Several marketing tactics were used during 2012 to reach customers. Examples include print advertising in newspapers, direct-mail, bill inserts, and trade shows. The use of social-media websites continued in 2012 to increase program awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on Idaho Power's website. Copies of the two H&CE Program 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

To increase contractor participation in the program, stronger relationships with the equipment wholesalers was necessary. In Idaho Power's service area, there are several major wholesalers supplying heat pumps to the contractors. The program specialist met with such wholesalers to provide them with the ability to promote the program with their contracting customers and share helpful information.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review the incentive applications and perform OSVs. This contractor provides direct support to participating contractors and the residential program participants. Honeywell offers local assistance through representative visits to contractors at their businesses as needed. Using a program database via a portal developed by Idaho Power, Honeywell reviews and submits incentive applications for Idaho Power payment. This allows

Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor.

On the national level, a 2011 federal tax credit for heat pumps contained in section 25C of the Internal Revenue Service (IRS) tax code was not renewed for 2012.

Cost-Effectiveness

The savings for heat pumps installed under the H&CE Program consists of both savings for the increased efficiency of the equipment and savings resulting from quality installation, including proper unit sizing, controls settings, and commissioning. While the core savings of air-source heat pumps were not updated or changed by the RTF during 2012, other measures currently not deemed by the RTF, including lower-tier savings heat pumps, evaporative A/Cs, and geothermal heat pumps savings sources were reviewed to ensure they were consistent with the current regional work done by the RTF. For 2012, participant costs' averages used for the cost-effectiveness analysis were calculated using Idaho Power-specific project data instead of relying on regional averages.

There were no changes in 8.5 HSPF air-source heat pump annual savings for 2012 when customers were displacing electric furnaces. Additional equipment savings were claimed in 2012 in cases were customers' equipment performance exceeded an HSPF rating of 9. An additional 115 to 128 annual kWh were claimed depending on the customer's climate zone.

The previous savings for evaporative coolers (swamp cooler) were based on the 2009 potential study and on a generic prototype evaporative cooler that was not differentiated between a direct or indirect cooler design. Indirect cooler designs have specialized equipment that pre-cools the air before the evaporation process occurs, which substantially increases the savings and equipment costs. The few incentives that Idaho Power paid for evaporative coolers were for the direct-cooler design that pushed direct outside air into the cooler with no pre-treatment. The savings were reduced from an annual savings rate 1,300 kWh over a seasonal energy efficiency ratio (SEER) 13 code central A/C to between 300 and 400 annual kWh depending on whether the cooler was installed in a multi-family manufactured home or single-family home. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power contracted with The Cadmus Group, Inc., to conduct an impact evaluation of 2011 savings results. The evaluation report indicated that most measures were installed in compliance with PTCS commissioning, controls, and sizing standards. Tracked data was complete and accurate, and ex-ante energy savings were a reasonable but needed refinement. The program ex-post realized savings rate was 94 percent as compared to ex-ante estimates.

The Cadmus Group, Inc., recommends the following: 1) program staff continue to collect detailed data on each project to refine individual project savings estimates, 2) perform a saturation study to determine intent to convert to all-electric heating and cooling, and 3) consider the promotion of on-bill financing to make a heat pump more attractive to customers. A copy of the complete report is included in *Supplement 2: Evaluation*.

The program performed random OSVs on 14 completed installations in the Idaho Power service area, resulting in 10 percent of the total applicants. These OSVs verified the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with respect to the contractors. The program specialist continues to work with contractors to help them understand the importance of accurate documentation.

2013 Strategies

There will be two changes to the program in 2013. The first change is the removal of measures involving air-source heat pumps below 8.5 HSPF. The measures include replacing an existing air-source heat pump, electric resistance, oil, or propane heating system with a new minimum 8.2 HSPF air-source heat pump. The primary reason for removing these measures is that the heat pump market has been slowly transforming to more efficient, higher HSPF heat pumps. In the last several years, only about 3.5 percent of all applications received in this program have been for units below 8.5 HSPF, rendering an incentive unnecessary.

The second change is to increase the incentive from $400 to $800 when replacing an electric-resistance heating system with an air-source heat pump having a minimum of 8.5 HSPF. Idaho Power made this change to increase the participation of this measure and to focus the program on higher efficiency measures. The incremental installed cost of a new heat pump is approximately $3,000. Idaho Power has evaluated the cost-effectiveness of this measure with an $800 incentive, and this measure continues to be cost effective.

Idaho Power will sponsor and provide training to new and existing contractors in the program to assist them in meeting program requirements and further their product knowledge. Sessions will be held at both local wholesaler and Idaho Power facilities.

Expanding the network of participating contractors remains a key strategy for the program. The goal is to support contractors currently in the program while adding new contractors. The performance of the program is substantially dependent on the success of the contractors' abilities to promote and leverage the measures offered in the program. Frequent individual meetings will be held with contractors in 2013. The program specialist, along with Idaho Power CRs, will arrange the discussions.

To increase participation in the program in the Idaho Power service area, the program specialist will work to strengthen relationships with equipment wholesalers. To accelerate the wholesalers' abilities to increase contractor awareness of the program, the program specialist will meet with the wholesalers and share information.

Numerous marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the H&CE Program, as well as the DHP Pilot. During the visits with contractors, the marketing specialist and the program specialist will specifically discuss the helpfulness and usability of a new contractor portal housed on Idaho Power's website. The portal will provide contractors access to pre-designed and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces to targeted customers who have high electric winter usage and who have moved into a new home. Research has shown new home buyers are more likely to make home upgrades in the first two years of ownership.

In 2013, Idaho Power plans to do a third-party process evaluation of the H&CE Program.

Home Improvement Program

		2012	2011
Participation and Savings			
	Participants (homes)	840	2,275
	Energy Savings (kWh)	457,353	917,519
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$385,091	$666,041
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$385,091	$666,041
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.044	$0.038
	Total Resource Benefit/Cost Ratio	$0.093	$0.155
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.15	
	Total Resource Benefit/Cost Ratio	1.21	
Program Characteristics			
	Program Jurisdiction	Idaho	
	Program Inception	2008	

Description

The Home Improvement Program offers incentives to homeowners for upgrading insulation in electrically heated homes. The program's list of measures and incentives in 2012 consisted of the following:

- Customer incentives for attic insulation, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing.
- Customer incentives to Idaho residential customers in the Idaho Power service area for additional insulation professionally installed was 15 cents per square foot for attic insulation, 50 cents per square foot for wall and under-floor insulation, and 30 cents per linear foot for air- and duct-sealing.
- Existing attic insulation must be an R-20 or less to qualify, and the final R-Value must meet the local energy code. Idaho Power's service area consists of climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-Value must be R-19.
- The existing insulation level of under-floor must be R-5 or less, and the final R-Value must be R-30.

On April 1, 2012, the program transitioned from an open contractor program to a participating contractor program. Participating contractors must successfully complete a two-day contractor training course administered by Fluid Market Strategies. Customers must use a participating contractor to qualify for the Idaho Power incentive.

Also on April 1, 2012, the program transitioned from being a fuel-neutral program to an electrically heated home program. To qualify for an incentive under this program, the home must be a single-family home, including duplexes and townhomes. The home must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system. Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor. On April 1, 2012, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing were added to the program.

2012 Activities

Due to the increased complexity of the program requirements, Idaho Power brought the outsourced, third-party incentive processing back in house. All Home Improvement Program incentive applications are now processed by Idaho Power staff.

Various marketing techniques were employed in 2012. Movie theater advertising ran during June, July, and August in the Boise, Nampa, Pocatello, and Cascade markets. A small-market print advertising campaign ran in November and December. An informational bill insert ran in October, and a direct-mail letter targeted to electrically heated customers was sent out in November. All of these marketing activities resulted in increased customer inquiries regarding program details and provided opportunities for customer education.

Cost-Effectiveness

Supplement 1: Cost-Effectiveness contains cost-effectiveness information for attic, wall, and floor insulation measures broken out by customers' electric heating source equipment type, R-value change, climate zone, and presence of central A/C if applicable. Additionally, the cost-effectiveness results in *Supplement 1: Cost-Effectiveness* are shown for the Home Improvement Program attic insulation measures phased out in the first trimester of 2013. These measures included previously available incentives for customers with central A/C, regardless of heating fuel type.

Although the RTF reviewed 2011 attic insulation measures for compliance and RTF guidelines during 2012, no changes were made to deemed annual savings values. Deemed-savings values specific to Idaho Power's climate zones were published by the RTF in October 2011, including cooling savings based on the RTF's deemed savings for single-family home weatherization published in July 2011.

A change in the Idaho Power cost-effectiveness analysis for 2012 was the inclusion of the RTF specifications requiring homes to be adequately air-sealed, including air ducts, prior to the installation of attic and floor insulation. Idaho Power included the costs of the $0.30-per-linear-foot incentive offered to program participants who needed to have air- and duct-sealing done to align with the updated guidelines. When calculating the TRC, the installed costs were averaged across attic and floor insulation projects, including costs to air- and duct-seal to assess cost-effectiveness. The additional project costs had minimal impacts to participant costs and the overall cost-effectiveness of project costs per square foot, staying consistent with the RTF deemed participant cost estimates. For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

For QA purposes, third-party contractors randomly reviewed 10 percent of all insulation jobs completed in the Home Improvement Program. With the addition of the new program requirements in April 2012, these QA contractors also performed in-progress QA to assist and educate the contractors on the new program requirements, particularly the air- and duct-sealing requirements. Of the 80 QA inspections completed in 2012, two issues concerning post-insulation depth were reported and corrected.

One voluntary marketing question, inquiring how the customer heard about the program, was added to the program incentive application form. Of the 840 applications, 196 customers answered the marketing question. Ninety-two customers (47%) heard about the program from an insulation contractor, while 66 customers (34%) heard about the program from an Idaho Power bill insert. Twenty-six customers (13%) received a referral from a friend or acquaintance, eight customers (4%) heard about the program from the Idaho Power website, and four customers (2%) heard about the program from a newspaper advertisement.

2013 Strategies

In February 2013, Idaho Power plans to add an energy-efficient-windows measure to the Home Improvement Program. Windows being replaced must be single-pane wood frame, single-pane metal frame, or double-pane metal frame. As with all other Home Improvement Program measures, only electrically heated homes qualify for an incentive.

In addition, beginning in February 2013, manufactured homes meeting all program qualifications will be eligible for all Home Improvement Program incentives.

Numerous marketing activities are planned for 2013. A new program brochure and web page update are planned for February 2013, in conjunction with program additions and updates. Informational bill inserts are planned for February and April. Targeted direct-mail letters are planned for April and October. Facebook advertisements in high-electric-usage areas are planned for January and September. Print advertisements in select rural areas are planned for February.

Home Products Program

	2012	2011
Participation and Savings		
Participants (appliances/fixtures)	16,675	15,896
Energy Savings (kWh)	887,222	1,485,326
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$640,098	$619,764
Oregon Energy Efficiency Rider	$18,829	$18,559
Idaho Power Funds	$105	$0
Total Program Costs—All Sources	$659,032	$638,323
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.061	$0.034
Total Resource Benefit/Cost Ratio	$0.075	$0.080
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.26	
Total Resource Benefit/Cost Ratio	1.40	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2008	

Description

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards. In 2012, the measures and related incentives included ENERGY STAR qualified clothes washers ($50), refrigerators ($30), and freezers ($20). Program participation is a simple process for customers, who have two options to submit their application: They may complete a mail-in incentive application and submit it with an itemized copy of the sales receipt or submit an online application, offered through Idaho Power's processing vendor's website, and upload or mail in the receipt. If the purchase qualifies, the customer receives an incentive check by mail.

The Home Products Program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point of purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products at the retail level. This mid/upstream incentive model is potentially anticipated to be powerful in changing markets when incentive dollars are small per product but the product category has a high volume of sales. "Upstream and midstream incentives offer the advantage that incentive amounts can sometimes be lower, as market partners may need less 'convincing' to make or sell efficient technologies."[2]

[2] http://www.epa.gov/cleanenergy/documents/suca/program_incentives.pdf.

One measure offered through the retailer markdown model is low-flow showerheads. Low-flow showerheads are part of the Simple Steps, Smart Savings™ markdown promotion administered by the BPA. Simple Steps, Smart Savings is coordinated by Fluid Market Strategies.

Idaho Power works in collaboration with NEEA on the Consumer Electronics Energy Forward Campaign program. This program provides a direct incentive to manufactures for producing the most energy-efficient televisions available. NEEA manages advertising, sales support, and in-store promotions for the program.

2012 Activities

Marketing the Home Products Program to customers occurs primarily through retail outlets. Idaho Power provides information to store managers and employees through training sessions at store staff meetings and through periodic visits by various Idaho Power representatives. In addition to brochures, fixture hang-tags and static clings—small, sticky decals—were distributed to nearly 80 retailers for placement on qualifying products. The prominent focus for using hang-tags and clings was to highlight the respective incentive amounts and eligible products.

In 2012, Idaho Power continued outsourcing the processing of applications for the Home Products Program to Advertising Checking Bureau, Inc. (ACB, Inc.), a third-party vendor. Participants have the option of online or paper applications. Both methods require the customer submit a copy of the sales receipt to confirm the product purchase. If submitting the application online, customers have the option of uploading their receipt, or mailing it in, along with a copy of their web page confirmation.

Idaho Power promoted the program to residential customers via retail store salespeople, bill stuffers, community promotions, Idaho Power field staff, and other outreach activities. During 2012, two bill inserts detailing the program were mailed to all residential customers. The spring (April) insert was shared with the Rebate Advantage program. The holiday bill insert (November) was shared with the DHP Pilot program.

As a result of findings from the 2011 impact evaluation completed by ADM Associates, Inc. (ADM), it was determined that ceiling fans, ceiling fan light kits, and LED light fixtures no longer met cost effectiveness requirements. Thus, these three products, along with CFL fixtures, were removed from the list of eligible products, effective March 1, 2012.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power evaluated including CFL fixtures in its administration of the Simple Steps, Smart Savings promotion. Due to different incentive structures and lower administration costs, CFL light fixture incentives are cost effective if delivered under the Simple Steps, Smart Savings markdown model. Therefore, in March 2012, light fixture incentives for select fixtures were added as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales for fixtures were reported in 2012 under this promotion.

An option on the application allows customers to donate their entire incentive to Project Share, an energy assistance program where Idaho Power partners with the Salvation Army. In 2012, Home Products Program participants donated $190 to this cause. A Project Share donation thank-you card created specifically for the Home Products Program was sent to customers who donated their incentive.

NEEA created a marketing campaign for the Energy Forward campaign in fall 2012 to promote energy-efficient televisions. The campaign objectives were to drive sales of Energy Forward televisions at partner retail stores, provide retailers, utilities, and manufacturers with additional channels of promotion; increase retailer and utility engagement and partnership in the promotion of Energy Forward televisions; and increase consumer awareness and adoption of Energy Forward televisions.
The campaign included a sweepstakes hosted through the Energy Forward Facebook page located at www.Facebook.com/EnergyEfficientElectronics. Northwest residents could win Energy Forward televisions, tickets to college football games, and a grand prize of a VIP tailgate party in each of the four Northwest states—Idaho, Montana, Oregon, and Washington.

The campaign in Idaho generated 218 contest entries. Best Buy and Sears stores participated as full campaign partners, which included additional sales associate trainings and educational and campaign-related point of purchase material in all Best Buy and Sears stores. NEEA also secured discounted rates for in-store broadcasts of the *Energy Forward Most Efficient* video on televisions screens in the consumer electronics sections of Best Buy, Costco, Sam's Club, Sears, and Wal-Mart.

Through the Home Products Program, Idaho Power paid 16,675 incentives during 2012, resulting in 887,222 kWh savings. Incentives were issued for approximately 6,338 clothes washers, 4,497 refrigerators, 461 freezers, 285 light fixtures, 7 ceiling fans, 2 ceiling fan light kits, and 5,085 showerheads.

Cost-Effectiveness

In 2011, ADM reviewed the savings for each measure. ADM reduced the annual savings estimate for ceiling fans from 159.36 kWh to 59 kWh. The savings for ceiling fan light kits were based on the number of CFLs in each kit. In 2011, the RTF reduced the annual savings for CFLs from 24 kWh to 16 kWh. Additionally, ADM confirmed the RTF's assumptions and lower savings regarding LED light fixtures. As a result of these changes, the measures were determined not to be cost effective and were removed from the program in March 2012.

In 2012, the RTF updated the savings for clothes washers and freezers. For clothes washers, the RTF looked at the impact of the new federal standards and the efficiency levels of clothes washers readily available in the Pacific Northwest market. The RTF also updated the savings assumptions on annual loads of laundry using the research from the recent Residential Building Stock Assessment (RBSA) conducted by NEEA. As a result of this work, the baseline efficiency for clothes washers increased and the savings decreased. For programs like Idaho Power's that do not restrict the modified energy factor (MEF), the annual savings decreased from 122 kWh to 37 kWh, which has made the measure not cost effective. In the 2011 impact evaluation, ADM recommended applying the RTF's breakouts for clothes washer savings by MEFs; however, due to a measure definition change by the RTF, Idaho Power has applied the wide-ranging ENERGY STAR clothes washer savings for any type of domestic hot water heating system and any dryer type. As before, Idaho Power adjusted the savings downwards to reflect the electric hot-water heater and electric dryer saturation in the Idaho Power service area. The adjustment is based on information from the *2010 Home Energy Survey*.

The RTF updated the baseline for freezers based on sales data from the region and data from the California Energy Commission database. As a result of the review, savings for freezers decreased slightly; however, the measure life was extended from 20 years to 22 years. Freezers remain cost effective.

Due to the lower savings attributed to clothes washers, the program's overall administrative costs per kWh increased from $0.118 to $0.342 per kWh. As a result, two refrigerator measures are shown to have a TRC of 0.99. Idaho Power expects to incur lower administrative costs in 2013 once clothes washers are removed from the program, which will increase the cost-effectiveness of the measures within the program. There were no changes to the savings assumptions that drive the cost-effectiveness of refrigerators and low-flow showerheads. For detailed information for all measures within the Home Products Program, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Information gathered from a question on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. Ninety-one percent of the responses indicated customers learned about the incentive program through salespeople. Three percent learned from in-store materials (brochures); 3 percent from one of two Idaho Power bill inserts sent to all residential customers; and 3 percent from the Idaho Power website, newspaper/radio, or referral.

A customer satisfaction survey is scheduled for the Home Products Program in 2013.

2013 Strategies

Due to changes in the baseline threshold used to calculate energy savings, clothes washers will be discontinued, effective March 31, 2013. On February 15, 2013, Idaho Power filed Oregon Advice No. 13-03 with the Public Utility Commission of Oregon (OPUC) to remove clothes washers from the list of eligible appliances offered to Oregon customers through the Home Products Program. With the removal of the clothes washer incentives, several methods will be used to notify customers. Letters were mailed to all retailers in January 2013 to alert them of the changes. New table tents were created for distribution to all retailers in early February for display. These will inform customers of the removal of the clothes washer incentive and that they need to purchase their clothes washer before March 31, 2013, to qualify for the incentive. To announce the changes to the program, the Idaho Power website home page will be updated for February and March and an online advertising campaign will target potential purchasers. Idaho Power staff will visit retailers during February and March to discuss the changes and answer questions. Idaho Power will continually review potential products for addition to the program during 2013 and beyond.

The marketing strategy for 2013 will remain similar to 2012, with only minimal adjustments and updates as needed. Bill stuffers, in-store brochures, hang-tags, and clings will be the primary marketing avenues. Online banner advertisements and keyword search terms will be added as a new media effort. Idaho Power will research if company billboards would be effective for the program. As a result of the removal of clothes washers, new brochures will be created and distributed to all retailers before April 1, 2013.

The company expects participation for 2013 to decrease significantly with the removal of clothes washers from the list of eligible products. In 2012, clothes washers accounted for more than half of applications received. In 2013, Idaho Power will explore transitioning the light fixtures and showerheads to a more comprehensive retailer markdown program and explore additional product categories for this type of program model.

Oregon Residential Weatherization

		2012	2011
Participation and Savings			
	Participants (homes)	5	8
	Energy Savings (kWh)	11,985	21,908
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$4,051	$6,690
	Idaho Power Funds	$465	$1,236
	Total Program Costs—All Sources	$4,516	$7,926
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.022	$0.021
	Total Resource Benefit/Cost Ratio	$0.056	$0.027
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.88	
	Total Resource Benefit/Cost Ratio	1.55	
Program Characteristics			
	Program Jurisdiction	Oregon	
	Program Inception	1980	

Description

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program offered under Oregon Schedule 78. Upon a customer's request, an Idaho Power CR visits the home to analyze it for energy efficiency opportunities. An estimate of costs and savings for specific measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

2012 Activities

During May, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. Eight Oregon customers responded. Each customer returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Eight audits and responses to customer inquiries to the program were completed, with five incentives paid.

Idaho Power issued five rebates totaling $1,722 for 11,985 kWh savings. All rebates and related savings were attributed to the addition of new windows, ceiling insulation, and floor insulation. There were no loans made through this program during 2012.

Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program as provided for in Oregon Schedule 78. The cost-effectiveness of this program is defined within this schedule. Pages 3 and 4 of the schedule list the measures determined to be cost effective and the required measure-life cycles for specific measures. This schedule also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years.

Five projects were completed under this program in 2012. Projects consisted of increasing attic and floor insulation and putting in new windows. The projects combined for an annual energy savings of 11,985 kWh at a levelized TRC per kWh of 5.6 cents over the 30-year measure life as defined by the Oregon Schedule 78. The CEL for insulation (30-year measure life) is $1.09 per annual kWh saved and $0.95 per annual kWh for new windows (25-year measure life) is. Since the actual levelized cost of energy savings for the 2012 projects was 3.4 cents from the TRC perspective, these projects are considered cost effective.

2013 Strategies

Plans for the upcoming year include notifying customers in their May bill about the program.
Idaho Power will complete requested audits and fulfill all cost-effective rebate and loan applications.

Rebate Advantage

		2012	2011
Participation and Savings			
	Participants (homes)	35	25
	Energy Savings (kWh)	187,108	159,325
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$34,926	$59,241
	Oregon Energy Efficiency Rider	$2,316	$4,228
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$37,241	$63,469
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.012	$0.024
	Total Resource Benefit/Cost Ratio	$0.024	$0.033
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	8.71	
	Total Resource Benefit/Cost Ratio	3.87	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2003	

Description

Idaho Power residential customers who purchase a new, all-electric ENERGY STAR® qualified manufactured home in 2012 and sited it in Idaho Power's service area were eligible for a $500 rebate through the Rebate Advantage program. Salespersons received a $100 incentive for each qualified home they sold.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured (NEEM) housing program establishes quality-control (QC) and energy efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

The Rebate Advantage program helps Idaho Power customers with the initial costs associated with purchasing a new, energy-efficient ENERGY STAR qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. In addition, Idaho Power encourages sales consultants to discuss energy efficiency with their customers during the sales process.

2012 Activities

During 2012, Idaho Power paid 35 incentives on new manufactured homes, which accounted for 187,108 annual kWh savings. Despite three dealerships closing in 2012, the number of incentives processed increased by 40 percent over 2011.

Marketing strategies used in 2012 included maintaining the Google AdWords campaign, a billboard campaign, and one bill insert. The program specialist, marketing specialist, and Idaho Power field staff visited numerous dealerships throughout the company's service area over the summer to answer any questions and notify them of a planned incentive increase, effective 2013.

Idaho Power continued to support dealerships in 2012 by providing them with Rebate Advantage brochures and applications as needed. CRs visited these dealerships to distribute material, promote the program, and answer salespersons' questions.

Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness for ENERGY STAR manufactured homes. All cost-effective analyses were based on the January 2011 approval decision by the RTF. The measures remained cost-effective for 2012. The measure is currently under review by the RTF and will be updated in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

2013 Strategies

The Rebate Advantage incentive amounts for customers and salespeople will double in 2013. Customers who purchase an all-electric ENERGY STAR manufactured home will receive a $1,000 incentive. Salespersons will receive a $200 incentive for each qualified home they sell. This new rebate offsets the cost of the ENERGY STAR enhancements and is designed to offset a greater portion of the cost differential between these homes and non-ENERGY STAR homes. This program remains cost effective with the increased incentive levels.

In early 2013, a bill insert will be mailed to all residential customers to inform them of the change in the incentive amount. The new posters and brochures that were created and distributed in 2012 to all local dealerships to promote the increase in the incentive amount will continue to be used throughout 2013. Idaho Power continues to explore new marketing methods and promote the program using internal resources and externally at the dealership level. CRs will enhance relationships with dealerships by visiting each dealership, offering program support, answering questions, and distributing materials. The interaction of local Idaho Power staff with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

Idaho Power will continue to examine additional marketing strategies directed at the end consumer. These will include the continuation and revision, as needed, of the Google AdWords campaign and additional bill inserts sent to all residential customers. This strategy may be shared with the Home Products Program, as done in 2012. Strategies may include other banner-type promotional materials at the physical dealerships. Participation in this option will be determined by direct contact with the dealerships to determine how many show interest in having the banner displayed at their dealership. In addition, new research from the upcoming *2013 Manufactured Home Market Facts Report* by Foremost® Insurance will be used to determine the best marketing strategies.

See ya later, refrigerator®

	2012	2011
Participation and Savings		
Participants (refrigerators/freezers)	3,176	3,449
Energy Savings (kWh)	1,576,426	1,712,423
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$596,167	$634,967
Oregon Energy Efficiency Rider	$16,979	$19,426
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$613,146	$654,393
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.046	$0.046
Total Resource Benefit/Cost Ratio	$0.046	$0.046
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.70	
Total Resource Benefit/Cost Ratio	1.70	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2009	

Description

The See ya later, refrigerator® program acquires energy savings through the removal of qualified refrigerators and stand-alone freezers in residential homes throughout Idaho Power's service area. Each application is screened upon enrollment by Idaho Power to determine whether each refrigerator or freezer unit under consideration meets all program eligibility requirements, including the requirement that a unit must be residential-grade, a minimum of 10 cubic feet as measured using inside dimensions, no larger than 30 cubic feet, and in working condition. Customers receive a $30 incentive check mailed after the removal of the unit. The program targets older, extra units for maximum savings.

Idaho Power contracts with JACO to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Idaho Power provides participant confirmation, supplemental marketing, and internal program administration.

2012 Activities

In July 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000th unit. Idaho Power invited local media to watch the unit get unloaded from the collection truck to a trailer used to haul units to the recycling facility in Salt Lake City, Utah. The story was picked up by several television stations.

Idaho Power continued to offer See ya later, refrigerator® participants, upon enrollment, the option to receive their $30 incentive or donate it to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army. The program helps customers who need help paying for energy services, including fuel bills and furnace repairs. In 2012, 2.7 percent of Idaho Power's See ya later, refrigerator® participants chose this option, raising $2,610 for Project Share.

In 2012, program staff visited the JACO recycling facility in Salt Lake City. According to the contract terms, JACO is responsible for dismantling and properly recycling or disposing of parts of each unit. This trip confirmed the contract conditions were being met.

The program continued to use a variety of marketing channels including bill inserts, direct mail, Valpak®, and promotion at events. In 2012, the program tested a new marketing avenue, cinema advertising at a theater in Nampa, ID. Idaho Power developed a 30-second spot that aired 5,824 times.

The See ya later, refrigerator® program was one of three programs that sponsored the Idaho Stampede's Green Week games. The promotion included highlighting Idaho Power's energy efficiency programs at two home games through announcements, posters, and staffed displays providing attendees the opportunity to talk with Idaho Power employees about energy efficiency. As part of the promotion, Idaho Power ran a 30-second PSA regarding See ya later, refrigerator®, which aired at both home games. Idaho Power posted the PSA to its website and YouTube.

The program also tested different types of direct-mail in 2012. In January and April, letters were sent to customers encouraging enrollment in the program. In June, a magnet mailer was sent. All mailings used market segmentation to create the mailing list. In the April and June mailings, the lists were further refined using total energy use and length-of-time as customers. By evaluating energy use, homes with extremely low use (and therefore unlikely to have a secondary appliance) were removed. By evaluating length-of-time as customer, the mailing targeted those customers identified by market research as more likely to participate in this program.

Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness of the two measures that are part of this program, which include the decommissioning of secondary freezers and refrigerators. All cost-effective analyses are based on the RTF's approval decision dated July 2010. Both program measures remained cost effective in 2012.

Refrigerator and freezer recycling measures were reviewed by the RTF during the year as part of the comprehensive review of most residential measures and RTF guideline updates. Savings and measure-life estimates were updated by the RTF late in 2012 and will be included in the claimed savings in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

In 2012, Idaho Power considered the recommendations provided by the 2011 process evaluation conducted for the program by ADM. The evaluation included two recommendations. The first recommendation was to continue researching "existing retailer involvement in the program." Idaho Power continues to track referrals through retailers. The goal of the program is to collect secondary units and remove them from customer homes. Energy savings are maximized when the unit is removed and not replaced. In 2012, 67 percent of participants that reported hearing about the program through retailers also indicated they intended to replace the unit. This is compared to 49 percent of all program participants that indicated they intended to replace the unit. Since retailer referrals have a higher replacement rate, resulting in lower energy savings, marketing through retailers is not a preferred approach at this time.

The second recommendation was to monitor customer understanding of program requirements. Anecdotal comments in the evaluation suggested some participants may not always understand the purpose of the program or eligibility requirements. Idaho Power continues to include major program requirements on its marketing materials to enhance customers' understanding of program parameters. Idaho Power also emphasizes the energy-saving benefits of the program on its marketing materials. In addition, JACO's call center and online enrollment process include screening to ensure program requirements are met.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. ADM noted the program appears to be running smoothly with an ex-post realization rate of 95 percent as compared to ex-ante estimates.

The ADM report also indicated the JACO screening process is mostly preventing ineligible units from entering the program. Also, the current RTF-approved unit energy savings (UES) values were correctly applied as ex-ante estimates, and the parameters supporting those values appear applicable to the Idaho Power program.

ADM recommended Idaho Power continue to actively monitor the RTF UES list of measures for deemed-savings updates since, although appliance decommissioning measures are RTF approved, they were listed as "under review" at the time of the publication of the evaluation. These measures are subject to change as updates to the estimation procedures and/or data sources are made. A copy of the complete report is included in *Supplement 2: Evaluation*.

JACO tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2012 unit data showed that 22 percent of units the program picked up were stand-alone freezers, and 78 percent of the units were refrigerators. Fifty-seven percent of the units were secondary, 28 percent were primary, and 14 percent were unknown. This shows slight improvement in the collection of secondary units over 2011. The average vintage of units collected was 1986, with 57 percent of the units manufactured from 1965 to 1990, generally the least efficient years of manufacture. In 2011, 64 percent of units were of this vintage, suggesting the program is still collecting older units.

The program reclaims or recycles up to 95 percent of the components of each unit collected. In 2012, this translated into over 417,676 pounds of materials. Reclaimed materials may include oils or refrigerants that can be distilled, then reused.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 49 percent of customers reported learning of the program through bill inserts that ran in February, May, August, and October 2012. A portion of these customers reporting bill inserts may refer to the article that appeared in the *Customer Connection* newsletter in the September bill. Eighteen percent of customers reported learning of the program through a friend or neighbor. Other word-of-mouth activities, such as events, account for an additional one percent of signups.

In 2012, direct-mail was used three times and resulted in 6 percent of the enrollments. Direct-mail is sent to a subset of customers. Idaho Power market-segmentation data and national research show participants in utility refrigerator recycling programs are likely to have common characteristics, including older, empty-nesters, smaller households, homeowners, single-family homes, and higher incomes. Nielsen's PRIZM segmentation software was used to identify customers with these characteristics. In addition to the segmentation software, two other criteria were applied to list: energy use and length of time in the home. As older refrigerators can use up to 1,400 kWh per year, homes with very low energy use were considered unlikely to have a second unit and removed from the list. Second, the length of time in the home may correlate to age. As likely participants are older, the length of time in the home was applied on top of the segmentation criteria.

Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel. The program focuses on the removal of secondary units rather than replacing existing units. Retailers sell new units to replace older units. In addition, a retailer selling a new unit will usually pick up and recycle the old one.

Newspaper advertisements comprise 3 percent of enrollments. Newspaper advertisements ran one to two times per month for seven months in regional publications throughout the Idaho Power service area. Eighty-one percent of customers who enrolled used the toll-free telephone number, and 19 percent used the online enrollment form. Idaho Power uses the customer information that JACO collects and the surveys from Idaho Power evaluations to target future marketing efforts and increase the effectiveness of marketing while reducing the cost.

Figure 7 indicates information sources and the percentage of customers reporting hearing about the program through particular sources. The Other category includes sources such as community event, repeat customer, truck advertisement, and unknown sources.

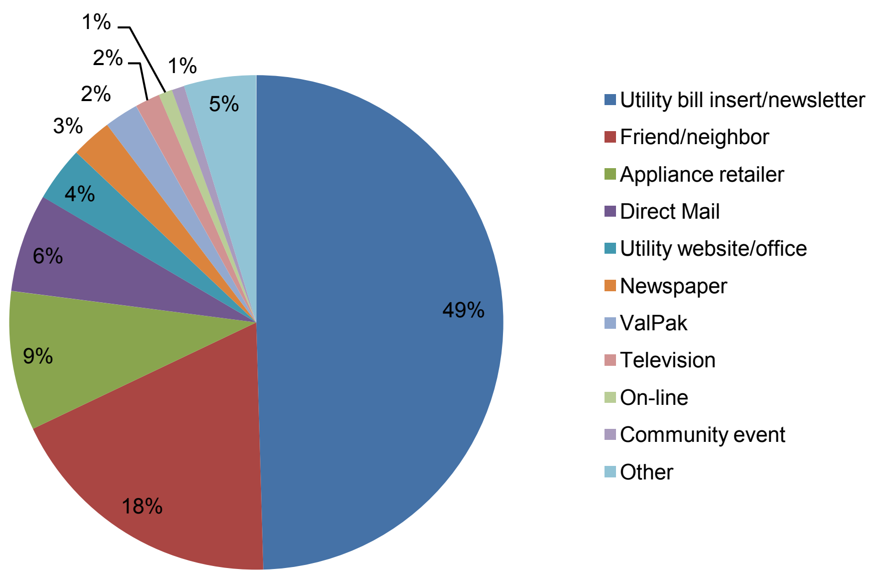


Figure 7. How customers heard about See ya later, refrigerator®

2013 Strategies

Idaho Power plans to continue implementing the program and managing the contract with JACO.

The marketing plan for 2013 includes a continued focus on a variety of channels, including bill inserts, newspaper advertisements, and customer newsletters. Digital media pay-per-click advertisements will be on Google all year. The company will continue promotions at energy efficiency and community outreach events and on the Idaho Power website. A program process evaluation conducted by ADM in 2011 indicated that 52 percent of program participants reported convenience was the aspect of the program that provided them the most value. Therefore, new messaging will be developed and tested with a group of Idaho Power customers, focusing on the convenience aspect of the program as a motivation.

Weatherization Assistance for Qualified Customers

		2012	2011
Participation and Savings			
	Participants (homes/non-profits)	238	287
	Energy Savings (kWh)	648,304	2,783,648
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$1,370,141	$1,324,415
	Total Program Costs—All Sources	$1,370,141	$1,324,415
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.129	$0.029
	Total Resource Benefit/Cost Ratio	$0.172	$0.042
Program Life Benefit/Cost Ratios[a]			
	Utility Benefit/Cost Ratio	4.39	
	Total Resource Benefit/Cost Ratio	2.84	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	1989	

[a] The 2012 one-year B/C ratios are 0.84 for the UC and 0.71 for the TRC.

Description

The WAQC program provides funding to install weatherization measures in qualified owner-occupied and rental homes that are electrically heated. In 2012, qualified households included those with incomes up to 200 percent of the federal poverty-level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house non-profit organizations who serve special-needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the Community Action Partnership (CAP) agencies to administer the WAQC program in its service area.

WAQC is modeled after the US Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. While Idaho Power funds the WAQC program, CAP agencies in Idaho Power's service area serve as the administrators of the WAQC program. Federal funds are allocated to the Idaho Department of Health and Welfare (IDHW) and Oregon Housing and Community Services, then to CAP agencies based on US Census data of qualifying household incomes within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. WAQC funding allows these state agencies to leverage their federal weatherization dollars and serve more residents by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. The Idaho Weatherization Assistance Program calculates savings with the EA5 energy audit program (EA5). Idaho implemented the upgrade from the EA4 energy audit program (EA4) to the EA5 in September 2011. By January 2012, all agencies began using the EA5 to report savings. Consistent with the Idaho Weatherization Assistance Program, WAQC offers several measures that have costs but do not save energy or for which savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a household's existing indoor air quality. Other non-energy-savings measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Non-profit building measures that have costs but do not save energy or for which savings cannot be measured are health and safety, vents, furnace repair, and energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2011 Annual Report*, April 1, 2012, located in *Supplement 2: Evaluation*.

2012 Activities

During 2012, CAP agencies weatherized 224 electrically heated homes in Idaho and 10 in Oregon, totaling 234 weatherized homes. Four Idaho buildings housing non-profit organizations that serve special-needs populations were weatherized in 2012.

On February 15, 2012, IPUC staff filed Case No. GNR-E-12-01, Cost-Effectiveness and Funding of Low Income Weatherization Programs. As part of this case, IPUC staff sponsored workshops from March 19 to 20, 2012, to discuss investor-owned utility weatherization programs. Also discussed at the workshops was the need for an appropriate funding level for low-income weatherization programs and an overall program design. IPUC staff filed a report on October 23, 2013, providing recommendations on funding, cost-effectiveness, and the low-income energy conservation education programs. Notice of the IPUC decision meeting on January 28, 2013, reports that the IPUC took this case into private deliberation, and Idaho Power is awaiting an order.

Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation under contract with Idaho Power. This study resulted in significantly lower realized energy savings for the WAQC program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 2,684 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,103-kWh annual savings as reported by the EA4 in 2011. Since the D&R International report did not give a per-unit savings amount for non-profit building weatherized under the WAQC program, these four project savings were adjusted by applying the overall program 29-percent realization rate from the evaluation. Even though the WAQC program used the EA5 in 2012, the company believes the average annual saving per home estimate provided by D&R International is applicable because the weatherization activities have not changed and the reported savings from the EA5 are similar to the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the WAQC program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.71 and a UC ratio of 0.84. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power used independent third-party verification companies across its service area to randomly check 5 percent of the weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers, as well as discuss the program with these customers. Home verifiers visited 39 homes for feedback about the program. When asked how much customers learned about saving electricity, 26 answered they learned "a lot" or "some." When asked about how many ways they tried to save electricity, 29 responded "a lot" or "some."

The Idaho Power program specialist participates in the Idaho state peer-review process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and the IDHW reviewing homes weatherized by each of the CAP agencies. Results show that all CAP agency weatherization departments are weatherizing in accordance with federal guidelines.

Additionally, the DOE audits the state agencies each year. The DOE audits include field work, as well as paperwork and billing audits and show that the Idaho State Weatherization Assistance Program is in compliance with DOE standards.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology, as used in 2011, for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates resulting in a 29-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load while not calculating cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of the DOE-approved EA5, which ranks heating measures and duct improvements by the savings-to-investment ratio (SIR) and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the CAP agencies to administer the WAQC program. The company hopes to compare the savings estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power will also require the contractor to compare the modeled savings estimates to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in the GNR-E-12-01 case from the IPUC, will help determine future modifications to the company's low-income weatherization programs. In 2013, Idaho Power also plans to conduct a third-party process evaluation of the WAQC program.

The company will continue its involvement with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho. The council will continue to review state grant applications.

Idaho Power plans to selectively market WAQC throughout 2013. The program is promoted at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions in an attempt to reach customers who may benefit from the program. The Idaho Power web page for WAQC will be updated with new graphics and expanded copy. Marketing for this program is conducted in cooperation with weatherization managers to ensure a manageable response level at the agencies.

Weatherization Solutions for Eligible Customers

		2012	2011
Participation and Savings			
	Participants (homes)	141	117
	Energy Savings (kWh)	257,466	1,141,194
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,048,461	$774,254
	Oregon Energy Efficiency Rider	$0	$(2,306)
	Idaho Power Funds	$22,094	$16,200
	Total Program Costs—All Sources	$1,070,556	$788,148
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.254	$0.042
	Total Resource Benefit/Cost Ratio	$0.254	$0.042
Program Life Benefit/Cost Ratios[a]			
	Utility Benefit/Cost Ratio	1.47	
	Total Resource Benefit/Cost Ratio	1.47	
Program Characteristics			
	Program Jurisdiction	Idaho	
	Program Inception	2008	

[a] The 2012 one-year B/C ratios are 0.43 for the UC and 0.47 for the TRC.

Description

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are slightly above poverty level and, therefore, do not financially qualify for the company's weatherization assistance program, WAQC. The measures in the program and the methods of delivery mirror WAQC. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a SIR of 1 or higher. The amount spent on each home is limited to an annual average per home. Homes considered for this program are electrically heated and either owned or rented. If rented, the landlord's permission is needed, along with an agreement to maintain the unit's current rent for a minimum of one year.

Idaho customers eligible for this program earn income just above the federal poverty level. They typically do not have expendable income to participate in other residential energy efficiency programs, and they live in similar housing as WAQC customers.

2012 Activities

The 2012 program ended the year with 141 weatherization jobs completed. Qualifying customers for the year earned an income between 175 percent and 250 percent of the federal poverty level. The program served customers in Idaho Power's Southern, Western, Eastern, and Capital service areas.

Table 7 shows the number of jobs and costs associated with measures installed in homes called production costs. Also shown are job average costs and total payments to contractors for the year.

Table 7. 2012 weatherization solutions financial breakdown

Contractor	Number of Jobs	Production Costs	Average Job Cost*	Administrative Payment to Contractor	Total Payment
Energy Zone	63	$ 454,545	$ 7,215	$ 45,455	$ 500,000
Home Energy Management	41	272,900	6,656	27,290	300,190
Power Savers	20	106,461	5,323	10,646	117,107
Savings Around Power	17	87,450	5,144	8,745	96,195
Total	**141**	**$ 921,356**	**$ 6,534**	**$ 92,136**	**$ 1,013,492**

* Average Job Cost is calculated based on the direct cost of installed measures without the administration adder.

Marketing of the program was done several ways in 2012. All four contractors advertised the program in their regions with program flyers and door hangers distributed by contractors throughout mobile-home parks and at specific property-management offices. Flyers were also left with previous customers to spread information about the program to families and friends who might qualify. Word of mouth continued to be an effective marketing tool for the program in 2012. Several articles about the program were featured in various local publications and at an Idaho Power booth at weatherization conferences.

Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation of the Weatherization Solutions for Eligible Customers program under contract with Idaho Power. This study resulted in significantly lower energy savings estimates for this program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 1,826 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,754-kWh annual savings per home as reported by the EA4 in 2011. This is a realization rate of 19 percent of the savings reported under the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the Weatherization Solutions for Eligible Customers program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.47 and a UC ratio of 0.43. Since the evaluation did not calculate an average measure level saving or realization rate by measure for this report, Idaho Power is not including measure level cost-effectiveness in this report, a change from previous reports. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

In 2012, the program contractors conducted a customer satisfaction survey. Questionnaires were given to customers after the contractor completed the job. Of the 141 participants, 89 customers provided written feedback about the work done and about energy conservation in their home. Each response complimented the work crew and expressed thanks for the program. These contractor surveys include high-level questions and are administered by the contractors, not by Idaho Power.

Idaho Power hired independent third-party verification companies across its service area to randomly check weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers and discuss the program with these customers. Of the 141 jobs completed in 2012, verifiers visited 25 homes for feedback about the program. When these 25 customers were asked how much they learned about saving electricity during weatherization, 16 answered from the choices offered that they learned "a lot" or "some." When asked about how many ways they tried to save electricity in their home, 21 responded "a lot" or "some." This customer feedback is collected as a part of the actual job verification. The documents containing individual customer information include these two questions.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology currently used for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates, resulting in a 19-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load and does not calculate cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of DOE-approved EA5, which ranks heating measures and duct improvements by the SIR and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the contractors to administer the Weatherization Solutions for Eligible Customers program. The company hopes to compare the saving estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power also will require the contractor to determine per-measure savings for this program and compare them to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in Case No. GNR-E-12-01 from the IPUC, will help determine future modifications to the company’s low-income weatherization programs. Additionally, Idaho Power plans to conduct a third-party process evaluation of the Weatherization Solutions for Eligible Customers program in 2013.

In 2013, Idaho Power plans to offer this program to Idaho Power customers in the Southern, Eastern, Western, and Capital regions. Weatherization Solutions for Eligible Customers anticipates weatherizing 165 homes through the program in 2013.

Home Energy Management, LLC (HEM, LLC) is under contract to weatherize approximately 40 homes in Idaho Power’s Southern region; Energy Zone, LLC is under contract to weatherize approximately 50 homes in Idaho Power’s Western region; and Savings Around Power is contracted to weatherize approximately 25 homes in the Eastern region. Power Savers, serving Idaho Power’s Capital region, is under contract to weatherize approximately 50 homes.

An annual allowable average cost of $7,200 per home will be used again in 2013. Contractors will be paid 10 percent of the production costs per home as an administrative fee. All measures that provide energy savings will meet the minimum SIR when applied through the state-approved energy audit. Each total job will also meet the minimum SIR requirements.

Eligible customers will include Idaho Power customers who heat their homes electrically and earn an income between 175 percent and 250 percent of the federal poverty level. Customers who are either purchasing or renting their homes may be eligible. As in 2011 and 2012, the identification of potential participants will be made through several means. Energy Assistance/LIHEAP applicants at CAP agencies who do not meet WAQC income qualifications are sent denial letters. Program contractors will use this list of denied customers at CAP agencies to market the Weatherization Solutions for Eligible Customers program. Contractors will distribute flyers and door hangers explaining the program and qualifying guidelines to customers heating their homes electrically.

Idaho Power's plans to market the Weatherization Solutions for Eligible Customers program throughout 2013. Direct-mail letters proved successful in 2012, and these targeted mailings will continue along with bill inserts and online advertisements. The web page for the program will be updated with new graphics and expanded copy. Marketing for this program is conducted in close cooperation with contractors to ensure the marketing activity is done at a level each contractor is able to service in a timely manner.

This page left blank intentionally.

Commercial/Industrial Sector Overview

Description

Idaho Power's commercial and industrial sector consists of over 65,857 customers. In 2012, the commercial sector's number of new customers increased by 683, an increase of 1 percent over 2011. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 27.4 percent of Idaho Power's total electricity usage.

The industrial customers and special-contract sector are Idaho Power's largest individual energy consumers. There are approximately 116 industrial customers. These customers can use millions of kWh a month and account for 22.2 percent of Idaho Power's total electricity usage.

The Custom Efficiency program continued to represent the highest total energy savings among commercial and industrial programs in 2012, with a total savings of 54,253 MWh. The Building Efficiency program saw the highest percentage increase among commercial and industrial programs, with annual savings increasing by 105 percent over 2011. Combined, the programs experienced a 4.54 percent increase in the number of completed projects over 2012. Overall, energy savings decreased less than 1 percent compared to 2011. Table 8 shows a summary of savings and expenses from the three commercial and industrial energy efficiency programs and one demand response program.

Programs

Table 8. 2012 commercial/industrial program summary

		Total Cost		Savings	
Program	**Participants**	**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response					
FlexPeak Management	102 sites	$ 3,009,822	$ 3,009,822	n/a	52.8
Total		**$ 3,009,822**	**$ 3,009,822**		**52.8**
Energy Efficiency					
Building Efficiency	84 projects	$ 1,592,572	$ 8,204,883	20,450,037	2.3
Easy Upgrades	1,838 projects	5,349,753	9,245,297	41,568,672	4.7
Custom Efficiency	126 projects	7,092,581	12,975,629	54,253,106	7.6
Total		**$ 14,034,906**	**$ 30,425,809**	**116,271,815**	**14.6**

Note: See Appendix 3 for notes on methodology and column definitions.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, the building shell, plug loads, and food-service equipment. These energy-saving measures give customers the option of choosing the best selections for incorporating energy efficiency into their business. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost-opportunity savings. This program continues to be successful, incorporating qualified energy-saving improvements for lighting, cooling, building shells, and energy control options. Participants in the Easy Upgrades program can receive incentives of up to $100,000 per site per year for approved, completed projects. There are no incentive caps on Building Efficiency- and Custom Efficiency-approved and completed projects. The Custom Efficiency program offers financial incentives for large commercial and industrial energy users undertaking more complex projects to improve the efficiency of their electrical systems or processes.

Incentive levels are 70 percent of the project cost or 12 cents per kWh for first-year savings, whichever is less. Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

FlexPeak Management, a demand response program, is offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracts directly with Idaho Power's commercial and industrial customers to achieve demand reduction.

2012 proved to be another challenging, rewarding, and successful year for Idaho Power's commercial and industrial energy efficiency programs. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Building Efficiency experienced substantial growth in both the number of completed projects and energy savings. Easy Upgrades also experienced growth in both the number of completed projects and energy savings. These are remarkable accomplishments considering the economic environment Idaho Power's business customers continue to navigate. The commercial and industrial programs continued to develop and strengthen Idaho Power's strategic partnerships. These partnerships include the IDL, engineering and architectural firms, a vast network of trade allies, and most importantly, Idaho Power customers. Training and education continued to be an important aspect of the company's programs in 2012. Trade ally meetings included training on lighting design and technologies. Custom Efficiency continued to offer a host of industrial training sessions that were well attended. Finally, Building Efficiency sponsored a number of outreach training sessions conducted by the IDL.

The Green Rewind offering is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 42 Green Rewind motors achieved a total annual savings of 84,193 kWh in 2012, with 19 commercial/industrial sector motors contributing 54,154 kWh per year and 23 irrigation sector motors contributing 30,039 kWh per year.

Twenty-one service centers in Idaho Power's service area have the necessary equipment and training to participate in the Green Rewind offering. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, eight service centers have signed on as Green Motors Practice Group (GMPG) members. The GMPG also will expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA) Standard hp-rated motor between 15 and 5,000 hp for industrial uses and 25 to 5,000 hp for agricultural uses that receive a verified Green Rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with a quality check and QA.

In 2012, Idaho Power entered into the third year of a three-year contract with the IDL to meet the following objectives:

- Educate architects, engineers, and other design and construction professionals about energy efficiency topics through an in-firm summer series. This series was expanded in 2011 and 2012 to include firms outside the Treasure Valley.

- Facilitate the Idaho Building Simulation Users' Group to improve the energy efficiency-related simulation skills of local design and engineering professionals.
- Support Idaho Power employees in promoting energy efficiency and providing Idaho Power's customers with up-to-date and accurate information regarding energy efficiency technologies and best practices.
- Create a hands-on demonstration and training area for electrical contractors to learn the necessary skills to successfully install and commission daylight-harvesting lighting control systems.
- Review daylight photo-control incentives to improve the quality and performance of installed systems.
- Develop and maintain a measurement equipment tool loan library, including a web-based equipment tool loan-tracking system.
- Stimulate market awareness of energy use in buildings to promote energy efficiency by working with commercial real estate brokers or owners in the development of metrics to be used in the sale or lease of commercial property.
- Promote aggressive energy efficiency on new construction and major renovation projects in the Idaho Power service area.
- Promote improved energy efficiency in existing convenience stores in the Idaho Power service area.
- Provide measurement and verification services to investigate actual energy savings compared to computer simulation modeled savings or pre- and post-renovation/retrofit conditions.

Expanding on some of the prior year's results, the following objectives were added in 2012:

- Conduct a review of documents associated with the Building Efficiency program's application for incentives along with site inspections on a random percentage of projects to validate whether noted systems and components have been installed.
- Provide the design community with additional spreadsheet-style calculation tools to analyze the feasibility and capacity of various passive cooling design strategies (an expansion of prior climate design resource efforts.)
- Increase both the general public and design community literacy about how different classifications of commercial buildings consume energy and the metrics associated with these data.
- Investigate multi-family new construction and retrofit best practices for utility incentive programs and to investigate the potential for new program incentives.

Phase I of the Idaho Office of Energy Resources (IOER) K–12 Energy Efficiency Project for public schools in Idaho Power's service area concluded December 2012. The project invested federally provided funds into energy efficiency projects in public school buildings within Idaho Power's service area. In July 2011, Idaho Power entered into an agreement with the IOER that provided for the accumulation and reinvestment of energy efficiency incentive payments from Idaho Power's qualified energy efficiency programs for K–12 projects. These accumulated incentives will be used for additional cost-effective energy efficiency projects that meet current Idaho Power program requirements implemented in public school buildings within Idaho Power's service area and will be referred to as Phase II projects. The agreement will result in achieving a higher level of energy efficiency in public school buildings than either Idaho Power or the IOER could achieve with their individual programs. Phase II projects are anticipated to begin in mid-2013 and conclude in late 2014.

During the November 6 EEAG meeting, the Idaho Power commercial/industrial energy efficiency program leader discussed how the Building Efficiency program is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and the cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research is favorable and measures are cost effective, new measure offerings could be added to the program in 2013. EEAG was generally supportive of researching multi-family measure offerings.

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. Fifty-six percent of Idaho Power's large commercial and industrial customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 79 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 93 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated 42 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 21 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

In 2013, Idaho Power is anticipating adding at least two new initiatives within the Custom Efficiency program. Impact evaluations conducted on Building Efficiency and Easy Upgrades will be finalized in early 2013. Program specialists will be analyzing the findings from these reports and will adjust programs as needed. Training, education, and outreach will continue to be a focus aimed at driving projects. Additionally, the company will analyze ways to improve Idaho Power programs based on customer and trade ally feedback, as well as internally driven research.

Building Efficiency

	2012	2011
Participation and Savings		
Participants (projects)	84	63
Energy Savings (kWh)	20,450,037	11,514,641
Demand Reduction (MW)	2.3	0.9
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,579,121	$1,277,422
Oregon Energy Efficiency Rider	$13,451	$14,003
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$1,592,572	$1,291,425
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.007	$0.010
Total Resource Benefit/Cost Ratio	$0.036	$0.026
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	6.50	
Total Resource Benefit/Cost Ratio	2.56	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2004	

Description

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions are eligible to receive incentives. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special-contract customers are eligible to participate. Program marketing is targeted toward architects, engineers, and other design professionals.

Fourteen measures are offered through this program and include interior-light load reduction, exterior-light load reduction, daylight photo controls, occupancy sensors, high-efficiency exit signs, premium-efficiency HVAC units, additional HVAC-unit efficiency bonuses, efficient chillers, air-side economizers, a reflective roof treatment, high-performance windows, energy- management control systems, demand-controlled ventilation, and variable-frequency drives (VFD).

Idaho Power is a primary sponsor of the IDL, which provides technical assistance and training seminars to local architects, engineers, and designers. Some of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the biannual BetterBricks awards held in Boise. The BetterBricks awards recognize leaders whose work supports the design and operations of high-performance buildings and their commitment to energy efficiency. The Building Efficiency program also sponsors technical lunch-and-learn sessions geared to educate design professionals and the Idaho Building Simulation Users' Group. The Idaho Building Simulation Users' Group is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

2012 Activities

The Building Efficiency program completed 84 projects, resulting in 20,450,037 kWh in annual energy savings in Idaho. Overall, the program increased kWh savings almost 78 percent over 2011. The dramatic increase in energy savings for 2012 was impacted by some large, multi-year construction projects being completed for qualified program incentives. Examples include regional hospitals in Twin Falls and Pocatello. Additionally, design professionals have become more familiar with the program in recent years. In 2012, vinyl construction banners were produced for the first time and installed at a building site to publicly showcase the building was being "built with energy efficiency in mind."

The Building Efficiency program was last modified in 2011, although the cap of $100,000 on Idaho projects was removed in 2012. Also in 2012, an impact evaluation was completed, focus groups were held with architects and engineers, and in-depth interviews were conducted with building owners to gain feedback on the program. Based on the outcome of these activities, minor changes will be made to the program in mid-2013 once all recommendations have been evaluated thoroughly. New construction and major renovation project design and construction life is much longer than small retrofits and requires consistency in program measures and operation. Program consistency reduces confusion for customers with long construction and project timelines.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Twenty-one technical training lunches were completed in 2012, with 235 attendees, including architects, engineers, interior designers, and project managers. Technical training sessions were held in Boise, Twin Falls, Pocatello, Idaho Falls, and Ketchum. Topics included Integrated Design Principals, Energy Benchmarking and Energy Goal Setting, Daylight In Buildings: Schematic Design Methods, Daylighting: Getting the Details Right, Multi-Zone Demand Control Ventilation Systems, Climate Responsive Design: Tools and Methods, Advanced Envelope Construction, Radiant System Design Considerations, High-Performance Classrooms, Role-of-Life Cycle Cost Assessment in Integrated Design, Center for Advanced Energy Studies and Integrated Design, and Commissioning. The Building Efficiency program, in conjunction with the Custom Efficiency program, sponsored 12 training sessions, with 145 attendees for the Building Simulations User Group through the IDL. Additionally, Idaho Power was a sponsor of the American Institute of Architects 2030 Challenge held in Boise. The 2030 Challenge was a 10-session learning course designed to educate architects, engineers, and other design professionals on integrated design practices in new construction. Approximately 40 design professionals were enrolled in the program. The 10 sessions started in fall 2011 and concluded in spring 2012.

Additional *Success Stories* were added to the Idaho Power website in 2012, with one specific to new construction titled *Idaho Power Helps Motorcycle Parts Manufacturer Keep Jobs at Home*. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Building Efficiency has teamed up with the Building Owners and Managers Association (BOMA) and NEEA to offer a Kilowatt Crackdown™ competition for office buildings over 15,000 ft^2 located in the Treasure Valley. The initial sign-up closed on December 31, 2012. Over 40 buildings signed up to participate in the year-long competition, which includes benchmarking their building in

ENERGY STAR® Portfolio Manager—an interactive energy-management tool that allows tracking and assessing of energy and water consumption—and implementing low-cost and no-cost efficiency measures in their building throughout 2013. Participating buildings have access to an energy coach, scoping audit of their building, and education opportunities. The purpose of this commercial building energy competition is to facilitate and educate businesses on wise energy use. The competition will continue through the beginning of 2014. Idaho Power is contributing marketing and technical expertise to help ensure the success of the competition. At the November 6 EEAG meeting, Idaho Power provided an update on the Kilowatt Crackdown competition in the Treasure Valley market. Idaho Power also sponsors the American Society of Architects Honor awards, the BetterBricks awards, the Smart Growth awards, and the Association of Idaho Cities Annual Conference.

At the November 6 EEAG meeting, Idaho Power also discussed the work being done regarding multi-family dwellings. Building Efficiency is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research shows the measures are cost effective, new measure offerings could be added to the program in 2013.

Cost-Effectiveness

For 2012, the Idaho Power incentive structure remained consistent with the 2011 program.

To calculate energy savings, the Building Efficiency program verifies the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters for both the measure at code and at efficiency. The other method for calculating savings in the program is based on industry standard assumptions when precise measurements are unavailable. Since Building Efficiency is a prescriptive program and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry standard assumptions from the International Energy Conservation Code (IECC) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures. In 2012, ADM conducted an impact evaluation of the 2011 program savings. The report recommended a revision to the prescriptive formulas used to estimate the reported savings in three measures. The revised formula has been applied to the 2012 savings results. The program remains cost effective.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kW reduction as the unit being used. For 2012, Idaho Power's incentive structure remained consistent with the 2011 program. Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. The evaluation report indicates that, overall, the Building Efficiency program does a good job ensuring rebated energy efficiency equipment efficiencies are above those mandated by applicable building code. The 2011 program savings realization rate was estimated to be 73 percent as compared to ex-ante estimates.

The report identified two areas that contributed to over 40 percent of the reduction in the ex-post savings adjustment, which included 1) errors in ex-ante prescriptive formulas used to estimate savings for some HVAC equipment and controls and 2) baseline definition issues that redefined subsets of measures as baseline equipment. Some equipment installed as upgrades were actually required as part of code.

ADM recommends 1) the revision of prescriptive formulas used to estimate savings for air-side economizers, energy-management system building controls, and demand-control ventilation; 2) making prescriptive algorithms more rigorous; 3) making each algorithm more specific to the application for which it is applicable; 4) select a larger number of HVAC controls and VFD projects for detailed application review to screen for potential code or baseline issues; and 5) update the application to include specific applications for which VFDs will not qualify for incentives. A revised version of the impact evaluation report was received after the printing of *Supplement 2: Evaluation*. These revisions do not materially change the results of the evaluation. A copy of the complete report is included in *Supplement 2: Evaluation*. A copy of the revised report is available on request.

In 2012, Idaho Power contracted with Market Decisions Corporation to provide participant focus groups with architects, engineers, and designers and to conduct phone interviews with building owners and operators to gain feedback on the Building Efficiency program. Two in-person two-hour focus groups were held with 14 architects, engineers, or designers in attendance. Ten 30-minute in-depth phone interviews were conducted with building owners and operators. Participants were asked a series of questions by a Market Decisions Corporation moderator and asked to candidly share their experience and satisfaction with the Building Efficiency program.

As a qualitative study, the following key findings only reflect the general thoughts of those that participated in the research groups and are not representative of the entire program. Overall, the research participants are "highly satisfied" with the program. Architects and engineers are familiar with all program incentives and owners are familiar with the incentives applicable to their projects. The architects and engineers typically bring the Building Efficiency program to the owner's attention during the project's design phase. All research participants also expressed a high level of satisfaction with the pre-application process and Idaho Power staff engagement during their projects. A copy of the report can be found in *Supplement 2: Evaluation*.

Building Efficiency continued random installation verification on 10 percent of projects in 2012. The purpose of these verifications was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 9 of the 84 projects, which encompasses approximately 10 percent of the total completed projects in the program. Out of the nine projects verified, eight projects were installed with only minor or no discrepancies compared to how they were declared. The minor discrepancies resulted in a total increase of energy-efficient measures. Only one project was installed with less energy-efficient measures than were declared. Random project installation verification will continue in 2013.

2013 Strategies

The Building Efficiency program will make program updates in mid-2013 once the impact evaluation and focus group research has been evaluated. Research is currently being conducted on multi-family construction. The outcome of the research may lead to additional Building Efficiency offerings in the multi-family sector. A future filing with the OPUC regarding mid-2013 program changes would include the removal of the $100,000 cap on Building Efficiency projects in Oregon. The Building Efficiency program will continue to perform random post-project verifications on a minimum of 10 percent of completed projects.

The Building Efficiency program will continue to sponsor technical training through the IDL. Technical trainings will continue to address the energy efficiency education needs of design professionals in the Boise, Pocatello, Twin Falls, and Sun Valley markets. Additionally, the program will continue to support organizations focused on promoting energy efficiency in commercial construction. Idaho Power hopes to replicate the vinyl construction banners publicly showcasing buildings as “built with energy efficiency in mind” across a number of energy-efficient buildings in the coming year. The feasibility and value of advertising in specific trade publications will be determined in 2013.

In 2013, Idaho Power plans to contract with a third-party to conduct a research project for the Building Efficiency program that will evaluate existing and new measures for the program.

Custom Efficiency Program

		2012	2011
Participation and Savings			
	Participants (projects)	126	166
	Energy Savings (kWh)[a]	54,253,106	67,979,157
	Demand Reduction (MW)	7.6	7.8
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$923,050	$413,959
	Oregon Energy Efficiency Rider	$115,866	$1,385,613
	Idaho Power Funds	$6,053,665	$6,984,239[b]
	Total Program Costs—All Sources	$7,092,581	$8,783,811
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.012	$0.012
	Total Resource Benefit/Cost Ratio	$0.021	$0.026
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	7.48	
	Total Resource Benefit/Cost Ratio	3.31	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2003	

[a] Includes kWh savings from Green Rewind.

[b] Capitalized incentive payments per IPUC Order No. 32245.

Description

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy efficiency projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education regarding energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power, or by the customer as applicable to the facility. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application and an agreement finalizing the terms and conditions of the applicant's and Idaho Power's obligations. In some cases, large, complex projects may take as long as two years to be completed. Often, Idaho Power conducts follow-up or post-inspection validation via third-party engineering firms on projects of this nature. Every project is verified post-completion by Idaho Power staff or an Idaho Power contractor. All lighting projects are pre- and post-inspected by an Idaho Power contractor or an Idaho Power representative. Incentive levels for the Custom Efficiency program remained at 70 percent of the project cost, or 12 cents per kWh for first-year savings, whichever is less.

2012 Activities

Custom Efficiency experienced another successful year in 2012. A total of 126 projects were completed by 110 customers, including four Oregon projects from four customers. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Program energy savings decreased in 2012 by 20 percent over 2011, from 67,979 MWh to 54,253 MWh. The decrease in program energy savings was a result of several factors: 2012 was a presidential election year and customers mentioned they were hesitant to move forward with large projects until after the election was determined. This, along with general economic uncertainty, impacted the 2012 numbers. Also, the program may have reached some saturation through maturation, as nearly 90 percent of the large-power service customers have submitted an application for a project through 2012. Finally, with the high percentage of industrial customers that have completed projects in the program, deeper energy savings with be challenging to achieve.
There were 137 approved applications for active projects at the end of 2012, representing 64,034 MWh of savings. Table 9 indicates the program's 2012 annual energy savings by primary project measures.

Table 9. 2012 Custom Efficiency annual energy savings by primary project measure

Program Summary by Measure	Number of Projects	KWh Saved
Lighting	63	20,107,218
HVAC	6	11,885,602
CFL	19	5,321,048
Refrigeration	15	5,319,400
Motors	3	2,289,748
Compressed Air	4	2,228,709
Pump	2	1,425,757
Fan	9	1,380,649
VFDs	3	951,665
Green Rewind	19	54,154
Other	2	3,289,155
Total	**126[a]**	**54,253,106**

[a] Does not include Green Rewind projects.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. Because the link between energy audits and the completion of projects is historically significant, Idaho Power reevaluated its current offerings and strengthened them where appropriate. It is anticipated, effective by the second quarter of 2013, that detailed audits will go from 50 percent reimbursement or $10,000, whichever is less, to 75 percent reimbursement or $12,500. Scoping audit details did not change in 2012.

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. The training is coordinated by the NEEA Industrial Training Project, and Idaho Power is a co-sponsor. Idaho Power also co-funds the trainings, which allows twice the trainings in Idaho Power service area. Additionally, Idaho Power covers the cost of each customer's subsidized attendance in the classroom-based training sessions. A total of nine technical classroom-based training sessions were completed in 2012. Four of these classes were two-day classes, and the rest were one-day classes. Topics included compressed air, chilled water systems and cooling towers, pump systems, VFDs, data-center efficiency, energy management, and industrial refrigeration. A schedule of training events is posted on Idaho Power's website.

The level of attendance remained high in 2012, with 171 Idaho Power-sponsored seats filled with 146 end-use customers and various Idaho Power staff, consultants, and trade allies. Customer feedback indicated average overall satisfaction levels over 97 percent.

There were two training sessions outside of the Idaho Power service area attended by Idaho Power customers. One was a pump certification training in Eugene, Oregon, attended by two Idaho Power customers. The second was a conveyance systems training in Portland, Oregon, attended by one customer. The conveyance system training is planned to be offered within Idaho Power's service area in 2013.

Additionally, 2012 encompassed Phase II of the Webinar Pilot Plan coordinated by NEEA. Twelve webinars were presented free to all attendees. Topics included VFDs; lighting; data centers; energy-management topics, including developing an energy plan, investment analysis energy management for industrial customers, and energy auditing and troubleshooting. There were 50 Idaho Power region seats filled with end-use customers and multiple Idaho Power personnel and consultants attending the webinar recordings. Idaho Power posted the recordings and PDFs on the newly established training page on the Idaho Power website.

Figure 8 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the 2012 in-class NEEA industrial trainings. This figure uses data from ECOVA™'s summary of the trainings provided in the *NEEA Regional Industrial Training Update, December 2012,* included in *Supplement 2: Evaluation*.

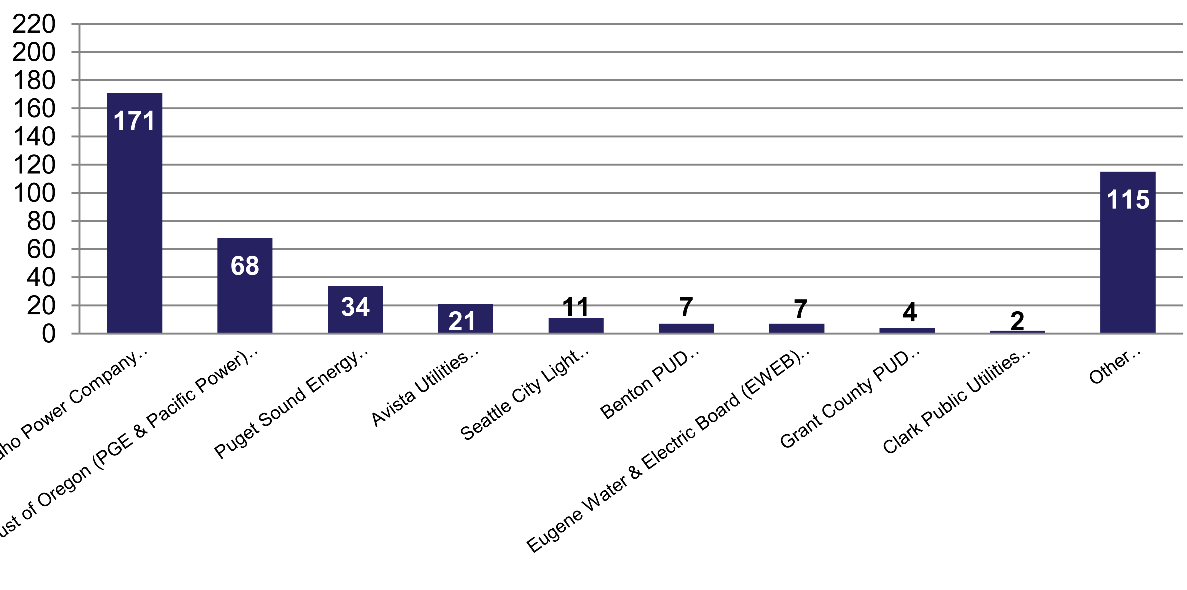


Figure 8. NEEA chart of attendees (seats filled) by attendee sponsor[3]

[3] Data source: *NEEA Regional Industrial Training Update, December 2012*.

As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency and ensures an efficient use of electricity to run the motor. There were 19 Green Rewind motors in the commercial/industrial sector in 2012, contributing 54,154 kWh in annual savings.

The Custom Efficiency program has achieved a high service-area penetration rate. As stated previously, through 2012, nearly 90 percent of the large-power service customers have submitted applications for a project. Idaho Power engineers have met with the remaining viable Rate 19 and special-contract customers to discuss energy efficiency programs and opportunities within customer facilities.

In 2012, the Idaho Power CR&EE department filled a summer internship position with a Boise State University mechanical engineering student. A Custom Efficiency engineer served as the intern mentor. The intern was involved with many aspects of the day-to-day program operation including, but not limited to, measurement and verification of energy efficiency aspects related to Custom Efficiency program lighting projects, attendance at customer meetings related to energy efficiency, familiarization, and communication of all three commercial incentive programs, calculation and review of energy-saving projects, exposure to program marketing and planning activities, and administrative work related to the Custom Efficiency program. Another internship will be offered in summer 2013 and will involve activities similar to the 2012 internship. These internships are important mechanisms that help drive work-force development in the energy efficiency profession.

Early in 2012, the Custom Efficiency staff noticed that program energy savings were trending downward with respect to the prior few years. Several utilities in the region started to implement behavioral, strategic energy management, maintenance-related, energy coaching, resource conservation manager, and other non capital-intensive programs. Thus, Custom Efficiency engineers investigated the potential of bringing some of these offerings to Idaho Power as part of the Custom Efficiency program offerings. Three separate offerings were developed in 2012 and have been budgeted for in 2013. These include 1) Refrigeration Operator Coaching for Energy Efficiency (ROCEE), 2) Small Industrial or Custom Efficiency Express, and 3) Strategic Energy Management (SEM).

Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement, and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is thoroughly reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculates the energy savings. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, and especially larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or major customer representatives solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to participate in the Custom Efficiency program posting the customers' *Success Stories* on the Idaho Power website. In 2012, six new *Success Stories* describing 2012 projects were posted on the company's website. An example of a *Success Story* posted in 2012, titled *Idaho Power incentives help Ballard Dairy and Cheese bring the kids back to their family operation*, refers to a project Ballard Dairy and Cheese completed early in 2012. Idaho Power provided $28,604 in incentives for energy efficiency upgrades that reduced costs and is expected to save over $12,000 in annual utility bills. The owner said, "We had help from the Small Business Administration and the USDA, too, but we really couldn't have done it without Idaho Power's assistance." Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

2013 Strategies

Both the Custom Efficiency and Easy Upgrades programs offer lighting incentives to commercial and industrial customers. In 2013, Idaho Power will continue to make program changes to lighting projects within both Custom Efficiency and Easy Upgrades to be as consistent with each program as possible. Better alignment of the incentives between the two programs will lessen program confusion and potentially increase participant satisfaction. One significant change occurring to lighting projects in 2013 will be the addition of allowing incentives for existing T-8 lighting to more efficient technology, T-8 to LED case lighting, and T-8/T-5HO to reduced wattage T-8/T-5HO.

Early in 2013, detailed audits will go from a 50 percent reimbursement or $10,000, whichever is less, to a 75 percent reimbursement or $12,500, while scoping audits will be revised to have a $3,500 maximum, up from $3,000 in 2012.

In 2013, Idaho Power will conduct customer satisfaction research on the Custom Efficiency program. The actual methodology for the research is under review. Research will be conducted late in the year.

Custom Efficiency plans to launch three new program offerings in 2013 aimed at expanding support for customers implementing energy efficiency within their facilities. The first program, tentatively titled Small Industrial or Custom Efficiency Express, is planned for launch in the third quarter of 2013. It is designed to address the smaller compressed air, pump and fan VFDs (other than HVAC and irrigation), cold storage doors, and small refrigeration projects that do not justify the study costs associated with a typical large and/or complex custom project. The program offering will be administrated by Cascade Energy Engineering and will leverage vendor relationships, incorporate simplified analysis tools, and streamline the incentive process. This offering has not officially been named yet. The second Custom Efficiency program offering anticipated for launch in March 2013 is the ROCEE. This offering will provide highly relevant hands-on energy efficiency training to key individuals whose actions have a direct bearing on the energy performance of energy-intensive systems. Using services provided by NEEA and Cascade Energy Engineering, this offering will engage 6 to 10 large customer facilities to reduce energy associated with their refrigeration systems. The third program offering under development, SEM, will provide training and incentives to program-offering participants focused on low-cost or no-cost measures that may be more behavioral or operations and maintenance-related. Due to concerns with the persistence of savings and/or measure life, these types of projects have historically not been eligible for incentives. However, with a new SEM program offering, these concerns can be addressed appropriately, leading to an increased energy savings potential within the program. The Small Industrial, ROCEE, and SEM program offerings were described to EEAG at the November 6 meeting, resulting in favorable comments from EEAG members.

In 2013, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities and through continued development of strategic partnerships. These activities will include direct marketing of the Custom Efficiency program by Idaho Power major CRs to further educate customers on Idaho Power energy efficiency programs, identify potential ways the customer can reduce energy costs, and drive program participation. Idaho Power will continue to provide site visits and energy audits for project identification; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored energy improvement practices to customers. Additionally, program staff will continue to engage and support the Center for Advanced Energy Studies (CAES), the IDL, and the Industrial Assessment Center.

Each year, the company designs and pays for a "Top 10" advertisement that appears in the *Idaho Business Review*. This advertisement publicly congratulates companies that had the most energy savings throughout the year. *Success Stories* will continue to be written and produced throughout 2013. These stories focus on businesses that took advantage of Idaho Power's Custom Efficiency program and the resulting benefits. *Success Stories* are posted on Idaho Power's website as PDFs so the highlighted businesses can print and use them to publicize their energy-efficient projects. In addition to these success stories, Idaho Power assists with public-relations opportunities, creating certificates for display within the building and having an Idaho Power representative speak at press events.

Easy Upgrades

	2012	2011
Participation and Savings		
Participants (projects)	1,838	1,732
Energy Savings (kWh)	41,568,672	38,723,073
Demand Reduction (MW)	4.7	4.4
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$5,150,422	$4,598,019
Oregon Energy Efficiency Rider	$199,331	$121,447
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$5,349,753	$4,719,466
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.012	$0.011
Total Resource Benefit/Cost Ratio	$0.020	$0.022
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	7.57	
Total Resource Benefit/Cost Ratio	3.29	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2007	

Description

The Easy Upgrades program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering customer incentives. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shells, VFDs, plug loads, and food-service equipment. Easy Upgrades is one of the company's largest programs. A complete list of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial and industrial customers taking service under Rate Schedule 7 (Small General Service), Rate Schedule 9 (Large General Service), Rate Schedule 19 (Large Power Service), and special-contract customers are eligible. For projects with expected incentive payments of more than $1,000 or that contain VFDs or non-standard lighting measures, applicants must submit a pre-approval application prior to initiating the project. In those cases, the customer or contractor completes the pre-approval application and submits it with the required documentation. For projects not requiring pre-approval, customers may elect to skip the pre-approval application process and submit their payment application and accompanying documentation. Under the Easy Upgrades program, customers may assign their incentive payment to a third party (e.g., their contractor or supplier), as approved by Idaho Power.

2012 Activities

Easy Upgrades experienced strong program participation in 2012. The number of completed projects increased by 6 percent over 2011, and energy savings increased by 7 percent.

Several process-improvement activities were implemented in 2012. A written program procedures manual was developed, a non-lighting verification protocol was put in place, and work was undertaken to expand program reporting capability. To provide quicker project turnaround, and in anticipation of an increase in project applications submitted to the program, Idaho Power hired an additional contract employee to assist with application processing. Trade allies experienced and appreciated the improved turnaround.

The program conducted eight lighting trade ally program information workshops across the Idaho Power service area. In addition, three technical lighting classes were offered to trade allies and two lighting classes were given for Idaho Power CRs. Two of the three technical classes qualified for continuing education credits for eligible, licensed trade allies. For the first time, the program held technical and program information classes in McCall. The program was well received, resulting in increased project submissions from that area. A total of 362 people received lighting information/education from the Easy Upgrades program in 2012.

In addition to the formal training classes held, program staff and Idaho Power CRs visited trade allies in the field, at the trade ally's business, or at a customer location to further educate them on program criteria and to respond to their inquiries.

Significant field time was spent visiting lighting trade allies throughout the Idaho Power service area. The program experienced a lull in application submissions mid-year, and trade ally outreach was used to help ameliorate that issue. Over 75 visits were made for the purposes of strengthening relationships; encouraging program participation; increasing knowledge of the Easy Upgrades program; receiving trade ally feedback about the market, the program, and their experiences; and learning how the program can better support trade allies (including where to focus training efforts in the future). Visits targeted electrical supply businesses and electrical contractors who were fairly new to the Easy Upgrades program. The upswing in project submissions post trade ally visits was noticeable.

An Easy Upgrades program specialist participated as a member of the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency development group. This group formed through collaboration with stakeholders to identify opportunities and strategic needs to support the region's success in commercial lighting. This strategic report will be finalized and presented to the NEEA Regional Portfolio Advisory Committee (RPAC) in January 2013. Implementation of the approved regional strategy is proposed to begin shortly thereafter.

Idaho Power continued to contract with Evergreen Consulting Group, LLC to provide ongoing lighting specialist expertise, project support, and trade ally training. Two lighting specialists provided support in trade ally outreach, as well as trade ally training. Idaho Power contracted with Honeywell, Inc., to perform non-lighting project reviews and pre- and post-project inspections.

To ensure projects participating in the program met program specifications and to verify conditions in the field were as stated on the program application, the Easy Upgrades program conducted pre- and post-inspections on numerous projects throughout 2012. The majority of inspections performed (1,030) were for lighting projects and consisted of 453 pre-inspections and 577 post-inspections. Seventy-three non-lighting projects received inspections, of which 19 were pre-inspections and 54 were post-inspections.

Program site inspections resulted in a variety of findings. The field conditions proved an exact match to the information on the application in many instances. For projects where discrepancies were found, incentive payments were adjusted to reflect actual field conditions, anywhere from lowering or increasing the incentive amount to denying the project incentive altogether. Examples of lighting discrepancies included fixture count and fixture type differences. Examples of non-lighting inspections not matching the project applications included facility square-footage differences; projects not meeting program criteria, such as insulating an unconditioned space; and projects that applied for one measure, but the actual project pertains to a different measure. Program management used inspection findings to identify areas for program improvement and modification and for trade ally training opportunities.

In addition to verifying that the information provided on the incentive application matched conditions in the field, the inspections provided an opportunity for Easy Upgrades to receive feedback from customers and trade allies about their projects and the program. Customers shared how their energy-efficient upgrade benefited their business. They also appreciated the inspections and viewed them as value added. In many cases, inspections resulted in identifying additional retrofit opportunity that resulted in increased energy savings for customers and Idaho Power. A frequent comment heard from trade allies was that knowing Idaho Power had inspectors verifying projects randomly in the field increased the accuracy of project information submitted to the program.

To advance energy savings and quality lighting design, Idaho Power was one of four utilities that participated with NEEA in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. The purpose of the pilot was to provide valuable information regarding the program design, level of incentives, and program support needed to achieve success in securing projects with increased energy savings using a comprehensive approach. Easy Upgrades program staff await NEEA's evaluation report of the pilot expected February 2013.

Cost-Effectiveness

In 2012, Idaho Power made several small adjustments to the measure offerings in the program. The lighting tool was updated to accept electronic T-12 ballasts. An initial analysis was conducted to see if the lighting measures shown in the tool would remain cost effective with the addition of the electronic T-12 ballasts. While the savings decreased slightly, it was shown to still be cost effective based on the average input watts and hours of operation. The actual savings for each lighting project are calculated based on existing light fixtures, the replacement light fixtures, and hours of operation.

NEMA Premium Efficiency general purpose motors were removed from the program in 2012. The motors are now the federal standard. The VFD measures listed on the Motors and HVAC worksheets were moved to one new worksheet.

In the *Demand-Side Management 2011 Annual Report*, Idaho Power listed several measures it planned to remove, change, or update in 2012. The company anticipated making these changes to the non-lighting measures of the program after the completion of the impact evaluation. However, due to the timing of results from the impact evaluation, the changes to the program have been postponed to 2013. Additionally, Idaho Power is currently working with a contractor to review selected non-lighting measures in the program and to provide updated deemed values to use going forward. Currently, most deemed-savings values for non-lighting measures come from the *Demand-Side Management Potential Study* conducted by Nexant, Inc., in 2009; however, Idaho Power uses data from the RTF for a dozen measures.

As part of a comprehensive review of all deemed measures, the RTF reviewed and updated the savings for commercial ENERGY STAR® refrigerators and freezers in October 2012. Because of the change in federal efficiency standards and the very high level of ENERGY STAR market penetration, the baseline changed and the savings decreased causing the measures to no longer be cost-effective. Five incentives for solid or glass door ENERGY STAR refrigerators and freezers of varying sizes were paid an Easy Upgrades program incentive in 2012. Idaho Power will review the measure in 2013 and determined what changes needed to be made. The remaining RTF measures have either not been updated or have not changed significantly to impact cost-effectiveness.

For current, detailed cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

An example of a satisfied customer is indicated in a *Success Story* posted on Idaho Power's website in 2012, *Upgrading its lighting gives Dominick's Quick Print whiter whites, brighter colors, and more cheerful employees*. This story describes how Joe Dominick, owner/manager/president of Dominick's Quick Print in Ontario, Oregon (and mayor of Ontario), was considering a lighting upgrade for his print shop. His electrician told him about the Idaho Power Easy Upgrades incentive program to help ease his worries about potential expenses. "I gulped when he first told me the cost," Joe said, "but when he told me that Idaho Power's incentive program could cut the cost by 65 percent, that got my attention. That made the project possible." Through Idaho Power's Easy Upgrades program, this small business owner changed out all 41 of his T-12 light fixtures to efficient T-8 fixtures, resulting in an estimated 7,586 kWh savings per year. A copy of this *Success Story* is provided in *Supplement 2: Evaluation*.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. This evaluation showed that lighting projects, which represented approximately 57 percent of 2011 savings, had a realization rate of 101 percent, while non-lighting projects had a realization rate of 33 percent. The overall realization rate was 72 percent as compared to ex-ante estimates.

The performance of VFD and HVAC controls (specifically programmable thermostat measures), accounted for approximately 80 percent of the reduction in ex-post savings due to the high volatility in savings potential and difficulty in estimating measure savings using deemed estimates.

ADM recommends the use of a partially deemed approach using a stipulated formula with site-specific inputs along with tables of deemed inputs to reduce the variance in realized savings for all VFD measure savings estimates. In addition, they recommend increasing the volume of projects receiving a detailed review of the project scope and measure applicability for both VFD and HVAC controls. A copy of the complete report is included in *Supplement 2: Evaluation*.

2013 Strategies

Several measure changes will be implemented in 2013. The program expects to offer incentives for qualifying T-8 lamps to reduced wattage T-8 lamps, T-5 High Output (T-5HO) lamps to reduced-wattage T-5HO lamps, screw-in metal halide lamps, and T-8 to LED refrigeration/case lighting. Incentives for permanent fixture decommissioning will also be offered as a way to encourage proper lighting design.

The program expected to undertake an evaluation of the non-lighting measures in 2012 similar to the extensive review of lighting measures conducted in 2011. However, with the program impact evaluation slated for mid-year 2012, Idaho Power postponed the non-lighting measure review until after receipt of the impact evaluation to incorporate its findings. Based on the results of the impact evaluation, the following recommendations were provided:

- Use custom calculations for large projects involving VFDs or for projects involving VFDs in process applications.
- Perform a thorough review of the project scope and affected equipment. This recommendation has particular applicability to the energy-management system controls and economizer measures.
- Consider applying interactive factors to lighting savings.
- Consider adopting a concurrent evaluation paradigm.

A review of these recommendations and a plan of action (or reason for no action) are targeted for completion in the first quarter of 2013.

Increased trade ally and customer training will be a focus for the program in 2013. Lighting 101 and lighting controls classes, both with continuing education credits, will be offered throughout the company service area. These classes will be offered in Salmon, a first for that area. Additionally, Easy Upgrades will secure American Institute of Architects CEUs and promote the lighting classes to the design community.

The program will expand beyond its lighting classes and offer technical training for trade allies and customers with in-house technical staff in the areas of VFDs and HVAC/controls.

Due to the success of the focused trade ally visits in 2012 and because the majority of customers participating in the program first learned about the program from trade allies, Easy Upgrades will continue to invest time and effort in trade ally visits across the Idaho Power service area. The purposes for these trade ally visits is noted in the previous 2012 Activities section.

Marketing outreach efforts targeted at small to medium customers will increase in 2013 to better inform/educate customers of the Easy Upgrades program and the various incentives offered. This marketing outreach will include a variety of strategies: direct-mail letters, articles in the company monthly customer newsletter, internet banner advertisements, articles and advertorials in local papers and/or local chamber of commerce newsletters, biannual commercial newsletters, and other tactics as identified throughout the year.

Results from the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency group will be evaluated, and Idaho Power will participate in the various aspects of the strategy it determines to be applicable to Idaho Power's market, program strategy, and goals.

Results from the NEEA Comprehensive Lighting Pilot evaluation will be reviewed, and opportunities for program implementation will be evaluated.

Idaho Power participated in regional discussions regarding the Standards for General Service Fluorescent Lamps protocol that became effective July 14, 2012. Due to the extensive T-12 lamp inventory and manufacturers continuing to produce T-12 lamps that meet the exception clause of the new ruling, Idaho Power will continue offering T-12 to T-8 incentives throughout 2013. Idaho Power discussed this at the July 19, 2012, EEAG meeting. Members were unanimously supportive of continuing to offer incentives for T-12 retrofit projects.

Idaho Power is aware of the RTF Lighting Protocols being drafted and will monitor these protocol outcomes to determine their applicability to the Easy Upgrades program.

In 2013, Idaho Power plans to contract with a third-party consultant to evaluate existing and new measures for the program.

FlexPeak Management

		2012	2011
Participation and Savings			
	Participants (sites)	102	111
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	52.8	58.8
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$98,973	$1,954,850
	Oregon Energy Efficiency Rider	$150,489	$102,880
	Idaho Power Funds	$2,760,360	$0
	Total Program Costs—All Sources	$3,009,822	$2,057,730
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.22	
	Total Resource Benefit/Cost Ratio	1.22	
Program Characteristics			
	Program Jurisdiction	Idaho/Oregon	
	Program Inception	2009	

Description

FlexPeak Management is a voluntary demand response program available in Idaho and Oregon service areas designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak days. The program objective is to reduce the demand on Idaho Power's system during peak times through customers' voluntary electrical-use reduction. The program is active June 1 to August 31 between 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand-reduction event two hours prior to the start of the event, and events last between two and four hours. Reduction events may be called a maximum of 60 hours per season.

In November 2008, EnerNOC, Inc., was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805. In June 2010, the program was approved by the OPUC in Order No. 10-206.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours with minimal impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week during the active season, EnerNOC commits a demand-reduction level in MW to Idaho Power that EnerNOC is obligated to meet during a demand-reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand-reduction event in aggregate. Customers can also continuously monitor their demand-reduction performance using their individual, near real-time energy-usage data through EnerNOC's proprietary software. This metering data and software is available to participating customers throughout the year.

2012 Activities

There were no changes to the program in 2012. During the first week of the program, EnerNOC committed to provide a meter-level reduction of 30.5 MW. This weekly commitment, or nomination, was comprised of 99 facility sites, of which 96 participated in the program in 2011 and 3 facility sites were added in 2012. The weekly nomination at the end of the season was 38.8 MW and comprised of 101 facility sites.

EnerNOC was contractually obligated to commit to provide at least 35 MW of reduction for each week in 2012. Their weekly commitments ranged from 29.6 MW to 38.8 MW. Four of the first five weekly commitments were below the 35 MW minimum; therefore, EnerNOC was subject to a penalty for those weeks. The remaining 10 weeks of the season they were above the 35 MW minimum and did not receive a penalty. Their commitment peaked in August at 38.8 MW.

Idaho Power called four demand response events for the FlexPeak Management program in 2012. One event occurred in June, two in July, and one in August. EnerNOC successfully exceeded the committed MW reduction in two of the four events. For the other two events, EnerNOC did not reach their committed MW reduction; performances were 91 percent and 87 percent of the committed levels. The highest hourly reduction achieved was in July at 54.2 MW (47.9 MW at the meter), which exceeded the target reduction of 35 MW for summer 2012.

Cost-Effectiveness

The B/C analysis for the FlexPeak Management program is based on a 10-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The settlement workshop led to a stipulation that was filed on February 14, 2013. FlexPeak Management was not included in the original filing due the company's contractual obligation to EnerNOC; however, Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond. At the time this report was written, Idaho Power was negotiating with EnerNOC on potential contract amendments aimed at reducing overall program costs for 2013. Because these negotiations are ongoing, the company conducted the cost-effectiveness analysis using the same cost and benefit assumptions it has in the past and used the 2013 budgeted expenses and forecasted performance, only updating 2012 actual demand reductions and costs.

Because demand response programs are analyzed over their program life, the analysis includes historical program demand reduction and expenses, as well as forecasted program activity. The program is analyzed over a 10-year program life because the 5-year contract with EnerNOC includes an option to extend the contract for another five years.

This analysis is updated annually with actual B/Cs. For the FlexPeak Management program, the benefits are based on measured demand reduction at the participant's meter. The costs include the fees paid to EnerNOC and Idaho Power administration for the program. The 2012 cost-effective analysis demonstrated the FlexPeak Management program has a TRC ratio of 1.22 from a long-term perspective and a TRC ratio of 1.21 for 2012. *Supplement 1: Cost-Effectiveness* contains details on the cost-effectiveness assumptions and data.

Customer Satisfaction and Evaluations

EnerNOC sent a post-event survey via email after the first event in June 2012 to 195 participants representing all the sites enrolled in the event. Eighteen participants responded, for a 9-percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8.6. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.3.

EnerNOC sent a second post-event survey via email after the August 2012 event to 201 participants, again representing all the sites enrolled in the event. Twenty-one participants responded, for a 10 percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was again 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.1. A summary of the results is in *Supplement 2: Evaluation*. Also included in the supplement is the *FlexPeak Management Annual Report*.

2013 Strategies

The 2013 peak season will be the final season of Idaho Power's current contract with EnerNOC. EnerNOC is contractually obligated to commit to provide at least 35 MW of reduction for each week of the active season in 2013. EnerNOC plans to conduct a post-season customer satisfaction survey for the 2012 season during the first quarter of 2013. The results will be made available to Idaho Power. Idaho Power will continue to evaluate the best use of the program to meet the program objectives, maximize the benefit to Idaho Power's system, and refine internal criteria to call demand-reduction events.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the FlexPeak Management program and produce an internal report, including 2013 activities, demand reduction, and a cost-effectiveness analysis summary.

Oregon Commercial Audits

	2012	2011
Participation and Savings		
Participants (audits)	14	12
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$0	$0
Oregon Energy Efficiency Rider	$12,470	$13,597
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$12,470	$13,597
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	n/a	
Total Resource Benefit/Cost Ratio	n/a	
Program Characteristics		
Program Jurisdiction	Oregon	
Program Inception	1983	

Description

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program offered under Oregon Rate Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

2012 Activities

Idaho Power sent out its annual mailing to approximately 3,400 Oregon commercial customers in August 2012. Customers were notified of the availability of no-cost energy audits and were provided with the Idaho Power publication *Saving Energy Dollars*. Fourteen customers requested an audit, with five audits completed by Idaho Power and nine completed by a third-party contractor.

Idaho Power contracts with EnerTech Services to perform the third-party portion of requested audits. Energy audits include a review of the customers past billing data and an inspection of the building shell, HVAC equipment, operating schedules if available, and lighting systems. Additionally, specific business operating practices that can be incorporated to improve energy use are discussed. During the audits, customers receive Idaho Power energy efficiency program information.

Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82. Since the required parameters of the Commercial Energy Audit Program are specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost effective. Idaho Power claims no energy savings from this program.

Customer Satisfaction and Evaluations

The value of an audit is the identification of actual savings opportunities in the customer's facility. Audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Both activities can lead to energy efficiency projects being undertaken. Customers are generally pleased with the audit process. This is especially true when the business owner is fully engaged in the audit. Business owners can make the decisions to change operating practices or make capital improvements designed to use energy wisely. Additionally, the audits help identify energy-saving opportunities that may not be obvious to the business owner.

2013 Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities. The audits help pinpoint favorable energy-saving actions that customers may pursue through customer behavioral changes or potential capital projects, such as replacing inefficient lighting. Additionally, the audit process will be used to introduce customers to Idaho Power's energy efficiency incentive programs. The program will be marketed through the annual customer notification.

This page left blank intentionally.

IRRIGATION SECTOR OVERVIEW

Description

The irrigation sector is composed of agricultural customers operating water pumping or water delivery systems to irrigate agricultural crops or pasturage. The end-use equipment primarily consists of agricultural irrigation pumps and center pivots. This customer group does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2012, the active and inactive irrigation service locations totaled 19,045 system-wide. This was an increase of 1 percent compared to 2011, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow-irrigated to sprinkler irrigation systems. Irrigation customers accounted for 2,048,435 MWh of energy usage in 2012, which was up from 2011 by 22.4 percent due to the hotter, dryer summer. This sector represented 14.5 percent of Idaho Power's total electricity usage and about 25 percent of peak demand in the summer. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to provide a system peak resource, and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind offering in which motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 hp and 5,000 hp for agricultural uses that receives a verified Green Rewind. Participation in Green Rewind ensures the motor's original efficiency is maintained if it is rewound at an approved service center.

The Irrigation Peak Rewards program had 340 MW of available demand-reduction capacity for summer 2012, an increase of almost 20 MW, or a 6.2-percent increase over 2011 summer's program capacity. For the 2012 season, 2,433 service points were enrolled, compared to 2,342 in 2011, representing a 3.9-percent increase.

The Irrigation Efficiency Rewards program, in operation since 2003, saw its annual savings decrease by 1,363 MWh to 12,617 MWh compared to 2011 reported savings. The savings decrease in 2012 was primarily due to fewer larger projects being done in 2012. During 2012, irrigation customers contributed 30,039 kWh per year of energy savings from 23 motors participating in Green Rewind.

Table 10 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

Programs

Table 10. 2012 irrigation program summary

Program	Participants		Total Cost		Savings	
			Utility	Resource	Annual Energy (kWh)	Peak Demand (MW)
Demand Response						
Irrigation Peak Rewards	2,433	service points	$12,423,364	$12,423,364	n/a	339.9
Total			**$12,423,364**	**$12,423,364**	**n/a**	**339.9**
Energy Efficiency						
Irrigation Efficiency Rewards	908	projects	$ 2,373,201	$11,598,185[a]	12,617,164	3.1
Total			**$ 2,373,201**	**$11,598,185**	**12,617,164**	**3.1**

[a] See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 54 percent of Idaho Power irrigation customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-five percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 29 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 88 percent are “very” or “somewhat” satisfied with the program.

Irrigation Efficiency Rewards

	2012	2011
Participation and Savings		
Participants (projects)	908	880
Energy Savings (kWh)[a]	12,617,164	13,979,833
Demand Reduction (MW)	3.1	3.8
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,978,729	$2,153,613
Oregon Energy Efficiency Rider	$360,689	$176,619
Idaho Power Funds	$33,782	$30,072
Total Program Costs—All Sources	$2,373,201	$2,360,304
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.022	$0.020
Total Resource Benefit/Cost Ratio	$0.110	$0.113
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.66	
Total Resource Benefit/Cost Ratio	1.76	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

[a] Includes kWh savings from Green Rewind.

Description

The Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help customers recover a portion of the costs of installing a new, more efficient irrigation system and energy-efficient improvements to existing systems.

Two options help meet the needs for major or minor changes on new or existing systems.
The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per the first year of kWh saved above standard installation methods, not to exceed 10 percent of the total project cost. For existing system upgrades, the incentive is 25 cents per the first year of kWh saved, or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh usage of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in most situations, post-usage demand data are available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which small maintenance upgrades provide energy savings from 11 separate measures. These measures include the following:

- New flow-control nozzles
- Replacement of worn brass or plastic nozzles
- Rebuilt or new impact sprinklers
- Rebuild kits for wheel-line levelers
- New low-pressure or rotating-type sprinklers
- New low-pressure regulators
- New drains, riser caps, and gaskets
- New wheel line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on predetermined average kWh savings per component.

Participation in Green Rewind is an opportunity that enables customers to maintain the motor's original efficiency and ensures an efficient use of electricity to run the motor. Motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 and 5,000 hp that receives a verified Green Rewind. The RTF approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings for industrial and agricultural applications.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power agricultural representatives sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits conducted by Idaho Power agricultural representatives evaluate prospective customers' potential savings. Agricultural representatives from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing their awareness of the program and promoting it through the irrigation equipment distribution channels. Marketing efforts include direct mailings, advertisements in agricultural publications, and participation in agricultural workshops and conferences. Idaho Power's agricultural representatives are funded approximately 30 percent by the Idaho and Oregon Riders and 70 percent from base rates.

2012 Activities

Of the 908 irrigation efficiency projects completed in 2012, 790 were associated with the Menu Incentive Option, providing an estimated 7,015 MWh of energy savings and 1.37 MW of demand reduction. The Custom Incentive Option had 118 projects, of which 65 were new irrigation systems and 53 were on existing systems. This option provided 5,572 MWh of energy savings and 1.7 MW of demand reduction for the year. Also during 2012, irrigation customers contributed 30,039 kWh of energy savings from 23 motors participating in the Green Rewind opportunity.

In June 2012, with approval from the EEAG and OPUC (Tariff Advice No. 12-09), Idaho Power changed the Menu Incentive Option for new or rebuilt wheel-line levelers to only rebuilt wheel-line levelers or rebuild kits. This change came about because the cost of a new wheel-line leveler made this measure not cost effective.

Idaho Power agricultural representatives, the program specialist, and the agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2012, Idaho Power provided six workshops promoting the Irrigation Efficiency Rewards program throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference.

Cost-Effectiveness

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. To estimate the effectiveness of a project, Idaho Power uses a service point's previous five years of electricity usage history and, based on the specific equipment to be installed, calculates the estimated post-installation energy consumption of the system. The company also verifies the completion of the system design through aerial photographs, maps, and field visits by Idaho Power agricultural representatives to ensure the irrigation system is used in the manner the documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure savings are achieved. Payments are calculated on predetermined average kWh savings per measure. In some cases, the energy savings estimated in the Menu Incentive Option are adjusted downward to reflect how the components are actually being used. No changes occurred to the assumptions that drive the cost-effectiveness of the measures that are part of this program.

All cost-effective analyses were based on the savings approved by the RTF in January 2010. The measures were reviewed for compliance with the new RTF savings guidelines in 2011 and were determined to be out of compliance. In 2012, the RTF approved of a plan to bring the measure back into compliance with the guidelines. Idaho Power will meet with the RTF in early 2013 to evaluate the research done by the University of Idaho to study the savings impacts of the measures provided in the Menu Incentive Option.

Based on the available deemed savings from the RTF, nearly all the measures offered under the Menu Incentive Option are cost effective. The rebuilt and new wheel-line levelers were shown not to be cost effective in 2010. After reviewing the measure, it was determined that the cost of the new wheel-line levelers was negatively impacting the cost-effectiveness of the measure. In 2012, the measure was modified to include only rebuilt wheel-line levelers in the program's offerings.

For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

At the February 2012 EEAG meeting, Idaho Power discussed the plan of partnering with the University of Idaho to research the Menu Incentive Option measures of the Irrigation Efficiency Rewards program to gather more information about menu measures. A sub-committee of the RTF will review the research and present aspects of the study to the RTF in 2013.

In 2012, Idaho Power contracted with the University of Idaho to conduct research regarding the Irrigation Efficiency Rewards program Menu Incentive Option. This research evaluated energy savings associated with the repairing of leaks and worn components listed in the Menu Incentive Option. The final report is included in *Supplement 2: Evaluation*.

2013 Strategies

Marketing plans for 2013 include conducting 7 to 10 customer-based irrigation workshops. Additionally, Idaho Power program specialists, agriculture representatives, and an agriculture engineer will attend five regional trade shows. These workshops and trade shows enable discussions between Idaho Power representatives, the company's customers, irrigation dealers, and trade allies while continually educating them about irrigation best practices, the program, and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power is reviewing the program regarding measures offered in the Menu Incentive Option. The research provided by the University of Idaho will be presented to the RTF in early 2013. The results of this research project will help determine changes to the program in future years and validate energy savings attributed to the replacement of irrigation components offered in the Menu Incentive Option.

A 2013 media plan has been created aimed at increasing the impact of advertising on this program. In addition, the effectiveness of online advertisements will be evaluated with this target audience. A database of irrigation dealers and vendors is also being developed for direct-mail purposes. Irrigation dealers and vendors are a key component to the successful marketing of the program; therefore, direct mailings containing the most up-to-date program information, brochures, and dealer specific meetings ensure correct program promotion.

Irrigation Peak Rewards

	2012	2011
Participation and Savings		
Participants (service points)	2,433	2,342
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	339.9	320.0
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,309,107	$11,790,216
Oregon Energy Efficiency Rider	$95,863	$254,013
Idaho Power Funds	$11,018,394	$41,993
Total Program Costs—All Sources	$12,423,364	$12,086,222
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.79	
Total Resource Benefit/Cost Ratio	1.72	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2004	

Description

Idaho Power's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to minimize or delay the need to build new supply-side resources. The program pays irrigation customers a financial incentive for the ability to turn off specified irrigation pumps with the use of one or more load control devices during the program season of June 15 through August 15.

In 2012, all Idaho Power irrigation customers taking service under Schedule 24 in both Idaho and Oregon were eligible, and participants chose between three options: 1) the Electric Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn off participants' pumps, or 3) a Manual Dispatch Option designed for large-service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during a load control event.

Participants in the Manual Dispatch Option are required to nominate the amount of kW they are enrolling in the program by June 1 of the program year. Participants in the Electronic Timer Option can choose to have all irrigation pumps on a single, metered service point turned off one, two, or three times per week. Interruptions occur from 4:00 p.m. to 8:00 p.m., and Idaho Power determines the specific weekday or weekdays to schedule the interruption of all pumps at each service point. Installation fees between $250 and $500 are applied to participating service locations less than 75 hp. For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. For 2012, dispatchable load control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday. Customers who choose to participate until 9:00 p.m. receive a higher variable incentive for events. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. Installation fees between $500 and $1,000 were applied to participating service points with less than 50 hp depending on the option customers chose.

The incentive structure includes a fixed and variable incentive payment. A customer's fixed incentive appears as a bill credit that sums the demand credit and energy credit for the interruption option selected and applies to a customer's monthly bills. The variable incentive is a summary of all load control event kWh multiplied by the variable incentive credit paid in the form of a check within 45 days of the end of the program season. Credits are prorated for periods when reading/billing cycles do not align with the program season dates from June 15 to August 15. All customer incentives participating in the Electric Timer Option, Automatic Dispatch Option, or Manual Dispatch Options are calculated using Idaho Power meter billing data. In addition, Manual Dispatch Option customers' incentives are calculated using interval metering data and nominated kW. Installation fees and opt-out penalties are completed through manual bill adjustments. Incentives, determined from interval meter data for service points classified as large-service locations, are completed through a manual process, and customers received the incentives in the form of a check in 2012. The incentives offered are listed in Table 11.

Table 11. Option incentives

Dispatchable Interruption Option Incentives							
	Fixed Incentive Payment				Variable Incentive Payment		
Dispatchable Option	Demand Credit ($/billing kW)		Energy Credit ($/billing kWh)		Standard Interruption Variable[a]		Extended Interruption Variable[b]
Options 1, 2, and 3	$5.00	**and**	$0.019	**plus**	$0.159	**or**	$0.209

[a] Energy Credit: 4 hours between 1–8 p.m. ($/event kWh)
[b] Energy Credit: 4 hours between 1–9 p.m. ($/event kWh)

Electronic Timer Option Incentives			
Option	**Demand Credit ($ per billing kW)**		**Energy Credit ($ per billing kWh)**
Timer Option Incentives			
One weekday	$3.15		
Two weekdays	$4.65	**plus**	$0.002
Three weekdays	$4.65	**plus**	$0.007

Under the rules of the Automatic and Manual Dispatch Options, participants have the ability to opt out of dispatch events five times per service point. Each opt-out incurs a fee of $1 per kW based on the current month's billing kW, which may be prorated to correspond with the dates of program operation and are completed through manual bill adjustments.

2012 Activities

Participation in this program was strong in 2012. Service points increased by 91, a 3.9-percent increase over 2011. Most of the challenges surrounding communication with some dispatch devices that occurred in prior years were resolved. In 2012, the program had the potential to achieve a maximum peak load reduction of approximately 340 MW. This represents a 6-percent increase from 2011, even though the company did not solicit new participants. Of all eligible irrigation service locations, approximately 13 percent participated in the program. In 2012, there were 2,433 metered service points enrolled in the program, with approximately 3.4 percent enrolled in the Electric Timer Option, 95.1 percent enrolled in the Automatic Dispatch Option, and 1.5 percent in the Manual Dispatch Option.

Idaho Power attempted to distribute the Electric Timer Option participating service points evenly throughout each weekday based on cumulative demand-reduction potential. However, due to service-point size variability, enrollment opt-outs, and other variables, the load reduction could not be exactly balanced. All participants in the Automatic and Manual Dispatch Options were grouped into five regional areas to be dispatched on each scheduled event day. Table 12 shows the MW reduction achieved daily on a week-by-week basis.

Table 12. Total program daily MW reduction without distribution losses using realization rates

Measure	Monday	Tuesday	Wednesday	Thursday	Friday
June 15	n/a	n/a	n/a	n/a	3.1
June 18–22	4.2	4.0	3.9	4.2	3.3
June 25–29	4.2	4.0	3.9	339.9[a]	3.3
July 2–6	4.0	3.8	3.7	3.9	3.1
July 9–13	4.0	3.8	3.7	320.7[b]	3.1
July 16–20	3.5	3.3	3.2	3.5	2.7
July 23–27	3.5	3.3	3.2	3.5	2.7
July 30–August 3	3.2	3.1	3.0	3.2	2.5
August 6–10	3.2	3.1	3.0	3.2	2.5
August 13–15	3.2	3.1	3.0	n/a	n/a

[a] The shaded cell reflects the estimated MW load reduction capacity available through the program.
[b] The shaded cell is Idaho Power's peak load day and reflects the estimated MW load reduction capacity available through the program.

Although the load reduction provided by the Irrigation Peak Rewards program was available to Idaho Power throughout the 2012 program season, dispatching the program was unnecessary. This was due to resources being able to meet system peak demands, low energy prices, and lack of system emergencies during the summer. Under the program's variable incentive design, taking into account both the extended interruption incentive and program realization rates, the program had an approximate dispatch price of $240 per MWh, which would total about $300,000 per event if all customers were interrupted for four hours. The program would be used if the company could not meet its peak needs with other resources, if hourly energy prices were greater than the dispatch cost of the program, or to avert a system emergency.

In February 2012, a customer mailing was sent to irrigation customers who participated in the program in 2011. The mailing included a program explanation, a program application, contract agreement, the program's incentive structure, a list of the customer's eligible service points, and an incentive estimate for each program option. Customers that had not participated in the program and did not receive the initial mailing but requested to participate were sent the same information.

Idaho Power did not market the program in 2012 but did provide program information at six workshops throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. The company also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths, where company representatives were available to answer questions, were displayed at regional agricultural trade shows, including the Eastern and the Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. Additionally, numerous one-on-one conversations with Idaho Power agriculture representatives familiarized customers with the technology and program details.

At the July 2012 EEAG meeting, Idaho Power presented the concept of changing the Irrigation Peak Rewards program to have three or four interruption events included in the fixed portion of the incentive customers receive. This would mean the program would not have to pay the variable incentive for these events. The events would be used primarily for customer awareness of what happens when events are called. It was discussed that without these included events the program could go multiple years without initiating any load control events. EEAG members were generally accepting of the concept.

Cost-Effectiveness

The B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation was filed on February 14, 2013. Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

Demand response programs are analyzed over the program life, this includes historical program demand reduction and expenses, as well as forecasted program activity. Because of the uncertainty of the program costs and because an order in the IPC-E-12-29 case is pending, for this report, the company conducted its cost-effectiveness analysis using the information know prior to the filing to temporarily suspend the Irrigation Peak Rewards program in 2013. The costs and demand capacity for 2012 were included with the forecast demand reduction and costs based on the 2013 budget and expected results. The Irrigation Peak Rewards program had a TRC ratio of 1.72. From a one-year perspective, the Irrigation Peak Rewards program had a TRC ratio of 2.4. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

Customer Satisfaction and Evaluations

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load reduction analysis, cost-effectiveness, and program changes. A copy is included in *Supplement 2: Evaluation*.

2013 Strategies

As referenced previously, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC to temporarily suspend the Irrigation Peak Rewards program for the 2013 season. The 2013 IRP is under development, and the IRP analysis indicates there will not be a need for demand response programs like the Irrigation Peak Rewards program during 2013. The proposed temporary suspension of Irrigation Peak Rewards will allow Idaho Power to work with stakeholders to determine the future course of action for its demand response programs. Idaho Power has proposed to continue to maintain the load control devices currently in place until further direction indicates otherwise.

Idaho Power plans to also file with the OPUC to suspend the program for 2013.

Market Transformation

Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market-transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates the marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. 2012 was the third year of NEEA's current, five-year plan.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

In 2012, Idaho Power energy efficiency staff served on NEEA's Board of Directors, attended advisory meetings, served on sub-committees, and participated in NEEA-sponsored studies and research.

Commercial and Industrial NEEA Activities in Idaho

NEEA continued to provide support for commercial energy efficiency activities in Idaho in 2012. This included partial funding of the IDL and local BetterBricks® trainings and workshops. Idaho Power's commercial sector programs Building Efficiency and Easy Upgrades are designed to leverage NEEA, the IDL, and BetterBricks activities.

In the industrial sector, NEEA continued its efforts to embed Continuous Energy Improvement (CEI) in small- to medium-sized businesses defined as less than 250 employees per site. CEI is a multi-year strategic effort designed to improve energy efficiency in the industrial sector. Prior CEI efforts focused on two regional industries considered heavy energy users: 1) the food processing industry and 2) the pulp and paper industry. Participants achieve cost savings through the adoption of energy-efficient business practices. CEI provides expert support, resources, and services, supplying companies with the training and tools for making energy efficiency a core business value. This effort is supported by providing technical knowledge to organizations and to Idaho Power customers collaborating on energy efficiency implementation. NEEA has a demonstration project for the agricultural sector taking place in Idaho. The project will provide information on control systems and variable-rate irrigation to improve overall efficiency.

Technical training and education continue to be important in helping Idaho Power's industrial customers identify where they may have energy efficiency opportunities within their facilities. Nine technical training classes were completed in 2012. Topics included compressed air, chilled water systems and cooling towers, pumping systems, VFDs, industrial refrigeration, data-center efficiency, and energy-management systems. The level of attendance at these classes remains high, with 171 participants attending the workshops.

In the commercial sector, NEEA has been working with utilities and lighting trade allies to develop a comprehensive lighting program. Idaho Power was one of four utilities that participated in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. NEEA has also been working to secure a pilot project in Idaho for their Existing Building Renewal initiative. This initiative is aimed at developing and testing new industry tools for commercial property owners engaging in deep energy retrofits.

Residential NEEA Activities in Idaho

NEEA supported a variety of residential programs and associated activities in Idaho Power's service area in 2012.

Among Idaho Power's programs, NEEA is directly involved in providing additional funding and support for ENERGY STAR® Homes Northwest, the DHP Pilot, the Residential Economizer study, and the Consumer Electronics Energy Forward campaign.

NEEA provides ENERGY STAR Homes Northwest builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates the various building specifications and requirements with the EPA and utilities in Idaho, Montana, Oregon, and Washington. Most of these activities are managed through a third-party implementer hired by NEEA.

In June, Idaho Power partnered with NEEA to promote the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home featuring a state-of-the-art DHP. NEEA secured the donation of the DHP from the manufacturer. An Idaho Power bill insert promoted the ENERGY STAR qualified Dream Home, and NEEA donated an ENERGY STAR flat-screen television to be used as a raffle prize.

NEEA has coordinated the DHP pilot research project since 2009, which includes data collection, design, results analysis, savings calculations, and ongoing promotional activities. The goal of the pilot is to encourage the adoption of these products while displacing the use of existing electric-resistance zonal heating systems in homes. NEEA created and launched a regional marketing program in 2012, conducted from September through December. The goal of the program was to increase consumer awareness of DHPs. The promotion included the use of social media, as well as radio, television, and newspaper advertising. Idaho Power currently offers a $750 cash incentive for qualified homeowners who install a qualified DHP system.

NEEA coordinated a residential Heat Pump Water Heater (HPWH) research project in the Northwest region that started approximately three years ago. A goal of the project is to promote the adoption of higher-efficiency water heaters over units built with only electric-resistance heat. Another goal is to provide a business case to the DOE by April 2016 encouraging the DOE to modify the 2020 federal standards and test methods for domestic electric water heaters. Water heaters built with only electric-resistance heat will not meet the proposed modified standard. The research project includes data collection, design, analysis, savings calculations, and marketing activities. NEEA's promotion offers a $1,000 rebate through June 2013 to residential homeowners who have certain HPWHs installed. The promotion requires the HPWH to be installed by a contractor trained by NEEA. In 2012, NEEA trained 18 contractors in the Idaho Power service area. NEEA also arranged for a HPWH discount program to be offered through Sears, a national appliance retailer, using 30 of their stores in the Northwest. Discounts were made available to homeowners who purchased certain HPWHs. Idaho Power participated in a HPWH summit in Portland in June 2012. The goal of the summit was to increase collaboration and cohesion with all regional utilities and other stakeholders.

In 2012, an Idaho Power residential program specialist participated on the selection committee for the HPWH Model Validation & Process Evaluation. This study strives to provide energy-savings data through the installation of HPWHs and data-logging equipment in residential homes. The committee scored contractor bids and selected the contractor Evergreen Economics to provide the HPWH Model Validation and Process Evaluation. Evaluation data will be compared to energy-savings data generated by the RTF's computer modeling created specifically for this study.

Idaho Power's partnership with NEEA's Consumer Electronics Energy Forward Campaign continued in 2012. The Energy Forward campaign highlighted the most energy-efficient televisions available. Retailers who represent more than 80 percent of televisions sold in the Northwest partnered with NEEA to promote Energy Forward televisions, including Best Buy, Costco, Kmart, Sam's Club, Sears, and Wal-Mart. Although final 2012 numbers are not yet available, as of late 2012, approximately 37 percent of televisions sold in the region were Energy Forward-qualified.

NEEA developed and launched a number of marketing tactics, including a fall marketing campaign to drive sales of qualifying televisions and engage national retailers in the promotion of these televisions. The campaign was a sweepstakes in which consumers could enter to win one of four "VIP tailgates" at a home game (one in each state of Idaho, Montana, Oregon, and Washington) or a chance to win weekly sub-prizes like Energy Forward televisions. Best Buy, Sears, and ENERGY STAR were campaign sponsors, and NEEA conducted public relations, advertising, social media, and online promotional tactics, including promotional packages with universities.

NEEA also launched a marketing campaign on October 1 with Best Buy, Sears, and ENERGY STAR as campaign sponsors. The primary objectives of the campaign were to increase retailer participation in promoting Energy Forward Most Efficient televisions, increase sales associates' awareness of them, and increase sales associates' ability to communicate qualifying television benefits to consumers leading into Black Friday. Mass consumer outreach via public relations, paid media, social media, community events, and partner outreach enticed retail partners to participate in the campaign and also helped increase consumer awareness and demand leading into the busiest shopping season of the year. NEEA representatives maintained retail partnerships by visiting each store at various times throughout the year, setting up point-of-purchase materials, and educating the sales staff.

Idaho Power has also participated in NEEA's Residential Advisory Committee meetings and activities throughout 2012 and served on the advisory team to contribute to ongoing improvements of Conduit, a regional online community for energy efficiency program managers in the Pacific Northwest. The goal of Conduit is to expedite the delivery and adoption of energy efficiency programs and activities. NEEA launched the website in May 2011. Conduit houses a library, discussion forums, and collaboration space. Similar to Facebook in features and benefits, Conduit is a space for energy efficiency professionals to congregate and share ideas, concerns, and questions. It is open to trade allies, state agencies, regulators, research institutions, and utility professionals. Additionally, two members of the residential programs team attended NEEA's annual conference, Connections Northwest, which provided updates on NEEA-sponsored programs and research, as well as valuable networking opportunities with other utility program managers.

An Idaho Power residential program specialist participated on the Regional Emerging Technologies Advisory Committee (RETAC) during 2012. The committee reviewed and updated the RETAC charter to effectively integrate the charter with other committees such, as the RPAC. Another RETAC committee purpose was to develop a 2013 plan to support the charter and member needs. The 2012 portfolio of emerging technologies under review at NEEA was discussed. Idaho Power and other utilities participating in RETAC reported on the energy efficiency projects the utility companies were interested in or had investigated.

In 2012, an Idaho Power residential program specialist participated on the National Energy Efficiency Technology Road Mapping Summit committee. The purpose of the committee was to revise current technology characteristics and the research and development (R&D) associated with the individual residential and commercial technology roadmaps contained in the Roadmap Portfolio. The Roadmap Portfolio helps guide and prioritize the regional investigation of technologies. The portfolio contains many technologies, along with the specific drivers, capability gaps, characteristics, and R&D programs associated with each technology. Idaho Power participated in revisions to the HVAC technology roadmap. The prioritization of all residential and commercial roadmaps is to be completed by March 2013.

An Idaho Power residential specialist was involved in 2012 with the NWRRC. This collaborative is a forum to evaluate and coordinate regional retail strategy. The first official meeting as a collaborative was held on November 27, 2012, at the Puget Sound Energy office in Olympia, Washington. Activities included a presentation to NEEA's Portfolio Committee, approval and adaption of Charter and Working Agreements, and the development of a scoping process for 20 potential measures identified for review at subsequent meetings.

Other NEEA Activities in Idaho

Over the last two years, Idaho Power's energy efficiency analysts participated in two committees to collect basic information on building stock and energy use of buildings throughout the Pacific Northwest. The results of the studies help form the future regional planning efforts. In 2011, NEEA moved forward with the RBSA. With the RBSA, customers from households in Washington, Oregon, Idaho, and parts of Montana were selected randomly to participate in a phone survey. A subset of those customers was then selected to participate in an on-site survey and, in some cases, a more in-depth energy review of the home. The *Single-Family Characteristics and Energy Use Report* was released in September 2012. The *Manufactured Home Characteristics and Energy Use Report* was published in January 2013. The multi-family report is expected to be released in 2013. Organizations, such as the RTF, have begun to revise measure saving using updated assumptions from the RBSA.

In addition to the RBSA, NEEA began work on the Commercial Building Stock Assessment (CBSA). An Idaho Power energy efficiency analyst participated in the RFP selection committee and the Sampling Priorities Working Group. Work on the CBSA will continue throughout 2013, with a final report expected in 2014.

Idaho Power is a participant in NEEA's Cost Effectiveness Advisory Committee. This committee meets three to four times a year to review NEEA cost-effectiveness models, assumptions, and, ultimately, energy-savings estimates. Idaho Power also participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally.

NEEA Funding

In 2012, Idaho Power began the third year of the 2010 to 2014 Regional Energy Efficiency Initiative Agreement with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market-transformation programs in Idaho Power's service area. Of this amount in 2012, 100 percent was funded through the Idaho and Oregon Riders.

In 2012, Idaho Power paid $3,379,756 to NEEA. The Idaho jurisdictional share of the payments was $3,210,768, while $168,988 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

For this report, NEEA provides Idaho Power an early estimate of its annual savings for the previous year. In the *Demand-Side Management 2011 Annual Report*, the NEEA savings reported were 16,109 MWh. The revised estimate included in this report for 2011 NEEA savings is 20,547 MWh. Preliminary estimates reported by NEEA for 2012 indicate that Idaho Power's share of regional market-transformation MWh savings for 2012 is 17,741 MWh, or 2 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at www.nwalliance.org.

This page left blank intentionally.

OTHER PROGRAMS AND ACTIVITIES

Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative's goal is to promote energy efficiency to the residential sector. This goal is achieved by creating and delivering educational materials and programs that increase Idaho Power's energy efficiency program participation and result in wise and informed choices regarding energy use.

The Residential Energy Efficiency Education Initiative continued to lead the production and distribution of the 2012 energy efficiency guides.

The first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313 due to additional newspaper subscriptions, insertion into the *Boise Weekly* magazine, and an extra 800 copies for hand delivery by Idaho Power representatives to locations, such as senior centers. The *Summer Energy Efficiency Guide*, inserted into newspapers on May 20, focused on ways to save money and make wise use of electricity during the cooling season. To get information out well in advance of the heating season, a third energy efficiency guide was published and distributed on November 11. This guide introduced tools and checklists to assist customers in getting the most savings per dollar invested in energy-related upgrades. It also suggested low and no-cost ways to increase comfort and manage bills while maintaining equipment and planning for future improvements.

During 2012, Idaho Power changed the style of the energy efficiency guides and incorporated a more consistent look and feel, including a catalog identification number to facilitate subsequent in-house printings. These process improvements allowed the company to increase the shelf-life and begin to build a library of flexible resources at a minimal cost. In 2012, 1,405 additional guides were distributed as educational handouts at energy efficiency presentations and events. About 10 percent of customers who requested *30 Simple Things You Can Do To Save Energy* also requested one or more of the energy efficiency guides.

In 2012, Idaho Power continued to build its social-media presence. Compared to this time last year, Facebook fans nearly doubled to just over 3,600, and Idaho Power's Twitter following quadrupled to 800 users. The company continued to leverage both channels to communicate information about Idaho Power energy efficiency programs, incentives, and events. Idaho Power's YouTube channel also saw increased activity; the 45 videos currently posted generated 13,500 views, of which 5,500 came from Idaho Power's educational video on DHPs. Across all channels, content was timed to align with print and broadcast campaigns so as to reinforce the message and heighten customer awareness. Additionally, Idaho Power's Energy Efficiency Program managers responded to 362 web inquiries with detailed written answers.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of other communication methods during 2012. Increased customer awareness of energy-saving ideas was accomplished via continued distribution of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. During the year, 8,707 English and 1,008 Spanish copies were distributed directly to customers via community events and local libraries; by CRs during in-home visits; by participating contractors in the

Home Improvement Program, Energy House Calls, H&CE Program, Boise Home Audit Project, and See ya later, refrigerator® program; through direct web requests; and in response to inquiries received by Idaho Power's customer service center. Of the books distributed in 2012, 1,106 were mailed directly to customers at their request, including 1,087 sent to customers who contacted Idaho Power's Customer Service Center with questions about how to reduce energy use and 19 in response to direct requests received through Idaho Power's website. Idaho Power also mailed 876 copies of the informational brochure *Practical Ways to Manage Your Electricity Bill* to customers who called specifically with concerns about high bills.

Idaho Power continues to recognize that educated employees are effective advocates for Idaho Power's energy efficiency programs. To keep employees informed and up to date, Idaho Power conducted its annual energy efficiency awareness campaign in March. Activities during 2012 included weekly articles in internal publications to engage employees in learning more about Idaho Power's programs and wise energy use. A texting competition was implemented and employees were encouraged to text answers to weekly questions focused on energy efficiency. Posters for display in Idaho Power's offices and distribution of wearable buttons encouraging employees to become "Energy Efficiency Rock Stars" rounded out the month.

Although the formal partnership with the Idaho Commission for Libraries expired in June 2011, the Kill A Watt™ Meter Program remained active in 2012. With this commitment complete, Idaho Power reached out to local libraries to assist with the continued promotion of the program. Idaho Power developed a travelling, interactive table display for individual library use to create buzz and interest around the Kill A Watt kits. All participating libraries received an invitation to schedule the display. Eight libraries responded and three displays moved amongst the libraries throughout the summer and fall.

Idaho Power took the lead in strengthening the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2012, twenty teachers completed the 3-day, 2-credit professional development seminar facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Lab (INL).

Other energy education partnerships included working with the IDL in late autumn to offer two residential-focused training seminars in the BetterBricks® series. Twenty-four participants attended the session titled "Advanced Insulation Techniques" and 16 attended "The People Side of Sustainability." Both sessions had two off-site participants that attended via live video streaming. Videotapes of the seminars are available for download from the IDL's website. The workshops averaged 15 post-lecture downloads in 2012. Idaho Power continued its co-sponsorship of the "Sustainable Energy Sustainable Homes" lecture series. The eight workshops, facilitated by local trade experts, provided information and expertise to encourage energy efficiency upgrades. Attendance increased from an average of 12 participants per session in 2011 to an average of 18 participants per session in 2012. Idaho Power continued to partner with the City of Hailey on the educational portion of their Hailey Community Climate Challenge grant by participating in the delivery of seven workshops during the year.

In addition to these activities, Idaho Power continued sponsorship of the fifth annual Idaho Green Expo in June. As part of Idaho Power's commitment to the Expo, the company sponsored a direct-mail effort to increase participation and publicize the new location. Data from Idaho Power's 2010 and 2011 Green Expo Surveys was mined to determine the best Treasure Valley homeowners to include. Two-for-one coupons were provided the week prior to the Expo to 26,000 targeted participants. The Idaho Power Expo booth consisted of a "Summer of '78" theme, where participants were encouraged to set their summertime thermostats to 78 degrees and given other stay-cool tips. In addition to sharing this message at the booth, Idaho Power partnered with six other sustainably minded organizations to sponsor a broad educational activity that used text messaging to engage attendees and their families for the length of their expo visit. The activity exceeded expectations with 186 unique individuals, representing 6 percent of total expo attendees, choosing to play. Together, they texted 3,093 correct answers to the specified telephone number. On average, these 186 players texted 17 correct answers each and thus received 34 pieces of valuable information during their expo visit. The regional director for the vendor, who processed the text messages, stated, "These results are quite fantastic. In a typical setting I would estimate 1.5 percent to 2 percent participation. You all have tripled that. Great effort!"

For the third year running, Idaho Power partnered with GreenWorks Idaho to develop and administer an exit survey, resulting in 342 completed surveys. The Green Expo participant profiles will be used to further improve messaging and goals and increase an understanding of Idaho Power's return-on-investment for future sponsorship of this event. It will also be used for tracking energy efficiency-related trends among expo attendees. Thirty percent of this year's survey participants reported having received an energy efficiency incentive payment from Idaho Power, up from 21 percent in 2011. The survey summary is provided in *Supplement 2: Evaluation*.

In September 2012, Idaho Power participated in the St. Luke's Women's Show for the fifth consecutive year. The event continues to be important due to the size of the audience and because its demographic component aligns with Idaho Power's residential energy efficiency target audience. Numerous marketing research studies have shown the people most likely to participate in energy efficiency programs tend to be females with higher education and income levels than the general population. This target audience aligns well with individuals who attend this event.

Idaho Power requested booth visitors complete an in-depth survey. The survey was redesigned in 2012 based on results from the previous two years' surveys to gather key market data and establish a baseline regarding attitudes toward energy-efficient and sustainable behaviors. Another improvement with the 2012 survey was that participants were given the opportunity to complete an online survey prior to the show through the show sponsor. This resulted in a more positive experience in completing the survey for many, since there were frequently waiting lines in previous years. In total, the company collected 670 completed surveys, exceeding the target of 400. The opportunity to complete the survey online shortened the waiting line at the booth and resulted in 274 of the 670 survey respondents completing the survey from a remote location.

Although the respondents are not a random sample, key findings from the Women's Show survey indicated Idaho Power's ENERGY STAR® Homes Northwest continues to be the most recognized energy efficiency program, with most respondents (77%) indicating they were "aware of" the program. Respondents also indicated awareness of other ENERGY STAR branded programs and the See ya later, refrigerator® program. Energy House Calls was the least recognized program, with a majority of respondents (65%) indicating they had "never heard of" the program. The Home Products Program and A/C Cool Credit program were most identified by participants as a program they had participated in.

Of the Women's Show participants that completed the survey (98% female), the majority said they review and pay the monthly bills in their home and are the primary decision makers for managing thermostats, purchasing light bulbs and fixtures, and making appliance and electronics purchases. However, less than half of respondents indicated they are the primary decision maker for home upgrades, such as adding insulation.

When asked if they had plans to reduce their electricity consumption, less than 8 percent indicated they had no plans to do so. Forty-three percent indicated they were already taking some action, while 49 percent indicated they were either currently exploring ways or starting to take some action to reduce electricity use. Of the actions presented, turning lights off when leaving the room, adjusting thermostats up two degrees in the summer, and replacing incandescent light bulbs with CFLs were the most likely behavioral changes respondents would take to save money and to positively impact the environment. Respondents were slightly more inclined to reduce their water heater temperature 10 degrees and participate in the A/C Cool Credit program for positive environmental benefits than cost savings.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 171 outreach activities, including events, presentations, trainings, and other outreach activities. As part of process improvement accomplishments, the Outreach Tracking System, the database that records educational and outreach activities, again received some enhancements for additional metrics. In 2012, a special effort was made to increase the quantity and quality of post-event feedback recorded in the database. At the conclusion of 2012, 71 percent of events taking place during the year had some post-event documentation recorded in the system.

In addition to the outreach activities noted previously, Idaho Power field staff throughout Idaho Power's service area delivered another 176 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2012, the Community Education team provided 92 presentations on *The Power to Make a Difference* to 2,690 people. More specifically, 53 of these presentations were to students, and 29 of them were community presentations. The breakdown of attendance was 1,539 students and 1,151 community members. The community education representatives and other staff members also completed 42 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 1,473 seniors in the company service area.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and other needs of Idaho Power's Corporate Communications department. The initiative staff supplied information for various Idaho Power publications, such as *News Scans, Green Power Newsletter*, *A/C Cool Credit Newsletter*, *Customer Connections*, and Idaho Power's Facebook page. Additionally, the initiative worked with the Energy-Use Advisory Tool (EUAT) team to provide appropriate tips and suggestions for the account manager enhancements implemented in March. One of the major goals of this web enhancement was to educate customers and encourage behavioral change by linking specific energy-related behaviors and choices to their monetary consequences. Time-of-Day promotional materials and calculators were also created with energy efficiency suggestions from the initiative.

During 2013, the initiative's goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. Based on guidance from EEAG, plans for 2013 include more opportunities to educate and influence young people regarding wise energy use and continued work with Idaho Power program specialists, partners, and participating contractors to influence behavioral change, particularly when energy efficiency upgrades are made. Energy efficiency educational materials and channels will continue to be evaluated and either developed or revised, as necessary, to increase customer reach, improve distribution, and enhance presentation opportunities. Beginning in 2013, two issues of *Customer Connections* (the monthly newsletter included in customer bills) will be devoted entirely to energy efficiency. Idaho Power will continue to actively evaluate existing data to determine how future research and data collection may be improved to further the Residential Energy Efficiency Education Initiative's goals.

Easy Savings Program

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP and provides $125,000 to be paid to CAP agencies in the Idaho Power service area on a prorated basis. In addition, this order specified that Idaho Power provide educational information for households that heat their homes with electricity provided by Idaho Power.

Three main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes to use energy wisely, to allow hands-on experience while installing a low-cost measure, and to reduce the energy burden for energy assistance/LIHEAP applicants.

In past years, the primary target for the program was households applying for energy assistance that did not qualify for weatherization prioritization. Households that were targeted through the Easy Savings Program generally did not include elderly or disabled individuals or families with children that are already prioritized for other Idaho Power weatherization services. For the 2011 to 2012 program, the priority status for weatherization assistance exclusion was removed. Customers with priority status for weatherization are now eligible to receive Easy $avings® program kits.

Each provided kit contained the following low-cost/no-cost energy saving items:

- CFLs (13 W and 18 W)
- Hot-water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers
- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets for the laundry
- *Quick Start Guide* to installation
- Survey inquiring about the installation experience and actions taken to reduce energy use

All educational materials are printed in English and Spanish. Returned surveys are used to track the effectiveness of the program. Tracking is done via a kit/survey unique numbering system.

In August 2012, Idaho Power placed an order with the Easy Savings Program vendor, Resource Action Programs (RAP), for a two-year supply of kits. This allowed time for the regional CAP agencies to receive kits and ready them for distribution by the beginning of the LIHEAP season, which begins on November 1 each year and ends the following March, depending on funding availability.

Fulfilling the payment requirements for program years 2011 to 2012, $250,000 were sent by Idaho Power to CAP agency executive directors in each region. Each agency used 30 percent of the agency's allotment to cover expenses for administering the program at their agency. An order for 4,255 kits was placed in August 2012. Kits were shipped from the vendor and received at agencies in October 2012 for distribution to customers. The goal is to have all kits distributed prior to November 2013.

Between October 2012 and December 31, 2012, 850 kits were distributed to Idaho Power customers approved to receive energy assistance benefits on their Idaho Power bills. A participant survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits. Tracking was done via a kit/survey numbering system. Returned surveys were used to track the educational impact of the program.

Of the 850 surveys distributed, 126 completed surveys were received back from customers describing their experience in installing kit items in their homes. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit, as well as questions confirming the installation of kit items.

Ninety-one percent of household respondents reported they have, or will, lower their heat during the day, and 82 percent reported they will lower their heat at night. Eighty-two percent of the households reported installing both CFLs provided, and another 12 percent said they installed one of the CFLs provided. Seventy-nine percent of the households reported installing the high-efficiency showerhead.

Overall, survey results show that over 58 percent of the households that received the kits and returned a survey installed five or more kit items. Seventy-four percent of the respondent households reported learning a lot about saving energy and money in their home after completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

Gift certificates valued at $100 each will be provided by CAPAI to encourage survey completion on the remaining 3,405 kits. A drawing from all returned surveys will be held in 2013. Five households will win a $100 gift certificate. Upon anticipated completion of kit distribution in October 2013, Idaho Power and CAPAI will consider changes for the program in 2014.

Commercial Education Initiative

Since 2008, the Commercial Education Initiative has informed and educated commercial customers regarding energy efficiency, increased awareness of and participation in existing commercial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives. A major strength of the initiative is the emphasis on building strategic relationships. The program specialist works closely with Idaho Power CRs assigned to commercial market segments to capitalize on their established relationships with customers.

The initiative oversees the distribution of informational materials and works directly with trade allies and other market players who, in turn, support and promote Idaho Power's energy efficiency programs. Routinely, individual site visits are conducted to educate customers on energy-savings opportunities at their business. Additionally, these site visits serve as training opportunities for field staff, raising their knowledge for future site visits.

In 2012, Idaho Power carried out its plan to capitalize on effective customer projects by posting on Idaho Power's website six *Success Stories* highlighting customers' 2012 energy efficiency projects. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency programs. The Commercial Education Initiative works with and supports multiple stakeholders and organizations to increase customers' energy efficiency knowledge. Examples of key stakeholders include the IDL; BOMA; US Green Building Council; and American Society of Heating, Refrigeration, and Air-Conditioning Engineers. Through funding provided by Idaho Power, the IDL performs several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities include sponsoring a building-simulation users group, conducting lunch-and-learn sessions held at various design and engineering firms, and offering a tool loan library. Customers also have access to equipment that enables them to measure and monitor energy consumption on various systems within their operation.

In 2012, the Commercial Education Initiative sought further opportunities to assist small communities interested in learning more about energy efficiency. The initiative continued to conduct site visits, used the Equipment Efficiency Specification Sheets, and distributed target market information tip sheets. Additionally, Idaho Power offered assistance to colleges providing energy-related technical education.

Plans for 2013 include 1) working with Idaho Power marketing specialists to increase customer awareness of the company's energy efficiency programs and their specific offerings, 2) coordinating training opportunities for CRs to increase their energy expertise, and 3) refining tools that allow customers to perform a cursory evaluation of their own facilities to identify energy efficiency opportunities and determine if a more in-depth evaluation or audit is needed. Customer support via facility walk-throughs and site-specific efficiency guidance will continue. Idaho Power will continue working with key stakeholders to provide outreach and training opportunities. In a partnership with NEEA and BOMA, Idaho Power is piloting an energy-savings competition for commercial office buildings. Similar competitions have successfully been held in Seattle, Washington, and Portland, Oregon. Branded as the Kilowatt Crackdown™, the goal of the competition is to help participants raise their energy awareness and increase building performance community wide. The Kilowatt Crackdown will be a beneficial educational opportunity for participants.

Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs but that still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

Idaho Power received four applications for LEEF in 2012. Projects included 1) the installation of computerized controllers on existing engine-block heaters in a bus yard, 2) the use of a solar thermal system to heat a residence in Idaho City, 3) the installation of a programmable logic controller on manufacturing ovens to reduce peak demand, and 4) the construction of an energy-efficient micro-home for demonstration purposes.

For each of these projects, Idaho Power convened a working group of engineers and cost-effectiveness analysts to review the application, request additional information, and perform a cost-effectiveness analysis. None of the projects were funded for the reasons stated below.

Three of the projects did not meet cost-effectiveness tests for various reasons. The committee found that less expensive timers would achieve the same savings as the proposed controllers for the block heaters. The residence in Idaho City planned to have a pellet stove for backup heat, so the primary heat source was not going to be electric. The manufacturing ovens proposal shifted use, but the existing peak period was not during Idaho Power's peak demand period, and there were no proposed energy savings associated with the proposal. The micro-home project was specific to the 2012 Green Expo trade show, and the application was received too late for the completion of funding and construction prior to the show. However, funding was put into the Residential Energy Efficiency Education Initiative budget in 2013 to complete a similar project that could be used for demonstration purposes.

Residential Economizer Project Study

In 2011, a Residential Economizer Project Study was initiated involving the installation of 19 economizers into residential houses. An economizer draws cool, outside evening air into the A/C system of a house. Its purpose is to reduce the summer cooling energy required to cool the house. The reduction of cooling energy is derived from the reduced run time of the A/C mechanical system. Data collection devices were used to capture energy and temperature values in the houses fitted with these systems. The data was collected during summer 2011. It was analyzed by Idaho Power and third parties to determine potential energy savings. The installation of data-logging equipment, field monitoring, and the energy analysis report was performed by the IDL.

In early 2012, with the advice of EEAG, it was determined that securing additional data during summer 2012 would be beneficial when combined with data collected the prior year. Twenty-two additional houses were fitted with economizers and data-logging equipment. Twelve of the houses data logged in 2011 were also data logged in 2012. Ongoing progress was reported in February and July 2012 EEAG meetings. All 34 houses were analyzed at the end of 2012. The final report from the IDL is due after December 2012.

NEEA has been involved with the study since its beginning in 2011. The 2012 results will be shared with them. In 2011, NEEA planned to contribute to four study reports. Three of the studies were completed in 2011. These three include the baseline energy study, the contractor survey, and the customer survey. NEEA will review the 2012 results to determine if the fourth report, the market-transformation report, will be necessary based on factors including reported energy savings.

Regional Technical Forum

The BPA and the Northwest Power and Conservation Council (NPCC) established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating on various sub-committees.

The forum's purpose is to advise the BPA, the NPCC, the region's utilities, and organizations, including NEEA and the Energy Trust of Oregon (ETO), on technical matters related to energy efficiency and renewable-resources development. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and renewable resource goals. Providing feedback and suggestions for improving the effectiveness of regional energy efficiency and renewable-resource development programs are additional activities of the RTF. The RTF also recommends a list of eligible conservation measures and the estimated savings associated with those measures. Idaho Power uses the information provided by the RTF when conducting research and analysis on new and current measures. The RTF meets monthly to review and provide comments on analyses and other materials prepared by the NPCC, BPA staff, and RTF contractors. Idaho Power uses the savings estimates and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics. In 2012, Idaho Power staff participated in all of the RTF's meetings and was involved in various sub-committees, such as the RTF Policy Advisory Committee. Idaho Power is also working with the RTF to bring the "out-of-compliance" irrigation hardware measures into compliance. The company partnered with the University of Idaho to conduct field testing of various irrigation components during the 2012 growing season. The research will be presented to the RTF in early 2013.

Since 2010, the RTF has been working toward developing a set of operative guidelines to describe the RTF's methods to select, develop, and maintain measure savings, costs, and other benefits. The guidelines were completed and adopted in 2012. In the meantime, the RTF has spent the past two years reviewing previously deemed measures and determining its compliance to the new guidelines. A measure may fall under one of the four measure categories and one of the four measure statuses.

Measure categories include proven, provisional, planning, and small-saver savings. Proven savings meet the highest quality and reliability standards. Provisional savings estimates are those the RTF conditionally approves and requires additional data collection. It must be possible to obtain the data necessary to meet the proven quality of standards. Planning savings do not meet the quality of standards of the provisional or proven categories; however, these measures may be needed for the regional program operators. A data-collection plan must be developed that can bring the measure to the provisional or proven category. Small savers are measures that have savings too small to necessitate the resources needed to bring the measure to proven or provisional quality of standards.

Measure statuses include active, under review, de-activated, and out-of-compliance. The active measure status is when the measure's source data is current and contains reliable savings.

Prior to a measure's sunset date, a measure may change its status to under review if new sources of data become available. The measure's savings will be reviewed and may be re-estimated. A de-activated measure status refers to when the sunset date for a measure has passed and new savings estimates have not been approved. A measure may be de-activated if new findings invalidate the measure savings. Out-of-compliance measures are those measures that do not comply with one or more of the requirements from the guidelines. Once the RTF determines a measure is out of compliance, a plan to bring the measure into compliance must be approved within a year. This status is applicable to measures approved prior to June 1, 2011.

Boise City Home Audit Project

In 2011, Idaho Power and the City of Boise partnered to create a limited-term, residential energy audit project that installed low-cost energy-saving measures and identified additional efficiency improvements. The City of Boise received ARRA funding from the DOE Energy Efficiency Conservation Block Grant (EECBG). At the end of 2011, a portion of the funds remained, and the project was extended to provide for an additional 226 home audits.

The home audit extension in 2012 resembled the original project. Idaho Power contracted with HPSs to perform the energy audits and installation of measures. The energy audit included a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Potential low-cost energy-saving measures that could be installed in each home included limited sealing of air leaks, such as mastic around the furnace unit; installing CFLs; insulating water pipes that are three feet or less between the water heater and the structure; and installing water heater blankets. The audit included instructing customers on a variety of items, including the replacement of their furnace filter and how to lower the temperature on their water heater.

Participating customers paid $49 for the audit and installation of measures, with the remaining cost covered by the EECBG funds. Energy audits of this type normally cost $300 or more, not including the measures, materials, and labor. The cost of the materials potentially installed at each home was approximately $100.

After the audit was complete, homeowners received a report and were provided information on programs that could assist them with the costs of implementing additional measures, including information on the City of Boise's Home Improvement Loan Program.

The target audience for this project was Boise residential customers living in single-family, site-built homes under 3,000 ft^2. The homes had to be owner-occupied year-round. The target was for 25 percent of participating homes to be all-electric.

Participants were recruited through direct-mail. In 2012, six small batches of recruitment letters were mailed for a total of 12,342 letters, with a response rate of 2.3 percent. Customers who were interested in participating in the project were directed to a website to complete an application. Those who either did not have internet access or were uncomfortable with filling out the application online were able to call and have their application taken over the phone. Participants were selected on a first-come, first-served basis.

The three energy auditors from the original project were selected to continue with the extension. Audits were randomly and evenly distributed between the three auditors.

Of the 225 audited homes, 182 homes (81%) were heated by gas, two homes (1%) were heated by oil, and 41 (18%) were heated by electricity. The average age of the homes in the 2012 project extension was 37.6 years old.

Home sizes ranged from 913 ft^2 to 3,176 ft^2. The average home size was 1,933 ft^2. Although the recommended maximum home size was 3,000 ft^2, a few homes over this size were completed. Table 13 shows the 2012 number of participating homes by ranges of square-foot increments.

Table 13. Number of participating homes by size

Home Size	Count
700–1000 ft^2	4
1001–1500 ft^2	63
1501–2000 ft^2	53
2001–2500 ft^2	66
2501–3000 ft^2	31
3001–3328 ft^2	9

Homes were located throughout the Boise city limits, with larger amounts of recruitment letters mailed in those zip codes reported to have a higher percentage of electrically heated homes. Table 14 compares the 2012 number of participating homes per zip code that heat by using electricity, gas, or oil.[2]

Table 14. Number of participating homes by zip code and heating source

Zip Code	Electric	Gas	Oil	Total
83702	7	19	1	27
83703	7	6	0	13
83704	8	52	0	60
83705	5	9	0	14
83706	8	29	0	37
83709	3	25	0	28
83712	1	10	1	12
83713	3	23	0	26
83714	0	1	0	1
83716	0	8	0	8

When performing an audit, the HPS determined which available measures were appropriate for the home, and, if the homeowner approved, those measures were installed. Table 15 lists by heating source and quantity of items installed in participating homes in 2012.

Table 15. Measures installed in participating homes by heat source

	Quantity	Gas Home	Electric Home	Other
CFLs	776			
Water heater blankets		4	1	
Pipe insulation		79	13	1
Mastic		55	11	1

Once an audit was complete, the information obtained by the auditor was entered into a database. A personalized report was created and mailed to each participant detailing what was found at the home, what measures were installed, and further energy efficiency recommendations.

A survey was sent after the participant received their personalized report and allowed time for participant action regarding suggested energy efficiency actions. The survey gathered data on immediate actions the participant initiated following the audit and short-term actions they planned to take at a future date. It also inquired about reasons for inaction, such as expenses or difficulty finding a contractor. A copy of the survey is included in *Supplement 2: Evaluation*.

Idaho Power contracted the IDL and the City of Boise to provide an impact evaluation of the Boise City Home Audit Pilot. Using ARRA funds, energy audits were conducted and low-cost energy efficiency measures were installed at 650 homes located in Boise. The audits took place from late 2010 through summer 2011 and identified additional energy efficiency measures for future consideration by the customer.

The final report indicated that the average savings per home from direct install measures was 308 kWh in electricity and 3 therms in natural gas per year. Based on the average residential consumption in Idaho Power's service area, this represents a 2.4-percent reduction in annual electricity consumption. Although these savings estimates were to be originally calibrated using utility billing data, according to the International Performance Measurement and Verification Protocol (IPMVP), savings were not large enough to accurately differentiate from historical billing data.

The cost-effectiveness analysis conducted under IDLs assumptions indicates that this program, with installed measures for dual-fuel homes, would only be cost-effective under the PCT. The analysis shows that this program with the same installed measures for electrically heated homes would be cost effective under the UCT and TRC. A copy of the complete report is included in *Supplement 2: Evaluation*.

This page left blank intentionally.

Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27 filed with the IPUC on October 22, 2010, and is described in more detail below.

Since 2002, Idaho Power has recovered most its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM costs. In addition, since January 1, 2012, funding of Idaho customer incentives of demand response programs is now included in base rates and tracked in the annual PCA mechanism. On December 30, 2011, the IPUC issued Order No. 32426 in General Rate Case No. IPC-E-11-08 that approved including $11.3 million of demand response incentive payments as part of base rates. As of June 1, 2012, Idaho Power is including in the PCA an amount to true-up actual demand response incentive expenses for the previous year if the amount is different than the $11.3 million in base rates.

To address the removal of financial disincentives, Idaho Power tested the effects of an FCA mechanism in a five-year pilot initiative. In 2011, the FCA completed its fifth year in pilot status. As part of the 2011 General Rate Case No. IPC-E-11-08, Idaho Power requested the FCA become permanent. The IPUC decided the FCA should be addressed in a separate case. On October 19, 2011, the company filed Case No. IPC-E-11-19 with the IPUC. The case requested to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company submitted its Compliance Filing, requesting the IPUC issue an order authorizing either the continued use of the existing FCA methodology, without change, or in the alternative, a modified methodology that introduces a symmetrical cap on the calculated FCA balance based on the change in the annual energy consumption per customer of plus or minus 2 percent from the historical average. On January 31, 2013, the IPUC issued Final Order No. 32731, directing the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for Idaho customer incentives paid through the Custom Efficiency program as a regulatory asset beginning January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in DSRs. As of December 31, 2012, proceedings relating to this case are ongoing.

Fixed-Cost Adjustment

Under the FCA, rates are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in energy efficiency and demand response resources designed to reduce customer usage. The FCA is limited to the residential and small general-service customer classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through their volumetric energy charges.

During the five-year period in which the FCA Schedule 54 was in a pilot status, Idaho Power made strong progress toward improving and enhancing its efforts to promote energy efficiency and DSM activities. The company increased the number of energy efficiency and demand response programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained through these activities. Results from the first five years of the pilot indicated the true-up mechanism was working as intended.

As stated previously, on March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers.

On May 8, 2012, the IPUC issued Order No. 32544, approving the company's request to implement FCA rates for fixed-cost deferrals in 2011. Beginning June 1, 2012, the company implemented an overall rate adjustment of 0.28 percent to residential and small general-service customers to collect a combined $10.3 million in under-collected fixed costs. Residential customers experienced a rate increase of 0.0227 cents/kWh, while small general-service customers experienced an increase of 0.0324 cents/kWh. The rate adjustments will result in a collection of an additional $1 million over the then-current billed amounts and will be in place until May 31, 2013.

Custom Efficiency Incentive Recovery

On October 31, 2012, the company filed Case No. IPC-E-12-24 requesting authority to include Custom Efficiency program Idaho incentive payments in rates. Previously, on May 17, 2011, the IPUC in Order No. 32245 had authorized Idaho Power to account for Custom Efficiency program incentive payments as a regulatory asset.

In the October 31, 2012, filing, Idaho Power requested the following of the IPUC: Recognize the 2011 Custom Efficiency incentive amounts as "used and useful"; begin recovery of these amounts in rates on June 1, 2013; specify the company's rate of return as the carrying charge for the regulatory asset account prior to amortization; specify a four-year amortization period for the regulatory asset; acknowledge that the unamortized portion of the regulatory asset will earn the company's rate of return, allow the company to institute annual spring filings for this process; and authorize the implementation of Schedule 56. The incremental annual revenue requested in the filing is $2,949,340, with a requested rate change effective date of June, 1, 2013, to coincide with other anticipated rate changes associated with the annual PCA and the annual FCA.

Energy Efficiency Rider—Prudence Determination of Expenditures

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15 with the IPUC requesting an order finding that the company had prudently incurred $42,641,706 (later adjusted to $42,641,361) in DSM expenses in 2011. This adjusted number included $35,622,976 in Idaho Rider expenses and $7,018,385 in Custom Efficiency program incentive expenses. The filing included three reports: *Demand-Side Management 2011 Annual Report*, *Supplement 1: Cost Effectiveness*, and *Supplement 2: Evaluation*. Supplement 2 included *NEEA Market Effects Evaluations*. In Final Order No. 32667, dated October 22, 2012, and Reconsideration Order No. 32690, dated December 11, 2012, the IPUC approved in part and denied in part Idaho Power's request. In these orders, the IPUC approved $42,468,904.50 in 2011 DSM expenditures, including $35,450,519.50 in Idaho Rider expenses and $7,018,385 in Custom Efficiency program incentives, as prudently incurred expenses. The IPUC disallowed the recovery of $82,855.50 for incentives paid to participants of the A/C Cool Credit program who did not receive a signal to cycle even though Idaho Power thought they were being cycled. In addition, the IPUC declined to decide the reasonableness of Idaho Power's 2011 Rider-funded, labor-related expense increase until the company provides further information.

Cost-Effectiveness and Funding of Low-Income Weatherization

On February 15, 2012, the IPUC issued a notice that opened Case No. GNR-E-12-01 and scheduled a public workshop from March 19 to 20, 2012. This case was initiated in part because both Rocky Mountain Power and Avista Utilities had recently conducted evaluations of their low-income programs and found them not to be cost effective. In 2012, Idaho Power began an evaluation of their low-income program. In addition, CAPAI asked the IPUC to increase funding for low-income programs in both Idaho Power's and Rocky Mountain Power's service areas. In this case, utilities, interested persons, and IPUC staff were to explore in greater detail issues related to the funding, implementation, and evaluation of utility low-income weatherization and energy conservation education programs. IPUC staff, utilities, CAPAI, and CAP agencies participated in the March workshop.

On October 23, 2012, IPUC staff issued their draft *Report on Low Income Weatherization and Energy Conservation Education Programs*. In this draft report, IPUC staff set out their suggested criteria for consideration when increased funding is being deliberated. IPUC staff also provided recommendations and comments on cost-effective calculations and procedures, as well as utility funding level considerations. Parties to the case, including the three Idaho investor-owned electric utilities, provided reply comments in November 2012. Idaho Power, in its comments, emphasized that low-income program funding should be based on the need exhibited by qualified weatherization customers. A proposed methodology was provided in Idaho Power's comments. On December 7, 2012, IPUC staff filed reply comments. An IPUC order is still anticipated in this case.

Demand Response Programs Suspension

On December 21, 2012, Idaho Power filed Case No. IPC-E-12-29, requesting a temporary suspension of two of its three demand response programs, A/C Cool Credit and Irrigation Peak Rewards. The temporary suspension was requested because the current load and resource balance being used to develop the 2013 IRP does not show a peak-hour deficit in the near term, making these programs unnecessary in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for these programs. The temporary suspension of the two demand response programs and their associated incentive payments would result in reduced costs for all Idaho Power customers in the form of a reduction in the 2013 to 2014 PCA that will be updated June 1, 2013. Before making this filing, Idaho Power convened a special meeting of EEAG on December 14, 2012, to review the issues and solicit member input. The group understood the rational for the filing; however, concerns were expressed about the impact on program participants and about how these program changes integrate in the IRP planning process. The temporary suspension of the programs requested in the filing will provide time to work with stakeholders on the redesign of the programs. The company requested the IPUC issue an order by March 1, 2013.

This page left blank intentionally.

CONTINUED COMMITMENT

Every year, Idaho Power enhances its commitment to provide DSM programs that offer broader opportunities for Idaho Power's customers to manage their energy and demand use. Idaho Power also continues its effort to make its own facilities more energy efficient and to find ways to promote energy efficiency in its communities and with its employees. A review of specific efforts is listed in the following sections.

Continued Expansion and Broad Availability of Energy Efficiency and Demand Response Programs

In 2012, Idaho Power broadened the marketing efforts and portfolio of programs offered to customers. Programs continue to add service areas where they are available to customers and continue to add new measures for customer participation. This expansion of programs and offerings helps ensure more customers each year have the opportunity to participate in programs. Some highlights for 2012 are as follows:

- Custom Efficiency awarded the single largest incentive in the program's history, on a chilled water economizer project designed to save approximately 10 million kWh annually.
- The See ya later, refrigerator® program reached a milestone when it picked up its 10,000th unit.
- In the education arena, the first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313.
- The network of participating contractors for the DHP Pilot expanded in 2012. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation trainings to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22-percent increase over 2011.
- The first biannual *Energy at Work* commercial newsletter was launched by the company. The goal of the newsletter is to provide pertinent and useful information to a customer segment with limited time.
- Idaho Power increased its use of online and social marketing, including an Easy Upgrades online advertising campaign and targeted behavioral advertisements on Facebook and Yahoo!.
- The Weatherization Solutions for Eligible Customers program expanded its service area into the Boise area through a new trade ally called Power Savers.
- In May 2012, Idaho Power issued its inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship.
- In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*.

Building-Code Improvement Activity

Since 2005, the State of Idaho has been on a cycle of adopting a state-specific version of the IECC. The most recent example of this was the adoption of the 2009 IECC that became effective in Idaho on January 1, 2011. The 2012 IECC was published in 2012, and the Idaho Building Code Board took public comments on whether or not to pursue a similar code update for Idaho based on the latest IECC. Idaho Power is participating in these ongoing meetings and monitoring the situation to assess where support may be offered. The Idaho Building Code Board has convened another Energy Codes Collaborative in 2013 to revise the current energy code in Idaho.

Idaho Power also contributed to the *Idaho Residential Energy Code Compliance* study commissioned by NEEA in 2012. This report is measuring Idaho's level of compliance with energy codes as required by the 2009 ARRA, which mandates that states receiving these funds achieve 90-percent compliance with target codes by 2017. The report describes the study of Idaho residential compliance with the amended version of the 2009 IECC. The report, included in *Supplement 2: Evaluation*, indicates a relatively high compliance by builders with the residential energy code in Idaho and suggests the overall 90-percent compliance rate has already been achieved, although some measures, such as wall insulation and lighting, are below that rate.

Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power continues to support a policy of gradually moving all customers into rates designed to reflect their cost of service, provide cost-based price signals, and encourage the wise and efficient use of energy.

On January 19, 2012, Idaho Power filed Tariff Advice No. 12-02 to expand Schedule 05, Time-of-Day Pilot Plan, to Idaho customers while at the same time suspend Schedule 04, Energy Watch plan. Idaho Power proposed to expand Energy Watch plan at a later time. Included in the Advice filing, which later became Case No. IPC-E-12-05, was a report titled *2012 Time-Variant Pricing (TVP) Implementation Plan*. The overall goal of this implementation plan was to "utilize the new AMI system to offer customers a choice of pricing plans while providing them with better tools to manage their energy usage, to provide the company with the opportunity to further study the effects of a time-variant rate on customers' usage, and to help shape the company's future communication efforts." The company also planned to evaluate the impact of this new rate plan on its revenues and costs. The Time-of-Day pricing structure was designed to send price signals to customers that more closely reflect the costs of serving those customers. The plan provides participants the opportunity to move their usage from higher-priced time periods to lower-priced time periods and possibly lower their bills. On March 27, 2012, the IPUC issued Order No. 32499 and approved the proposed changes to the tariffs and directed Idaho Power to file a report analyzing the *2012 TVP Implementation Plan* results to IPUC staff prior to further revising its TVP tariffs.

Idaho Power set up a study to determine changes in energy usage caused by changes in participants' behavior in response to the new rate structure. A target market was determined and, throughout spring and summer 2012, participants were solicited by a weekly direct-mail effort. Potential participants were encouraged to visit Idaho Power's website (http://www.idahopower.com/TOD) to evaluate their usage under the different plan options and to make an educated decision regarding which plan was best for them. Over 126,000 customers were solicited. The direct-mail solicitation process ended in September. As of the end of 2012, over 1,500 customers signed up to become Time-of-Day plan participants. Through late 2012 and early 2013, Idaho Power will evaluate initial study findings and will file its report with the IPUC in spring 2013.

Third-Party, Independent Verification

Idaho Power recognizes that the timely, credible, and transparent evaluation of all its DSM programs is critical in ensuring maximum program performance and the accurate reporting of program energy savings. Third-party contractors are used to provide primary research and impact, process, and market evaluations. These evaluations and research help ensure programs are being administered effectively and best-practice specifications are met. Reports from these evaluations provide valuable recommendations for program improvement and validate energy savings achieved through the company's DSM programs.

In 2012, impact evaluations were completed by third-party contractors on the following six DSM programs: Building Efficiency; Easy Upgrades; H&CE Program; See ya later, refrigerator®; Weatherization Solutions for Eligible Customers; and WAQC. A process evaluation was completed for the A/C Cool Credit program. Primary research was conducted on the Irrigation Efficiency Rewards and A/C Cool Credit programs. Copies of the reports can be found in *Supplement 2: Evaluation*.

In addition, Idaho Power uses third-party contractors to perform QA and OSVs for most programs. The H&CE Program, Home Improvement Program, ENERGY STAR® Homes Northwest, Easy Upgrades, and Building Efficiency programs use third-party contractors to perform QA or OSVs on approximately 10 percent of completed customer projects. The Energy House Calls and WAQC programs contract with third-party experts to perform QA analyses on approximately 5 percent of customer completed projects.

Throughout 2012, Idaho Power participated with NEEA to conduct several third-party assessments. These studies included the Residential Building Stock Assessment, an evaluation of the Northwest DHP Initiative, assessment of four Residential Consumer Electronics products, and several market effects evaluations in the residential, commercial, and industrial sectors. Copies of these reports can be found in *Supplement 2: Evaluation*.

The company also funds and participates in the RTF. The RTF is an advisory committee that was created in 1999 to develop regional standards and for the establishment of deemed savings derived from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information regarding energy efficiency programs and measures and uses the RTF databases to provide deemed-savings estimates for many of the energy efficiency measures implemented as part of the company's DSM programs.

It is anticipated that in 2013, Idaho Power will contract with third-party evaluators to complete process evaluations for the Energy Efficient Lighting, ENERGY STAR Homes Northwest, H&CE Program, Weatherization Solutions for Eligible Customers, WAQC, Easy Upgrades, and FlexPeak Management programs. The *2010–2013 Evaluation Plan* can be found in *Supplement 2: Evaluation*.

Energy Efficiency Potential Study

Idaho Power contracted with EnerNOC Utility Solutions Consulting (EnerNOC Solutions) to provide an analysis of the technical, economic, and achievable energy efficiency over the next 20 years in the company's service area. In addition, EnerNOC Solutions provided an executable dynamic model that supports the potential study and allows for the testing of sensitivity. EnerNOC Solutions also updated load profiles by sector, program, and end use. Because of their disproportionate energy use, special-contract customer potential was analyzed separately. The achievable energy efficiency potential by sector is shown as follows:

- Residential achievable potential projects: 189,469 MWh in 2017, or approximately 21.6 aMW. This level of potential is equivalent to 3.5 percent of the residential baseline projection for that year. By 2032, the cumulative achievable projection savings are 701,104 MWh, 10.8 percent of the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Commercial achievable potential projects: 194,418 MWh, or approximately 22.2 aMW, of energy savings in 2017, which corresponds to 5.2 percent of the commercial baseline projection for that year. By 2032, the cumulative achievable projection savings are 633,771 MWh, 13.9 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Industrial achievable potential projects: 174,526 MWh, or approximately 19.9 aMW, of energy savings in 2017, which corresponds to 18 percent of the industrial baseline projection for that year. By 2032, the cumulative achievable projection savings are 488,465 MWH, 12.8 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Irrigation achievable potential projects: 36,360 MWh, or approximately 4.2 aMW, of energy savings in 2017, which corresponds to 6.8 percent of the irrigation baseline projection for that year. By 2032, the cumulative achievable projection savings are 229,821 MWh, 11.3 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

Achievable potential across the residential, commercial, industrial, and irrigation sectors is projected to be 594,772 MWh, or 67.9 aMW, in 2017 and increases to 234.4 aMW by 2032. This represents 4.3 percent of the baseline projection in 2017 and 12.2 percent in 2032. By 2032, achievable potential offsets 12.2 percent of the growth in the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, providing incentives, and educating its customers.

At the annual shareholders meeting held in May 2012, IDACORP, Inc., and Idaho Power issued the inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship. The sustainability report featured articles highlighting the company's long-standing commitment to operating in a sustainable manner, including groundbreaking raptor protection programs and innovative methods to gather and analyze data in waterways supporting company operations. IDACORP plans to issue its second sustainability report in May 2013.

The Idaho Power Green Team championed sustainable activities conducted by Idaho Power and its employees. In 2012, projects included coordinating monthly Green Bag educational seminars, supporting company-wide alternative transportation efforts, and implementing a project at the company café to compost the organic portion of its wastes.

Idaho Power's corporate headquarters (CHQ) continued to participate in the strategic elimination of power loads during peak use through the FlexPeak Management program. In August 2010, Idaho Power entered into an agreement with EnerNOC, Inc., to enroll the CHQ in FlexPeak Management—Idaho Power's commercial/industrial demand response program. EnerNOC enlists and contracts with Idaho Power's commercial and industrial customers to voluntarily reduce their electricity use primarily during times of Idaho Power system peaks. EnerNOC provides participants with auditing assistance, energy-monitoring software, demand-reduction performance monitoring, coaching, and other related services. EnerNOC works closely with its program participants to estimate their reduction potential accurately. Unlike other program participants, Idaho Power does not receive any financial incentives to participate.

In 2012, Idaho Power committed to reduce its electrical consumption by 100 kW during demand-reduction events. The CHQ participated in all four of the FlexPeak events, which were initiated in June, July, and August. The average reduction achieved by the facility across the four events was 425 kW. The CHQ exceeded the committed reduction in all events. The maximum hourly reduction was 775 kW, achieved in July. Reductions were mostly obtained by turning off lights, adjusting A/C set-points, decreasing fan speeds, and curtailing elevator use. The facility reduction plan in place could be executed at any time to reduce electricity use if necessary.

In 2012, Idaho Power began an aggressive lighting retrofit in several of its facilities. This included upgraded lighting at eight of its hydroelectric power plants, the CHQ building, and two operations centers. Total projected first-year electrical savings were approximately 562,100 kWh. These savings should continue for 10 to 12 years.

Changes at the power plants included replacing magnetic ballasts and T-12 lamps with more efficient electronic ballasts and T-8 lamps. At the Hells Canyon Dam, external mercury vapor fixtures were replaced with LED fixtures.

Energy-efficient T-8 lighting was installed in all of the CHQ's hallways, basement, loading dock, stairwells, restrooms, coffee rooms, copy rooms, first/second floor light wall, electrical rooms, data rooms, and penthouse. Efficient electronic ballasts and lamps replaced the inefficient magnetic ballasts and lamps. Wall-, ceiling-, or fixture-mounted occupancy sensors were installed as appropriate. Halogen art display fixtures were retrofitted with LED lamps. In elevator shafts and pump rooms, CFLs replaced incandescent lamps.

The lighting retrofit and space remodel at the Payette Operations Center continued during 2012 with the removal of T-12 lighting, installation of T-8 lighting retrofit packages, and a decrease in cubicle heights to 53 inches for improved natural lighting. In addition, the Boise Center West (BCW) project installed dimmable LED lighting fixtures throughout the new data center.

In 2013, the BCW project will incorporate several energy-efficient attributes. Plans include using indirect clerestory windows, placing Dyson hand-insertion electric air dryers and water-saving features within the restrooms.

During 2012, planning continued for the 2013 installation of a new energy-efficient chilled water system for the CHQ. Although remodeling of the CHQ (carpets, blinds, lighting upgrade, paint, and new lowered cube height) was postponed for one year, the company anticipates continuing this project through 2016. Sub-station lighting retrofits were initiated in 2012 and will continue to be a focal point through at least 2020.

This page left blank intentionally.

APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2012, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders, Idaho Custom Efficiency incentive payments, and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency and demand response programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2012. Appendix 4 shows similar data as Appendix 3 but also includes data for past years' program performance and B/C ratios from the utility and TRC perspectives for active programs. Appendix 5 contains program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. In these appendices, the data has been rounded to the nearest whole unit, which may result in minor rounding differences.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost-effectiveness information by program and energy-savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The *2012 DSM Detailed Expenses by Program* table reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of Idaho Power's third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information are included with each supplement.

This page left blank intentionally.

Appendix 1. Idaho Rider, Oregon Rider, Idaho Custom Efficiency, and NEEA funding balances

Idaho Energy Efficiency Rider		
2012 Beginning Balance	$	(5,321,997)
2012 Funding plus Accrued Interest		35,101,807
Total 2012 Funds		**29,779,810**
2012 Expenses		(25,822,044)
2011 AC Cool Credit Disallowance		82,856
2012 Year-End Balance	**$**	**4,040,622**
Oregon Energy Efficiency Rider		
2012 Beginning Balance	$	(3,537,441)
2012 Funding plus Accrued Interest		1,004,836
Total 2012 Funds		**(2,532,605)**
2012 Expenses		(1,382,330)
2012 Year-End Balance	**$**	**(3,914,935)**
Idaho Custom Efficiency Incentives		
2012 Beginning Balance Accrued Incentives	$	(7,018,385)
2012 Beginning Balance Accrued Interest		(212,339)
2012 Total Beginning Balance	**$**	**(7,230,724)**
2012 Incentives Accrued		(6,019,222)
2012 Interest Accrued		(836,255)
2012 Year-End Balance	**$**	**(14,086,201)**
NEEA Payments and Escrow Credit Funds Balance		
2012 Idaho Power Contractual Obligation[a]	$	3,379,756
2012 Year-End Balance	**$**	**3,379,756**

[a] Idaho Power shall prepay estimated expenses quarterly, where the amount shall be amortized over the respective quarter. Funding of NEEA, approved by IPUC Order 31080 dated 5/12/10. Reconciliation between the estimated expenditures and the actual expenditures for the quarter will be completed 30 days after the quarter end or by March 1 for year-end. A true-up of the variance will be included in the next quarter’s invoice, not to exceed 125 percent of its five-year total direct-funding contribution.

Appendix 2. 2012 DSM expenses by funding source (dollars)

Sector/Program	Idaho Rider	Oregon Rider	Idaho Power	Total Program
Energy Efficiency/Demand Response				
Residential				
A/C Cool Credit[a]	$ 4,804,566	$ 92,810	$ 830,618	**$ 5,727,994**
Ductless Heat Pump Pilot	153,017	6,850	0	**159,867**
Energy Efficient Lighting	1,110,329	16,507	0	**1,126,836**
Energy House Calls	272,666	3,217	0	**275,884**
ENERGY STAR® Homes	450,727	2,458	0	**453,186**
Heating & Cooling Efficiency Program	175,483	6,798	0	**182,281**
Home Improvement Program	385,091	0	0	**385,091**
Home Products Program	640,098	18,829	105	**659,032**
Oregon Residential Weatherization	0	4,051	465	**4,516**
Rebate Advantage	34,926	2,316	0	**37,241**
See Ya Later Refrigerator	596,167	16,979	0	**613,146**
Weatherization Assistance for Qualified Customers	0	0	1,370,141	**1,370,141**
Weatherization Solutions for Eligible Customers	1,048,461	0	22,094	**1,070,556**
Commercial/Industrial				
Building Efficiency	1,579,121	13,451	0	**1,592,572**
Comprehensive Lighting	64,094	0	0	**64,094**
Easy Upgrades	5,150,422	199,331	0	**5,349,753**
FlexPeak Management[a]	98,973	150,489	2,760,360	**3,009,822**
Oregon Commercial Audit	0	12,470	0	**12,470**
Custom Efficiency[b]	923,050	115,866	6,053,665	**7,092,581**
Irrigation				
Irrigation Efficiency Rewards	1,978,729	360,689	33,782	**2,373,201**
Irrigation Peak Rewards[a]	1,309,107	95,863	11,018,394	**12,423,364**
Energy Efficiency/Demand Response Total	**$ 20,775,027**	**$ 1,118,975**	**$ 22,089,624**	**$ 43,983,625**
Market Transformation				
NEEA[c]	3,210,768	168,988	0	**3,379,756**
Market Transformation Total	**$ 3,210,768**	**$ 168,988**	**$ 0**	**$ 3,379,756**
Other Programs and Activities				
Residential				
Residential Economizer Pilot[d]	93,593	(101)	0	**93,491**
Residential Energy Efficiency Education Initiative	165,919	8,819	0	**174,738**
Commercial				
Commercial Energy Efficiency Education Initiative	70,099	3,689	0	**73,788**
Other				
Energy Efficiency Direct Program Overhead	271,622	14,329	0	**285,951**
Other Programs and Activities Total	**$ 601,233**	**$ 26,736**	**$ 0**	**$ 627,968**
Indirect Program Expenses				
Residential Overhead	172,819	9,051	0	**181,869**
Commercial/Industrial/Irrigation Overhead	171,673	9,096	7,784	**188,554**
Energy Efficiency Accounting and Analysis	898,944	47,050	142,241	**1,088,236**
Energy Efficiency Advisory Group	2,710	142	0	**2,853**
Special Accounting Entries[e]	(93,985)	2,291	(34,308)	**(126,002)**
Indirect Program Expenses Total	**$ 1,152,161**	**$ 67,631**	**$ 115,718**	**$ 1,335,509**
Totals	**$ 25,739,188**	**$ 1,382,330**	**$ 22,205,341**	**$ 49,326,859**

[a] Per order 32426 the IPUC determined that IPC may recover 100 percent of its Idaho demand response incentives through the PCA mechanism.
[b] Idaho Custom Efficiency incentives, Idaho Power balance of $6,053,665, not included in base rates for 2012.
[c] NEEA Funding addressed in IPUC per Order No. 31080, dated May 12, 2010. 2013 annual expense expected at $3.8 million (see footnote, Appendix 1 for additional information).
[d] Residential Economizer 2011 Oregon Rider balance of $101 was reclassified to Idaho Rider in 2012.
[e] Special Accounting Entries, Idaho Power accrual amount of ($34,146), not included in base rates for 2012.

Appendix 3. 2012 DSM program activity

		Total Costs		Savings			Nominal Levelized Costs[a]	
Program	Participants	Utility[b]	Resource[c]	Annual Energy (kWh)	Peak Demand[d] (MW)	Measure Life (Years)	Utility ($/kWh)	Total Resource ($/kWh)
Demand Response								
A/C Cool Credit	36,454 homes	$ 5,727,994	$ 5,727,994	n/a	44.9	n/a	n/a	n/a
Irrigation Peak Rewards[1]	2,177 service points	12,423,364	12,423,364	n/a	339.9	n/a	n/a	n/a
FlexPeak Management	102 sites	3,009,822	3,009,822	n/a	52.8	n/a	n/a	n/a
Total		**$ 21,161,180**	**$ 21,161,180**	**n/a**	**437.6**			
Energy Efficiency								
Residential								
Ductless Heat Pump Pilot	127 homes	159,867	617,833	444,500		20	$ 0.024	$ 0.094
Energy Efficient Lighting	925,460 bulbs	1,126,836	2,407,355	16,708,659		5	0.012	0.025
Energy House Calls	668 homes	275,884	275,884	1,192,039		18	0.016	0.016
ENERGY STAR® Homes Northwest	410 homes	453,186	871,310	537,447		35	0.046	0.089
Heating & Cooling Efficiency Program	141 projects	182,281	676,530	688,855		20	0.018	0.066
Home Improvement Program	840 insulation projects	385,091	812,827	457,353		45	0.044	0.093
Home Products Program	16,675 appliances/fixtures	659,032	817,924	887,222		14	0.061	0.075
Oregon Residential Weatherization	5 home	4,516	11,657	11,985		30	0.022	0.022
Rebate Advantage	35 homes	37,241	71,911	187,108		25	0.012	0.024
See ya later, refrigerator®	3,176 refrigerators/freezers	613,146	613,146	1,576,426		8	0.046	0.046
Weatherization Assistance for Qualified Customers	238 homes/non-profits	1,370,141	1,819,945	648,304		25	0.129	0.172
Weatherization Solutions for Eligible Customers	141 homes	1,070,556	1,070,556	257,466		25	0.254	0.254
Sector Total		**$ 6,337,777**	**$ 10,066,879**	**23,597,363**		**9**	**$ 0.029**	**$ 0.046**
Commercial								
Building Efficiency	84 projects	1,592,572	8,204,883	20,450,037	2.3	12	0.007	0.036
Easy Upgrades	1,838 projects	5,349,753	9,245,297	41,568,672	4.7	12	0.012	0.020
Oregon Commercial Audits	14 audits	12,470	12,470					
Sector Total		**$ 6,954,795**	**$ 17,462,650**	**62,018,709**	**7.1**	**12**	**$ 0.010**	**$ 0.025**
Industrial								
Custom Efficiency[2]	126 projects	7,092,581	12,975,629	54,253,106	7.6	12	0.012	0.021
Sector Total		**$ 7,092,581**	**$ 12,975,629**	**54,253,106**	**7.6**	**12**	**$ 0.012**	**$ 0.021**
Irrigation								
Irrigation Efficiency Rewards[3]	908 projects	2,373,201	11,598,185	12,617,164	3.1	8	0.022	0.110
Sector Total		**$ 2,373,201**	**$ 11,598,185**	**12,617,164**	**3.1**	**8**	**$ 0.022**	**$ 0.110**

Appendix 3. 2012 DSM program activity (continued)

		Total Costs		Savings			Nominal Levelized Costs[a]	
Program	Participants	Utility[b]	Resource[c]	Annual Energy (kWh)	Peak Demand[d] (MW)	Measure Life (Years)	Utility ($/kWh)	Total Resource ($/kWh)
Market Transformation								
Northwest Energy Efficiency Alliance[4]		$ 3,379,756	$ 3,379,756	17,741,430				
Other Programs and Activities								
Residential								
Residential Economizer		93,491	93,491					
Residential Energy Efficiency Education Initiative		174,738	174,738					
Commercial								
Commercial Education Initiative		73,788	73,788					
Comprehensive Lighting[5]		64,094	64,094					
Other								
Energy Efficiency Direct Program Overhead		285,951	285,951					
Local Energy Efficiency Funds								
Total Program Direct Expense		**$ 47,991,350**	**$ 77,336,341**	**170,227,773**	**455.3**			
Indirect Program Expenses		1,335,509						
Total DSM Expense		**$ 49,326,859**						

[a] Levelized Costs are based on financial inputs from Idaho Power's 2011 IRP and calculations include line-loss adjusted energy savings.
[b] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.
[c] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
[d] Summer Peak Demand is reported where program MW reduction is documented. Demand response program reductions are reported with 13-percent peak loss assumptions.
[1] Peak demand represents enrolled capacity of the program during summer 2012.
[2] Custom Efficiency savings includes 19 Green Motors participants totaling 54,154 kWh of annual savings, but not in project totals.
[3] Irrigation Efficiency includes 23 Green Motors participants totaling 36,039 kWh of annual savings, not counted in project totals.
[4] Savings are preliminary estimates provided by NEEA.
[5] Comprehensive Lighting annual savings of 447,620 kWh from 6 projects are included in Easy Upgrades savings totals. For the combined cost-effectiveness analysis, see Easy Upgrades in Supplement 1.

Appendix 4. Historical DSM expense and performance 2002–2012

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Demand Response											
A/C Cool Credit											
2003	204	$ 275,645	$ 275,645			0.0					
2004	420	287,253	287,253			0.5					
2005	2,369	754,062	754,062			3.1					
2006	5,369	1,235,476	1,235,476			6.3					
2007	13,692	2,426,154	2,426,154			12.2					
2008	20,195	2,969,377	2,969,377			25.5					
2009	30,391	3,451,988	3,451,988			38.5					
2010	30,803	2,002,546	2,002,546			39.0					
2011	37,728	2,896,542	2,896,542			24.0					
2012	36,454	5,727,994	5,727,994			44.9					
Total		**$ 22,027,036**	**$ 22,027,036**							**1.33**	**1.33**
FlexPeak Management											
2009	33	528,681	528,681			19.3					
2010	60	1,902,680	1,902,680			47.5					
2011	111	2,057,730	2,057,730			58.8					
2012	102	3,009,822	3,009,822			52.8					
Total		**$ 7,498,913**	**$ 7,498,913**							**1.22**	**1.22**
Irrigation Peak Rewards											
2004	58	344,714	344,714			5.6					
2005	894	1,468,282	1,468,282			40.3					
2006	906	1,324,418	1,324,418			31.8					
2007	947	1,615,881	1,615,881			37.4					
2008	897	1,431,840	1,431,840			35.1					
2009	1,512	9,655,283	9,655,283			160.2					
2010	2,038	13,330,826	13,514,246			249.7					
2011	2,342	12,086,222	12,086,222			320.0					
2012	2,433	12,423,364	12,423,364			339.9					
Total		**$ 53,680,830**	**$ 53,864,250**							**1.79**	**1.72**

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Residential Efficiency											
Ductless Heat Pump Pilot											
2009	96	$ 202,005	$ 451,605	409,180	0.05		18	$ 0.031	$ 0.086		
2010	104	189,231	439,559	364,000	0.04		20	0.044	0.103		
2011	131	191,183	550,033	458,500	0.05		20	0.028	0.081		
2012	127	159,867	617,833	444,500	0.05		20	0.024	0.094		
Total	**458**	**$ 742,286**	**$ 2,059,030**	**1,676,180**			**20**	**$ 0.036**	**$ 0.105**	**4.22**	**1.44**
Energy Efficiency Packets											
2002	2,925	755	755	155,757	0.02		7	0.001	0.001		
Total	**2,925**	**$ 755**	**$ 755**	**155,757**			**7**	**$ 0.001**	**$ 0.001**		
Energy Efficient Lighting											
2002	11,618	243,033	310,643	3,299,654	0.38		7	0.012	0.015		
2003	12,662	314,641	464,059	3,596,150	0.41		7	0.014	0.021		
2004											
2005	43,760	73,152	107,810	1,734,646	0.20		7	0.007	0.010		
2006	178,514	298,754	539,877	6,302,794	0.72		7	0.008	0.014		
2007	219,739	557,646	433,626	7,207,439	0.82		7	0.012	0.017		
2008	436,234	1,018,292	793,265	14,309,444	1.63		7	0.011	0.013		
2009	549,846	1,207,366	1,456,796	13,410,748	1.53		5	0.020	0.024		
2010	1,190,139	2,501,278	3,976,476	28,082,738	3.21		5	0.020	0.031		
2011	1,039,755	1,719,133	2,764,623	19,694,381	2.25		5	0.015	0.024		
2012	925,460	1,126,836	2,407,355	16,708,659	1.91		5	0.012	0.025		
Total	**4,607,727**	**$ 9,060,131**	**$ 13,254,530**	**114,346,653**		**0.0**	**5**	**$ 0.017**	**$ 0.025**	**4.47**	**3.05**
Energy House Calls											
2002	17	26,053	26,053	25,989	0.00		20	0.082	0.082		
2003	420	167,076	167,076	602,723	0.07		20	0.023	0.023		
2004	1,708	725,981	725,981	2,349,783	0.27		20	0.025	0.025		
2005	891	375,610	375,610	1,775,770	0.20		20	0.017	0.017		
2006	819	336,701	336,701	777,244	0.09		20	0.035	0.035		
2007	700	336,372	336,372	699,899	0.08		20	0.039	0.039		
2008	1,099	484,379	484,379	883,038	0.10		20	0.045	0.045		
2009	1,266	569,594	569,594	928,875	0.11		20	0.052	0.052		

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	**Participants**	**Utility Cost[c]**	**Resource Cost[d]**	**Annual Energy (kWh)**	**Average Energy[e] (aMW)**	**Peak Demand[f] (MW)**	**Measure Life (Years)**	**Total Utility ($/kWh)**	**Total Resource ($/kWh)**	**Utility**	**Total Resource**
Residential Efficiency											
Energy House Calls											
2010	1,602	$ 762,330	$ 762,330	1,198,655	0.14		20	$ 0.054	$ 0.054		
2011	881	483,375	483,375	1,214,004	0.14		20	0.027	0.027		
2012	668	275,884	275,884	1,192,039	0.14		18	0.016	0.016		
Total	**10,071**	**$ 4,543,355**	**$ 4,543,355**	**11,648,019**			**18**	**$ 0.034**	**$ 0.034**	**3.05**	**3.05**
ENERGY STAR® Homes Northwest											
2003		13,597	13,597	0							
2004	44	140,165	335,437	101,200	0.01	0.1	25	0.103	0.246		
2005	200	253,105	315,311	415,600	0.05	0.4	25	0.045	0.056		
2006	439	469,609	602,651	912,242	0.10	0.9	25	0.038	0.049		
2007	303	475,044	400,637	629,634	0.07	0.6	25	0.056	0.047		
2008	254	302,061	375,007	468,958	0.05	0.6	25	0.048	0.059		
2009	474	355,623	498,622	705,784	0.08	1.1	25	0.039	0.055		
2010	630	375,605	579,495	883,260	0.10		25	0.033	0.051		
2011	308	259,762	651,249	728,030	0.08		32	0.020	0.051		
2012	410	453,186	871,310	537,447	0.06		35	0.046	0.089		
Total	**3,062**	**$ 3,097,757**	**$ 4,643,317**	**5,382,155**			**35**	**$ 0.039**	**$ 0.058**	**3.77**	**2.51**
Heating & Cooling Efficiency Program											
2006		17,444	17,444								
2007	4	488,211	494,989	1,595	0.00		18	27.344	27.710		
2008	359	473,551	599,771	561,440	0.06		18	0.073	0.092		
2009	349	478,373	764,671	1,274,829	0.15		18	0.034	0.054		
2010	217	327,669	1,073,604	1,104,497	0.13		20	0.025	0.083		
2011	130	195,770	614,523	733,405	0.08		20	0.018	0.056		
2012	141	182,281	676,530	688,855	0.08		20	0.018	0.066		
Total	**1,200**	**$ 2,163,300**	**$ 4,241,532**	**4,364,621**			**20**	**$ 0.041**	**$ 0.080**	**3.49**	**1.78**

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]		
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource	
Residential Efficiency												
Home Improvement Program												
2008	282	$ 123,454	$ 157,866	317,814	0.04		25	$ 0.029	$ 0.037			
2009	1,188	321,140	550,148	1,338,876	0.15		25	0.019	0.032			
2010	3,537	944,716	2,112,737	3,986,199	0.46		45	0.016	0.035			
2011	2,275	666,041	2,704,816	917,519	0.10		45	0.038	0.155			
2012	840	385,091	812,827	457,353	0.05		45	0.044	0.093			
Total	**8,122**	**$ 2,440,442**	**$ 6,338,394**	**7,017,761**			**45**	**$ 0.022**	**$ 0.058**	**3.15**	**1.21**	2
Home Products Program												
2007		9,275	9,275	0								
2008	3,034	250,860	468,056	541,615	0.06		15	0.044	0.082			
2009	9,499	511,313	844,811	1,638,038	0.19		15	0.031	0.051			
2010	16,322	832,161	1,025,151	1,443,580	0.16		15	0.057	0.070			
2011	15,896	638,323	1,520,977	1,485,326	0.17		15	0.034	0.080			
2012	16,675	659,032	817,924	887,222	0.10		14	0.061	0.075			
Total	**61,426**	**$ 2,900,964**	**$ $4,686,194**	**5,995,781**			**14**	**$ 0.048**	**$ 0.078**	**2.26**	**1.40**	
Oregon Residential Weatherization												
2002	24	(662)	23,971	4,580			25	0.010	0.389			
2003		(943)										3
2004	4	1,057	1,057									
2005	4	612	3,608	7,927	0.00		25	0.006	0.034			
2006		4,126	4,126									4
2007	1	3,781	5,589	9,971	0.00		25	0.028	0.042			
2008	3	7,417	28,752	22,196	0.00		25	0.025	0.096			
2009	1	7,645	8,410	2,907	0.00		25	0.203	0.223			
2010	1	6,050	6,275	320	0.00		30	0.011	0.062			
2011	8	7,926	10,208	21,908	0.00		30	0.021	0.027			
2012	5	4,516	11,657	11,985	0.00		30	0.022	0.056			
Total	**51**	**$ 41,525**	**$ 103,653**	**81,794**			**30**	**$ 0.036**	**$ 0.089**	**3.88**	**1.55**	5

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Residential Efficiency											
Rebate Advantage											
2003	73	$ 27,372	$ 79,399	227,434	0.03		45	$ 0.008	$ 0.022		
2004	105	52,187	178,712	332,587	0.04		45	0.010	0.034		
2005	98	46,173	158,462	312,311	0.04		45	0.009	0.032		
2006	102	52,673	140,289	333,494	0.04		45	0.010	0.027		
2007	123	89,269	182,152	554,018	0.06		45	0.010	0.021		
2008	107	90,888	179,868	463,401	0.05		45	0.012	0.025		
2009	57	49,525	93,073	247,348	0.03		25	0.015	0.029		
2010	35	39,402	66,142	164,894	0.02		25	0.018	0.031		
2011	25	63,469	85,044	159,325	0.02		25	0.024	0.033		
2012	35	37,241	71,911	187,108	0.02		25	0.012	0.024		
Total	**760**	**$ 548,199**	**$ 1,235,052**	**2,981,920**			**25**	**$ 0.014**	**$ 0.031**	**8.71**	**3.87**
See ya later, refrigerator®											
2009	1,661	305,401	305,401	1,132,802	0.13		8	0.041	0.041		
2010	3,152	565,079	565,079	1,567,736	0.18		8	0.054	0.054		
2011	3,449	654,393	654,393	1,712,423	0.20		8	0.046	0.046		
2012	3,176	613,146	613,146	1,576,426	0.18		8	0.046	0.046		
Total	**11,438**	**$ 2,138,019**	**$ 2,138,019**	**5,989,387**			**8**	**$ 0.052**	**$ 0.052**	**1.70**	**1.70**
Weatherization Solutions for Eligible Customers											
2008	16	52,807	52,807	71,680	0.01		25	0.057	0.057		
2009	41	162,995	162,995	211,719	0.02		25	0.059	0.059		
2010	47	228,425	228,425	313,309	0.04		25	0.056	0.056		
2011	117	788,148	788,148	1,141,194	0.13		25	0.042	0.042		
2012	141	1,070,556	1,070,556	257,466	0.03		25	0.254	0.254		
Total	**362**	**$ 2,302,931**	**$ 2,302,931**	**1,995,368**			**25**	**$ 0.086**	**$ 0.086**	**1.47**	**1.47**
Window AC Trade-Up Pilot											
2003	99	6,687	10,492	14,454			12	0.051	0.079		
Total	**99**	**$ 6,687**	**$ 10,492**	**14,454**			**12**	**$ 0.051**	**$ 0.079**		

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	**Participants**	**Utility Cost[c]**	**Resource Cost[d]**	**Annual Energy (kWh)**	**Average Energy[e] (aMW)**	**Peak Demand[f] (MW)**	**Measure Life (Years)**	**Total Utility ($/kWh)**	**Total Resource ($/kWh)**	**Utility**	**Total Resource**
Residential—Weatherization Assistance for Qualified Customers (WAQC)											
WAQC—Idaho											
2002	197	$ 235,048	$ 492,139								
2003	208	228,134	483,369								
2004	269	498,474	859,482	1,271,677	0.15		25	$ 0.0290	$ 0.050		
2005	570	1,402,487	1,927,424	3,179,311	0.36		25	0.0330	0.045		
2006	540	1,455,373	2,231,086	2,958,024	0.34		25	0.0370	0.056		
2007	397	1,292,930	1,757,105	3,296,019	0.38		25	0.0290	0.040		
2008	439	1,375,632	1,755,749	4,064,301	0.46		25	0.0250	0.032		
2009	427	1,260,922	1,937,578	4,563,832	0.52		25	0.0210	0.033		
2010	373	1,205,446	2,782,597	3,452,025	0.39		25	0.0260	0.060		
2011	273	1,278,112	1,861,836	2,648,676	0.30		25	0.0360	0.053		
2012	228	1,321,927	1,743,863	621,464	0.02		25	0.1590	0.210		
Total	**3,921**	**$ 11,554,485**	**$ 17,832,228**	**26,055,329**			**25**	**$ 0.0330**	**$ 0.051**	**4.36**	**2.83**
WAQC—Oregon											
2002	31	24,773	47,221	68,323	0.01		25	0.0270	0.051		
2003	29	22,255	42,335	102,643	0.01		25	0.0160	0.031		
2004	17	13,469	25,452	28,436	0.00		25	0.0350	0.067		
2005	28	44,348	59,443	94,279	0.01		25	0.0350	0.047		
2006							25				
2007	11	30,694	41,700	42,108	0.00		25	0.0540	0.074		
2008	14	43,843	74,048	73,841	0.01		25	0.0400	0.068		
2009	10	33,940	46,513	114,982	0.01		25	0.0230	0.031		
2010	27	115,686	147,712	289,627	0.03		25	0.0300	0.038		
2011	14	46,303	63,981	134,972	0.02		25	0.0260	0.035		
2012	10	48,214	76,083	26,840	0.00		25	0.1340	0.212		
Total	**191**	**$ 423,525**	**$ 624,488**	**976,051**			**25**	**$ 0.0323**	**$ 0.048**	**4.26**	**2.89**
WAQC—BPA Supplemental											
2002	75	55,966	118,255	311,347	0.04		25	0.0130	0.028		
2003	57	49,895	106,915	223,591	0.03		25	0.0170	0.036		
2004	40	69,409	105,021	125,919	0.01		25	0.0410	0.062		
Total	**172**	**$ 175,270**	**$ 330,191**	**660,857**			**25**	**$ 0.0200**	**$ 0.037**	**6.73**	**3.57**
WAQC—All Total		**$ 12,153,280**	**$ 18,786,907**	**27,692,237**			**25**	**0.0330**	**0.051**	**4.39**	**2.84**

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Commercial											
Air Care Plus Pilot											
2003	4	$ 5,764	$ 9,061	33,976			10	$ 0.021	$ 0.033		
2004		344	344								
Total	**4**	**$ 6,108**	**$ 9,405**	**33,976**			**10**	**$ 0.022**	**$ 0.034**		
Building Efficiency Program											
2004		28,821	28,821								
2005	12	194,066	233,149	494,239	0.06	0.2	12	0.043	0.052		
2006	40	374,008	463,770	704,541	0.08	0.3	12	0.058	0.072		
2007	22	669,032	802,839	2,817,248	0.32	0.5	12	0.015	0.040		
2008	60	1,055,009	1,671,375	6,598,123	0.75	1.0	12	0.017	0.028		
2009	72	1,327,127	2,356,434	6,146,139	0.70	1.3	12	0.024	0.043		
2010	70	1,509,682	3,312,963	10,819,598	1.24	0.9	12	0.016	0.035		
2011	63	1,291,425	3,320,015	11,514,641	1.31	0.9	12	0.010	0.026		
2012	84	1,592,572	8,204,883	20,450,037	2.33	0.6	12	0.007	0.036		
Total	**423**	**$ 8,041,743**	**$ 20,394,250**	**59,544,566**			**12**	**$ 0.015**	**$ 0.038**	**6.50**	**2.56**
Easy Upgrades											
2006		31,819	31,819								
2007	104	711,494	1,882,035	5,183,640	0.59	0.8	12	0.015	0.040		
2008	666	2,992,261	10,096,627	25,928,391	2.96	4.5	12	0.013	0.043		
2009	1,224	3,325,505	10,076,237	35,171,627	4.02	6.1	12	0.011	0.032		
2010	1,535	3,974,410	7,655,397	35,824,463	4.09	7.8	12	0.013	0.024		
2011	1,732	4,719,466	9,519,364	38,723,073	4.42	4.4	12	0.011	0.022		
2012	1,838	5,349,753	9,245,297	41,568,672	4.75	4.8	12	0.012	0.020		
Total	**7,099**	**$ 21,104,708**	**$ 48,506,776**	**182,399,866**			**12**	**$ 0.013**	**$ 0.029**	**7.57**	**3.29**
Holiday Lighting											
2008	14	28,782	73,108	259,092	0.03		10	0.014	0.035		
2009	32	33,930	72,874	142,109	0.02		10	0.031	0.066		
2010	25	46,132	65,308	248,865	0.03		10	0.024	0.034		
2011	6	2,568	2,990	66,189	0.01		10	0.004	0.005		
Total	**77**	**$ 111,412**	**$ 214,280**	**716,255**			**10**	**$ 0.019**	**$ 0.037**	**3.70**	**1.92**

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]		
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource	
Commercial												
Oregon Commercial Audit												
2002	24	$ 5,200	$ 5,200									
2003	21	0	4,000									
2004	7	0	0									
2005	7	5,450	5,450									
2006	6											
2007		1,981	1,981									
2008		58	58									
2009	41	20,732	20,732									
2010	22	5,049	5,049									
2011	12	13,597	13,597									
2012	14	12,470	12,470									
Total	**154**	**$ 64,537**	**$ 68,537**									7
Oregon School Efficiency												
2005		86	86									
2006	6	24,379	89,771	223,368	0.03		12	$ 0.012	$ 0.044			
Total	**6**	**$ 24,465**	**$ 89,857**	**223,368**			**12**	**$ 0.012**	**$ 0.044**			
Industrial												
Custom Efficiency												
2003		1,303	1,303									
2004	1	112,311	133,441	211,295	0.02		12	0.058	0.069			
2005	24	1,128,076	3,653,152	12,016,678	1.37		12	0.010	0.033			
2006	40	1,625,216	4,273,885	19,211,605	2.19		12	0.009	0.024			
2007	49	3,161,866	7,012,686	29,789,304	3.40	3.6	12	0.012	0.026			
2008	101	4,045,671	16,312,379	41,058,639	4.69	4.8	12	0.011	0.044			
2009	132	6,061,467	10,848,123	51,835,612	5.92	6.7	12	0.013	0.024			
2010	223	8,778,125	17,172,176	71,580,075	8.17	9.5	12	0.014	0.027			
2011	166	8,783,811	19,830,834	67,979,157	7.76	7.8	12	0.012	0.026			
2012	126	7,092,581	12,975,629	54,253,106	6.19	7.6	12	0.012	0.021			
Total	**862**	**$ 40,790,426**	**$ 92,213,608**	**347,935,471**			**12**	**$ 0.013**	**$ 0.029**	**7.48**	**3.31**	

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]		
Program/Year	**Participants**	**Utility Cost[c]**	**Resource Cost[d]**	**Annual Energy (kWh)**	**Average Energy[e] (aMW)**	**Peak Demand[f] (MW)**	**Measure Life (Years)**	**Total Utility ($/kWh)**	**Total Resource ($/kWh)**	**Utility**	**Total Resource**	
Irrigation												
Irrigation Efficiency Program												
2003	2	$ 41,089	$ 54,609	36,792	0.00	0.0	15	$ 0.106	$ 0.141			
2004	33	120,808	402,978	802,812	0.09	0.4	15	0.014	0.048			
2005	38	150,577	657,460	1,012,883	0.12	0.4	15	0.014	0.062			
2006	559	2,779,620	8,514,231	16,986,008	1.94	5.1	8	0.024	0.073			
2007	816	2,001,961	8,694,772	12,304,073	1.40	3.4	8	0.024	0.103			
2008	961	2,103,702	5,850,778	11,746,395	1.34	3.5	8	0.026	0.073			
2009	887	2,293,896	6,732,268	13,157,619	1.50	3.4	8	0.026	0.077			
2010	753	2,200,814	6,968,598	10,968,430	1.25	3.3	8	0.030	0.096			
2011	880	2,360,304	13,281,492	13,979,833	1.60	3.8	8	0.020	0.113			
2012	908	2,373,201	11,598,185	12,617,164	1.44	3.1	8	0.022	0.110			
Total	**5,837**	**$ 16,425,973**	**$ 62,755,370**	**93,612,009**			**8**	**$ 0.026**	**$ 0.098**	**4.66**	**1.76**	8
Other Programs												
Building Operator Training												
2003	71	48,853	48,853	1,825,000	0.21		5	0.006	0.006			
2004	26	43,969	43,969	650,000	0.07		5	0.014	0.014			
2005	7	1,750	4,480	434,167	0.05		5	0.001	0.002			
Total	**104**	**$ 94,572**	**$ 97,302**	**2,909,167**			**5**	**$ 0.007**	**$ 0.007**			
Commercial Education Initiative												
2005		3,497	3,497									
2006		4,663	4,663									
2007		26,823	26,823									
2008		72,738	72,738									
2009		120,584	120,584									
2010		68,765	68,765									
2011		89,856	89,856									
2012		73,788	73,788									
Total		**$ 460,714**	**$ 460,714**									

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Other Programs											
Comprehensive Lighting											
2011		$ 2,404	$ 2,404								
2012		64,094	64,094								
Total		**$ 66,498**	**$ 66,498**								
Distribution Efficiency Initiative											
2005		21,552	43,969								
2006		24,306	24,306								
2007		8,987	8,987								
2008		(1,913)	(1,913)								
Total		**$ 52,932**	**$ 75,349**								
DSM Direct Program Overhead											
2007		56,909	56,909								
2008		169,911	169,911								
2009		164,957	164,957								
2010		117,874	117,874								
2011		210,477	210,477								
2012		285,951	285,951								
Total		**$ 1,006,079**	**$ 1,006,079**								
Other C&RD and CRC BPA											
2002		55,722	55,722								
2003		67,012	67,012								
2004		108,191	108,191								
2005		101,177	101,177								
2006		124,956	124,956								
2007		31,645	31,645								
2008		6,950	6,950								
Total		**$ 495,654**	**$ 495,654**								

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	**Participants**	**Utility Cost[c]**	**Resource Cost[d]**	**Annual Energy (kWh)**	**Average Energy[e] (aMW)**	**Peak Demand[f] (MW)**	**Measure Life (Years)**	**Total Utility ($/kWh)**	**Total Resource ($/kWh)**	**Utility**	**Total Resource**
Other Programs											
Residential Economizer Pilot											
2011		$ 101,713	$ 101,713								
2012		93,491	93,491								
Total		**$ 195,204**	**$ 195,204**								
Residential Education Initiative											
2005		7,498	7,498								
2006		56,727	56,727								
2007											
2008		150,917	150,917								
2009		193,653	193,653								
2010		222,092	222,092								
2011		159,645	159,645								
2012		174,738	174,738								
Total		**$ 965,270**	**$ 965,270**								
Solar 4R Schools											
2009		42,522	45,522								
Total		**$ 42,522**	**$ 45,522**								
Local Energy Efficiency Fund											
2003	56	5,100	5,100								
2004		23,449	23,449								
2005	2	14,896	26,756	78,000	0.01		10	$ 0.024	$ 0.042		
2006	480	3,459	3,459	19,027	0.00		7	0.009	0.009		
2007	1	7,520	7,520	9,000	0.00		7	0.135	0.135		
2008	2	22,714	60,100	115,931	0.01	0.0	15	0.019	0.049		
2009	1	5,870	4,274	10,340	0.00	0.0	12	0.064	0.047		
2010	1	251	251		0.00	0.0					
2011	1	1,026	2,052	2,028			30	0.036	0.071		
Total	**544**	**$ 84,285**	**$ 132,961**	**234,326**			**14**	**$ 0.037**	**$ 0.058**	**2.95**	**1.87**

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Market Transformation											
NEEA											
2002		$ 1,286,632	$ 1,286,632	12,925,450	1.48						
2003		1,292,748	1,292,748	11,991,580	1.37						
2004		1,256,611	1,256,611	13,329,071	1.52						
2005		476,891	476,891	16,422,224	1.87						
2006		930,455	930,455	18,597,955	2.12						
2007		893,340	893,340	28,601,410	3.27						
2008		942,014	942,014	21,024,279	2.40						
2009		968,263	968,263	10,702,998	1.22						
2010		2,391,217	2,391,217	21,300,366	2.43						
2011		3,108,393	3,108,393	20,547,192	2.35						
2012		3,379,756	3,379,756	17,741,430	2.03						
Total		**$ 16,926,319**	**$ 16,926,319**	**193,183,955**							
Consumer Electronic Initiative											
2009		160,762	160,762								
Total		**$ 160,762**	**$ 160,762**								
Annual Totals											
2002		1,932,520	2,366,591	16,791,100	1.92	0.0					
2003		2,566,228	3,125,572	18,654,343	2.12	0.0					
2004		3,827,213	4,860,912	19,202,780	2.19	6.6					
2005		6,523,348	10,383,577	37,978,035	4.34	44.3					
2006		11,174,181	20,950,110	67,026,303	7.65	44.4					
2007		14,896,816	27,123,018	91,145,357	10.40	58.5					
2008		20,213,216	44,775,829	128,508,579	14.67	74.9					
2009		33,821,062	53,090,852	143,146,365	16.34	236.6					
2010		44,643,541	69,164,744	193,592,637	22.10	357.7					
2011		44,877,117	79,436,532	183,861,776	20.99	419.6					
2012		47,991,352	77,411,652	170,227,773	19.43	453.6					
Total Direct Program		**$ 232,466,593**	**$ 392,689,390**	**1,070,135,047**							

Appendix 4. Historical DSM expense and performance 2002–2012 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction		Peak Demand[f] (MW)	Measure Life (Years)	Levelized Costs[a]		Program Life Benefit/ Cost Ratios[b]	
		Utility Cost[c]	Resource Cost[d]	Annual Energy (kWh)	Average Energy[e] (aMW)			Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Indirect Program Expenses											
DSM Overhead and Other Indirect											
2002		$ 128,855									
2003		(41,543)									
2004		142,337									
2005		177,624									
2006		309,832									
2007		765,561									
2008		980,305									
2009		1,025,704									
2010		1,189,310									
2011		1,389,135									
2012		1,335,509									
Total		**$ 7,402,629**									
Total Expenses											
2002		2,061,375									
2003		2,524,685									
2004		3,969,550									
2005		6,700,972									
2006		11,484,013									
2007		15,662,377									
2008		21,193,521									
2009		34,846,766									
2010		45,832,851									
2011		46,266,252									
2012		49,326,859									
Total 2002–2012		**$ 239,869,220**									

[a] Levelized Costs are based on financial inputs from IPC's 2009 IRP and calculations include line-loss adjusted energy savings.
[b] Program life B/C ratios are provided for active programs only.
[c] The Total Utility Cost is all cost incurred by IPC to implement and manage a DSM program.
[d] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of IPC and its customers as a whole.
[e] Average Demand = Annual Energy/8,760 annual hours.
[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13-percent peak line losses.
[1] Peak MW achieved based on mid-week load reduction schedule.
[2] B/C ratios reflect impacts of the 28-percent realization rate for years 2008–2010 from the ADM 2011 impact evaluation.
[3] Utility cost reflects collected funds on previous bad loan write-offs.
[4] Utility cost reflects only audit and administration costs, there was no further activity in 2006.
[5] Levelized cost calculation includes bad loan write-off expense and funds collected from previously written off loans.
[6] Beginning in 2005, BPA funds were no longer applied to CAP agency payments.
[7] Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.
[8] Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).
[9] Savings are preliminary estimates provided by NEEA.

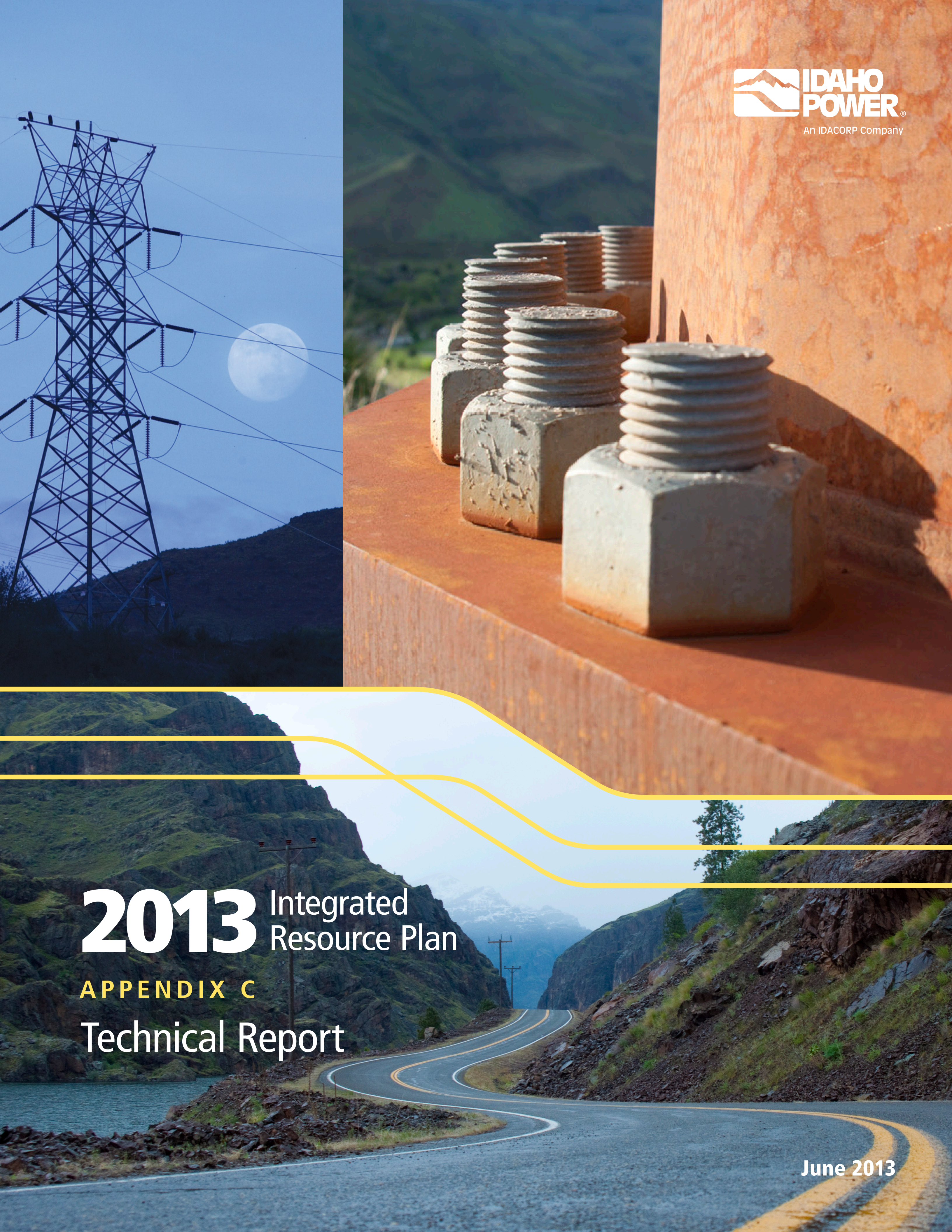
Appendix 5. 2012 DSM program activity by state jurisdiction

	Idaho			Oregon		
Program	**Participants**	**Utility Costs**	**Demand Reduction/ Annual Energy Savings**	**Participants**	**Utility Costs**	**Demand Reduction/ Annual Energy Savings**
Demand Response			**(MW)**			**(MW)**
A/C Cool Credit	35,969 homes	$ 5,635,184	44.3	482 homes	$ 92,810	0.6
Irrigation Peak Rewards	2,396 service points	12,325,148	338.0	37 service points	98,216	1.6
FlexPeak Management	97 sites	2,859,333	41.2	5 sites	150,489	11.6
Total		**$ 20,819,664**	**423.5**		**$ 341,515**	**13.9**
Energy Efficiency			**(kWh)**			**(kWh)**
Residential						
Ductless Heat Pump Pilot	122 homes	153,017	427,000	5 homes	6,850	17,500
Energy Efficient Lighting	913,397 bulbs	1,110,329	16,496,129	12,063 bulbs	16,507	212,530
Energy House Calls	620 homes	272,666	1,122,497	48 homes	3,217	69,542
ENERGY STAR® Homes Northwest	410 homes	450,727	537,447	0 homes	2,458	0
Heating & Cooling Efficiency Program	136 projects	175,483	669,607	5 projects	6,798	19,248
Home Improvement Program	840 insulation projects	385,091	457,353	0 insulation projects	0	0
Home Products Program	16,194 appliances/fixtures	640,203	858,202	481 appliances/fixtures	18,829	29,019
Oregon Residential Weatherization	0 home	0	0	5 home	4,516	11,985
Rebate Advantage	33 homes	34,926	173,414	2 homes	2,316	13,694
See ya later, refrigerator®	3,106 refrigerators/freezers	596,167	1,546,075	61 refrigerators/freezers	16,979	30,351
Weatherization Assistance for Qualified Customers	228 homes/non-profits	1,321,927	621,464	10 homes/non-profits	48,214	26,840
Weatherization Solutions for Eligible Customers	141 homes	1,070,556	257,466	0 homes	0	0
Sector Total		**$ 6,211,092**	**23,166,654**		**$ 126,684**	**430,709**
Commercial						
Building Efficiency	84 projects	1,579,121	20,450,037	0 projects	13,451	0
Easy Upgrades	1,787 projects	5,150,422	40,656,743	51 projects	199,331	911,929
Oregon Commercial Audits	0 audits	0	0	14 audits	12,470	0
Sector Total		**$ 6,729,543**	**61,106,780**		**$ 225,252**	**911,929**
Industrial						
Custom Efficiency	122 projects	6,976,700	53,137,995	4 projects	115,881	1,115,111
Sector Total		**$ 6,976,700**	**53,137,995**		**$ 115,881**	**1,115,111**
Irrigation						
Irrigation Efficiency Rewards	869 projects	2,010,822	11,163,948	39 projects	362,378	1,453,216
Sector Total		**$ 2,010,822**	**11,163,948**		**$ 362,378**	**1,453,216**

Appendix 5. 2012 DSM program activity by state jurisdiction (continued)

	Idaho			Oregon		
Program	**Participants**	**Utility Costs**	**Demand Reduction/ Annual Energy Savings**	**Participants**	**Utility Costs**	**Demand Reduction/ Annual Energy Savings**
Market Transformation			**(kWh)**			**(kWh)**
Northwest Energy Efficiency Alliance[1]		$ 3,210,768	16,854,359		$ 168,988	887,072
Other Programs and Activities						
Residential						
Residential Economizer Project		93,593			(101)	
Residential Energy Efficiency Education Initiative		165,919			8,819	
Commercial						
Commercial Education Initiative		70,099			3,689	
Comprehensive Lighting		64,094				
Other						
Energy Efficiency Direct Program Overhead		271,622			14,329	
Total Program Direct Expense		**$ 46,623,916**			**$ 1,367,435**	
Indirect Program Expense		1,260,377			75,132	
Total Annual Savings			**165,429,736**			**4,798,037**
Total DSM Expense		**$ 47,884,293**			**$ 1,442,567**	

[1] Savings are preliminary estimates provided by NEEA. Oregon is credited with 5 percent of annual NEEA savings.



IDAHO POWER
An IDACORP Company

2013 Integrated Resource Plan

APPENDIX C

Technical Report

June 2013

2013

Integrated Resource Plan

APPENDIX C

Technical Report

June 2013

An IDACORP Company

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2013 Integrated Resource Plan. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

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

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

TABLE OF CONTENTS

INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2013 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2013 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2012 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2013.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2623

irp@idahopower.com

IRP Advisory Council

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

As part of preparing the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and the natural gas power generation. Idaho Power also hosted 11 IRP Advisory Council meetings, including a resource portfolio design workshop. Idaho Power and members from the IRP Advisory Council also met in several small break-out sessions to discuss certain topics in greater detail. Idaho Power values these opportunities to convene, and the IRP Advisory Council members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRP Advisory Council and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRP Advisory Council recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

List of Advisory Council Members

Customer Representatives

Agricultural Representative..Sid Erwin
Boise State University...John Gardner
Idaho National Laboratory...Kurt Myers
Micron...John Velikoff
Simplot...Don Sturtevant

Public Interest Representatives

Boise Metro Chamber of Commerce..................................Ray Stark
Idaho Conservation League..Ben Otto
Idaho Department of Commerce..Gynii Gilliam
Idaho Office of Energy Resources......................................John Chatburn
Idaho State House of Representatives...............................Representative Brent Crane
Idaho State Senate..Senator Russ Fulcher
Idaho Technology Council...Jay Larsen
Northwest Power and Conservation Council......................Shirley Lindstrom
Northwest Power and Conservation Council......................Jim Yost
Oil and Gas Industry Advisor..David Hawk
University of Idaho Integrated Design Lab........................Kevin Van Den Wymelenberg
Water Issues Advisor..Vince Alberdi

Regulatory Commission Representatives

Idaho Public Utilities Commission.....................................Bryan Lanspery
Public Utility Commission of Oregon................................Brittany Andrus

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2012	Thursday, August 16	Background and Process Explanation of the IRP Process Summary of 2012 Summer Peak Load Season Preliminary Resources to Include in the Resource Stack DSM Potential Study Recent Transmission Issues Boardman to Hemingway Update
2012	Thursday, September 6	Thermal Fuels and Associated Issues Natural Gas Price Forecast and Transportation Coat and Gas Unit Forecast Renewable Energy Credit Carbon Adder and Proposed Federal Legislation CSPP Forecast
2012	Wednesday, October 10	Field Trip to Langly Gulch and Hemingway Substation
2012	Thursday, October 11	Hydro Resources and Issues, Customer Load Water Issues Hydro Forecast Load Forecast DSM Program Forecast
2012	Thursday, November 15	2011 IRP Update Environmental Compliance Cost Study Boardman to Hemingway Update Load Forecast Natural Gas Price Forecast DSM Update
2012	Friday, November 30	Portfolio Design Workshop
2012	Thursday, December 13	Portfolio Modeling Review Portfolio Workshop Review Load and Resource Balance Resource Cost Summary Portfolio Modeling Plan Aurora Model Overview Conservation Voltage Reduction
2013	Thursday, January 17	Meeting Canceled
2013	Thursday, February 21	2011 IRP Update Filing and Resource Analysis Coal Study Results Boardman to Hemingway Update Preliminary Resource Analysis Idaho Power Response to Hurricane Sandy
2013	Thursday, March 14	Risk Analysis Methods Resource Alternatives Risk Analysis Preliminary Resource Portfolio Analysis Hells Canyon Relicensing

Meeting Dates		Agenda Items
2013	Thursday, April 11	Risk Analysis Results Resource Portfolio Risk Analysis 2013 Water Year Projections DSM Annual Report
2013	Thursday, May 9	Risk Analysis Results (continued) Questions from the April Meeting Concerning the Resource Portfolio Risk Analysis Results from the Two Resource Portfolios that Retire the North Valmy Coal Plant
2013	Thursday, June 6	Conclusion Draft IRP Document IRP Public Presentation Review Energy Imbalance Market Summer 2013 Preparedness

PUBLIC POLICY ISSUES

Greenhouse Gas Emissions

Climate Change and the Regulation of Greenhouse Gas Emissions

Overview

Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- Changes in temperature and precipitation could affect customer demand and energy loads
- Extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities
- Changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation
- Legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general
- Consumer preference for, and resource planning decisions requiring, renewable or low greenhouse gas (GHG)-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure

Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. However, the regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units. Due in part to the uncertainty of future GHG regulations, in its 2011 IRP Idaho Power did not include any new conventional coal resources in its resource portfolios.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National and International GHG Initiatives

There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. In support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. Other communications from the Obama Administration have proposed the adoption of a clean energy standard in the U.S., calling for 80 percent of American energy to come from clean sources by 2035. Further, climate change regulation has been a recent priority of the U.S. Congress. In prior legislative sessions, legislation in both the U.S. House and Senate was introduced to enact a comprehensive climate change program, but these attempts were unsuccessful. At the same time, legislation has also been introduced seeking to amend the CAA to prohibit the EPA from promulgating regulations on the emissions of GHGs to address climate change and excluding GHGs from the definition of an "air pollutant" for purposes of addressing climate change. Neither areas of focus have culminated in legislation and have led to greater uncertainty as to the direction of GHG regulation.

At the same time, the EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. Lawsuits opposing EPA's endangerment finding and Tailoring Rule were unsuccessful. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the new GHG Tailoring Rules.

In addition, in April 2012, the EPA proposed New Source Performance Standards (NSPS) limiting CO_2 emissions from new electric utility generating units (EGUs) fired by fossil fuels. The proposed requirements, which are limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh. The EPA did not propose standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, if promulgated the new rule would impact the cost effectiveness of developing new generation units.

State and Regional GHG Initiatives

On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The mechanism was implemented in two phases, with Title V sources and entities with an air discharge permit required to start reporting 2009 emissions in 2010 and all other sources required to start reporting 2010 emissions in 2011. The Boardman coal-fired power plant, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel plants operating (i.e., Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

Idaho Power's Voluntary GHG Reduction Initiatives

Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated CO_2 emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 672, 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2011, 2010, 2009, 2008, and 2007, respectively.

In 2010, Idaho Power and Ida-West together ranked as the 37th lowest emitter of CO_2 per MWh produced and the 35th lowest emitter of CO_2 by tons of emissions among the nation’s 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, and other entities using publicly reported 2010 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the 58th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

Public Nuisance-Related Suits for GHGs

In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court’s decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

Flow Modeling

Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was recently updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also recently updated with the release of ESPAM 2.0 in July 2012. Subsequent to the completion of the modeling for the 2013 IRP, a corrected version ESPAM 2.1 was released in late 2012. The ESPAM 2.1 update corrected issues discovered within the model in locations in the Snake River basin above Idaho Falls, Idaho. After reviewing output from the updated version of ESPAM, it was determined that the corrections would have no significant impact on the modeling that had been performed for the 2013 IRP.

Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition. Idaho Power completed an update to the combined model for the 2013 IRP.

Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2009 and 2011 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dan demonstrated a statistically significant decline for the period of 1981 to 2011. Both reaches declined on average 29 cubic feet per second per month (cfs/month) with declines ranging from 25 to 35 cfs/month for American Falls and 18 to 39 cfs/month for Milner to Lower Salmon Falls. Declines in these two reaches met strict predefined criteria, and were therefore included as inputs into the model.

Weather modification was added to the model at two different levels of development. The existing level of development was added to the model for IRP years 2013 and 2014. For IRP years 2015 and beyond, weather modification was increased to reflect a projected level of a fully built-out program in Eastern Idaho. The amount of weather modification added to each year is based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 224,000 acre feet per year (acft/year) and the Upper Snake Basin adds an average of 410,000 acft/year.

Aquifer recharge was added to the model at levels reflected in the 2009 Comprehensive Aquifer Management Plan (CAMP) and the recharge limits included in the Swan Falls Reaffirmation agreement. Nine recharge diversions were modeled across the ESPA with a total maximum diversion of 1,315 cfs. Recharge peaks in IRP year 2019 at approximately 200,000 acft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

CAMP targeted a level of system conversion where ground water supplied irrigated land is converted to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources. The current model assumes a total of 13,683 acres of converted land on the ESPA with a total water savings of 1.4 acft or water per acre of irrigated land (acft/ac), and a maximum of 19,156 acft/year. This number is not solely based on the number of acres idled but also on available water to meet irrigation requirements. The modeled data show conversions reach a peak water savings of 17,600 acft in IRP year 2015. Subsequent reach declines reduce water available for system conversions. In IRP year 2027, water savings declined to 17,100 acft.

The model accounts for approximately 15,410 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions.

Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2013 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2013 through 2015 in response to increased weather modification in the Upper Snake River Basin. Flows peak in 2015 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.5 Million acft/year. In 2027, those flows have declined to approximately 11.25 Million acft/year, with most of the declines attributable to spring discharge in the Milner to Lower Salmon Falls reach.

2013 Model Parameters

	Managed Recharge (acft/yr)		Weather Modification (acft/yr)				Lease Water	Reach Declines (acft/yr)	
IRP Year	Above American Falls	Below American Falls	Snake River Basin	Payette Basin	System Conversions (Ac)	CREP (Ac)	740 cfs in August	American Falls Inflows	Below Milner
2013	54,500	48,400	124,000	224,000	13,683	16,684	Yes	82,671	84,535
2014	66,600	48,400	124,000	224,000	13,683	16,684	Yes	103,338	105,669
2015	66,600	90,800	410,000	224,000	13,683	16,684	Yes	124,006	126,803
2016	66,600	90,800	410,000	224,000	13,683	16,684	No	144,673	147,937
2017	66,600	108,900	410,000	224,000	13,683	16,684	No	165,340	169,071
2018	88,200	115,000	410,000	224,000	13,683	16,684	No	186,007	190,205
2019	88,200	122,100	410,000	224,000	13,683	16,684	No	206,674	211,339
2020	88,200	122,100	410,000	224,000	13,683	16,684	No	227,341	232,473
2021	88,200	122,100	410,000	224,000	13,683	16,684	No	248,008	253,607
2022	88,200	122,100	410,000	224,000	13,683	12,513	No	268,675	274,741
2023	88,200	122,100	410,000	224,000	13,683	8,342	No	289,342	295,875
2024	88,200	122,100	410,000	224,000	13,683	4,171	No	310,009	317,009
2025	88,200	122,100	410,000	224,000	13,683	0	No	330,676	338,143
2026	88,200	122,100	410,000	224,000	13,683	0	No	351,343	359,277
2027	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411
2028	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411
2029	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411
2030	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411
2031	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411
2032	88,200	122,100	410,000	224,000	13,683	0	No	372,010	380,411

Sales and Load Forecast Data

Average Annual Forecast Growth Rates

	2013–2018	2013–2023	2013–2032
Sales			
Residential Sales	1.07%	1.09%	1.08%
Commercial Sales	1.09%	1.07%	1.10%
Irrigation Sales	0.05%	0.07%	0.01%
Industrial Sales	2.25%	1.95%	1.71%
Additional Firm Sales	0.97%	2.03%	1.16%
System Sales	1.15%	1.18%	1.08%
Total Sales	1.15%	1.18%	1.08%
Loads			
Residential Load	1.08%	1.09%	1.08%
Commercial Load	1.08%	1.07%	1.10%
Irrigation Load	0.05%	0.07%	0.00%
Industrial Load	2.23%	1.94%	1.69%
Additional Firm Sales	0.97%	2.03%	1.16%
System Load Losses	1.08%	1.08%	1.03%
System Load	1.14%	1.17%	1.07%
Total Load	1.14%	1.17%	1.07%
Peaks			
System Peak	1.54%	1.52%	1.41%
Total Peak	1.54%	1.52%	1.41%
Winter Peak	0.81%	0.90%	0.82%
Summer Peak	1.54%	1.52%	1.41%
Customers			
Residential Customers	1.82%	1.68%	1.47%
Commercial Customers	1.94%	1.81%	1.59%
Irrigation Customers	1.30%	1.26%	1.20%
Industrial Customers	1.18%	1.15%	0.99%

Expected-Case Load Forecast

Monthly Summary[1]	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Average Load (aMW)–50th Percentile												
Residential	792	670	567	487	442	467	589	566	461	457	580	806
Commercial	487	444	415	397	403	429	504	491	435	406	428	505
Irrigation	2	2	2	72	298	524	643	502	295	43	0	1
Industrial	264	266	262	251	254	270	269	273	270	274	273	278
Additional Firm	118	116	113	115	110	112	116	116	112	112	120	122
Loss	164	146	131	128	148	180	214	195	155	124	135	169
System Load	1,828	1,644	1,491	1,451	1,655	1,982	2,336	2,143	1,728	1,416	1,537	1,882
Light Load	1,688	1,517	1,370	1,314	1,505	1,774	2,119	1,901	1,553	1,277	1,418	1,738
Heavy Load	1,938	1,739	1,586	1,550	1,774	2,149	2,506	2,317	1,882	1,516	1,632	2,005
Total Load	1,828	1,644	1,491	1,451	1,655	1,982	2,336	2,143	1,728	1,416	1,537	1,882
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,445	2,328	2,024	1,956	2,775	3,215	3,344	3,015	2,756	2,013	2,199	2,585
Total Peak Load	2,445	2,328	2,024	1,956	2,775	3,215	3,344	3,015	2,756	2,013	2,199	2,585

Monthly Summary[1]	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Average Load (aMW)–50th Percentile												
Residential	796	671	569	489	445	472	595	571	465	459	582	810
Commercial	494	449	421	403	409	436	512	499	443	412	435	512
Irrigation	2	2	2	72	300	528	647	505	296	43	0	1
Industrial	272	274	269	259	261	277	277	281	278	282	281	286
Additional Firm	121	117	115	117	113	110	118	118	114	114	122	124
Loss	166	148	133	129	150	182	217	198	157	125	137	170
System Load	1,850	1,661	1,510	1,470	1,678	2,004	2,366	2,172	1,754	1,436	1,558	1,903
Light Load	1,709	1,533	1,387	1,331	1,525	1,794	2,147	1,927	1,575	1,295	1,437	1,758
Heavy Load	1,962	1,757	1,606	1,571	1,798	2,173	2,539	2,365	1,896	1,538	1,664	2,017
Total Load	1,850	1,661	1,510	1,470	1,678	2,004	2,366	2,172	1,754	1,436	1,558	1,903
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,474	2,346	2,047	1,981	2,822	3,261	3,403	3,059	2,800	2,034	2,222	2,606
Total Peak Load	2,474	2,346	2,047	1,981	2,822	3,261	3,403	3,059	2,800	2,034	2,222	2,606

Monthly Summary[1]	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Average Load (aMW)–50th Percentile												
Residential	796	669	568	490	446	474	599	575	466	460	583	817
Commercial	498	452	424	407	413	441	517	504	448	416	438	517
Irrigation	2	2	2	73	301	530	649	507	298	43	0	1
Industrial	279	281	277	265	268	285	285	288	286	290	289	293
Additional Firm	124	121	119	120	116	113	121	121	117	117	126	128
Loss	167	148	134	130	151	183	219	199	158	127	138	172
System Load	1,866	1,673	1,524	1,485	1,695	2,025	2,390	2,194	1,773	1,452	1,574	1,928
Light Load	1,723	1,544	1,400	1,345	1,541	1,812	2,168	1,947	1,593	1,310	1,453	1,781
Heavy Load	1,979	1,770	1,621	1,587	1,827	2,180	2,564	2,389	1,917	1,555	1,681	2,044
Total Load	1,866	1,673	1,524	1,485	1,695	2,025	2,390	2,194	1,773	1,452	1,574	1,928
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,471	2,357	2,040	1,965	2,867	3,296	3,456	3,093	2,835	2,053	2,222	2,620
Total Peak Load	2,471	2,357	2,040	1,965	2,867	3,296	3,456	3,093	2,835	2,053	2,222	2,620

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–50th Percentile												
Residential	805	675	574	495	452	481	610	585	474	465	590	831
Commercial	503	457	429	411	417	446	523	510	454	421	443	523
Irrigation	2	2	2	72	298	524	643	502	294	43	0	1
Industrial	286	278	283	272	274	291	291	295	292	296	296	298
Additional Firm	124	117	119	120	116	113	121	121	117	117	126	128
Loss	169	149	135	132	152	185	220	201	160	128	140	175
System Load	1,889	1,676	1,542	1,502	1,710	2,041	2,408	2,214	1,791	1,471	1,595	1,955
Light Load	1,745	1,547	1,417	1,361	1,554	1,826	2,185	1,964	1,609	1,327	1,472	1,806
Heavy Load	2,014	1,772	1,632	1,606	1,844	2,197	2,600	2,394	1,937	1,585	1,694	2,073
Total Load	1,889	1,676	1,542	1,502	1,710	2,041	2,408	2,214	1,791	1,471	1,595	1,955
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,486	2,370	2,050	1,971	2,906	3,323	3,500	3,121	2,867	2,070	2,235	2,640
Total Peak Load	2,486	2,370	2,050	1,971	2,906	3,323	3,500	3,121	2,867	2,070	2,235	2,640

Monthly Summary[1]	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Average Load (aMW)–50th Percentile												
Residential	818	683	582	503	460	491	623	597	483	473	600	845
Commercial	507	460	433	415	421	451	529	516	459	426	447	528
Irrigation	2	2	2	72	298	524	642	501	294	42	0	1
Industrial	291	293	288	276	279	297	296	300	298	302	301	303
Additional Firm	125	122	120	121	117	114	122	122	118	118	127	129
Loss	171	152	137	134	154	187	223	203	162	130	142	177
System Load	1,915	1,711	1,562	1,522	1,729	2,063	2,435	2,240	1,814	1,491	1,617	1,982
Light Load	1,768	1,579	1,435	1,378	1,572	1,847	2,209	1,987	1,629	1,345	1,492	1,831
Heavy Load	2,041	1,810	1,653	1,636	1,853	2,222	2,629	2,422	1,961	1,606	1,718	2,112
Total Load	1,915	1,711	1,562	1,522	1,729	2,063	2,435	2,240	1,814	1,491	1,617	1,982
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,514	2,388	2,072	1,992	2,950	3,362	3,555	3,161	2,907	2,090	2,260	2,668
Total Peak Load	2,514	2,388	2,072	1,992	2,950	3,362	3,555	3,161	2,907	2,090	2,260	2,668

Monthly Summary[1]	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Average Load (aMW)–50th Percentile												
Residential	829	690	589	510	467	500	635	609	491	479	608	858
Commercial	511	463	436	418	425	456	534	520	464	430	451	533
Irrigation	2	2	2	72	299	526	644	503	295	43	0	1
Industrial	296	297	293	281	284	301	301	305	302	307	306	308
Additional Firm	125	121	119	121	117	114	122	122	118	118	127	128
Loss	173	153	139	135	156	189	225	206	164	131	143	180
System Load	1,936	1,726	1,578	1,538	1,747	2,085	2,461	2,265	1,834	1,508	1,635	2,007
Light Load	1,788	1,593	1,450	1,393	1,588	1,866	2,233	2,009	1,648	1,360	1,509	1,854
Heavy Load	2,052	1,826	1,670	1,654	1,872	2,245	2,657	2,449	1,997	1,615	1,737	2,139
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,936	1,726	1,578	1,538	1,747	2,085	2,461	2,265	1,834	1,508	1,635	2,007
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,536	2,402	2,088	2,009	2,993	3,400	3,609	3,199	2,944	2,107	2,279	2,691
Total Peak Load	2,536	2,402	2,088	2,009	2,993	3,400	3,609	3,199	2,944	2,107	2,279	2,691

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–50th Percentile												
Residential	839	696	595	517	474	508	646	619	498	485	616	868
Commercial	516	466	440	422	429	461	539	526	470	434	455	538
Irrigation	2	2	2	72	300	527	646	504	296	43	0	1
Industrial	301	303	298	286	288	306	306	310	307	312	311	313
Additional Firm	126	122	120	122	117	115	123	123	119	119	128	129
Loss	175	154	140	136	157	191	228	208	166	133	145	182
System Load	1,958	1,742	1,595	1,555	1,765	2,107	2,488	2,291	1,856	1,526	1,655	2,032
Light Load	1,808	1,608	1,466	1,409	1,605	1,886	2,258	2,032	1,667	1,376	1,527	1,877
Heavy Load	2,076	1,843	1,697	1,662	1,892	2,284	2,670	2,477	2,021	1,634	1,758	2,165
Total Load	1,958	1,742	1,595	1,555	1,765	2,107	2,488	2,291	1,856	1,526	1,655	2,032
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,560	2,418	2,107	2,028	3,036	3,439	3,664	3,239	2,983	2,126	2,301	2,716
Total Peak Load	2,560	2,418	2,107	2,028	3,036	3,439	3,664	3,239	2,983	2,126	2,301	2,716

Monthly Summary[1]	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Average Load (aMW)–50th Percentile												
Residential	846	699	600	521	478	515	656	628	504	490	622	878
Commercial	521	470	444	427	434	466	545	532	476	439	459	544
Irrigation	2	2	2	72	301	528	648	506	297	43	0	1
Industrial	306	297	303	290	293	312	312	315	313	317	316	318
Additional Firm	132	124	126	127	122	119	127	128	123	124	134	136
Loss	177	155	142	138	159	193	230	210	167	135	147	184
System Load	1,984	1,746	1,616	1,576	1,787	2,133	2,517	2,319	1,880	1,547	1,678	2,061
Light Load	1,832	1,612	1,485	1,428	1,625	1,909	2,284	2,058	1,689	1,395	1,548	1,904
Heavy Load	2,103	1,846	1,719	1,685	1,927	2,297	2,701	2,525	2,033	1,657	1,792	2,185
Total Load	1,984	1,746	1,616	1,576	1,787	2,133	2,517	2,319	1,880	1,547	1,678	2,061
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,588	2,436	2,129	2,048	3,084	3,481	3,722	3,281	3,024	2,148	2,326	2,745
Total Peak Load	2,588	2,436	2,129	2,048	3,084	3,481	3,722	3,281	3,024	2,148	2,326	2,745

Monthly Summary[1]	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Average Load (aMW)–50th Percentile												
Residential	829	690	589	510	467	500	635	609	491	479	608	858
Commercial	511	463	436	418	425	456	534	520	464	430	451	533
Irrigation	2	2	2	72	299	526	644	503	295	43	0	1
Industrial	296	297	293	281	284	301	301	305	302	307	306	308
Additional Firm	125	121	119	121	117	114	122	122	118	118	127	128
Loss	173	153	139	135	156	189	225	206	164	131	143	180
System Load	1,936	1,726	1,578	1,538	1,747	2,085	2,461	2,265	1,834	1,508	1,635	2,007
Light Load	1,788	1,593	1,450	1,393	1,588	1,866	2,233	2,009	1,648	1,360	1,509	1,854
Heavy Load	2,052	1,826	1,670	1,654	1,872	2,245	2,657	2,449	1,997	1,615	1,737	2,139
Total Load	1,936	1,726	1,578	1,538	1,747	2,085	2,461	2,265	1,834	1,508	1,635	2,007
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,536	2,402	2,088	2,009	2,993	3,400	3,609	3,199	2,944	2,107	2,279	2,691
Total Peak Load	2,536	2,402	2,088	2,009	2,993	3,400	3,609	3,199	2,944	2,107	2,279	2,691

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–50th Percentile												
Residential	839	696	595	517	474	508	646	619	498	485	616	868
Commercial	516	466	440	422	429	461	539	526	470	434	455	538
Irrigation	2	2	2	72	300	527	646	504	296	43	0	1
Industrial	301	303	298	286	288	306	306	310	307	312	311	313
Additional Firm	126	122	120	122	117	115	123	123	119	119	128	129
Loss	175	154	140	136	157	191	228	208	166	133	145	182
System Load	1,958	1,742	1,595	1,555	1,765	2,107	2,488	2,291	1,856	1,526	1,655	2,032
Light Load	1,808	1,608	1,466	1,409	1,605	1,886	2,258	2,032	1,667	1,376	1,527	1,877
Heavy Load	2,076	1,843	1,697	1,662	1,892	2,284	2,670	2,477	2,021	1,634	1,758	2,165
Total Load	1,958	1,742	1,595	1,555	1,765	2,107	2,488	2,291	1,856	1,526	1,655	2,032
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,560	2,418	2,107	2,028	3,036	3,439	3,664	3,239	2,983	2,126	2,301	2,716
Total Peak Load	2,560	2,418	2,107	2,028	3,036	3,439	3,664	3,239	2,983	2,126	2,301	2,716

Monthly Summary[1]	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Average Load (aMW)–50th Percentile												
Residential	846	699	600	521	478	515	656	628	504	490	622	878
Commercial	521	470	444	427	434	466	545	532	476	439	459	544
Irrigation	2	2	2	72	301	528	648	506	297	43	0	1
Industrial	306	297	303	290	293	312	312	315	313	317	316	318
Additional Firm	132	124	126	127	122	119	127	128	123	124	134	136
Loss	177	155	142	138	159	193	230	210	167	135	147	184
System Load	1,984	1,746	1,616	1,576	1,787	2,133	2,517	2,319	1,880	1,547	1,678	2,061
Light Load	1,832	1,612	1,485	1,428	1,625	1,909	2,284	2,058	1,689	1,395	1,548	1,904
Heavy Load	2,103	1,846	1,719	1,685	1,927	2,297	2,701	2,525	2,033	1,657	1,792	2,185
Total Load	1,984	1,746	1,616	1,576	1,787	2,133	2,517	2,319	1,880	1,547	1,678	2,061
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,588	2,436	2,129	2,048	3,084	3,481	3,722	3,281	3,024	2,148	2,326	2,745
Total Peak Load	2,588	2,436	2,129	2,048	3,084	3,481	3,722	3,281	3,024	2,148	2,326	2,745

Monthly Summary[1]	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Average Load (aMW)–50th Percentile												
Residential	852	702	603	525	483	521	664	637	510	494	627	887
Commercial	525	473	448	431	438	471	551	538	481	444	464	550
Irrigation	2	2	2	72	301	529	649	507	297	43	0	1
Industrial	311	313	308	295	298	317	317	320	318	322	321	323
Additional Firm	143	138	135	136	130	127	135	135	130	131	144	148
Loss	179	157	143	140	161	195	232	213	169	136	149	187
System Load	2,012	1,785	1,639	1,600	1,811	2,160	2,548	2,349	1,906	1,570	1,705	2,095
Light Load	1,858	1,647	1,506	1,449	1,647	1,934	2,312	2,084	1,712	1,416	1,573	1,936
Heavy Load	2,145	1,888	1,735	1,710	1,953	2,326	2,734	2,558	2,061	1,692	1,811	2,221
Total Load	2,012	1,785	1,639	1,600	1,811	2,160	2,548	2,349	1,906	1,570	1,705	2,095
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,614	2,462	2,148	2,064	3,135	3,523	3,782	3,324	3,067	2,173	2,350	2,776
Total Peak Load	2,614	2,462	2,148	2,064	3,135	3,523	3,782	3,324	3,067	2,173	2,350	2,776

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–50th Percentile												
Residential	859	706	607	530	488	528	674	646	516	498	633	898
Commercial	530	477	452	435	443	477	557	544	487	449	468	556
Irrigation	2	2	2	72	301	528	648	506	297	43	0	1
Industrial	316	318	313	300	303	322	322	326	323	328	327	328
Additional Firm	148	142	139	141	134	131	138	139	134	135	149	153
Loss	181	158	145	141	162	196	234	215	171	138	150	189
System Load	2,036	1,803	1,659	1,619	1,830	2,182	2,573	2,374	1,928	1,590	1,727	2,125
Light Load	1,881	1,664	1,524	1,466	1,664	1,953	2,335	2,106	1,732	1,434	1,594	1,963
Heavy Load	2,170	1,907	1,755	1,731	1,973	2,350	2,778	2,567	2,085	1,713	1,835	2,253
Total Load	2,036	1,803	1,659	1,619	1,830	2,182	2,573	2,374	1,928	1,590	1,727	2,125
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,636	2,480	2,164	2,077	3,180	3,559	3,835	3,361	3,104	2,194	2,370	2,803
Total Peak Load	2,636	2,480	2,164	2,077	3,180	3,559	3,835	3,361	3,104	2,194	2,370	2,803

Monthly Summary[1]	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Average Load (aMW)–50th Percentile												
Residential	868	711	613	536	494	536	685	656	523	504	640	908
Commercial	536	481	457	440	448	483	564	550	494	454	473	562
Irrigation	2	2	2	72	300	528	648	506	297	43	0	1
Industrial	321	323	318	305	308	327	327	331	328	333	332	333
Additional Firm	148	143	140	141	135	132	139	139	134	136	150	153
Loss	183	160	146	143	164	198	237	217	173	139	152	191
System Load	2,058	1,819	1,676	1,636	1,848	2,204	2,599	2,399	1,949	1,608	1,747	2,149
Light Load	1,901	1,679	1,540	1,482	1,680	1,972	2,358	2,128	1,751	1,450	1,612	1,985
Heavy Load	2,194	1,924	1,774	1,760	1,981	2,373	2,806	2,594	2,108	1,733	1,855	2,290
Total Load	2,058	1,819	1,676	1,636	1,848	2,204	2,599	2,399	1,949	1,608	1,747	2,149
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,659	2,495	2,182	2,094	3,223	3,596	3,889	3,399	3,142	2,213	2,391	2,826
Total Peak Load	2,659	2,495	2,182	2,094	3,223	3,596	3,889	3,399	3,142	2,213	2,391	2,826

Monthly Summary[1]	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Average Load (aMW)–50th Percentile												
Residential	875	714	617	540	499	542	694	665	529	508	645	917
Commercial	540	485	461	444	452	487	569	556	499	459	477	567
Irrigation	2	2	2	72	301	529	649	507	297	43	0	1
Industrial	326	317	323	310	312	332	332	336	333	338	337	338
Additional Firm	148	138	140	141	134	131	139	139	134	135	149	153
Loss	185	160	147	144	165	200	239	219	175	141	153	193
System Load	2,075	1,814	1,689	1,650	1,863	2,223	2,622	2,421	1,968	1,623	1,762	2,169
Light Load	1,917	1,674	1,552	1,495	1,694	1,989	2,379	2,148	1,768	1,464	1,626	2,004
Heavy Load	2,201	1,917	1,797	1,764	1,997	2,409	2,813	2,618	2,143	1,738	1,872	2,311
Total Load	2,075	1,814	1,689	1,650	1,863	2,223	2,622	2,421	1,968	1,623	1,762	2,169
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,668	2,502	2,186	2,096	3,263	3,630	3,939	3,433	3,176	2,228	2,399	2,840
Total Peak Load	2,668	2,502	2,186	2,096	3,263	3,630	3,939	3,433	3,176	2,228	2,399	2,840

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–50th Percentile												
Residential	881	716	620	544	503	548	703	673	534	511	650	927
Commercial	544	487	464	447	455	492	574	561	504	463	481	573
Irrigation	2	2	2	72	300	528	647	505	297	43	0	1
Industrial	330	333	327	314	317	337	337	341	338	343	342	343
Additional Firm	148	143	140	141	135	132	139	140	135	136	150	153
Loss	186	162	148	145	166	201	240	221	176	142	155	195
System Load	2,091	1,841	1,701	1,663	1,876	2,238	2,640	2,439	1,984	1,637	1,777	2,193
Light Load	1,931	1,699	1,563	1,506	1,706	2,003	2,396	2,164	1,782	1,476	1,639	2,026
Heavy Load	2,217	1,948	1,810	1,777	2,011	2,426	2,833	2,656	2,145	1,753	1,898	2,324
Total Load	2,091	1,841	1,701	1,663	1,876	2,238	2,640	2,439	1,984	1,637	1,777	2,193
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,670	2,511	2,184	2,088	3,302	3,657	3,985	3,461	3,205	2,242	2,402	2,855
Total Peak Load	2,670	2,511	2,184	2,088	3,302	3,657	3,985	3,461	3,205	2,242	2,402	2,855

Monthly Summary[1]	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Average Load (aMW)–50th Percentile												
Residential	890	721	625	550	509	557	715	684	542	517	657	940
Commercial	549	492	469	452	461	498	581	568	511	468	486	579
Irrigation	2	2	2	72	298	525	643	502	295	43	0	1
Industrial	335	338	332	319	322	342	342	346	343	348	347	348
Additional Firm	147	142	139	140	134	131	139	139	134	135	149	152
Loss	188	163	150	146	168	203	242	222	178	143	156	198
System Load	2,112	1,857	1,718	1,679	1,892	2,256	2,662	2,461	2,003	1,654	1,796	2,219
Light Load	1,951	1,714	1,578	1,521	1,720	2,019	2,415	2,183	1,799	1,492	1,657	2,050
Heavy Load	2,240	1,964	1,827	1,795	2,040	2,429	2,856	2,680	2,166	1,772	1,918	2,352
Total Load	2,112	1,857	1,718	1,679	1,892	2,256	2,662	2,461	2,003	1,654	1,796	2,219
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,691	2,525	2,199	2,102	3,343	3,688	4,034	3,494	3,240	2,259	2,421	2,879
Total Peak Load	2,691	2,525	2,199	2,102	3,343	3,688	4,034	3,494	3,240	2,259	2,421	2,879

Monthly Summary[1]	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Average Load (aMW)–50th Percentile												
Residential	900	726	631	556	516	565	727	695	549	523	665	951
Commercial	555	496	475	457	466	505	588	575	518	474	492	586
Irrigation	2	2	2	72	299	525	644	503	295	43	0	1
Industrial	340	343	337	323	327	347	347	351	348	353	352	353
Additional Firm	147	142	139	140	134	131	139	139	134	135	149	152
Loss	190	165	151	148	169	205	245	225	180	145	158	200
System Load	2,135	1,873	1,735	1,697	1,911	2,279	2,690	2,488	2,025	1,673	1,816	2,243
Light Load	1,972	1,728	1,594	1,537	1,737	2,039	2,440	2,207	1,819	1,509	1,675	2,072
Heavy Load	2,275	1,981	1,837	1,814	2,060	2,454	2,886	2,709	2,190	1,803	1,928	2,378
Total Load	2,135	1,873	1,735	1,697	1,911	2,279	2,690	2,488	2,025	1,673	1,816	2,243
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,714	2,539	2,217	2,120	3,386	3,729	4,090	3,535	3,281	2,278	2,442	2,902
Total Peak Load	2,714	2,539	2,217	2,120	3,386	3,729	4,090	3,535	3,281	2,278	2,442	2,902

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–50th Percentile												
Residential	907	729	635	560	521	572	736	704	556	527	670	962
Commercial	560	500	479	462	471	510	594	581	525	479	496	593
Irrigation	2	2	2	72	299	527	645	504	296	43	0	1
Industrial	345	335	342	328	331	352	352	356	353	358	357	358
Additional Firm	146	136	138	139	133	130	138	138	133	134	147	150
Loss	192	164	153	149	171	207	247	227	182	146	160	202
System Load	2,152	1,866	1,748	1,710	1,926	2,298	2,713	2,510	2,044	1,688	1,831	2,266
Light Load	1,987	1,722	1,606	1,549	1,751	2,057	2,462	2,227	1,836	1,522	1,689	2,094
Heavy Load	2,293	1,973	1,850	1,839	2,064	2,474	2,929	2,715	2,210	1,819	1,945	2,415
Total Load	2,152	1,866	1,748	1,710	1,926	2,298	2,713	2,510	2,044	1,688	1,831	2,266
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,721	2,548	2,220	2,120	3,427	3,763	4,141	3,570	3,316	2,293	2,449	2,918
Total Peak Load	2,721	2,548	2,220	2,120	3,427	3,763	4,141	3,570	3,316	2,293	2,449	2,918

Monthly Summary[1]	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Average Load (aMW)–50th Percentile												
Residential	916	734	640	566	527	580	748	715	563	533	678	974
Commercial	567	505	484	467	476	517	602	589	532	486	502	600
Irrigation	2	2	2	72	298	525	643	502	295	43	0	1
Industrial	350	352	347	333	336	357	357	361	358	363	362	363
Additional Firm	145	140	137	139	133	130	138	138	133	134	146	149
Loss	194	167	154	151	172	209	249	229	184	148	161	205
System Load	2,173	1,899	1,764	1,727	1,942	2,318	2,737	2,534	2,065	1,706	1,850	2,293
Light Load	2,007	1,753	1,621	1,564	1,766	2,074	2,483	2,248	1,855	1,538	1,706	2,119
Heavy Load	2,304	2,009	1,868	1,857	2,082	2,496	2,955	2,741	2,248	1,827	1,965	2,443
Total Load	2,173	1,899	1,764	1,727	1,942	2,318	2,737	2,534	2,065	1,706	1,850	2,293
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,740	2,560	2,234	2,132	3,468	3,798	4,192	3,606	3,353	2,311	2,466	2,942
Total Peak Load	2,740	2,560	2,234	2,132	3,468	3,798	4,192	3,606	3,353	2,311	2,466	2,942

Monthly Summary[1]	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Average Load (aMW)–50th Percentile												
Residential	926	739	646	572	534	589	761	727	571	539	686	986
Commercial	573	510	490	473	483	525	610	597	540	492	508	608
Irrigation	2	2	2	72	299	525	644	502	295	43	0	1
Industrial	355	357	352	337	341	362	362	366	363	368	367	368
Additional Firm	152	147	144	145	138	136	143	143	138	139	154	158
Loss	196	169	156	153	174	211	252	232	186	150	164	207
System Load	2,205	1,924	1,790	1,752	1,968	2,347	2,771	2,568	2,093	1,731	1,879	2,329
Light Load	2,036	1,775	1,645	1,587	1,789	2,101	2,515	2,278	1,881	1,562	1,733	2,152
Heavy Load	2,338	2,035	1,904	1,873	2,109	2,545	2,974	2,777	2,280	1,854	1,996	2,482
Total Load	2,205	1,924	1,790	1,752	1,968	2,347	2,771	2,568	2,093	1,731	1,879	2,329
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,776	2,586	2,262	2,159	3,519	3,847	4,256	3,656	3,402	2,338	2,498	2,979
Total Peak Load	2,776	2,586	2,262	2,159	3,519	3,847	4,256	3,656	3,402	2,338	2,498	2,979

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Average Load (aMW)–50th Percentile												
Residential	934	743	651	578	539	597	772	737	578	544	692	997
Commercial	580	516	496	479	489	532	618	605	548	499	514	616
Irrigation	2	2	2	72	299	526	645	504	296	43	0	1
Industrial	360	362	356	342	345	367	367	371	368	373	372	374
Additional Firm	151	146	143	144	138	135	143	143	138	139	153	156
Loss	198	170	157	154	176	213	255	235	188	152	165	210
System Load	2,226	1,938	1,806	1,769	1,987	2,370	2,799	2,595	2,116	1,749	1,897	2,355
Light Load	2,055	1,789	1,659	1,602	1,806	2,121	2,540	2,302	1,901	1,578	1,750	2,175
Heavy Load	2,349	2,050	1,921	1,891	2,117	2,570	2,987	2,825	2,273	1,873	2,015	2,484
Total Load	2,226	1,938	1,806	1,769	1,987	2,370	2,799	2,595	2,116	1,749	1,897	2,355
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,791	2,597	2,272	2,167	3,562	3,888	4,312	3,697	3,443	2,356	2,513	2,999
Total Peak Load	2,791	2,597	2,272	2,167	3,562	3,888	4,312	3,697	3,443	2,356	2,513	2,999

Monthly Summary[1]	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Average Load (aMW)–50th Percentile												
Residential	942	746	655	583	545	605	782	747	585	549	698	1,008
Commercial	587	521	502	485	495	539	627	613	557	506	521	625
Irrigation	2	2	2	72	299	526	644	503	295	43	0	1
Industrial	365	355	361	347	350	372	372	376	373	379	377	379
Additional Firm	151	140	142	144	137	135	142	142	137	138	152	156
Loss	200	170	159	156	177	215	257	237	190	153	167	212
System Load	2,246	1,933	1,822	1,786	2,004	2,391	2,825	2,619	2,137	1,767	1,916	2,380
Light Load	2,074	1,784	1,674	1,617	1,822	2,140	2,563	2,324	1,920	1,594	1,768	2,199
Heavy Load	2,370	2,055	1,928	1,909	2,147	2,575	3,014	2,852	2,296	1,904	2,025	2,511
Total Load	2,246	1,933	1,822	1,786	2,004	2,391	2,825	2,619	2,137	1,767	1,916	2,380
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,807	2,596	2,282	2,174	3,603	3,925	4,365	3,735	3,482	2,374	2,527	3,020
Total Peak Load	2,807	2,596	2,282	2,174	3,603	3,925	4,365	3,735	3,482	2,374	2,527	3,020

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Annual Summary

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Billed Sales (MWh)–50th Percentile										
Residential	5,024,661	5,054,545	5,063,083	5,130,952	5,221,061	5,299,496	5,371,170	5,426,100	5,476,110	5,532,311
Commercial	3,900,064	3,960,646	3,996,617	4,043,282	4,082,719	4,117,425	4,158,116	4,202,778	4,244,120	4,288,491
Irrigation	1,751,463	1,762,474	1,768,998	1,750,913	1,749,671	1,756,095	1,760,483	1,765,522	1,768,531	1,765,357
Industrial	2,334,380	2,402,175	2,466,748	2,523,489	2,568,734	2,609,536	2,653,663	2,698,998	2,743,911	2,788,219
Additional Firm	1,009,771	1,025,200	1,052,800	1,053,500	1,062,300	1,059,600	1,067,700	1,115,100	1,193,100	1,228,700
System Sales	14,020,339	14,205,040	14,348,247	14,502,137	14,684,485	14,842,152	15,011,132	15,208,498	15,425,772	15,603,078
Total Sales	14,020,339	14,205,040	14,348,247	14,502,137	14,684,485	14,842,152	15,011,132	15,208,498	15,425,772	15,603,078
Generation Month Sales (MWh)–50th Percentile										
Residential	5,027,296	5,055,690	5,068,397	5,154,035	5,227,150	5,305,125	5,375,632	5,447,007	5,480,685	5,537,710
Commercial	3,903,440	3,962,715	3,999,260	4,056,500	4,084,729	4,119,758	4,160,664	4,216,430	4,246,659	4,291,303
Irrigation	1,751,467	1,762,477	1,768,991	1,750,951	1,749,674	1,756,097	1,760,485	1,765,562	1,768,530	1,765,357
Industrial	2,340,228	2,407,744	2,471,642	2,527,392	2,572,253	2,613,342	2,657,573	2,702,871	2,747,733	2,792,033
Additional Firm	1,009,771	1,025,200	1,052,800	1,053,500	1,062,300	1,059,600	1,067,700	1,115,100	1,193,100	1,228,700
System Sales	14,032,203	14,213,826	14,361,089	14,542,378	14,696,106	14,853,922	15,022,054	15,246,971	15,436,707	15,615,103
Total Sales	14,032,203	14,213,826	14,361,089	14,542,378	14,696,106	14,853,922	15,022,054	15,246,971	15,436,707	15,615,103
Loss	1,380,235	1,396,630	1,408,407	1,426,063	1,440,637	1,456,526	1,472,745	1,492,086	1,505,449	1,520,629
Required Generation	15,412,437	15,610,455	15,769,496	15,968,441	16,136,743	16,310,448	16,494,799	16,739,057	16,942,156	17,135,732
Average Load (aMW)–50th Percentile										
Residential	574	577	579	587	597	606	614	620	626	632
Commercial	446	452	457	462	466	470	475	480	485	490
Irrigation	200	201	202	199	200	200	201	201	202	202
Industrial	267	275	282	288	294	298	303	308	314	319
Additional Firm	115	117	120	120	121	121	122	127	136	140
Loss	158	159	161	162	164	166	168	170	172	174
System Load	1,759	1,782	1,800	1,818	1,842	1,862	1,883	1,906	1,934	1,956
Light Load	1,599	1,620	1,636	1,653	1,674	1,693	1,712	1,732	1,758	1,778
Heavy Load	1,885	1,909	1,928	1,947	1,974	1,995	2,017	2,041	2,072	2,096
Total Load	1,759	1,782	1,800	1,818	1,842	1,862	1,883	1,906	1,934	1,956
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	3,344	3,403	3,456	3,500	3,555	3,609	3,664	3,722	3,782	3,835
Total Peak Load	3,344	3,403	3,456	3,500	3,555	3,609	3,664	3,722	3,782	3,835

	2023	2024	2024	2026	2027	2028	2029	2030	2031	2032
Billed Sales (MWh)–50th Percentile										
Residential	5,599,951	5,652,900	5,698,298	5,769,278	5,841,976	5,896,722	5,965,645	6,041,626	6,104,767	6,163,934
Commercial	4,337,889	4,377,042	4,412,765	4,464,888	4,517,788	4,562,924	4,618,921	4,680,777	4,740,317	4,802,348
Irrigation	1,764,576	1,768,216	1,763,156	1,752,206	1,754,887	1,758,862	1,752,877	1,753,702	1,757,850	1,755,683
Industrial	2,832,435	2,875,947	2,917,139	2,961,183	3,005,317	3,047,482	3,090,882	3,134,512	3,177,840	3,222,016
Additional Firm	1,234,000	1,231,300	1,234,000	1,228,400	1,228,300	1,217,500	1,212,000	1,268,000	1,262,200	1,257,000
System Sales	15,768,851	15,905,405	16,025,359	16,175,955	16,348,269	16,483,491	16,640,325	16,878,617	17,042,974	17,200,980
Total Sales	15,768,851	15,905,405	16,025,359	16,175,955	16,348,269	16,483,491	16,640,325	16,878,617	17,042,974	17,200,980
Generation Month Sales (MWh)–50th Percentile										
Residential	5,604,321	5,673,871	5,703,975	5,775,094	5,846,523	5,919,794	5,971,741	6,046,816	6,109,685	6,186,758
Commercial	4,340,155	4,390,757	4,415,734	4,467,902	4,520,389	4,578,115	4,622,430	4,684,166	4,743,845	4,818,548
Irrigation	1,764,577	1,768,253	1,763,152	1,752,207	1,754,889	1,758,898	1,752,877	1,753,704	1,757,849	1,755,721
Industrial	2,836,188	2,879,500	2,920,938	2,964,990	3,008,954	3,051,226	3,094,645	3,138,249	3,181,650	3,225,818
Additional Firm	1,234,000	1,231,300	1,234,000	1,228,400	1,228,300	1,217,500	1,212,000	1,268,000	1,262,200	1,257,000
System Sales	15,779,241	15,943,680	16,037,799	16,188,593	16,359,055	16,525,533	16,653,693	16,890,934	17,055,229	17,243,844
Total Sales	15,779,241	15,943,680	16,037,799	16,188,593	16,359,055	16,525,533	16,653,693	16,890,934	17,055,229	17,243,844
Loss	1,536,622	1,553,151	1,561,805	1,577,035	1,594,124	1,611,513	1,624,411	1,644,521	1,661,381	1,680,699
Required Generation	17,315,863	17,496,832	17,599,604	17,765,627	17,953,179	18,137,046	18,278,105	18,535,456	18,716,610	18,924,543
Average Load (aMW)–50th Percentile										
Residential	640	646	651	659	667	674	682	690	697	704
Commercial	495	500	504	510	516	521	528	535	542	549
Irrigation	201	201	201	200	200	200	200	200	201	200
Industrial	324	328	333	338	343	347	353	358	363	367
Additional Firm	141	140	141	140	140	139	138	145	144	143
Loss	175	177	178	180	182	183	185	188	190	191
System Load	1,977	1,992	2,009	2,028	2,049	2,065	2,087	2,116	2,137	2,154
Light Load	1,797	1,811	1,826	1,844	1,863	1,877	1,897	1,923	1,942	1,959
Heavy Load	2,119	2,134	2,153	2,172	2,196	2,213	2,236	2,267	2,283	2,301
Total Load	1,977	1,992	2,009	2,028	2,049	2,065	2,087	2,116	2,137	2,154
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	3,889	3,939	3,985	4,034	4,090	4,141	4,192	4,256	4,312	4,365
Total Peak Load	3,889	3,939	3,985	4,034	4,090	4,141	4,192	4,256	4,312	4,365

70th Percentile Load Forecast

Monthly Summary[1]	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Average Load (aMW)–70th Percentile												
Residential	816	698	581	494	457	491	612	579	471	468	592	820
Commercial	496	453	419	402	410	436	510	495	439	409	432	510
Irrigation	2	2	2	91	352	570	663	517	312	47	0	1
Industrial	264	266	262	251	254	270	269	273	270	274	273	278
Additional Firm	118	116	113	115	110	112	116	116	112	112	120	122
Loss	168	150	133	131	156	188	219	199	158	126	137	171
System Load	1,864	1,684	1,511	1,484	1,740	2,067	2,390	2,178	1,762	1,437	1,555	1,902
Light Load	1,722	1,554	1,388	1,344	1,582	1,850	2,168	1,933	1,583	1,296	1,435	1,757
Heavy Load	1,977	1,782	1,607	1,586	1,865	2,241	2,564	2,356	1,919	1,539	1,652	2,027
Total Load	1,864	1,684	1,511	1,484	1,740	2,067	2,390	2,178	1,762	1,437	1,555	1,902
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,505	2,384	2,092	1,971	2,805	3,264	3,382	3,027	2,778	2,026	2,267	2,683
Total Peak Load	2,505	2,384	2,092	1,971	2,805	3,264	3,382	3,027	2,778	2,026	2,267	2,683

Monthly Summary[1]	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Average Load (aMW)–70th Percentile												
Residential	820	699	583	496	460	496	618	585	474	470	595	823
Commercial	503	459	425	408	416	444	518	503	447	416	438	517
Irrigation	2	2	2	91	354	574	667	520	314	48	0	1
Industrial	272	274	269	259	261	277	277	281	278	282	281	286
Additional Firm	121	117	115	117	113	110	118	118	114	114	122	124
Loss	170	152	135	133	158	190	222	201	160	127	139	172
System Load	1,887	1,702	1,530	1,503	1,763	2,090	2,421	2,208	1,788	1,457	1,576	1,923
Light Load	1,743	1,570	1,406	1,362	1,603	1,871	2,197	1,959	1,606	1,314	1,454	1,777
Heavy Load	2,001	1,800	1,627	1,607	1,889	2,266	2,598	2,404	1,933	1,561	1,683	2,039
Total Load	1,887	1,702	1,530	1,503	1,763	2,090	2,421	2,208	1,788	1,457	1,576	1,923
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,534	2,403	2,115	1,996	2,852	3,310	3,442	3,071	2,822	2,047	2,289	2,704
Total Peak Load	2,534	2,403	2,115	1,996	2,852	3,310	3,442	3,071	2,822	2,047	2,289	2,704

Monthly Summary[1]	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Average Load (aMW)–70th Percentile												
Residential	820	696	582	496	462	499	622	588	476	470	596	831
Commercial	507	462	428	412	420	448	524	508	452	420	442	522
Irrigation	2	2	2	91	355	576	669	522	315	48	0	1
Industrial	279	281	277	265	268	285	285	288	286	290	289	293
Additional Firm	124	121	119	120	116	113	121	121	117	117	126	128
Loss	171	152	136	134	160	192	224	203	162	129	140	175
System Load	1,903	1,714	1,544	1,519	1,780	2,112	2,445	2,231	1,807	1,473	1,593	1,949
Light Load	1,758	1,582	1,418	1,376	1,619	1,890	2,219	1,979	1,624	1,329	1,470	1,800
Heavy Load	2,018	1,813	1,642	1,623	1,920	2,274	2,624	2,429	1,954	1,578	1,701	2,066
Total Load	1,903	1,714	1,544	1,519	1,780	2,112	2,445	2,231	1,807	1,473	1,593	1,949
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,530	2,413	2,108	1,980	2,898	3,345	3,495	3,106	2,856	2,065	2,289	2,718
Total Peak Load	2,530	2,413	2,108	1,980	2,898	3,345	3,495	3,106	2,856	2,065	2,289	2,718

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–70th Percentile												
Residential	829	702	588	502	468	507	634	599	483	476	603	845
Commercial	512	466	433	416	425	454	530	514	458	425	447	528
Irrigation	2	2	2	91	352	570	663	517	312	47	0	1
Industrial	286	278	283	272	274	291	291	295	292	296	296	298
Additional Firm	124	117	119	120	116	113	121	121	117	117	126	128
Loss	173	153	137	135	161	193	226	205	163	130	142	177
System Load	1,927	1,717	1,562	1,536	1,797	2,129	2,465	2,251	1,826	1,492	1,614	1,976
Light Load	1,779	1,585	1,436	1,391	1,633	1,905	2,236	1,997	1,640	1,346	1,489	1,826
Heavy Load	2,053	1,815	1,654	1,642	1,937	2,292	2,661	2,434	1,974	1,608	1,714	2,095
Total Load	1,927	1,717	1,562	1,536	1,797	2,129	2,465	2,251	1,826	1,492	1,614	1,976
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,546	2,426	2,118	1,986	2,937	3,371	3,541	3,134	2,888	2,083	2,303	2,738
Total Peak Load	2,546	2,426	2,118	1,986	2,937	3,371	3,541	3,134	2,888	2,083	2,303	2,738

Monthly Summary[1]	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Average Load (aMW)–70th Percentile												
Residential	842	711	597	511	477	518	648	612	492	484	613	859
Commercial	517	470	437	420	429	459	535	520	463	430	451	533
Irrigation	2	2	2	91	352	570	662	517	312	47	0	1
Industrial	291	293	288	276	279	297	296	300	298	302	301	303
Additional Firm	125	122	120	121	117	114	122	122	118	118	127	129
Loss	175	156	139	137	163	195	228	207	165	132	144	180
System Load	1,952	1,752	1,582	1,556	1,817	2,152	2,493	2,278	1,849	1,513	1,636	2,004
Light Load	1,803	1,617	1,454	1,409	1,652	1,926	2,262	2,021	1,661	1,364	1,509	1,851
Heavy Load	2,081	1,854	1,675	1,673	1,947	2,318	2,691	2,463	1,999	1,630	1,738	2,135
Total Load	1,952	1,752	1,582	1,556	1,817	2,152	2,493	2,278	1,849	1,513	1,636	2,004
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,574	2,445	2,139	2,007	2,982	3,410	3,596	3,174	2,929	2,103	2,328	2,765
Total Peak Load	2,574	2,445	2,139	2,007	2,982	3,410	3,596	3,174	2,929	2,103	2,328	2,765

Monthly Summary[1]	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Average Load (aMW)–70th Percentile												
Residential	853	718	604	518	484	527	661	624	501	490	621	872
Commercial	521	472	440	424	433	463	540	525	468	434	455	538
Irrigation	2	2	2	91	353	572	665	518	313	47	0	1
Industrial	296	297	293	281	284	301	301	305	302	307	306	308
Additional Firm	125	121	119	121	117	114	122	122	118	118	127	128
Loss	177	157	141	138	164	197	231	209	167	134	145	182
System Load	1,974	1,768	1,599	1,572	1,835	2,175	2,520	2,303	1,869	1,529	1,654	2,029
Light Load	1,823	1,631	1,469	1,424	1,668	1,946	2,286	2,043	1,679	1,379	1,526	1,874
Heavy Load	2,093	1,870	1,692	1,691	1,966	2,342	2,720	2,491	2,036	1,638	1,757	2,162
Total Load	1,974	1,768	1,599	1,572	1,835	2,175	2,520	2,303	1,869	1,529	1,654	2,029
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,595	2,459	2,156	2,023	3,025	3,448	3,651	3,212	2,966	2,120	2,347	2,789
Total Peak Load	2,595	2,459	2,156	2,023	3,025	3,448	3,651	3,212	2,966	2,120	2,347	2,789

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–70th Percentile												
Residential	863	724	610	524	491	536	673	635	508	496	629	882
Commercial	525	476	444	428	437	469	546	530	474	438	459	544
Irrigation	2	2	2	91	354	573	666	520	314	47	0	1
Industrial	301	303	298	286	288	306	306	310	307	312	311	313
Additional Firm	126	122	120	122	117	115	123	123	119	119	128	129
Loss	179	158	142	140	166	199	233	212	169	135	147	184
System Load	1,996	1,785	1,616	1,590	1,854	2,198	2,547	2,330	1,891	1,548	1,674	2,054
Light Load	1,844	1,647	1,485	1,440	1,686	1,967	2,311	2,067	1,699	1,396	1,544	1,897
Heavy Load	2,117	1,888	1,719	1,699	1,987	2,383	2,734	2,519	2,060	1,657	1,778	2,188
Total Load	1,996	1,785	1,616	1,590	1,854	2,198	2,547	2,330	1,891	1,548	1,674	2,054
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,620	2,474	2,175	2,042	3,068	3,487	3,707	3,251	3,005	2,139	2,368	2,814
Total Peak Load	2,620	2,474	2,175	2,042	3,068	3,487	3,707	3,251	3,005	2,139	2,368	2,814

Monthly Summary[1]	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Average Load (aMW)–70th Percentile												
Residential	870	727	614	529	496	544	683	644	514	501	635	891
Commercial	531	480	449	432	442	474	552	537	480	443	464	550
Irrigation	2	2	2	91	355	575	668	521	315	48	0	1
Industrial	306	297	303	290	293	312	312	315	313	317	316	318
Additional Firm	132	124	126	127	122	119	127	128	123	124	134	136
Loss	181	159	144	141	168	202	236	214	171	137	149	186
System Load	2,022	1,789	1,637	1,611	1,877	2,225	2,578	2,359	1,916	1,569	1,698	2,083
Light Load	1,868	1,651	1,504	1,459	1,706	1,991	2,339	2,093	1,721	1,415	1,566	1,924
Heavy Load	2,144	1,891	1,741	1,722	2,023	2,396	2,766	2,568	2,072	1,680	1,813	2,208
Total Load	2,022	1,789	1,637	1,611	1,877	2,225	2,578	2,359	1,916	1,569	1,698	2,083
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,648	2,493	2,197	2,063	3,117	3,529	3,766	3,293	3,046	2,161	2,394	2,843
Total Peak Load	2,648	2,493	2,197	2,063	3,117	3,529	3,766	3,293	3,046	2,161	2,394	2,843

Monthly Summary[1]	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Average Load (aMW)–70th Percentile												
Residential	877	730	617	533	501	550	692	653	520	505	640	901
Commercial	535	484	453	436	446	479	558	542	485	448	468	555
Irrigation	2	2	2	91	355	575	669	522	315	48	0	1
Industrial	311	313	308	295	298	317	317	320	318	322	321	323
Additional Firm	143	138	135	136	130	127	135	135	130	131	144	148
Loss	183	161	145	143	170	204	238	216	173	138	150	189
System Load	2,051	1,828	1,660	1,635	1,901	2,253	2,609	2,389	1,942	1,592	1,725	2,117
Light Load	1,894	1,687	1,526	1,481	1,728	2,017	2,368	2,120	1,744	1,436	1,591	1,956
Heavy Load	2,186	1,933	1,758	1,748	2,050	2,426	2,800	2,601	2,100	1,716	1,832	2,244
Total Load	2,051	1,828	1,660	1,635	1,901	2,253	2,609	2,389	1,942	1,592	1,725	2,117
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,674	2,519	2,216	2,079	3,168	3,572	3,827	3,337	3,088	2,186	2,418	2,874
Total Peak Load	2,674	2,519	2,216	2,079	3,168	3,572	3,827	3,337	3,088	2,186	2,418	2,874

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–70th Percentile												
Residential	884	734	622	537	507	558	702	662	526	509	646	912
Commercial	540	488	457	440	451	485	564	548	492	453	473	562
Irrigation	2	2	2	91	355	575	668	521	315	48	0	1
Industrial	316	318	313	300	303	322	322	326	323	328	327	328
Additional Firm	148	142	139	141	134	131	138	139	134	135	149	153
Loss	185	163	147	145	171	205	240	219	175	140	152	191
System Load	2,075	1,846	1,680	1,654	1,921	2,276	2,635	2,414	1,964	1,612	1,747	2,147
Light Load	1,917	1,703	1,543	1,498	1,746	2,037	2,391	2,142	1,764	1,454	1,611	1,984
Heavy Load	2,212	1,953	1,778	1,768	2,071	2,451	2,845	2,611	2,123	1,737	1,855	2,276
Total Load	2,075	1,846	1,680	1,654	1,921	2,276	2,635	2,414	1,964	1,612	1,747	2,147
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,696	2,537	2,232	2,092	3,213	3,608	3,881	3,374	3,126	2,207	2,438	2,901
Total Peak Load	2,696	2,537	2,232	2,092	3,213	3,608	3,881	3,374	3,126	2,207	2,438	2,901

Monthly Summary[1]	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Average Load (aMW)–70th Percentile												
Residential	893	739	627	543	513	566	714	673	533	515	653	922
Commercial	546	492	462	445	456	491	571	555	498	458	478	568
Irrigation	2	2	2	91	355	574	668	521	315	48	0	1
Industrial	321	323	318	305	308	327	327	331	328	333	332	333
Additional Firm	148	143	140	141	135	132	139	139	134	136	150	153
Loss	187	164	148	146	173	207	243	221	177	141	154	193
System Load	2,097	1,862	1,697	1,672	1,940	2,298	2,662	2,440	1,985	1,630	1,766	2,171
Light Load	1,937	1,719	1,559	1,514	1,763	2,057	2,415	2,165	1,783	1,470	1,630	2,006
Heavy Load	2,235	1,970	1,796	1,798	2,078	2,475	2,874	2,638	2,147	1,757	1,876	2,313
Total Load	2,097	1,862	1,697	1,672	1,940	2,298	2,662	2,440	1,985	1,630	1,766	2,171
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,719	2,551	2,249	2,109	3,257	3,645	3,935	3,412	3,164	2,225	2,458	2,924
Total Peak Load	2,719	2,551	2,249	2,109	3,257	3,645	3,935	3,412	3,164	2,225	2,458	2,924

Monthly Summary[1]	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Average Load (aMW)–70th Percentile												
Residential	900	742	631	548	519	574	724	682	539	519	658	931
Commercial	551	495	466	449	460	496	576	561	504	463	482	573
Irrigation	2	2	2	91	355	575	669	522	315	48	0	1
Industrial	326	317	323	310	312	332	332	336	333	338	337	338
Additional Firm	148	138	140	141	134	131	139	139	134	135	149	153
Loss	188	164	149	147	174	209	245	223	178	143	155	195
System Load	2,115	1,857	1,710	1,686	1,955	2,318	2,685	2,462	2,004	1,645	1,782	2,191
Light Load	1,953	1,714	1,572	1,527	1,778	2,075	2,437	2,185	1,800	1,484	1,644	2,024
Heavy Load	2,242	1,963	1,820	1,802	2,095	2,513	2,882	2,663	2,182	1,762	1,893	2,334
Total Load	2,115	1,857	1,710	1,686	1,955	2,318	2,685	2,462	2,004	1,645	1,782	2,191
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,728	2,558	2,254	2,111	3,298	3,679	3,987	3,445	3,198	2,240	2,467	2,938
Total Peak Load	2,728	2,558	2,254	2,111	3,298	3,679	3,987	3,445	3,198	2,240	2,467	2,938

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–70th Percentile												
Residential	905	744	634	551	523	580	733	690	545	522	663	941
Commercial	554	498	469	453	464	501	581	566	509	467	485	579
Irrigation	2	2	2	91	354	574	667	520	314	48	0	1
Industrial	330	333	327	314	317	337	337	341	338	343	342	343
Additional Firm	148	143	140	141	135	132	139	140	135	136	150	153
Loss	190	166	150	148	175	211	247	225	180	144	157	197
System Load	2,130	1,885	1,723	1,699	1,969	2,334	2,705	2,481	2,020	1,659	1,796	2,215
Light Load	1,967	1,739	1,583	1,538	1,790	2,089	2,454	2,201	1,815	1,496	1,657	2,046
Heavy Load	2,259	1,994	1,833	1,816	2,110	2,530	2,902	2,702	2,184	1,777	1,918	2,348
Total Load	2,130	1,885	1,723	1,699	1,969	2,334	2,705	2,481	2,020	1,659	1,796	2,215
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,730	2,568	2,252	2,103	3,337	3,705	4,033	3,473	3,226	2,254	2,470	2,952
Total Peak Load	2,730	2,568	2,252	2,103	3,337	3,705	4,033	3,473	3,226	2,254	2,470	2,952

Monthly Summary[1]	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Average Load (aMW)–70th Percentile												
Residential	915	749	640	557	530	589	745	702	552	528	670	954
Commercial	560	503	474	458	470	507	589	573	516	473	491	586
Irrigation	2	2	2	91	353	571	663	517	312	47	0	1
Industrial	335	338	332	319	322	342	342	346	343	348	347	348
Additional Firm	147	142	139	140	134	131	139	139	134	135	149	152
Loss	192	167	152	150	177	212	249	227	181	146	158	200
System Load	2,152	1,900	1,739	1,715	1,985	2,353	2,727	2,503	2,039	1,677	1,815	2,241
Light Load	1,987	1,754	1,598	1,553	1,804	2,105	2,474	2,221	1,832	1,512	1,675	2,070
Heavy Load	2,282	2,010	1,850	1,833	2,140	2,533	2,926	2,726	2,205	1,795	1,939	2,375
Total Load	2,152	1,900	1,739	1,715	1,985	2,353	2,727	2,503	2,039	1,677	1,815	2,241
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,751	2,581	2,267	2,117	3,379	3,737	4,083	3,506	3,262	2,272	2,489	2,977
Total Peak Load	2,751	2,581	2,267	2,117	3,379	3,737	4,083	3,506	3,262	2,272	2,489	2,977

Monthly Summary[1]	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Average Load (aMW)–70th Percentile												
Residential	924	754	645	564	537	598	758	713	560	534	678	964
Commercial	567	508	480	463	475	514	596	580	523	479	496	592
Irrigation	2	2	2	91	353	571	664	518	313	47	0	1
Industrial	340	343	337	323	327	347	347	351	348	353	352	353
Additional Firm	147	142	139	140	134	131	139	139	134	135	149	152
Loss	194	169	153	152	178	215	251	229	183	147	160	202
System Load	2,174	1,916	1,757	1,733	2,004	2,377	2,755	2,530	2,062	1,695	1,835	2,265
Light Load	2,008	1,768	1,614	1,570	1,822	2,127	2,500	2,245	1,852	1,529	1,693	2,092
Heavy Load	2,317	2,027	1,859	1,852	2,161	2,559	2,957	2,755	2,230	1,827	1,949	2,401
Total Load	2,174	1,916	1,757	1,733	2,004	2,377	2,755	2,530	2,062	1,695	1,835	2,265
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,774	2,596	2,285	2,135	3,422	3,777	4,139	3,547	3,303	2,291	2,509	3,000
Total Peak Load	2,774	2,596	2,285	2,135	3,422	3,777	4,139	3,547	3,303	2,291	2,509	3,000

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–70th Percentile												
Residential	931	757	649	568	542	606	768	723	566	538	683	975
Commercial	572	512	484	467	480	519	602	586	529	484	501	599
Irrigation	2	2	2	91	354	573	666	519	314	47	0	1
Industrial	345	335	342	328	331	352	352	356	353	358	357	358
Additional Firm	146	136	138	139	133	130	138	138	133	134	147	150
Loss	195	169	155	153	180	216	254	231	185	149	161	204
System Load	2,191	1,910	1,769	1,747	2,020	2,397	2,780	2,553	2,081	1,710	1,850	2,288
Light Load	2,024	1,762	1,626	1,582	1,837	2,145	2,522	2,265	1,869	1,542	1,707	2,114
Heavy Load	2,335	2,019	1,873	1,878	2,165	2,581	3,001	2,761	2,250	1,842	1,965	2,438
Total Load	2,191	1,910	1,769	1,747	2,020	2,397	2,780	2,553	2,081	1,710	1,850	2,288
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,781	2,605	2,288	2,135	3,463	3,812	4,191	3,582	3,337	2,306	2,517	3,016
Total Peak Load	2,781	2,605	2,288	2,135	3,463	3,812	4,191	3,582	3,337	2,306	2,517	3,016

Monthly Summary[1]	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Average Load (aMW)–70th Percentile												
Residential	940	761	654	574	549	615	781	734	574	543	690	988
Commercial	578	517	489	473	486	526	610	594	537	490	507	607
Irrigation	2	2	2	91	353	571	664	517	313	47	0	1
Industrial	350	352	347	333	336	357	357	361	358	363	362	363
Additional Firm	145	140	137	139	133	130	138	138	133	134	146	149
Loss	197	171	156	154	182	218	256	234	187	150	163	207
System Load	2,212	1,943	1,786	1,763	2,037	2,417	2,804	2,578	2,101	1,728	1,869	2,315
Light Load	2,043	1,793	1,641	1,597	1,852	2,163	2,545	2,287	1,888	1,558	1,724	2,139
Heavy Load	2,346	2,055	1,890	1,896	2,183	2,603	3,028	2,788	2,288	1,850	1,985	2,467
Total Load	2,212	1,943	1,786	1,763	2,037	2,417	2,804	2,578	2,101	1,728	1,869	2,315
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,800	2,616	2,301	2,147	3,505	3,847	4,244	3,619	3,375	2,324	2,534	3,040
Total Peak Load	2,800	2,616	2,301	2,147	3,505	3,847	4,244	3,619	3,375	2,324	2,534	3,040

Monthly Summary[1]	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Average Load (aMW)–70th Percentile												
Residential	950	766	660	581	556	625	794	746	582	550	698	1,000
Commercial	585	522	496	479	492	534	618	602	545	497	513	615
Irrigation	2	2	2	91	353	571	664	518	313	47	0	1
Industrial	355	357	352	337	341	362	362	366	363	368	367	368
Additional Firm	152	147	144	145	138	136	143	143	138	139	154	158
Loss	200	173	158	156	184	221	259	236	189	152	165	210
System Load	2,245	1,967	1,811	1,789	2,064	2,448	2,840	2,612	2,130	1,754	1,898	2,352
Light Load	2,073	1,815	1,664	1,620	1,876	2,191	2,577	2,317	1,914	1,581	1,751	2,172
Heavy Load	2,380	2,081	1,927	1,912	2,212	2,654	3,047	2,824	2,320	1,878	2,016	2,506
Total Load	2,245	1,967	1,811	1,789	2,064	2,448	2,840	2,612	2,130	1,754	1,898	2,352
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,836	2,642	2,329	2,174	3,556	3,895	4,308	3,668	3,424	2,351	2,566	3,077
Total Peak Load	2,836	2,642	2,329	2,174	3,556	3,895	4,308	3,668	3,424	2,351	2,566	3,077

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Average Load (aMW)–70th Percentile												
Residential	958	770	665	586	562	633	805	757	589	554	705	1,011
Commercial	592	527	501	485	499	541	627	610	553	504	519	623
Irrigation	2	2	2	91	354	572	665	519	313	47	0	1
Industrial	360	362	356	342	345	367	367	371	368	373	372	374
Additional Firm	151	146	143	144	138	135	143	143	138	139	153	156
Loss	202	174	160	158	185	223	262	239	192	154	167	212
System Load	2,265	1,981	1,827	1,806	2,083	2,472	2,868	2,639	2,153	1,771	1,917	2,377
Light Load	2,092	1,828	1,679	1,636	1,893	2,212	2,603	2,341	1,934	1,598	1,768	2,196
Heavy Load	2,390	2,096	1,944	1,930	2,219	2,679	3,060	2,874	2,313	1,897	2,036	2,507
Total Load	2,265	1,981	1,827	1,806	2,083	2,472	2,868	2,639	2,153	1,771	1,917	2,377
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,851	2,654	2,339	2,181	3,599	3,936	4,365	3,710	3,465	2,369	2,580	3,097
Total Peak Load	2,851	2,654	2,339	2,181	3,599	3,936	4,365	3,710	3,465	2,369	2,580	3,097

Monthly Summary[1]	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Average Load (aMW)–70th Percentile												
Residential	965	773	669	591	568	641	817	767	596	559	710	1,021
Commercial	599	533	508	491	505	549	635	619	561	510	526	632
Irrigation	2	2	2	91	353	572	665	518	313	47	0	1
Industrial	365	355	361	347	350	372	372	376	373	379	377	379
Additional Firm	151	140	142	144	137	135	142	142	137	138	152	156
Loss	204	174	161	159	187	225	264	241	194	155	169	214
System Load	2,286	1,977	1,843	1,822	2,100	2,493	2,894	2,664	2,174	1,789	1,935	2,402
Light Load	2,111	1,824	1,694	1,650	1,910	2,231	2,626	2,364	1,953	1,614	1,785	2,219
Heavy Load	2,412	2,101	1,951	1,948	2,251	2,685	3,088	2,901	2,336	1,928	2,045	2,534
Total Load	2,286	1,977	1,843	1,822	2,100	2,493	2,894	2,664	2,174	1,789	1,935	2,402
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,867	2,652	2,349	2,189	3,642	3,973	4,418	3,748	3,504	2,387	2,594	3,118
Total Peak Load	2,867	2,652	2,349	2,189	3,642	3,973	4,418	3,748	3,504	2,387	2,594	3,118

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Annual Summary

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Billed Sales (MWh)–70th Percentile										
Residential	5,164,791	5,195,891	5,206,261	5,276,623	5,369,337	5,450,107	5,523,750	5,580,441	5,632,102	5,689,844
Commercial	3,948,571	4,009,836	4,046,655	4,094,416	4,134,995	4,170,810	4,212,514	4,258,123	4,300,385	4,345,653
Irrigation	1,881,550	1,892,561	1,899,085	1,881,000	1,879,758	1,886,182	1,890,570	1,895,609	1,898,618	1,895,444
Industrial	2,334,380	2,402,175	2,466,748	2,523,489	2,568,734	2,609,536	2,653,663	2,698,998	2,743,911	2,788,219
Additional Firm	1,009,771	1,025,200	1,052,800	1,053,500	1,062,300	1,059,600	1,067,700	1,115,100	1,193,100	1,228,700
System Sales	14,339,064	14,525,663	14,671,549	14,829,029	15,015,124	15,176,235	15,348,197	15,548,270	15,768,116	15,947,860
Total Sales	14,339,064	14,525,663	14,671,549	14,829,029	15,015,124	15,176,235	15,348,197	15,548,270	15,768,116	15,947,860
Generation Month Sales (MWh)–70th Percentile										
Residential	5,167,413	5,197,036	5,211,598	5,300,406	5,375,457	5,455,753	5,528,219	5,602,024	5,636,673	5,695,236
Commercial	3,951,973	4,011,934	4,049,337	4,107,904	4,137,048	4,173,184	4,215,100	4,272,056	4,302,959	4,348,499
Irrigation	1,881,554	1,892,564	1,899,078	1,881,038	1,879,761	1,886,184	1,890,572	1,895,649	1,898,617	1,895,444
Industrial	2,340,228	2,407,744	2,471,642	2,527,392	2,572,253	2,613,342	2,657,573	2,702,871	2,747,733	2,792,033
Additional Firm	1,009,771	1,025,200	1,052,800	1,053,500	1,062,300	1,059,600	1,067,700	1,115,100	1,193,100	1,228,700
System Sales	14,350,940	14,534,478	14,684,455	14,870,240	15,026,819	15,188,062	15,359,163	15,587,701	15,779,082	15,959,913
Total Sales	14,350,940	14,534,478	14,684,455	14,870,240	15,026,819	15,188,062	15,359,163	15,587,701	15,779,082	15,959,913
Loss	1,414,977	1,431,581	1,443,654	1,461,800	1,476,685	1,492,948	1,509,490	1,529,225	1,542,768	1,558,213
Required Generation	15,765,916	15,966,059	16,128,108	16,332,040	16,503,504	16,681,010	16,868,653	17,116,926	17,321,850	17,518,125
Average Load (aMW)–70th Percentile										
Residential	590	593	595	603	614	623	631	638	643	650
Commercial	451	458	462	468	472	476	481	486	491	496
Irrigation	215	216	217	214	215	215	216	216	217	216
Industrial	267	275	282	288	294	298	303	308	314	319
Additional Firm	115	117	120	120	121	121	122	127	136	140
Loss	162	163	165	166	169	170	172	174	176	178
System Load	1,800	1,823	1,841	1,859	1,884	1,904	1,926	1,949	1,977	2,000
Light Load	1,636	1,657	1,673	1,690	1,712	1,731	1,750	1,771	1,797	1,818
Heavy Load	1,928	1,953	1,972	1,992	2,019	2,040	2,063	2,087	2,119	2,143
Total Load	1,800	1,823	1,841	1,859	1,884	1,904	1,926	1,949	1,977	2,000
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	3,382	3,442	3,495	3,541	3,596	3,651	3,707	3,766	3,827	3,881
Total Peak Load	3,382	3,442	3,495	3,541	3,596	3,651	3,707	3,766	3,827	3,881

	2023	2024	2024	2026	2027	2028	2029	2030	2031	2032
Billed Sales (MWh)–70th Percentile										
Residential	5,758,958	5,813,316	5,860,061	5,932,333	6,006,257	6,062,171	6,132,197	6,209,218	6,273,351	6,333,447
Commercial	4,395,933	4,435,955	4,472,534	4,525,502	4,579,235	4,625,191	4,681,997	4,744,649	4,804,978	4,867,787
Irrigation	1,894,663	1,898,303	1,893,243	1,882,293	1,884,974	1,888,949	1,882,964	1,883,789	1,887,937	1,885,770
Industrial	2,832,435	2,875,947	2,917,139	2,961,183	3,005,317	3,047,482	3,090,882	3,134,512	3,177,840	3,222,016
Additional Firm	1,234,000	1,231,300	1,234,000	1,228,400	1,228,300	1,217,500	1,212,000	1,268,000	1,262,200	1,257,000
System Sales	16,115,989	16,254,821	16,376,977	16,529,711	16,704,083	16,841,293	17,000,039	17,240,168	17,406,305	17,566,020
Total Sales	16,115,989	16,254,821	16,376,977	16,529,711	16,704,083	16,841,293	17,000,039	17,240,168	17,406,305	17,566,020
Generation Month Sales (MWh)–70th Percentile										
Residential	5,763,317	5,834,947	5,865,721	5,938,129	6,010,781	6,085,880	6,138,263	6,214,376	6,278,234	6,356,880
Commercial	4,398,233	4,449,963	4,475,535	4,528,549	4,581,867	4,640,688	4,685,537	4,748,069	4,808,536	4,884,307
Irrigation	1,894,665	1,898,340	1,893,239	1,882,294	1,884,976	1,888,985	1,882,964	1,883,791	1,887,936	1,885,808
Industrial	2,836,188	2,879,500	2,920,938	2,964,990	3,008,954	3,051,226	3,094,645	3,138,249	3,181,650	3,225,818
Additional Firm	1,234,000	1,231,300	1,234,000	1,228,400	1,228,300	1,217,500	1,212,000	1,268,000	1,262,200	1,257,000
System Sales	16,126,403	16,294,050	16,389,434	16,542,362	16,714,878	16,884,279	17,013,410	17,252,484	17,418,556	17,609,813
Total Sales	16,126,403	16,294,050	16,389,434	16,542,362	16,714,878	16,884,279	17,013,410	17,252,484	17,418,556	17,609,813
Loss	1,574,463	1,591,342	1,600,133	1,615,595	1,632,909	1,650,617	1,663,620	1,683,930	1,700,984	1,720,590
Required Generation	17,700,866	17,885,392	17,989,567	18,157,957	18,347,787	18,534,896	18,677,030	18,936,415	19,119,540	19,330,402
Average Load (aMW)–70th Percentile										
Residential	658	664	670	678	686	693	701	709	717	724
Commercial	502	507	511	517	523	528	535	542	549	556
Irrigation	216	216	216	215	215	215	215	215	216	215
Industrial	324	328	333	338	343	347	353	358	363	367
Additional Firm	141	140	141	140	140	139	138	145	144	143
Loss	180	181	183	184	186	188	190	192	194	196
System Load	2,021	2,036	2,054	2,073	2,094	2,110	2,132	2,162	2,183	2,201
Light Load	1,837	1,851	1,867	1,884	1,904	1,918	1,938	1,965	1,984	2,000
Heavy Load	2,166	2,181	2,200	2,221	2,244	2,261	2,284	2,316	2,332	2,351
Total Load	2,021	2,036	2,054	2,073	2,094	2,110	2,132	2,162	2,183	2,201
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	3,935	3,987	4,033	4,083	4,139	4,191	4,244	4,308	4,365	4,418
Total Peak Load	3,935	3,987	4,033	4,083	4,139	4,191	4,244	4,308	4,365	4,418

Load and Resource Balance Data

Monthly Average Energy Load and Resource Balance

	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Existing DSM (EE)	7	7	7	8	8	8	8	8	8	8	7	7
Load Forecast (70^{th}% w/DSM)	(1,864)	(1,684)	(1,511)	(1,484)	(1,740)	(2,067)	(2,390)	(2,178)	(1,762)	(1,437)	(1,555)	(1,902)
Existing Resources												
Coal	933	933	806	699	841	915	933	933	933	933	932	933
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	579	603	595	676	868	703	517	383	436	413	364	469
Hydro (70^{th}%)—Other	216	234	215	236	328	337	278	251	224	219	202	208
Shoshone Falls Upgrade (70^{th}%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70^{th}%)	795	837	811	912	1,195	1,040	867	634	660	632	566	677
CSPP (PURPA)	201	207	212	262	306	297	263	241	247	235	242	199
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange– Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	62	74	54	54	72	73	75	75	61	43	55	82
Firm Pacific NW Import Capability	0	0	0	0	205	292	194	264	68	0	0	0
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,539	2,342	1,882	1,926	2,620	3,126	2,837	2,662	2,249	2,127	2,084	2,431
Monthly Surplus/Deficit	675	657	371	442	880	1,059	447	483	487	690	529	529
2013 IRP DSM												
Irrigation	0	0	0	1	2	3	3	3	1	0	0	0
Commercial/Industrial	6	6	6	6	6	7	7	7	6	6	6	6
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Total New DSM (aMW)	6	6	6	7	9	10	10	9	8	7	6	7
Monthly Surplus/Deficit	682	664	378	449	889	1,068	457	493	495	697	535	535
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	682	664	378	449	889	1,068	457	493	495	697	535	535

Monthly Average Energy Load and Resource Balance (continued)

	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Existing DSM (EE)	14	14	14	15	16	16	16	16	15	14	14	14
Load Forecast (70th% w/DSM)	(1,887)	(1,702)	(1,530)	(1,503)	(1,763)	(2,090)	(2,421)	(2,208)	(1,788)	(1,457)	(1,576)	(1,923)
Existing Resources												
Coal	933	933	779	668	853	915	932	932	932	932	931	932
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	575	602	594	673	867	701	516	381	435	410	364	466
Hydro (70th%)—Other	215	221	213	228	327	336	278	250	223	219	201	207
Shoshone Falls Upgrade(70th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70th%)	790	823	806	901	1,194	1,037	865	632	658	629	565	673
CSPP (PURPA)	203	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange– Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	62	74	54	54	72	73	75	75	61	43	55	82
Firm Pacific NW Import Capability	0	0	0	0	230	352	237	277	113	0	0	1
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,536	2,341	1,863	1,896	2,667	3,195	2,889	2,683	2,302	2,134	2,094	2,438
Monthly Surplus/Deficit	650	639	333	392	904	1,104	468	475	515	677	518	515
2013 IRP DSM												
Irrigation	0	0	0	1	4	6	6	5	3	0	0	0
Commercial/Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Total New DSM (aMW)	13	13	13	14	17	19	20	19	16	14	13	13
Monthly Surplus/Deficit	663	653	347	407	921	1,124	487	494	530	691	531	528
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	663	653	347	407	921	1,124	487	494	530	691	531	528

Monthly Average Energy Load and Resource Balance (continued)

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Existing DSM (EE)	21	21	21	22	24	24	24	23	23	22	21	21
Load Forecast (70^{th}% w/DSM)	(1,903)	(1,714)	(1,544)	(1,519)	(1,780)	(2,112)	(2,445)	(2,231)	(1,807)	(1,473)	(1,593)	(1,949)
Existing Resources												
Coal	932	932	832	648	687	812	932	932	932	932	931	932
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	582	619	598	715	869	705	516	381	434	418	363	479
Hydro (70^{th}%)—Other	218	258	214	259	331	340	278	251	224	221	202	209
Shoshone Falls Upgrade(70^{th}%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70^{th}%)	799	877	813	974	1,199	1,045	865	632	658	639	566	688
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange– Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	62	74	54	54	72	73	75	75	61	43	55	82
Firm Pacific NW Import Capability	0	0	0	0	276	342	237	274	147	0	0	15
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,557	2,395	1,922	1,949	2,552	3,089	2,889	2,681	2,336	2,145	2,095	2,467
Monthly Surplus/Deficit	654	681	378	430	771	978	444	450	529	671	502	518
2013 IRP DSM												
Irrigation	0	0	0	2	6	8	8	7	4	1	0	0
Commercial/Industrial	19	19	19	19	19	20	20	20	19	19	19	19
Residential	1	1	1	1	1	1	1	1	1	1	1	1
Total New DSM (aMW)	20	20	20	21	26	28	29	27	23	20	20	20
Monthly Surplus/Deficit	673	700	398	451	797	1,006	473	478	552	691	521	538
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	673	700	398	451	797	1,006	473	478	552	691	521	538

Monthly Average Energy Load and Resource Balance (continued)

	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Existing DSM (EE)	26	26	26	27	29	30	30	29	28	26	26	26
Load Forecast (70^{th}% w/DSM)	(1,927)	(1,717)	(1,562)	(1,536)	(1,797)	(2,129)	(2,465)	(2,251)	(1,826)	(1,492)	(1,614)	(1,976)
Existing Resources												
Coal	932	932	703	686	716	839	938	938	938	938	937	938
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	581	617	599	712	872	704	515	351	432	416	364	488
Hydro (70^{th}%)—Other	218	283	214	261	330	340	277	206	224	221	202	208
Shoshone Falls Upgrade(70^{th}%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	798	900	813	973	1,202	1,043	791	556	656	637	566	696
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	0	0	0	0	314	342	237	272	178	0	0	34
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,551	2,412	1,807	1,997	2,611	3,104	2,811	2,602	2,368	2,168	2,117	2,497
Monthly Surplus/Deficit	624	694	244	461	815	975	347	351	542	675	504	520
2013 IRP DSM												
Irrigation	0	0	0	2	7	9	10	8	4	1	0	0
Commercial/Industrial	25	24	24	24	25	25	25	25	24	24	24	24
Residential	2	2	2	2	2	2	2	2	2	2	2	2
Total New DSM (aMW)	27	26	26	28	33	36	37	35	31	27	26	26
Monthly Surplus/Deficit	651	721	270	489	848	1,012	383	386	572	703	530	547
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	651	721	270	489	848	1,012	383	386	572	703	530	547

Monthly Average Energy Load and Resource Balance (continued)

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Existing DSM (EE)	30	30	30	31	34	35	35	34	33	30	30	30
Load Forecast (70^{th}% w/DSM)	(1,952)	(1,752)	(1,582)	(1,556)	(1,817)	(2,152)	(2,493)	(2,278)	(1,849)	(1,513)	(1,636)	(2,004)
Existing Resources												
Coal	938	938	940	781	709	835	944	944	944	944	943	944
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	580	616	596	700	867	702	513	349	431	414	364	487
Hydro (70^{th}%)—Other	217	275	206	251	330	338	276	205	223	220	201	208
Shoshone Falls Upgrade(70^{th}%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	797	891	802	951	1,197	1,041	789	554	654	634	565	694
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	0	0	0	0	359	347	237	269	219	0	0	61
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,555	2,409	2,032	2,070	2,644	3,102	2,816	2,603	2,412	2,171	2,123	2,528
Monthly Surplus/Deficit	603	656	449	514	828	950	323	325	564	658	487	524
2013 IRP DSM												
Irrigation	0	0	0	2	8	11	11	9	5	1	0	0
Commercial/Industrial	29	29	29	29	30	30	30	30	29	29	29	30
Residential	4	4	4	4	4	3	3	3	4	4	4	4
Total New DSM (aMW)	33	33	33	35	41	44	45	43	38	34	33	33
Monthly Surplus/Deficit	636	689	482	550	868	994	368	368	602	692	520	558
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	636	689	482	550	868	994	368	368	602	692	520	558

Monthly Average Energy Load and Resource Balance (continued)

	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Existing DSM (EE)	34	34	34	35	39	40	40	39	37	34	34	34
Load Forecast (70th% w/DSM)	(1,974)	(1,768)	(1,599)	(1,572)	(1,835)	(2,175)	(2,520)	(2,303)	(1,869)	(1,529)	(1,654)	(2,029)
Existing Resources												
Coal	944	944	881	731	743	922	948	948	948	948	947	948
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	579	606	588	699	866	694	512	348	430	410	364	480
Hydro (70th%)—Other	215	233	206	250	330	337	276	204	222	219	201	207
Shoshone Falls Upgrade(70th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	795	839	794	949	1,196	1,032	788	552	652	630	564	687
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	0	0	0	0	385	342	237	267	257	0	0	86
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,559	2,363	1,965	2,017	2,704	3,175	2,818	2,603	2,452	2,170	2,126	2,550
Monthly Surplus/Deficit	585	595	367	445	869	1,000	298	299	583	641	472	521
2013 IRP DSM												
Irrigation	0	0	0	2	9	12	13	11	6	1	0	0
Commercial/Industrial	35	35	35	35	35	36	36	36	35	35	35	35
Residential	7	7	7	7	7	6	6	6	7	7	7	7
Total New DSM (aMW)	42	42	41	44	51	55	55	53	48	42	42	42
Monthly Surplus/Deficit	627	636	408	489	920	1,055	353	352	630	683	513	563
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	827	836	608	989	1,420	1,555	853	852	1,130	883	713	763

Monthly Average Energy Load and Resource Balance (continued)

	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Existing DSM (EE)	37	37	37	39	44	45	45	44	41	38	37	37
Load Forecast (70th% w/DSM)	(1,996)	(1,785)	(1,616)	(1,590)	(1,854)	(2,198)	(2,547)	(2,330)	(1,891)	(1,548)	(1,674)	(2,054)
Existing Resources												
Coal	948	948	901	833	731	865	954	954	954	954	953	954
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	578	602	588	695	865	690	511	347	428	399	363	474
Hydro (70th%)—Other	215	223	200	243	329	337	275	203	221	219	199	207
Shoshone Falls Upgrade(70th%)	0	0	0	0	0	0	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	793	825	788	937	1,195	1,027	788	549	649	618	564	684
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	0	0	0	0	384	342	237	265	270	0	0	111
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,561	2,353	1,979	2,109	2,690	3,113	2,825	2,604	2,468	2,164	2,131	2,577
Monthly Surplus/Deficit	565	568	363	519	836	915	277	274	576	617	457	524
2013 IRP DSM												
Irrigation	0	0	0	3	10	14	15	12	7	1	0	0
Commercial/Industrial	40	39	40	39	40	41	41	41	40	39	40	40
Residential	10	10	10	10	10	9	9	9	10	10	10	10
Total New DSM (aMW)	49	49	49	52	60	64	65	62	56	50	49	50
Monthly Surplus/Deficit	614	617	412	571	895	979	342	337	633	667	507	573
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	814	817	612	1,071	1,395	1,479	842	837	1,133	867	707	773

Monthly Average Energy Load and Resource Balance (continued)

	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Existing DSM (EE)	42	42	42	44	49	50	51	49	46	43	42	42
Load Forecast (70th% w/DSM)	(2,022)	(1,789)	(1,637)	(1,611)	(1,877)	(2,225)	(2,578)	(2,359)	(1,916)	(1,569)	(1,698)	(2,083)
Existing Resources												
Coal	948	948	949	762	686	910	954	954	954	954	954	954
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	577	599	588	691	865	687	510	345	427	395	364	469
Hydro (70th%)—Other	214	220	198	236	329	336	274	202	220	218	198	206
Shoshone Falls Upgrade(70th%)	6	15	0	1	15	17	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	798	834	786	929	1,208	1,039	786	547	647	613	563	677
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	0	0	0	0	383	342	237	262	269	0	4	139
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,566	2,361	2,025	2,029	2,657	3,170	2,822	2,599	2,464	2,160	2,136	2,598
Monthly Surplus/Deficit	543	572	388	418	781	945	245	240	549	591	439	515
2013 IRP DSM												
Irrigation	0	0	0	3	12	16	17	14	8	1	0	0
Commercial/Industrial	45	45	45	45	46	47	47	47	45	45	46	45
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM (aMW)	54	54	54	57	66	71	72	69	62	55	55	54
Monthly Surplus/Deficit	598	626	443	475	847	1,017	317	309	610	647	493	570
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	798	826	643	975	1,347	1,517	817	809	1,110	847	693	770

Monthly Average Energy Load and Resource Balance (continued)

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Existing DSM (EE)	45	45	45	48	54	55	56	54	51	46	45	45
Load Forecast (70^{th}% w/DSM)	(2,051)	(1,828)	(1,660)	(1,635)	(1,901)	(2,253)	(2,609)	(2,389)	(1,942)	(1,592)	(1,725)	(2,117)
Existing Resources												
Coal	894	863	811	624	658	791	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	576	593	588	687	864	684	508	344	425	395	364	479
Hydro (70^{th}%)—Other	213	219	196	238	327	333	273	201	219	217	197	205
Shoshone Falls Upgrade(70^{th}%)	6	12	0	1	15	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	795	824	784	926	1,206	1,033	784	544	643	612	562	686
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	87	0	0	0	434	395	290	313	320	0	83	225
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,596	2,267	1,884	1,888	2,678	3,099	2,819	2,593	2,458	2,104	2,159	2,639
Monthly Surplus/Deficit	545	439	224	253	776	845	209	204	516	512	435	522
2013 IRP DSM												
Irrigation	0	0	0	4	13	19	20	16	9	2	0	0
Commercial/Industrial	51	51	50	51	52	53	53	53	51	51	51	51
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM (aMW)	60	60	60	64	74	80	80	77	69	62	60	60
Monthly Surplus/Deficit	605	499	284	317	851	925	290	281	585	574	495	582
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	805	699	484	817	1,351	1,425	790	781	1,085	774	695	782

Monthly Average Energy Load and Resource Balance (continued)

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Existing DSM (EE)	45	45	45	48	54	55	56	54	51	46	45	45
Load Forecast (70th% w/DSM)	(2,051)	(1,828)	(1,660)	(1,635)	(1,901)	(2,253)	(2,609)	(2,389)	(1,942)	(1,592)	(1,725)	(2,117)
Existing Resources												
Coal	894	863	811	624	658	791	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	576	593	588	687	864	684	508	344	425	395	364	479
Hydro (70th%)—Other	213	219	196	238	327	333	273	201	219	217	197	205
Shoshone Falls Upgrade(70th%)	6	12	0	1	15	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	795	824	784	926	1,206	1,033	784	544	643	612	562	686
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	87	0	0	0	434	395	290	313	320	0	83	225
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,596	2,267	1,884	1,888	2,678	3,099	2,819	2,593	2,458	2,104	2,159	2,639
Monthly Surplus/Deficit	545	439	224	253	776	845	209	204	516	512	435	522
2013 IRP DSM												
Irrigation	0	0	0	4	13	19	20	16	9	2	0	0
Commercial/Industrial	51	51	50	51	52	53	53	53	51	51	51	51
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM (aMW)	60	60	60	64	74	80	80	77	69	62	60	60
Monthly Surplus/Deficit	605	499	284	317	851	925	290	281	585	574	495	582
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	805	699	484	817	1,351	1,425	790	781	1,085	774	695	782

Monthly Average Energy Load and Resource Balance (continued)

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Existing DSM (EE)	49	49	49	51	58	60	60	58	55	50	49	49
Load Forecast (70^{th}% w/DSM)	(2,075)	(1,846)	(1,680)	(1,654)	(1,921)	(2,276)	(2,635)	(2,414)	(1,964)	(1,612)	(1,747)	(2,147)
Existing Resources												
Coal	894	863	784	702	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	575	592	588	685	863	682	507	342	423	391	364	471
Hydro (70^{th}%)—Other	212	218	194	233	326	332	273	200	218	216	196	204
Shoshone Falls Upgrade(70^{th}%)	6	9	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	793	819	782	919	1,204	1,031	782	542	641	607	561	677
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	113	0	0	0	433	349	237	308	318	0	103	254
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,620	2,262	1,856	1,959	2,747	3,060	2,763	2,585	2,453	2,099	2,178	2,659
Monthly Surplus/Deficit	544	416	177	305	826	784	128	171	490	488	431	512
2013 IRP DSM												
Irrigation	0	0	0	4	15	22	22	19	10	2	0	0
Commercial/Industrial	59	58	58	58	59	60	60	60	58	58	58	58
Residential	9	9	10	10	9	8	8	8	9	9	9	10
Total New DSM (aMW)	68	67	67	72	84	90	91	88	78	70	68	67
Monthly Surplus/Deficit	613	483	244	376	910	875	219	258	567	557	499	580
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	813	683	444	876	1,410	1,375	719	758	1,067	757	699	780

Monthly Average Energy Load and Resource Balance (continued)

	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Existing DSM (EE)	52	52	52	55	62	64	65	62	58	53	52	52
Load Forecast (70th% w/DSM)	(2,097)	(1,862)	(1,697)	(1,672)	(1,940)	(2,298)	(2,662)	(2,440)	(1,985)	(1,630)	(1,766)	(2,171)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	574	591	587	682	862	681	505	341	422	387	364	463
Hydro (70th%)—Other	211	214	193	223	326	332	272	199	217	216	195	202
Shoshone Falls Upgrade(70th%)	6	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	791	812	780	905	1,202	1,029	779	539	638	602	560	668
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	136	0	0	0	431	346	237	306	316	0	123	291
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,641	2,254	1,848	1,905	2,743	3,055	2,761	2,581	2,449	2,094	2,198	2,687
Monthly Surplus/Deficit	543	392	151	234	804	757	99	141	464	464	431	516
2013 IRP DSM												
Irrigation	0	0	0	5	18	25	26	22	11	2	0	0
Commercial/Industrial	64	64	64	64	65	67	67	67	64	64	64	65
Residential	10	10	10	10	10	9	9	9	10	10	10	10
Total New DSM (aMW)	74	74	73	79	92	100	101	97	85	76	74	74
Monthly Surplus/Deficit	617	466	224	313	896	857	200	237	549	540	505	590
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	817	666	424	813	1,396	1,357	700	737	1,049	740	705	790

Monthly Average Energy Load and Resource Balance (continued)

	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Existing DSM (EE)	55	54	55	57	65	68	68	66	62	56	55	55
Load Forecast (70^{th}% w/DSM)	(2,115)	(1,857)	(1,710)	(1,686)	(1,955)	(2,318)	(2,685)	(2,462)	(2,004)	(1,645)	(1,782)	(2,191)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	573	590	587	677	861	680	504	339	421	383	364	458
Hydro (70^{th}%)—Other	209	212	191	211	325	331	271	198	216	215	194	201
Shoshone Falls Upgrade(70^{th}%)	5	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	787	809	778	889	1,201	1,027	777	537	637	598	559	662
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	143	0	0	0	430	342	237	303	315	0	132	312
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,643	2,251	1,846	1,889	2,741	3,049	2,759	2,575	2,446	2,090	2,206	2,702
Monthly Surplus/Deficit	529	394	135	203	785	731	74	113	442	445	424	511
2013 IRP DSM												
Irrigation	0	0	0	6	20	28	29	25	13	2	0	0
Commercial/Industrial	71	71	71	71	71	74	74	74	72	71	71	72
Residential	12	12	12	12	12	11	11	11	12	12	12	12
Total New DSM (aMW)	84	83	84	89	104	113	114	109	97	86	84	84
Monthly Surplus/Deficit	612	478	219	292	889	844	188	222	540	531	508	595
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	812	678	419	792	1,389	1,344	688	722	1,040	731	708	795

Monthly Average Energy Load and Resource Balance (continued)

	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Existing DSM (EE)	57	57	57	60	68	71	72	69	64	58	57	57
Load Forecast (70th% w/DSM)	(2,130)	(1,885)	(1,723)	(1,699)	(1,969)	(2,334)	(2,705)	(2,481)	(2,020)	(1,659)	(1,796)	(2,215)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	572	589	587	667	861	678	502	338	420	379	365	457
Hydro (70th%)—Other	208	212	190	210	325	330	270	197	215	214	193	200
Shoshone Falls Upgrade(70th%)	5	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	784	807	777	877	1,200	1,025	775	535	635	593	559	660
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	160	0	0	0	428	342	237	300	313	0	135	321
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,658	2,249	1,845	1,877	2,737	3,047	2,757	2,570	2,442	2,085	2,208	2,709
Monthly Surplus/Deficit	528	365	122	178	769	713	52	89	422	426	412	494
2013 IRP DSM												
Irrigation	0	0	0	6	23	32	33	28	15	3	0	0
Commercial/Industrial	77	77	77	77	77	80	80	80	77	77	78	77
Residential	16	16	16	16	16	14	14	14	16	16	16	16
Total New DSM (aMW)	93	93	93	99	116	126	127	122	108	96	94	93
Monthly Surplus/Deficit	621	458	216	278	885	839	179	211	530	522	506	587
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	821	658	416	778	1,385	1,339	679	711	1,030	722	706	787

Monthly Average Energy Load and Resource Balance (continued)

	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Existing DSM (EE)	59	59	59	62	71	74	75	72	67	60	59	59
Load Forecast (70^{th}% w/DSM)	(2,152)	(1,900)	(1,739)	(1,715)	(1,985)	(2,353)	(2,727)	(2,503)	(2,039)	(1,677)	(1,815)	(2,241)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70^{th}%)—HCC	570	588	587	666	860	677	501	336	419	375	365	456
Hydro (70^{th}%)—Other	205	211	189	209	325	329	269	196	214	213	192	200
Shoshone Falls Upgrade(70^{th}%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70^{th}%)	779	805	775	875	1,199	1,022	773	532	632	588	558	659
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	183	0	0	0	427	342	237	298	311	0	154	319
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,676	2,247	1,843	1,876	2,735	3,045	2,754	2,565	2,438	2,081	2,226	2,706
Monthly Surplus/Deficit	524	347	104	161	750	692	28	62	399	404	411	465
2013 IRP DSM												
Irrigation	0	0	0	7	26	36	38	32	17	3	0	0
Commercial/Industrial	83	83	83	83	84	86	86	86	83	83	84	83
Residential	21	21	21	21	21	18	18	18	21	21	21	21
Total New DSM (aMW)	104	104	104	111	131	141	142	136	120	107	105	104
Monthly Surplus/Deficit	628	451	208	271	881	833	170	198	519	511	516	569
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	828	651	408	771	1,381	1,333	670	698	1,019	711	716	769

Monthly Average Energy Load and Resource Balance (continued)

	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Existing DSM (EE)	61	61	61	64	74	77	77	74	69	63	61	61
Load Forecast (70th% w/DSM)	(2,174)	(1,916)	(1,757)	(1,733)	(2,004)	(2,377)	(2,755)	(2,530)	(2,062)	(1,695)	(1,835)	(2,265)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	218	0	0	0	425	342	237	295	308	0	174	317
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,700	2,245	1,841	1,874	2,731	3,042	2,752	2,560	2,433	2,077	2,246	2,702
Monthly Surplus/Deficit	526	329	84	141	727	666	(3)	29	371	382	411	437
2013 IRP DSM												
Irrigation	0	0	0	8	29	41	43	36	19	4	0	0
Commercial/Industrial	89	88	88	88	90	92	92	92	89	89	89	89
Residential	27	27	27	27	26	23	23	23	27	27	27	27
Total New DSM (aMW)	116	115	115	123	146	156	158	151	134	119	115	115
Monthly Surplus/Deficit	642	444	199	264	873	822	155	181	505	501	526	552
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	842	644	399	764	1,373	1,322	655	681	1,005	701	726	752

Monthly Average Energy Load and Resource Balance (continued)

	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Existing DSM (EE)	63	62	62	66	75	79	79	76	71	64	63	63
Load Forecast (70th% w/DSM)	(2,191)	(1,910)	(1,769)	(1,747)	(2,020)	(2,397)	(2,780)	(2,553)	(2,081)	(1,710)	(1,850)	(2,288)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	236	0	7	0	423	342	237	293	306	0	182	314
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,718	2,245	1,848	1,874	2,729	3,042	2,752	2,558	2,431	2,077	2,254	2,699
Monthly Surplus/Deficit	527	336	78	127	709	646	(27)	4	350	367	403	410
2013 IRP DSM												
Irrigation	0	0	0	9	33	46	48	40	21	4	0	0
Commercial/Industrial	96	94	94	95	96	98	98	98	95	95	95	96
Residential	33	33	33	33	33	29	29	29	33	33	33	33
Total New DSM (aMW)	128	127	127	137	161	174	175	168	149	132	128	128
Monthly Surplus/Deficit	655	463	206	264	871	819	148	172	499	499	531	538
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	855	663	406	764	1,371	1,319	648	672	999	699	731	738

Monthly Average Energy Load and Resource Balance (continued)

	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Existing DSM (EE)	64	64	64	68	77	80	81	78	73	65	64	64
Load Forecast (70th% w/DSM)	(2,212)	(1,943)	(1,786)	(1,763)	(2,037)	(2,417)	(2,804)	(2,578)	(2,101)	(1,728)	(1,869)	(2,315)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	247	0	24	0	421	342	237	290	304	0	199	312
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,729	2,245	1,865	1,874	2,727	3,042	2,752	2,555	2,429	2,077	2,271	2,697
Monthly Surplus/Deficit	517	303	79	111	690	625	(52)	(23)	327	349	402	381
2013 IRP DSM												
Irrigation	0	0	0	10	37	52	54	45	24	5	0	0
Commercial/Industrial	100	100	100	100	101	104	104	104	101	100	100	101
Residential	38	38	38	38	37	33	33	33	37	38	38	37
Total New DSM (aMW)	138	138	137	148	175	189	191	182	163	142	138	139
Monthly Surplus/Deficit	655	440	217	259	866	814	138	160	490	491	540	520
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	855	640	417	759	1,366	1,314	638	660	990	691	740	720

Monthly Average Energy Load and Resource Balance (continued)

	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Existing DSM (EE)	65	65	65	69	79	82	83	80	74	67	65	66
Load Forecast (70th% w/DSM)	(2,245)	(1,967)	(1,811)	(1,789)	(2,064)	(2,448)	(2,840)	(2,612)	(2,130)	(1,754)	(1,898)	(2,352)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	281	0	61	0	419	342	237	287	302	0	231	310
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,763	2,245	1,902	1,874	2,725	3,042	2,752	2,552	2,427	2,077	2,303	2,695
Monthly Surplus/Deficit	519	278	90	85	662	594	(87)	(60)	296	323	404	343
2013 IRP DSM												
Irrigation	0	0	0	11	38	54	56	47	25	5	0	0
Commercial/Industrial	105	105	105	105	105	109	109	109	106	105	105	106
Residential	43	43	43	43	43	38	38	38	43	43	43	43
Total New DSM (aMW)	148	148	148	158	186	200	202	194	174	152	148	149
Monthly Surplus/Deficit	667	426	239	243	848	795	115	134	470	476	553	492
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	867	626	439	743	1,348	1,295	615	634	970	676	753	692

Monthly Average Energy Load and Resource Balance (continued)

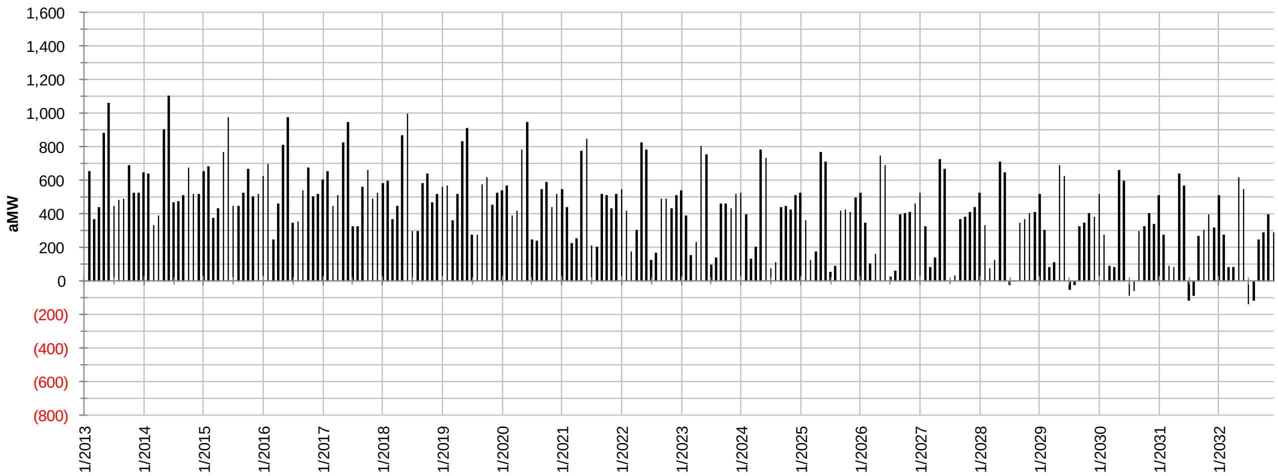
	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Existing DSM (EE)	66	66	66	70	80	83	84	81	75	68	66	66
Load Forecast (70th% w/DSM)	(2,265)	(1,981)	(1,827)	(1,806)	(2,083)	(2,472)	(2,868)	(2,639)	(2,153)	(1,771)	(1,917)	(2,377)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	37	36	34	31	31	35	37	26	31	41	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	68	67	65	62	62	65	68	57	62	72	78
Firm Pacific NW Import Capability	291	12	78	15	418	342	237	285	300	0	245	308
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,773	2,257	1,919	1,889	2,724	3,042	2,752	2,550	2,425	2,077	2,317	2,693
Monthly Surplus/Deficit	508	276	92	83	642	571	(116)	(89)	272	306	400	316
2013 IRP DSM												
Irrigation	0	0	0	11	40	56	58	49	26	5	0	0
Commercial/Industrial	110	110	110	109	110	114	114	114	110	109	111	110
Residential	48	48	48	48	48	42	42	42	48	48	47	48
Total New DSM (aMW)	158	157	158	168	198	212	214	205	184	162	159	158
Monthly Surplus/Deficit	666	433	249	252	840	783	98	116	455	468	559	474
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	866	633	449	752	1,340	1,283	598	616	955	668	759	674

Monthly Average Energy Load and Resource Balance (continued)

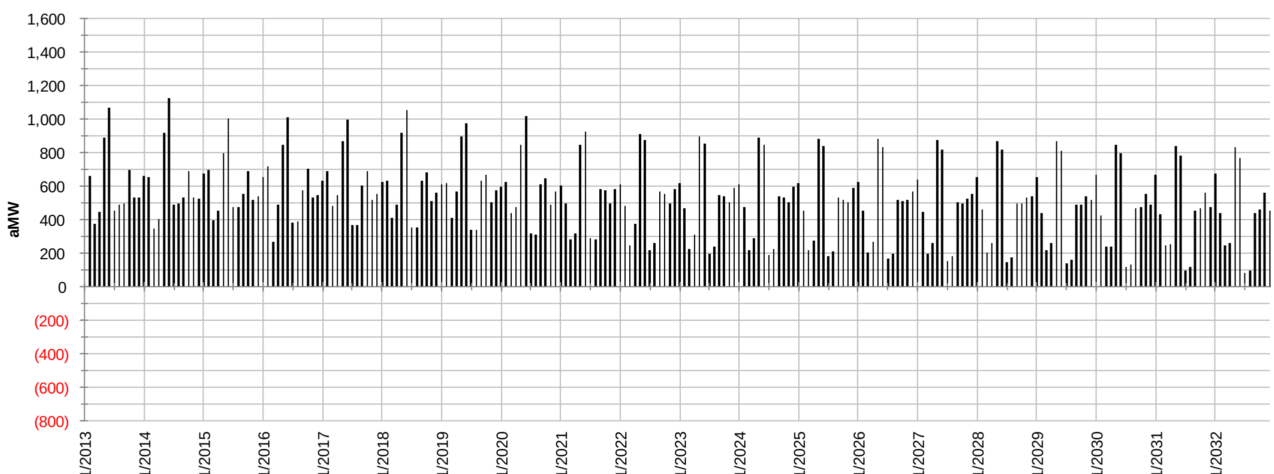
	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Existing DSM (EE)	67	67	67	70	81	84	84	81	75	68	67	67
Load Forecast (70th% w/DSM)	(2,286)	(1,977)	(1,843)	(1,822)	(2,100)	(2,493)	(2,894)	(2,664)	(2,174)	(1,789)	(1,935)	(2,402)
Existing Resources												
Coal	894	863	777	662	730	801	900	900	900	900	900	900
Gas (Langley Gulch)	296	291	0	0	0	278	276	277	279	284	289	296
Hydro (70th%)—HCC	562	587	586	665	859	676	500	335	417	372	365	455
Hydro (70th%)—Other	203	211	187	208	324	328	269	195	213	213	192	199
Shoshone Falls Upgrade(70th%)	4	6	0	0	14	16	2	0	0	0	1	3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	769	803	773	874	1,197	1,020	771	529	630	585	557	657
CSPP (PURPA)	214	221	223	273	317	308	275	253	259	246	254	210
PPAs												
Elkhorn Valley Wind	37	34	36	33	31	30	35	37	25	31	40	47
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	57	65	67	64	62	61	65	68	56	62	71	78
Firm Pacific NW Import Capability	313	10	85	33	416	342	237	281	299	0	259	306
Gas Peakers	253	0	0	0	0	231	229	238	0	0	0	244
Existing Resource Subtotal	2,795	2,252	1,926	1,906	2,722	3,041	2,752	2,546	2,423	2,077	2,329	2,691
Monthly Surplus/Deficit	510	275	83	84	622	548	(142)	(118)	249	288	394	288
2013 IRP DSM												
Irrigation	0	0	0	12	42	59	61	51	27	5	0	0
Commercial/Industrial	115	115	114	114	117	119	119	119	115	115	115	115
Residential	52	52	52	52	52	46	46	46	52	52	52	52
Total New DSM (aMW)	167	167	167	178	210	224	226	216	194	172	167	167
Monthly Surplus/Deficit	677	442	249	262	832	772	84	98	443	460	561	456
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	877	642	449	762	1,332	1,272	584	598	943	660	761	656

Monthly Average Energy Surplus/Deficit Charts

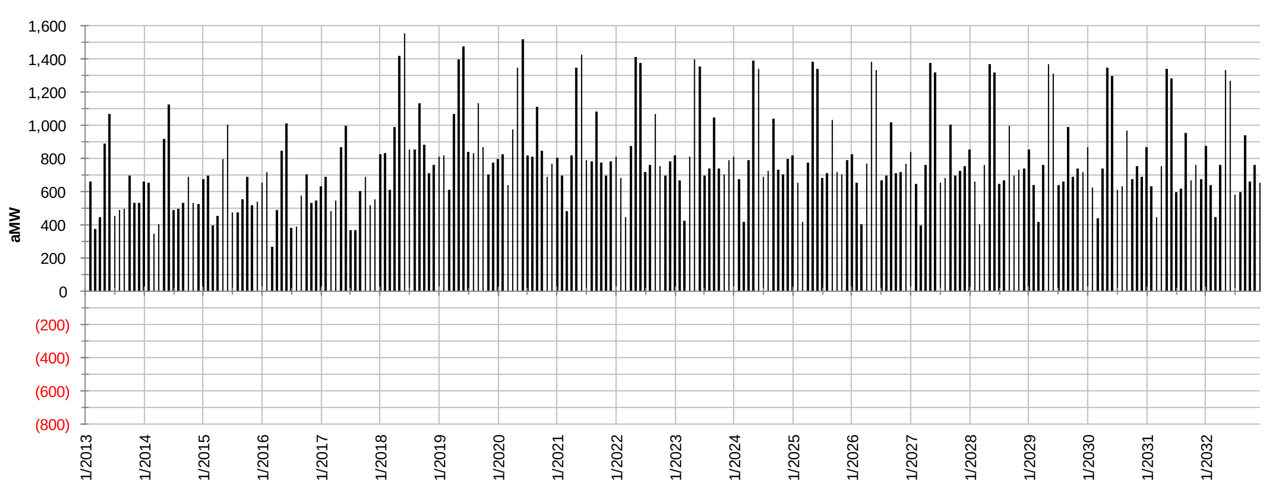
Average energy monthly surpluses and deficits with existing DSM and existing resources



Average energy monthly surpluses and deficits with existing DSM, existing resources, and IRP DSM



Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources



Peak-Hour Load and Resource Balance

	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Load Forecast (95th% w/no DSM)	(2,513)	(2,392)	(2,099)	(1,978)	(2,813)	(3,272)	(3,390)	(3,035)	(2,785)	(2,033)	(2,274)	(2,690)
Existing DSM (EE)	7	7	7	8	8	8	8	8	8	8	7	7
Peak-Hour Forecast w/DSM (EE)	(2,505)	(2,384)	(2,092)	(1,971)	(2,805)	(3,264)	(3,382)	(3,027)	(2,778)	(2,026)	(2,267)	(2,683)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,505)	(2,384)	(2,092)	(1,971)	(2,805)	(3,264)	(3,382)	(3,027)	(2,778)	(2,026)	(2,267)	(2,683)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	854	1,085	1,023	1,062	1,133	1,027	916	878	761	887	673	938
Hydro (90th%)—Other	245	246	224	244	347	360	304	270	255	249	240	245
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,099	1,331	1,247	1,306	1,480	1,387	1,268	1,148	1,016	1,136	912	1,183
CSPP (PURPA)	73	76	82	117	163	171	177	168	155	117	84	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
Total PPAs	29	40	30	27	42	43	41	40	39	27	23	39
Firm Pacific NW Import Capability	0	0	0	0	205	292	194	264	68	0	0	0
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,940	3,186	3,099	3,189	3,572	3,632	3,420	3,359	3,018	3,020	2,759	3,038
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	1	2	3	3	3	1	0	0	0
Commercial	6	6	6	6	6	7	7	7	6	6	6	6
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Total New DSM Peak Reduction	6	6	6	7	9	10	10	9	8	7	6	7
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	441	809	1,013	1,225	776	378	48	342	248	1,001	499	362

Peak-Hour Load and Resource Balance (continued)

	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Load Forecast (95th% w/no DSM)	(2,548)	(2,417)	(2,129)	(2,010)	(2,868)	(3,325)	(3,458)	(3,087)	(2,837)	(2,061)	(2,303)	(2,718)
Existing DSM (EE)	14	14	14	15	16	16	16	16	15	14	14	14
Peak-Hour Forecast w/DSM (EE)	(2,534)	(2,403)	(2,115)	(1,996)	(2,852)	(3,310)	(3,442)	(3,071)	(2,822)	(2,047)	(2,289)	(2,704)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,534)	(2,403)	(2,115)	(1,996)	(2,852)	(3,310)	(3,442)	(3,071)	(2,822)	(2,047)	(2,289)	(2,704)
Existing Resources												
Coal	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	852	1,078	1,017	1,061	1,132	1,024	914	874	758	880	673	935
Hydro (90th%)—Other	244	245	224	243	343	356	303	269	255	248	238	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,097	1,323	1,241	1,304	1,475	1,380	1,265	1,143	1,012	1,129	911	1,179
CSPP (PURPA)	75	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
Total PPAs	29	40	30	27	42	43	41	40	39	27	23	39
Firm Pacific NW Import Capability	0	0	0	0	230	352	237	277	113	0	0	1
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,940	3,192	3,103	3,141	3,661	3,697	3,471	3,379	3,070	3,024	2,769	3,047
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	1	4	6	6	5	3	0	0	0
Commercial	13	13	13	13	13	13	13	13	13	13	13	13
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Total New DSM Peak Reduction	13	13	13	14	17	19	20	19	16	14	13	13
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	419	803	1,001	1,159	825	406	49	326	265	991	493	356

Peak-Hour Load and Resource Balance (continued)

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Load Forecast (95th% w/no DSM)	(2,552)	(2,435)	(2,129)	(2,002)	(2,922)	(3,369)	(3,520)	(3,129)	(2,879)	(2,087)	(2,310)	(2,739)
Existing DSM (EE)	21	21	21	22	24	24	24	23	23	22	21	21
Peak-Hour Forecast w/DSM (EE)	(2,530)	(2,413)	(2,108)	(1,980)	(2,898)	(3,345)	(3,495)	(3,106)	(2,856)	(2,065)	(2,289)	(2,718)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,530)	(2,413)	(2,108)	(1,980)	(2,898)	(3,345)	(3,495)	(3,106)	(2,856)	(2,065)	(2,289)	(2,718)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	855	1,080	1,029	1,062	1,134	1,025	914	873	756	886	672	937
Hydro (90th%)—Other	244	246	231	245	352	365	304	272	255	252	241	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,100	1,326	1,260	1,307	1,487	1,390	1,266	1,145	1,011	1,138	913	1,181
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
Total PPAs	29	40	30	27	42	43	41	40	39	27	23	39
Firm Pacific NW Import Capability	0	0	0	0	276	342	237	274	147	0	0	15
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,954	3,195	3,122	3,202	3,718	3,697	3,472	3,377	3,103	3,033	2,771	3,063
Monthly Surplus/Deficit	0	0	0	0	0	0	(24)	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	2	6	8	8	7	4	1	0	0
Commercial	19	19	19	19	19	20	20	20	19	19	19	19
Residential	1	1	1	1	1	1	1	1	1	1	1	1
Total New DSM Peak Reduction	20	20	20	21	26	28	29	27	23	20	20	20
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	443	801	1,034	1,243	846	381	5	299	270	988	501	364

Peak-Hour Load and Resource Balance (continued)

	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Load Forecast (95th% w/no DSM)	(2,572)	(2,452)	(2,144)	(2,013)	(2,967)	(3,401)	(3,571)	(3,163)	(2,916)	(2,109)	(2,329)	(2,764)
Existing DSM (EE)	26	26	26	27	29	30	30	29	28	26	26	26
Peak-Hour Forecast w/DSM (EE)	(2,546)	(2,426)	(2,118)	(1,986)	(2,937)	(3,371)	(3,541)	(3,134)	(2,888)	(2,083)	(2,303)	(2,738)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,546)	(2,426)	(2,118)	(1,986)	(2,937)	(3,371)	(3,541)	(3,134)	(2,888)	(2,083)	(2,303)	(2,738)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	854	1,082	1,026	1,061	1,133	1,022	911	797	753	881	672	934
Hydro (90th%)—Other	244	248	231	244	353	365	303	233	256	252	241	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,098	1,329	1,257	1,305	1,485	1,388	1,215	1,030	1,009	1,133	913	1,178
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	314	342	237	272	178	0	0	34
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,948	3,194	3,125	3,209	3,692	3,688	3,415	3,256	3,129	3,037	2,784	3,076
Monthly Surplus/Deficit	0	0	0	0	0	0	(126)	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	2	7	9	10	8	4	1	0	0
Commercial	25	24	24	24	25	25	25	25	24	24	24	24
Residential	2	2	2	2	2	2	2	2	2	2	2	2
Total New DSM Peak Reduction	27	26	26	28	33	36	37	35	31	27	26	26
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(89)	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	100	100	100	0	0	0	0
New Resource Subtotal	0	0	0	0	0	100	100	100	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	429	794	1,034	1,251	788	452	11	258	272	981	508	364

Peak-Hour Load and Resource Balance (continued)

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Load Forecast (95th% w/no DSM)	(2,603)	(2,475)	(2,169)	(2,038)	(3,016)	(3,445)	(3,632)	(3,208)	(2,961)	(2,134)	(2,358)	(2,795)
Existing DSM (EE)	30	30	30	31	34	35	35	34	33	30	30	30
Peak-Hour Forecast w/DSM (EE)	(2,574)	(2,445)	(2,139)	(2,007)	(2,982)	(3,410)	(3,596)	(3,174)	(2,929)	(2,103)	(2,328)	(2,765)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,574)	(2,445)	(2,139)	(2,007)	(2,982)	(3,410)	(3,596)	(3,174)	(2,929)	(2,103)	(2,328)	(2,765)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	852	1,080	1,023	1,060	1,132	1,020	909	794	750	875	673	932
Hydro (90th%)—Other	244	246	231	244	350	363	303	232	256	252	240	244
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,096	1,326	1,254	1,304	1,482	1,383	1,212	1,026	1,006	1,126	914	1,176
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	359	347	237	269	219	0	0	61
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,946	3,191	3,123	3,208	3,791	3,688	3,413	3,250	3,167	3,030	2,785	3,101
Monthly Surplus/Deficit	0	0	0	0	0	0	(184)	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	2	8	11	11	9	5	1	0	0
Commercial	29	29	29	29	30	30	30	30	29	29	29	30
Residential	4	4	4	4	4	3	3	3	4	4	4	4
Total New DSM Peak Reduction	33	33	33	35	41	44	45	43	38	34	33	33
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(139)	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	0	0	150	150	150	0	0	0	0
New Resource Subtotal	0	0	0	0	0	150	150	150	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	405	779	1,016	1,236	850	471	11	269	276	961	490	368

Peak-Hour Load and Resource Balance (continued)

	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Load Forecast (95th% w/no DSM)	(2,629)	(2,492)	(2,190)	(2,059)	(3,064)	(3,488)	(3,691)	(3,251)	(3,003)	(2,154)	(2,381)	(2,823)
Existing DSM (EE)	34	34	34	35	39	40	40	39	37	34	34	34
Peak-Hour Forecast w/DSM (EE)	(2,595)	(2,459)	(2,156)	(2,023)	(3,025)	(3,448)	(3,651)	(3,212)	(2,966)	(2,120)	(2,347)	(2,789)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,595)	(2,459)	(2,156)	(2,023)	(3,025)	(3,448)	(3,651)	(3,212)	(2,966)	(2,120)	(2,347)	(2,789)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	850	1,073	1,013	1,058	1,131	1,017	907	790	747	870	673	930
Hydro (90th%)—Other	243	245	230	244	347	358	302	231	255	250	240	243
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,093	1,318	1,243	1,303	1,478	1,376	1,209	1,021	1,002	1,121	912	1,173
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	385	342	237	267	257	0	0	86
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,943	3,183	3,111	3,206	3,812	3,676	3,409	3,243	3,201	3,025	2,784	3,123
Monthly Surplus/Deficit	0	0	0	0	0	0	(242)	0	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	2	9	12	13	11	6	1	0	0
Commercial	35	35	35	35	35	36	36	36	35	35	35	35
Residential	7	7	7	7	7	6	6	6	7	7	7	7
Total New DSM Peak Reduction	42	42	41	44	51	55	55	53	48	42	42	42
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(187)	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	589	966	1,197	1,727	1,338	782	313	584	782	1,147	678	575

Peak-Hour Load and Resource Balance (continued)

	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Load Forecast (95th% w/no DSM)	(2,657)	(2,511)	(2,212)	(2,081)	(3,112)	(3,532)	(3,752)	(3,295)	(3,046)	(2,176)	(2,406)	(2,851)
Existing DSM (EE)	37	37	37	39	44	45	45	44	41	38	37	37
Peak-Hour Forecast w/DSM (EE)	(2,620)	(2,474)	(2,175)	(2,042)	(3,068)	(3,487)	(3,707)	(3,251)	(3,005)	(2,139)	(2,368)	(2,814)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,620)	(2,474)	(2,175)	(2,042)	(3,068)	(3,487)	(3,707)	(3,251)	(3,005)	(2,139)	(2,368)	(2,814)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	966	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	848	1,071	1,007	1,057	1,130	1,015	905	787	744	862	674	927
Hydro (90th%)—Other	243	245	230	243	344	355	302	231	229	250	238	242
Shoshone Falls Upgrade (90th%)	0	0	0	0	0	0	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,091	1,316	1,237	1,300	1,473	1,371	1,208	1,018	973	1,112	912	1,171
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	384	342	237	265	270	0	0	111
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,941	3,180	3,106	3,204	3,749	3,670	3,409	3,237	3,184	3,016	2,783	3,146
Monthly Surplus/Deficit	0	0	0	0	0	0	(298)	(14)	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	3	10	14	15	12	7	1	0	0
Commercial	40	39	40	39	40	41	41	41	40	39	40	40
Residential	10	10	10	10	10	9	9	9	10	10	10	10
Total New DSM Peak Reduction	49	49	49	52	60	64	65	62	56	50	49	50
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(233)	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	570	956	1,180	1,713	1,241	747	267	548	736	1,128	664	582

Peak-Hour Load and Resource Balance (continued)

	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Load Forecast (95th% w/no DSM)	(2,690)	(2,535)	(2,239)	(2,107)	(3,166)	(3,580)	(3,817)	(3,342)	(3,092)	(2,204)	(2,436)	(2,885)
Existing DSM (EE)	42	42	42	44	49	50	51	49	46	43	42	42
Peak-Hour Forecast w/DSM (EE)	(2,648)	(2,493)	(2,197)	(2,063)	(3,117)	(3,529)	(3,766)	(3,293)	(3,046)	(2,161)	(2,394)	(2,843)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,648)	(2,493)	(2,197)	(2,063)	(3,117)	(3,529)	(3,766)	(3,293)	(3,046)	(2,161)	(2,394)	(2,843)
Existing Resources												
Coal	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	843	1,068	1,005	1,056	1,128	1,013	902	783	741	853	673	927
Hydro (90th%)—Other	243	243	230	243	341	353	301	230	228	250	237	241
Shoshone Falls Upgrade (90th%)	3	2	0	0	9	11	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,088	1,313	1,235	1,298	1,479	1,377	1,205	1,013	968	1,103	910	1,170
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	0	0	0	0	383	342	237	262	269	0	4	139
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,938	3,178	3,104	3,202	3,811	3,676	3,406	3,230	3,179	3,007	2,785	3,173
Monthly Surplus/Deficit	0	0	0	0	0	0	(360)	(64)	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	3	12	16	17	14	8	1	0	0
Commercial	45	45	45	45	46	47	47	47	45	45	46	45
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM Peak Reduction	54	54	54	57	66	71	72	69	62	55	55	54
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(288)	0	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	545	939	1,161	1,696	1,261	719	212	506	695	1,101	646	584

Peak-Hour Load and Resource Balance (continued)

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Load Forecast (95th% w/no DSM)	(2,720)	(2,564)	(2,261)	(2,126)	(3,222)	(3,627)	(3,882)	(3,391)	(3,139)	(2,232)	(2,463)	(2,919)
Existing DSM (EE)	45	45	45	48	54	55	56	54	51	46	45	45
Peak-Hour Forecast w/DSM (EE)	(2,674)	(2,519)	(2,216)	(2,079)	(3,168)	(3,572)	(3,827)	(3,337)	(3,088)	(2,186)	(2,418)	(2,874)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,674)	(2,519)	(2,216)	(2,079)	(3,168)	(3,572)	(3,827)	(3,337)	(3,088)	(2,186)	(2,418)	(2,874)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	841	1,066	1,004	1,054	1,127	1,009	899	779	737	840	674	923
Hydro (90th%)—Other	242	243	229	243	341	328	300	229	227	248	235	241
Shoshone Falls Upgrade (90th%)	3	2	0	0	8	10	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,086	1,311	1,233	1,297	1,476	1,347	1,202	1,008	964	1,089	909	1,166
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	87	0	0	0	434	395	290	313	320	0	83	225
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,965	3,118	3,044	3,143	3,802	3,643	3,398	3,218	3,168	2,935	2,806	3,197
Monthly Surplus/Deficit	0	0	0	0	0	0	(429)	(119)	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	4	13	19	20	16	9	2	0	0
Commercial	51	51	50	51	52	53	53	53	51	51	51	51
Residential	9	9	9	9	9	8	8	8	9	9	9	9
Total New DSM Peak Reduction	60	60	60	64	74	80	80	77	69	62	60	60
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(349)	(41)	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	552	860	1,088	1,628	1,208	650	151	459	648	1,011	649	583

Peak-Hour Load and Resource Balance (continued)

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Load Forecast (95th% w/no DSM)	(2,745)	(2,585)	(2,281)	(2,144)	(3,272)	(3,668)	(3,941)	(3,432)	(3,180)	(2,257)	(2,487)	(2,950)
Existing DSM (EE)	49	49	49	51	58	60	60	58	55	50	49	49
Peak-Hour Forecast w/DSM (EE)	(2,696)	(2,537)	(2,232)	(2,092)	(3,213)	(3,608)	(3,881)	(3,374)	(3,126)	(2,207)	(2,438)	(2,901)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,696)	(2,537)	(2,232)	(2,092)	(3,213)	(3,608)	(3,881)	(3,374)	(3,126)	(2,207)	(2,438)	(2,901)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	839	1,063	1,000	1,052	1,126	1,006	896	775	733	831	674	920
Hydro (90th%)—Other	242	242	229	242	339	326	300	228	226	247	234	240
Shoshone Falls Upgrade (90th%)	3	2	0	0	8	9	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,083	1,307	1,229	1,294	1,473	1,342	1,198	1,003	960	1,078	909	1,162
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	113	0	0	0	433	349	237	308	318	0	103	254
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,988	3,115	3,040	3,140	3,798	3,591	3,341	3,208	3,162	2,924	2,826	3,222
Monthly Surplus/Deficit	0	0	0	0	0	(17)	(540)	(166)	0	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	4	15	22	22	19	10	2	0	0
Commercial	59	58	58	58	59	60	60	60	58	58	58	58
Residential	9	9	10	10	9	8	8	8	9	9	9	10
Total New DSM Peak Reduction	68	67	67	72	84	90	91	88	78	70	68	67
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(449)	(78)	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	560	845	1,075	1,619	1,168	574	51	422	614	987	656	588

Peak-Hour Load and Resource Balance (continued)

	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Load Forecast (95th% w/no DSM)	(2,771)	(2,603)	(2,301)	(2,164)	(3,319)	(3,709)	(4,000)	(3,474)	(3,222)	(2,278)	(2,510)	(2,976)
Existing DSM (EE)	52	52	52	55	62	64	65	62	58	53	52	52
Peak-Hour Forecast w/DSM (EE)	(2,719)	(2,551)	(2,249)	(2,109)	(3,257)	(3,645)	(3,935)	(3,412)	(3,164)	(2,225)	(2,458)	(2,924)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,719)	(2,551)	(2,249)	(2,109)	(3,257)	(3,645)	(3,935)	(3,412)	(3,164)	(2,225)	(2,458)	(2,924)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	835	1,061	1,001	1,051	1,124	1,003	893	770	730	828	674	918
Hydro (90th%)—Other	241	242	228	241	336	323	299	227	225	246	234	240
Shoshone Falls Upgrade (90th%)	3	2	0	0	7	9	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,078	1,305	1,229	1,292	1,467	1,335	1,195	997	955	1,074	908	1,159
CSPP (PURPA)	86	89	93	128	174	181	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	136	0	0	0	431	346	237	306	316	0	123	291
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,007	3,112	3,040	3,138	3,790	3,580	3,337	3,201	3,156	2,921	2,845	3,257
Monthly Surplus/Deficit	0	0	0	0	0	(65)	(598)	(211)	(9)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	5	18	25	26	22	11	2	0	0
Commercial	64	64	64	64	65	67	67	67	64	64	64	65
Residential	10	10	10	10	10	9	9	9	10	10	10	10
Total New DSM Peak Reduction	74	74	73	79	92	100	101	97	85	76	74	74
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(497)	(114)	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	562	834	1,064	1,608	1,125	535	3	386	577	971	661	607

Peak-Hour Load and Resource Balance (continued)

	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Load Forecast (95th% w/no DSM)	(2,783)	(2,613)	(2,308)	(2,168)	(3,363)	(3,746)	(4,055)	(3,511)	(3,259)	(2,296)	(2,522)	(2,993)
Existing DSM (EE)	55	54	55	57	65	68	68	66	62	56	55	55
Peak-Hour Forecast w/DSM (EE)	(2,728)	(2,558)	(2,254)	(2,111)	(3,298)	(3,679)	(3,987)	(3,445)	(3,198)	(2,240)	(2,467)	(2,938)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,728)	(2,558)	(2,254)	(2,111)	(3,298)	(3,679)	(3,987)	(3,445)	(3,198)	(2,240)	(2,467)	(2,938)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	832	1,058	999	1,049	1,112	1,000	891	766	727	819	673	917
Hydro (90th%)—Other	240	242	228	240	335	321	298	226	225	245	233	239
Shoshone Falls Upgrade (90th%)	3	2	0	0	7	9	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,075	1,301	1,228	1,289	1,453	1,330	1,191	992	951	1,064	906	1,158
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	143	0	0	0	430	342	237	303	315	0	132	312
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,011	3,109	3,039	3,135	3,775	3,572	3,334	3,192	3,150	2,911	2,852	3,276
Monthly Surplus/Deficit	0	0	0	0	0	(106)	(653)	(254)	(47)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	6	20	28	29	25	13	2	0	0
Commercial	71	71	71	71	71	74	74	74	72	71	71	72
Residential	12	12	12	12	12	11	11	11	12	12	12	12
Total New DSM Peak Reduction	84	83	84	89	104	113	114	109	97	86	84	84
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(539)	(144)	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	50	50	50	0	0	0	0
New Resource Subtotal	200	200	200	500	500	550	550	550	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	567	834	1,068	1,614	1,081	557	11	406	550	956	669	623

Peak-Hour Load and Resource Balance (continued)

	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Load Forecast (95th% w/no DSM)	(2,786)	(2,624)	(2,308)	(2,163)	(3,406)	(3,776)	(4,105)	(3,542)	(3,291)	(2,312)	(2,527)	(3,009)
Existing DSM (EE)	57	57	57	60	68	71	72	69	64	58	57	57
Peak-Hour Forecast w/DSM (EE)	(2,730)	(2,568)	(2,252)	(2,103)	(3,337)	(3,705)	(4,033)	(3,473)	(3,226)	(2,254)	(2,470)	(2,952)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,730)	(2,568)	(2,252)	(2,103)	(3,337)	(3,705)	(4,033)	(3,473)	(3,226)	(2,254)	(2,470)	(2,952)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	830	1,055	998	1,047	1,111	998	888	761	723	812	674	914
Hydro (90th%)—Other	240	241	228	240	334	320	298	225	224	245	232	239
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,073	1,298	1,225	1,287	1,451	1,326	1,188	987	947	1,057	906	1,155
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	160	0	0	0	428	342	237	300	313	0	135	321
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,025	3,105	3,036	3,133	3,771	3,569	3,331	3,184	3,144	2,903	2,854	3,282
Monthly Surplus/Deficit	0	0	0	0	0	(137)	(703)	(289)	(82)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	6	23	32	33	28	15	3	0	0
Commercial	77	77	77	77	77	80	80	80	77	77	78	77
Residential	16	16	16	16	16	14	14	14	16	16	16	16
Total New DSM Peak Reduction	93	93	93	99	116	126	127	122	108	96	94	93
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(10)	(575)	(167)	0	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	100	100	100	0	0	0	0
New Resource Subtotal	200	200	200	500	500	600	600	600	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	589	830	1,078	1,629	1,050	590	25	433	526	944	678	623

Peak-Hour Load and Resource Balance (continued)

	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Load Forecast (95th% w/no DSM)	(2,810)	(2,640)	(2,326)	(2,180)	(3,450)	(3,811)	(4,157)	(3,578)	(3,328)	(2,332)	(2,548)	(3,036)
Existing DSM (EE)	59	59	59	62	71	74	75	72	67	60	59	59
Peak-Hour Forecast w/DSM (EE)	(2,751)	(2,581)	(2,267)	(2,117)	(3,379)	(3,737)	(4,083)	(3,506)	(3,262)	(2,272)	(2,489)	(2,977)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,751)	(2,581)	(2,267)	(2,117)	(3,379)	(3,737)	(4,083)	(3,506)	(3,262)	(2,272)	(2,489)	(2,977)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	827	1,050	994	1,046	1,109	995	885	758	720	803	675	910
Hydro (90th%)—Other	239	241	227	239	331	318	297	225	223	244	231	238
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,068	1,292	1,222	1,285	1,447	1,322	1,184	982	943	1,047	906	1,150
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	183	0	0	0	427	342	237	298	311	0	154	319
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,044	3,099	3,032	3,131	3,766	3,564	3,327	3,177	3,138	2,893	2,874	3,275
Monthly Surplus/Deficit	0	0	0	0	0	(173)	(756)	(329)	(124)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	7	26	36	38	32	17	3	0	0
Commercial	83	83	83	83	84	86	86	86	83	83	84	83
Residential	21	21	21	21	21	18	18	18	21	21	21	21
Total New DSM Peak Reduction	104	104	104	111	131	141	142	136	120	107	105	104
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(32)	(613)	(193)	(3)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	150	150	150	0	0	0	0
New Resource Subtotal	200	200	200	500	500	650	650	650	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	597	822	1,069	1,625	1,018	618	37	457	497	928	690	603

Peak-Hour Load and Resource Balance (continued)

	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Load Forecast (95th% w/no DSM)	(2,835)	(2,657)	(2,346)	(2,199)	(3,496)	(3,854)	(4,217)	(3,622)	(3,372)	(2,354)	(2,570)	(3,061)
Existing DSM (EE)	61	61	61	64	74	77	77	74	69	63	61	61
Peak-Hour Forecast w/DSM (EE)	(2,774)	(2,596)	(2,285)	(2,135)	(3,422)	(3,777)	(4,139)	(3,547)	(3,303)	(2,291)	(2,509)	(3,000)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,774)	(2,596)	(2,285)	(2,135)	(3,422)	(3,777)	(4,139)	(3,547)	(3,303)	(2,291)	(2,509)	(3,000)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825.0	1,047.9	990.6	1,044.4	1,107.9	992.1	882.4	753.7	716.2	795.7	675.6	891.3
Hydro (90th%)—Other	238.7	239.8	226.9	213.9	330.4	317.5	296.2	223.9	222.7	243.8	230.5	237.7
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	218	0	0	0	425	342	237	295	308	0	174	317
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,077	3,097	3,028	3,104	3,761	3,560	3,324	3,170	3,131	2,886	2,894	3,254
Monthly Surplus/Deficit	0	0	0	0	0	(217)	(816)	(378)	(172)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	8	29	41	43	36	19	4	0	0
Commercial	89	88	88	88	90	92	92	92	89	89	89	89
Residential	27	27	27	27	26	23	23	23	27	27	27	27
Total New DSM Peak Reduction	116	115	115	123	146	156	158	151	134	119	115	115
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(61)	(658)	(226)	(37)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	200	200	200	0	0	0	0
New Resource Subtotal	200	200	200	500	500	700	700	700	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	619	816	1,059	1,593	985	639	42	474	463	914	700	570

Peak-Hour Load and Resource Balance (continued)

	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Load Forecast (95th% w/no DSM)	(2,844)	(2,667)	(2,350)	(2,201)	(3,538)	(3,891)	(4,270)	(3,659)	(3,408)	(2,370)	(2,579)	(3,079)
Existing DSM (EE)	63	62	62	66	75	79	79	76	71	64	63	63
Peak-Hour Forecast w/DSM (EE)	(2,781)	(2,605)	(2,288)	(2,135)	(3,463)	(3,812)	(4,191)	(3,582)	(3,337)	(2,306)	(2,517)	(3,016)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,781)	(2,605)	(2,288)	(2,135)	(3,463)	(3,812)	(4,191)	(3,582)	(3,337)	(2,306)	(2,517)	(3,016)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825.0	1047.9	990.6	1044.4	1107.9	992.1	882.4	753.7	716.2	795.7	675.6	891.3
Hydro (90th%)—Other	238.7	239.8	226.9	213.9	330.4	317.5	296.2	223.9	222.7	243.8	230.5	237.7
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	236	0	7	0	423	342	237	293	306	0	182	314
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,095	3,097	3,035	3,104	3,759	3,560	3,324	3,168	3,129	2,886	2,902	3,251
Monthly Surplus/Deficit	0	0	0	0	0	(252)	(868)	(414)	(208)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	9	33	46	48	40	21	4	0	0
Commercial	96	94	94	95	96	98	98	98	95	95	95	96
Residential	33	33	33	33	33	29	29	29	33	33	33	33
Total New DSM Peak Reduction	128	127	127	137	161	174	175	168	149	132	128	128
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(78)	(693)	(247)	(59)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	200	200	200	0	0	0	0
New Resource Subtotal	200	200	200	500	500	700	700	700	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	642	819	1,075	1,607	958	622	7	453	441	912	713	563

Peak-Hour Load and Resource Balance (continued)

	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Load Forecast (95th% w/no DSM)	(2,864)	(2,680)	(2,365)	(2,214)	(3,582)	(3,927)	(4,325)	(3,697)	(3,447)	(2,389)	(2,598)	(3,104)
Existing DSM (EE)	64	64	64	68	77	80	81	78	73	65	64	64
Peak-Hour Forecast w/DSM (EE)	(2,800)	(2,616)	(2,301)	(2,147)	(3,505)	(3,847)	(4,244)	(3,619)	(3,375)	(2,324)	(2,534)	(3,040)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,800)	(2,616)	(2,301)	(2,147)	(3,505)	(3,847)	(4,244)	(3,619)	(3,375)	(2,324)	(2,534)	(3,040)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825.0	1,047.9	990.6	1,044.4	1,107.9	992.1	882.4	753.7	716.2	795.7	675.6	891.3
Hydro (90th%)—Other	238.7	239.8	226.9	213.9	330.4	317.5	296.2	223.9	222.7	243.8	230.5	237.7
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	247	0	24	0	421	342	237	290	304	0	199	312
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,106	3,097	3,052	3,104	3,757	3,560	3,324	3,165	3,127	2,886	2,919	3,249
Monthly Surplus/Deficit	0	0	0	0	0	(287)	(920)	(454)	(248)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	10	37	52	54	45	24	5	0	0
Commercial	100	100	100	100	101	104	104	104	101	100	100	101
Residential	38	38	38	38	37	33	33	33	37	38	38	37
Total New DSM Peak Reduction	138	138	137	148	175	189	191	182	163	142	138	139
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(98)	(729)	(271)	(85)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	250	250	250	0	0	0	0
New Resource Subtotal	200	200	200	500	500	750	750	750	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	644	818	1,089	1,606	928	652	21	479	415	904	723	547

Peak-Hour Load and Resource Balance (continued)

	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Load Forecast (95th% w/no DSM)	(2,902)	(2,708)	(2,395)	(2,242)	(3,635)	(3,978)	(4,391)	(3,748)	(3,498)	(2,418)	(2,631)	(3,142)
Existing DSM (EE)	65	65	65	69	79	82	83	80	74	67	65	66
Peak-Hour Forecast w/DSM (EE)	(2,836)	(2,642)	(2,329)	(2,174)	(3,556)	(3,895)	(4,308)	(3,668)	(3,424)	(2,351)	(2,566)	(3,077)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,836)	(2,642)	(2,329)	(2,174)	(3,556)	(3,895)	(4,308)	(3,668)	(3,424)	(2,351)	(2,566)	(3,077)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825	1,048	991	1,044	1,108	992	882	754	716	796	676	891
Hydro (90th%)—Other	239	240	227	214	330	317	296	224	223	244	230	238
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	281	0	61	0	419	342	237	287	302	0	231	310
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,140	3,097	3,089	3,104	3,755	3,560	3,324	3,162	3,125	2,886	2,951	3,247
Monthly Surplus/Deficit	0	0	0	0	0	(336)	(984)	(507)	(299)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	11	38	54	56	47	25	5	0	0
Commercial	105	105	105	105	105	109	109	109	106	105	105	106
Residential	43	43	43	43	43	38	38	38	43	43	43	43
Total New DSM Peak Reduction	148	148	148	158	186	200	202	194	174	152	148	149
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(135)	(782)	(313)	(125)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	300	300	300	0	0	0	0
New Resource Subtotal	200	200	200	500	500	800	800	800	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	652	802	1,108	1,589	886	665	18	487	375	887	733	519

Peak-Hour Load and Resource Balance (continued)

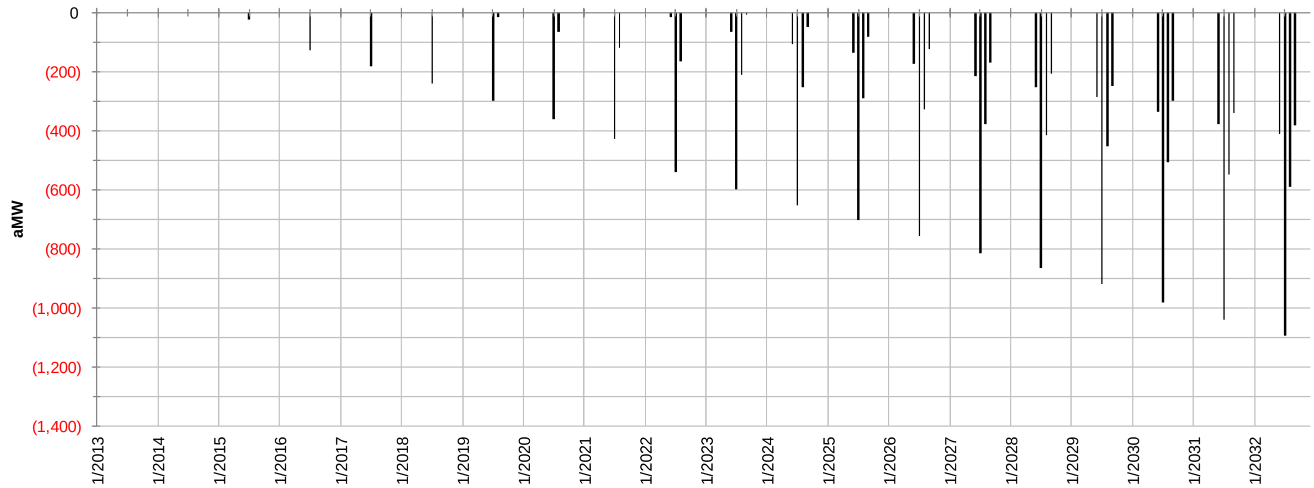
	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Load Forecast (95th% w/no DSM)	(2,918)	(2,720)	(2,405)	(2,251)	(3,679)	(4,019)	(4,448)	(3,790)	(3,540)	(2,437)	(2,646)	(3,163)
Existing DSM (EE)	66	66	66	70	80	83	84	81	75	68	66	66
Peak-Hour Forecast w/DSM (EE)	(2,851)	(2,654)	(2,339)	(2,181)	(3,599)	(3,936)	(4,365)	(3,710)	(3,465)	(2,369)	(2,580)	(3,097)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,851)	(2,654)	(2,339)	(2,181)	(3,599)	(3,936)	(4,365)	(3,710)	(3,465)	(2,369)	(2,580)	(3,097)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825	1,048	991	1,044	1,108	992	882	754	716	796	676	891
Hydro (90th%)—Other	239	240	227	214	330	317	296	224	223	244	230	238
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	291	12	78	15	418	342	237	285	300	0	245	308
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,150	3,109	3,106	3,119	3,754	3,560	3,324	3,160	3,123	2,886	2,965	3,245
Monthly Surplus/Deficit	0	0	0	0	0	(376)	(1,041)	(550)	(342)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	11	40	56	58	49	26	5	0	0
Commercial	110	110	110	109	110	114	114	114	110	109	111	110
Residential	48	48	48	48	48	42	42	42	48	48	47	48
Total New DSM Peak Reduction	158	157	158	168	198	212	214	205	184	162	159	158
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(164)	(827)	(345)	(158)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	350	350	350	0	0	0	0
New Resource Subtotal	200	200	200	500	500	850	850	850	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	656	812	1,125	1,606	853	686	23	505	342	879	743	505

Peak-Hour Load and Resource Balance (continued)

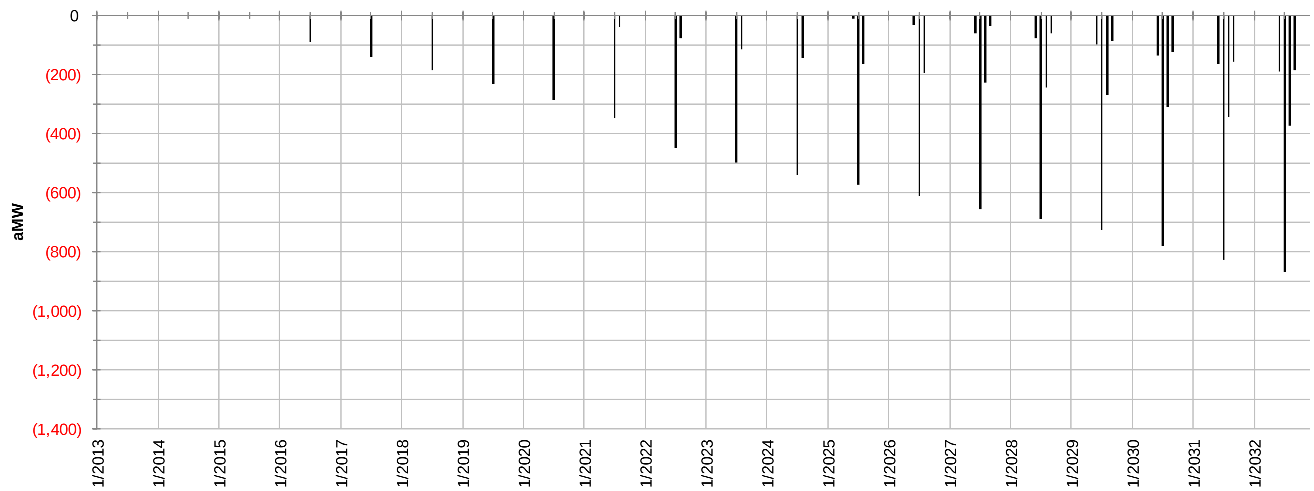
	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Load Forecast (95th% w/no DSM)	(2,933)	(2,719)	(2,416)	(2,260)	(3,722)	(4,057)	(4,503)	(3,829)	(3,579)	(2,455)	(2,661)	(3,185)
Existing DSM (EE)	67	67	67	70	81	84	84	81	75	68	67	67
Peak-Hour Forecast w/DSM (EE)	(2,867)	(2,652)	(2,349)	(2,189)	(3,642)	(3,973)	(4,418)	(3,748)	(3,504)	(2,387)	(2,594)	(3,118)
Existing DSM (DR)	0	0	0	0	0	0	0	0	0	0	0	0
Peak-Hour Forecast w/DSM (DR)	(2,867)	(2,652)	(2,349)	(2,189)	(3,642)	(3,973)	(4,418)	(3,748)	(3,504)	(2,387)	(2,594)	(3,118)
Existing Resources												
Coal	966	966	966	966	966	966	966	966	966	966	966	966
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	825	1,048	991	1,044	1,108	992	882	754	716	796	676	891
Hydro (90th%)—Other	239	240	227	214	330	317	296	224	223	244	230	238
Shoshone Falls Upgrade (90th%)	3	2	0	0	6	8	2	0	0	0	0	2
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,066	1,289	1,218	1,258	1,444	1,318	1,181	978	939	1,040	906	1,131
CSPP (PURPA)	86	89	93	128	174	182	189	179	167	128	96	88
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	9	9	9	9	9	9	9	9	9
Neal Hot Springs Geothermal	11	22	22	22	22	22	21	22	22	22	22	22
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	25	36	36	36	36	36	35	36	36	36	36	36
Firm Pacific NW Import Capability	313	10	85	33	416	342	237	281	299	0	259	306
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,172	3,107	3,113	3,137	3,752	3,560	3,324	3,156	3,122	2,886	2,979	3,243
Monthly Surplus/Deficit	0	0	0	0	0	(413)	(1,095)	(592)	(382)	0	0	0
2013 IRP DSM (EE)												
Irrigation	0	0	0	12	42	59	61	51	27	5	0	0
Commercial	115	115	114	114	117	119	119	119	115	115	115	115
Residential	52	52	52	52	52	46	46	46	52	52	52	52
Total New DSM Peak Reduction	167	167	167	178	210	224	226	216	194	172	167	167
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(190)	(869)	(375)	(187)	0	0	0
2013 IRP Resources												
2018 Boardman to Hemingway	200	200	200	500	500	500	500	500	500	200	200	200
Demand Response	0	0	0	0	0	370	370	370	0	0	0	0
New Resource Subtotal	200	200	200	500	500	870	870	870	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	672	821	1,131	1,627	821	680	1	495	313	871	752	492

Peak-Hour Surplus/Deficit Charts

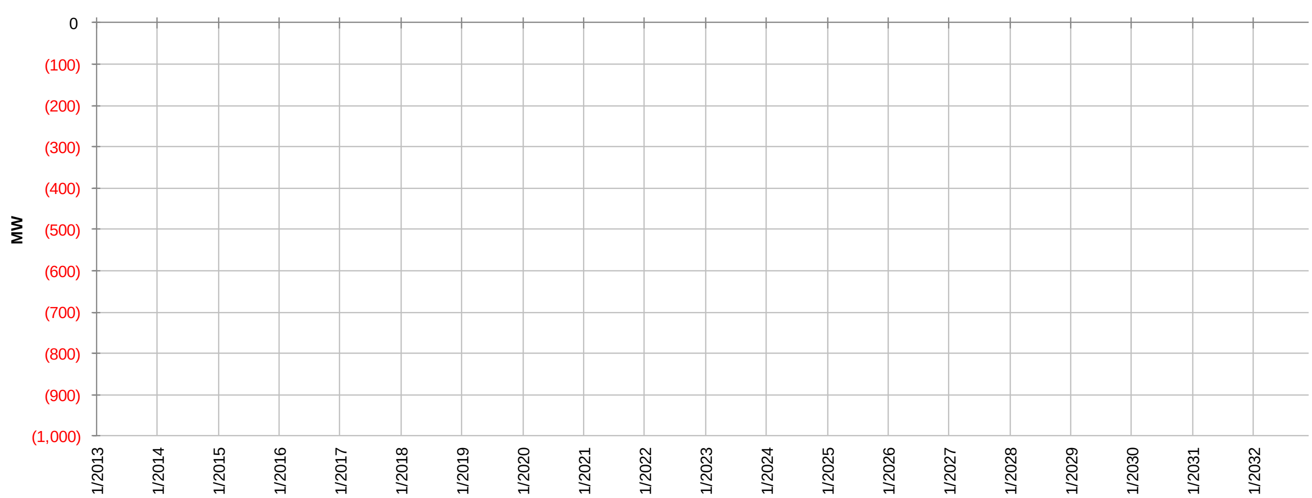
Peak-hour monthly deficits with existing DSM and existing resources



Peak-hour monthly deficits with existing DSM, existing resources, and IRP DSM



Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources



DEMAND-SIDE RESOURCE DATA

Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (http://www.idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant will verify the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations.

The financial assumptions used in the analysis for the 2013 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AURORA model. The preferred portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward marginal electricity prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing throughout each year of the planning period. The resulting categories are:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods. The estimated levelized capacity cost of a new SCCT is approximately $102 per kW over a 30-year period. When multiplied by the Effective Load Carry Capacity (ELCC) of 93 percent, the annual avoided capacity cost is $95/kW. For demand response or direct load control DSM programs $95 per kW becomes the cost threshold for program cost-effectiveness. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 depending on the calendar year.

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 3 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 show the 20-year cumulative forecasted impact of energy efficiency by customer class, and the associated annual TRC.

Table DSM-7 outlines the 20-year flow of avoided generation and the benefits attributed to energy efficiency programs.

Table DSM-8 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

Table DSM-9 summarizes the 20 year cumulative forecasted new potential for energy efficiency.

Table DSM-1. IRP financial assumptions

DSM Analysis Assumptions	
Avoided 30-Year Levelized Capacity Costs	
SCCT	$102/kW
Financial Assumptions	
Weighted average cost of capital (2008 year ending after tax)	6.77%
Financial escalation factor	3.00%
Transmission Losses	
Non-summer secondary losses	10.90%
Summer peak loss	13.00%

Table DSM-2. DSM alternate costs by pricing period

Year	Summer On-Peak* (SONP)	Summer Mid-Peak (SMP)	Summer Off-Peak (SOFP)	Non-Summer Mid-Peak (NSMP)	Non-Summer Off-Peak (NSOFP)
2013	$76.49	$34.48	$25.31	$34.93	$30.02
2014	$80.75	$37.08	$27.11	$37.34	$31.76
2015	$84.72	$39.35	$29.10	$40.13	$33.67
2016	$86.92	$40.96	$30.40	$41.62	$34.89
2017	$89.91	$43.92	$31.84	$43.66	$36.65
2018	$105.15	$56.81	$41.02	$56.36	$48.35
2019	$110.73	$59.75	$43.63	$58.59	$50.43
2020	$116.20	$63.46	$46.03	$60.93	$52.05
2021	$123.89	$68.11	$49.29	$65.65	$55.83
2022	$133.18	$73.43	$53.52	$71.81	$60.51
2023	$141.12	$76.86	$57.74	$76.07	$64.49
2024	$148.17	$83.42	$60.91	$80.83	$68.21
2025	$156.30	$87.00	$65.11	$86.57	$72.62
2026	$163.99	$91.41	$68.20	$92.53	$77.24
2027	$172.62	$96.14	$72.06	$97.31	$80.92
2028	$180.43	$102.13	$75.83	$103.04	$85.24
2029	$188.75	$107.61	$78.85	$106.65	$89.01
2030	$197.88	$116.12	$82.84	$112.22	$94.27
2031	$207.57	$121.61	$86.58	$118.59	$98.88
2032	$218.39	$133.14	$91.20	$125.54	$104.29

* Estimated variable operations and management costs of a 170 MW capacity SCCT.

Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
2	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
3	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
4	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
5	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
6	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
7	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
8	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
9	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
10	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
11	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
12	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
13	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
14	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
15	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
16	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
17	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
18	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
19	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
20	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
21	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
22	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
23	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
24	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP

Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
2	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
3	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
4	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
5	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
6	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
7	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
8	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
9	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
10	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
11	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
12	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
13	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
14	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
15	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
16	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
17	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
18	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
19	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
20	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
21	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
22	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
23	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
24	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP

Table DSM-5. Cumulative existing energy efficiency portfolio forecast 2013–2032
(aMW w/transmission losses)

Year	Commercial/Industrial	Irrigation	Residential	Total
2013	11	3	1	15
2014	20	7	3	30
2015	29	11	4	44
2016	37	14	5	56
2017	45	18	6	69
2018	53	22	7	82
2019	60	26	8	94
2020	68	27	10	105
2021	76	29	11	116
2022	86	30	13	129
2023	94	31	14	139
2024	103	35	16	154
2025	111	39	18	168
2026	118	44	19	181
2027	125	50	21	196
2028	133	57	23	213
2029	139	61	26	226
2030	145	67	27	239
2031	151	72	27	250
2032	157	76	28	261

Table DSM-6. Existing energy efficiency portfolio TRC 2013–2032

Year	Commercial/Industrial	Irrigation	Residential	Total All Sectors
2013	$17,684,888	$4,444,305	$5,086,693	$18,384,322
2014	$15,023,476	$4,457,135	$5,234,296	$19,369,878
2015	$14,489,836	$5,436,652	$4,658,449	$21,075,362
2016	$15,795,923	$5,422,132	$3,079,095	$24,297,150
2017	$12,804,433	$6,222,769	$3,485,460	$22,512,662
2018	$18,933,992	$8,491,051	$3,832,902	$31,257,946
2019	$14,504,997	$8,473,738	$4,116,430	$27,095,166
2020	$16,784,968	$11,988,119	$4,458,449	$33,231,536
2021	$16,569,043	$15,941,955	$4,777,871	$37,288,869
2022	$24,300,214	$12,054,486	$5,258,756	$41,613,456
2023	$21,616,897	$11,248,712	$5,519,440	$38,385,049
2024	$24,308,004	$22,807,017	$5,908,096	$53,023,117
2025	$19,146,569	$27,109,620	$6,319,791	$52,575,980
2026	$17,637,971	$18,967,276	$6,673,290	$43,278,537
2027	$16,436,862	$18,996,353	$7,018,133	$42,451,348
2028	$20,547,973	$19,800,123	$7,405,932	$47,754,028
2029	$18,360,242	$17,039,341	$7,748,039	$43,147,622
2030	$16,662,697	$19,003,939	$3,224,961	$38,891,596
2031	$15,856,083	$17,560,593	$3,375,416	$36,792,091
2032	$20,858,372	$12,799,825	$3,245,360	$36,903,556
20-Year NPV	**$188,245,928**	**$123,502,451**	**$52,623,496**	**$364,755,770**

Table DSM-7. Existing energy efficiency portfolio avoided energy costs 2013–2032

Year	Commercial/Industrial	Irrigation	Residential	Total All Sectors
2013	$1,995,192	$785,140	$82,481	$2,862,813
2014	$4,447,169	$1,877,276	$306,505	$6,630,950
2015	$7,448,806	$3,562,786	$608,946	$11,620,538
2016	$10,536,474	$4,823,818	$936,699	$16,296,990
2017	$13,603,373	$6,184,262	$1,326,187	$21,113,822
2018	$21,636,893	$10,091,290	$2,252,452	$33,980,635
2019	$26,150,714	$12,719,356	$2,941,227	$41,811,296
2020	$31,747,645	$13,994,828	$3,744,939	$49,487,412
2021	$37,762,710	$15,493,623	$4,672,567	$57,928,901
2022	$45,798,427	$17,142,980	$5,825,460	$68,766,868
2023	$52,827,025	$18,655,035	$7,029,285	$78,511,345
2024	$60,135,516	$21,307,128	$8,281,800	$89,724,444
2025	$67,330,305	$24,745,002	$9,733,405	$101,808,713
2026	$75,445,701	$29,484,780	$11,436,383	$116,366,864
2027	$83,498,887	$34,951,122	$13,269,044	$131,719,053
2028	$93,058,554	$41,361,986	$15,432,666	$149,853,206
2029	$101,824,572	$46,837,103	$17,697,063	$166,358,738
2030	$112,112,296	$53,607,202	$19,343,108	$185,062,606
2031	$120,032,498	$59,203,492	$20,675,610	$199,911,600
2032	$128,401,187	$64,820,001	$22,038,852	$215,260,039
20-Year NPV	**$437,466,195**	**$189,233,708**	**$63,693,931**	**$690,393,833**

Table DSM-8. Existing energy efficiency portfolio cost-effectiveness summary

	Impact	20-Year NPV		TRC	
	2032 Load (aMW)	Resource Costs	Alternate Energy Benefits	B/C Ratio	Levelized Costs ($/kWh)
Industrial/Commercial	157	$188,245,928	$467,521,430	2.5	0.028
Residential	76	$123,886,346	$190,935,664	1.5	0.046
Irrigation	28	$52,623,496	$76,220,052	1.4	0.049
Total	**261**	**$364,755,770**	**$734,677,146**	**2.0**	**0.035**

Table DSM-9. Cumulative new energy efficiency portfolio forecast 2013–2032
(aMW w/transmission losses)

Year	Commercial/ Industrial	Residential	Irrigation	Total
2013	6	0	1	8
2014	13	0	2	15
2015	19	1	3	23
2016	25	2	3	30
2017	30	4	4	37
2018	35	6	5	46
2019	40	10	5	55
2020	46	9	6	60
2021	51	9	7	67
2022	59	9	8	76
2023	65	9	9	83
2024	72	12	10	94
2025	78	16	12	105
2026	84	20	13	117
2027	90	26	15	130
2028	96	32	17	145
2029	101	36	19	157
2030	106	41	20	167
2031	111	46	21	178
2032	116	51	21	188

Supply-Side Resource Data

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.04%
Preferred	0.00%
Common	49.96%
Total	**100.00%**
Cost	
Debt	5.73%
Preferred	0.00%
Common	10.00%
Average Weighted Cost	7.86%

Financial Assumptions and Factors	
Plant operating (book) life	30 Years
Discount rate (weighted average cost of capital[1])	6.70%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	3.00%
Emissions adder escalation rate	3.00%
Annual property tax rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premiums (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.78%

[1] Incorporates tax effects.

Emission Intensity Rate (lbs per MWh by technology, adder brought into the analysis beginning in 2018)

	CO_2
Small aeroderivative SCCT	1,115
Large aeroderivative SCCT	1,047
Large frame SCCT	1,413
CCCT 1x1	809
CCCT 2x1	809
Combined heat and power (CHP)	1,115
Distributed generation–gas fired	1,115
Pulverized coal	1,901
IGCC	2,279
IGCC w/carbon sequestration	421

Emissions Adder Rates	
CO_2	$14.64 per ton (2018 $)

Fuel Forecast Base Case (Nominal, $ per MMBtu)

Year	Natural Gas[1]	Regional Coal	Uranium[2]
2013	$5.55	$2.32	$0.70
2014	$5.88	$2.44	$0.70
2015	$6.19	$2.42	$0.71
2016	$6.35	$2.45	$0.71
2017	$6.57	$2.56	$0.72
2018	$6.83	$2.68	$0.72
2019	$7.22	$2.64	$0.73
2020	$7.59	$2.70	$0.73
2021	$8.15	$2.79	$0.73
2022	$8.84	$2.89	$0.74
2023	$9.42	$2.98	$0.74
2024	$9.91	$3.07	$0.75
2025	$10.49	$3.17	$0.75
2026	$11.03	$3.27	$0.76
2027	$11.65	$3.38	$0.76
2028	$12.19	$3.48	$0.77
2029	$12.76	$3.59	$0.77
2030	$13.40	$3.71	$0.77
2031	$14.09	$3.87	$0.78
2032	$14.86	$4.00	$0.78
2033	$14.95	$4.02	$0.79
2034	$15.04	$4.04	$0.79
2035	$15.13	$4.07	$0.80
2036	$15.22	$4.09	$0.80
2037	$15.31	$4.12	$0.81
2038	$15.40	$4.14	$0.81
2039	$15.49	$4.17	$0.82
2040	$15.59	$4.19	$0.82
2041	$15.68	$4.22	$0.83
2042	$15.78	$4.24	$0.83

[1] Henry Hub + Sumas basis + transportation cost = Idaho city gate price

[2] Nuclear fuel

Cost Inputs and Operating Assumptions

(All costs in 2013 dollars)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital $/kW	Total Capital $/kW	Total Investment $/kW[2]	Fixed O&M $/kW[3]	Variable O&M $/kW	Emissions $/MWh	Heat Rate Btu/kWh
Advanced Nuclear	250	$6,866	$625	$7,491	$11,381	$143	$1	$0	10,488
Biomass Digesters	50	$4,311	$285	$4,596	$4,921	$107	$16	$0	NA
CCCT—(1x1) F Class	270	$1,120	$140	$1,260	$1,477	$8	$2	$7	6,800
CCCT—(2x1) F Class	580	$1,039	$109	$1,148	$1,346	$6	$2	$7	6,738
CHP/Co-Generation	100	$1,975	$25	$2,000	$2,142	$8	$5	$0	9,200
Conventional Scrubbed Coal	600	$3,253	$730	$3,983	$4,754	$26	$4	$26	9,200
Distributed Generation (Option # 1) Load shed	10	$0	$0	$0	$0	$63	$0	$0	9,050
Distributed Generation (Option # 2) Grid synchronized	15	$0	$160	$160	$166	$63	$0	$0	9,050
Geothermal—Idaho	26	$6,630	$979	$7,609	$8,442	$144	$5	$0	NA
Geothermal—Nevada	26	$6,630	$552	$7,182	$7,968	$144	$5	$0	NA
Geothermal—Oregon	26	$6,630	$787	$7,417	$8,229	$144	$5	$0	NA
IGCC	550	$4,513	$730	$5,243	$6,547	$35	$7	$25	8,765
Low Drop/Small Hydro New	10	$4,000	$80	$4,080	$4,784	$15	$4	$0	NA
Pulverized Coal w/ carbon capture and sequestration	455	$7,755	$730	$8,485	$10,595	$143	$7	$5	12,600
Pumped Storage Fueled by LL Wind	500	$2,510	$646	$3,156	$3,700	$5	$0	$0	NA
SCCT—Industrial Frame	170	$733	$88	$821	$875	$4	$3	$13	11,870
SCCT—Large Aeroderivative	100	$1,250	$149	$1,399	$1,491	$15	$3	$10	8,800
SCCT—Small Aeroderivative	47	$1,113	$31	$1,144	$1,219	$14	$5	$8	9,370
Solar—1-Axis Tracking Flat Plate PV (Utility)	1	$4,029	$0	$4,029	$4,108	$27	$0	$0	NA
Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW)	10	$3,268	$80	$3,348	$3,414	$27	$0	$0	NA
Solar—Concentrating Solar Power	100	$5,398	$212	$5,610	$6,578	$56	$0	$0	NA
Solar—Concentrating Solar Power with Energy Storage	100	$7,771	$212	$7,983	$9,360	$56	$0	$0	NA
Solar—Flat Plate PV (Distributed)[4]	10	$5,610	$0	$5,610	$5,720	$55	$0	$0	NA
Solar—Flat Plate PV (Utility)	1	$3,714	$0	$3,714	$3,787	$27	$0	$0	NA
Solar—Flat Plate PV (Utility 10MW)	10	$2,996	$80	$3,076	$3,136	$27	$0	$0	NA
Transmission—Boardman to Hemingway[5]	350	$0	$602	$602	$602	$1	$0	$0	NA
Wind—Eastern Oregon	100	$2,229	$1,210	$3,439	$3,675	$37	$1	$0	NA
Wind—Magic Valley	100	$2,229	$369	$2,598	$2,776	$37	$1	$0	NA
Wind—Southeast Idaho	100	$2,229	$382	$2,611	$2,790	$37	$1	$0	NA

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

[4] Approximately 2,500 4-kW PV systems.

[5] 350-MW average, 500-MW summer, and 200-MW winter.

Transmission Cost Assumptions

Cost Assumptions by Supply-Side Resource Type

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Advanced Nuclear				
250	$625	Pro-rated the 250 MW based on Idaho Power's present 21.2% share of estimated $900 million Boardman to Hemingway project cost plus BPA wheeling rates to get to Boardman Station	230 kV upgrades from Hemingway to Bowmont and Hubbard stations	Assume transmission in place by 2025 for access to Boardman area from Central Washington. Use BPA tariff rate to Boardman and pro-rata share of Boardman to Hemingway to Treasure Valley.
Biomass Digesters				
50	$285	Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker and miscellaneous line work and station reconfigurations.	Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker, and miscellaneous line work and station reconfigurations.	Assume pro-rata share of Midpoint West path upgrades.
CCCT—(1x1) F Class				
270	$140	Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line.	New supporting transmission will be required. Entire project assumed as backbone upgrade.	Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line.
CCCT—(2x1) F Class				
580	$109	Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation.	New supporting transmission will be required. Entire project assumed as backbone upgrade.	Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation.
CHP/Co-Generation				
100	$25	Assume Amalgamated Sugar location. Interconnection requires a tap of existing 138-kV line. Interconnection will require approximately 0.5 mile, 138-kV line and tap substation.	Approximately 0.5 mile, 138-kV line and 138-kV source substation with transformer.	Assume no additional transmission required.
Conventional Scrubbed Coal				
600	$730	Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project.	Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley.	Pro-rata share of Gateway.
Distributed Generation—(Option # 1) Load Shed				
10	$0	No upgrades required for load shed.	No upgrades required for load shed.	No backbone upgrades required.
Distributed Generation—(Option # 2) Grid synchronized				
15	$160	Assume feeder interconnection with minor amount of distribution rebuild.	Assume a small amount of distribution rebuild.	No backbone upgrades required.
Geothermal—Idaho				
26	$979	Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay. Assume 26 MW fits on existing backbone.	Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay.	No backbone upgrades required.

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Geothermal—Nevada				
26	$552	Assume a location 20 miles from existing 138-kV line. Assume 26 MW fits on existing 138-kV line.	Assume 20 miles of 138-kV local transmission to point of interconnection at 138-kV substation.	No backbone upgrades required.
Geothermal—Oregon				
26	$787	Assume a project similar to Neal Hot Springs Interconnect (1 breaker station, line switches, 10-mile interconnect). Assume 26 MW fits on existing backbone.	Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation.	No backbone upgrades required.
IGCC				
550	$730	Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project.	Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley.	Pro-rata share of Gateway.
Low Drop/Small Hydro New				
10	$80	Assume 46-kV sub-transmission or local feeder interconnection. Assume 4 miles of distribution rebuild required.	Assume 4 miles of distribution rebuild required.	No backbone upgrades required.
Pumped Storage Fueled by LL Wind				
500	$646	Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location.	Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location.	No backbone upgrades assumed in the upgrade costs; however, this assumption will vary drastically based on size of resource and number of locations
Pulverized Coal with Carbon Capture and Sequestration				
455	$730	Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project.	Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley.	Pro-rata share of Gateway.
SCCT—Industrial Frame				
170	$88	See requirements in previous estimate and also rebuild 16 miles of existing 230-kV construction to bundled conductor.	Langley Substation expansion, new transformer terminal.	9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation, 16 mile, 230-kV bundled conductor rebuild of Caldwell–Langley line.
SCCT—Large Aeroderivative				
100	$149	9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation plus Langley site expansion for second generating unit (new transformer terminal in substation).	Langley substation expansion, new transformer terminal.	9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation
SCCT—Small Aeroderivative				
47	$31	Assume an addition to existing generation site in Mountain Home area. New 230-kV terminal and associated station modifications.	New 230-kV terminal and associated station modifications.	No backbone upgrades required.
Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW)				
10	$80	Assume 34.5 kV feeder interconnection. Assume 4 miles of distribution rebuild required.	Assume 4 miles of distribution rebuild required.	No backbone upgrades required.
Solar—1-Axis Tracking Flat Plate PV (Utility)				
1	$0	12.5-kV feeder interconnection. No upgrades required.	12.5-kV feeder interconnection. No upgrades required.	No backbone upgrades required.
Solar—Flat Plate PV (Distributed)[2]				
10	$0	12.5-kV feeder interconnection. No upgrades required.	12.5-kV feeder interconnection. No upgrades required.	No backbone upgrades required.

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Solar—Flat Plate PV (Utility 10 MW)				
10	$80	Assume 34.5-kV feeder interconnection. Assume 4 miles of distribution rebuild required.	Assume 4 miles of distribution rebuild required.	No backbone upgrades required.
Solar—Flat Plate PV (Utility)				
1	$0	12.5-kV feeder interconnection. No upgrades required.	12.5-kV feeder interconnection. No upgrades required.	No backbone upgrades required.
Solar—Concentrating Solar Power				
100	$212	Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line.	Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station.	New three-terminal 230-kV switching station connecting existing 230-kV line.
Solar—Concentrating Solar Power with Energy Storage				
100	$212	Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line.	Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station.	New three-terminal 230-kV switching station connecting existing 230-kV line.
Transmission—Boardman to Hemingway				
350–Average 500–Summer 200–Winter	$602	Per the Boardman to Hemingway Funding Agreement, Idaho Power's share of the project is 21.2% of an estimated $900 million project cost. Project also requires 230-kV local interconnection upgrades from Hemingway into the Treasure Valley.	230-kV upgrades from Hemingway to Bowmont and Hubbard	Pro-rata share of Boardman to Hemingway.
Wind—Eastern Oregon				
100	$1,210	Assume location near Quartz Substation. A new 110 mile, 230-kV line will need to be constructed into Treasure Valley.	Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation.	110 mile, 230-kV line to Treasure Valley.
Wind—Magic Valley				
100	$369	Assume 10 mile interconnection to existing 230/138-kV substation plus 230-kV substation upgrades plus 1/16th share of Gateway West segment between Cedar Hill and Hemingway	Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation.	Upgrades at 230/138 kV integration substation + 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line
Wind—Southeast Idaho				
100	$382	Assume 10 mile interconnection to local 138-kV substation plus Borah West path RAS upgrades plus 1/16th share of Gateway West segment between Cedar Hill and Hemingway	Assume 138-kV step-up station with transformer with 10 miles of 138-kV local transmission to 138-kV point of interconnection.	New terminal at 138-kV point of interconnection plus Borah West RAS upgrades plus 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line

[1] 2013 dollars, no AFUDC

[2] Approximately 2,500 4-kW PV systems.

Levelized Cost of Production

30-Year Levelized Cost of Production (at stated capacity factors)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[1]	Fuel	Wholesale Energy	Emission Adders	Total Cost per MWh[1]	Annual Capacity Factor
Advanced Nuclear (250 MW)	$156	$41	$8	$0	$0	$205	85%
Biomass Digesters (50 MW)	$64	$47	$0	$0	$0	$111	90%
CCCT—1x1 (270 MW)	$27	$6	$67	$0	$7	$106	65%
CCCT—2x1 (580 MW)	$24	$7	$66	$0	$7	$104	65%
Combined Heat and Power (100 MW)	$27	$11	$74	$0	$0	$111	93%
Distributed Generation—Grid Sync (15 MW)	$1,941	$10,305	$0	$0	$0	$12,246	0%
Distributed Generation—Load Shed (10 MW)	$0	$10,305	$0	$0	$0	$10,305	0%
Geothermal—Idaho (26 MW)	$107	$41	$0	$0	$0	$148	92%
Geothermal—Nevada (26 MW)	$101	$41	$0	$0	$0	$142	92%
Geothermal—Oregon (26 MW)	$104	$41	$0	$0	$0	$145	92%
IGCC (550 MW)	$90	$24	$27	$0	$25	$166	85%
Low Drop/Small Hydro New (10 MW)	$124	$20	$0	$0	$0	$144	45%
Pulverized Coal (600 MW)	$63	$16	$29	$0	$26	$133	88%
Pulverized Coal w/Carbon Capture and Sequestration (455 MW)	$145	$48	$40	$0	$5	$238	85%
Pumped Storage Fueled by LL Wind	$173	$18	$0	$49	$0	$239	25%
SCCT—Industrial Frame (170 MW)	$170	$29	$116	$0	$13	$328	6%
SCCT—Large Aero (100 MW)	$174	$42	$86	$0	$10	$312	10%
SCCT—Small Aero (47 MW)	$178	$50	$92	$0	$8	$327	8%
Solar—Concentrating Energy (100 MW)	$206	$84	$0	$0	$0	$290	18%
Solar—Concentrating Energy Storage (100 MW)	$202	$63	$0	$0	$0	$265	28%
Solar—Flat Plate PV Distributed (10 MW) [2]	$227	$84	$0	$0	$0	$311	17%
Solar—Flat Plate PV Utility (10 MW)	$117	$38	$0	$0	$0	$154	19%
Solar—Flat Plate PV Utility (1 MW)	$179	$41	$0	$0	$0	$220	19%
Solar—Flat Plate Tracking PV Utility (1 MW)	$153	$34	$0	$0	$0	$187	24%
Solar—Flat Plate Tracking PV Utility (10 MW)	$102	$31	$0	$0	$0	$133	24%
Transmission—Boardman to Hemingway (350 MW)[3]	$20	$2	$0	$68	$0	$89	34%
Wind—Eastern Oregon (100 MW)	$165	$47	$0	$0	$0	$212	26%
Wind—Magic Valley (100 MW)	$125	$44	$0	$0	$0	$169	26%
Wind—Southeast Idaho(100 MW)	$125	$44	$0	$0	$0	$169	26%

[1] Includes fixed and variable costs and property taxes.

[2] Approximately 2,500 4-kW PV systems.

[3] 350-MW average, 500-MW summer, and 200-MW winter.

30-Year Levelized Capacity (fixed) Cost per kW/Month					
Supply-Side Resources	**Cost of Capital**	**Non-Fuel O&M[1]**	**Fuel**	**Emission Adders**	**Total Cost per kW**
Advanced Nuclear (250 MW)	$97	$25	$0	$0	$122
Biomass Digesters (50 MW)	$42	$16	$0	$0	$58
CCCT—1x1 (270 MW)	$13	$2	$0	$0	$14
CCCT—2x1 (580 MW)	$11	$2	$0	$0	$13
Combined Heat and Power (100 MW)	$18	$2	$0	$0	$21
Distributed Generation—Grid Sync (15 MW)	$1	$8	$0	$0	$9
Distributed Generation—Load Shed (10 MW)	$0	$8	$0	$0	$8
Geothermal—Idaho (26 MW)	$72	$23	$0	$0	$95
Geothermal—Nevada (26 MW)	$68	$22	$0	$0	$90
Geothermal—Oregon (26 MW)	$70	$23	$0	$0	$93
IGCC (550 MW)	$56	$9	$0	$0	$64
Low Drop/Small Hydro New (10 MW)	$41	$5	$0	$0	$46
Pulverized Coal (600 MW)	$40	$6	$0	$0	$47
Pulverized Coal w/Carbon Capture and Sequestration (455 MW)	$90	$24	$0	$0	$114
Pumped Storage Fueled by LL Wind	$32	$3	$0	$0	$35
SCCT—Industrial Frame (170 MW)	$7	$1	$0	$0	$9
SCCT—Large Aero (100 MW)	$13	$3	$0	$0	$15
SCCT—Small Aero (47 MW)	$10	$2	$0	$0	$13
Solar—Concentrating Energy (100 MW)	$56	$11	$0	$0	$67
Solar—Concentrating Energy Storage (100 MW)	$80	$13	$0	$0	$93
Solar—Flat Plate PV Distributed (10 MW)[1]	$49	$10	$0	$0	$59
Solar—Flat Plate PV Utility (1 MW)	$32	$6	$0	$0	$38
Solar—Flat Plate PV Utility (10 MW)	$27	$5	$0	$0	$32
Solar—Flat Plate Tracking PV Utility (1 MW)	$35	$6	$0	$0	$41
Solar—Flat Plate Tracking PV Utility (10 MW)	$29	$5	$0	$0	$35
Transmission—Boardman to Hemingway (350 MW)[2]	$5	$0	$0	$0	$5
Wind—Eastern Oregon (100 MW)	$31	$7	$0	$0	$38
Wind—Magic Valley (100 MW)	$24	$6	$0	$0	$30
Wind—Southeast Idaho(100 MW)	$24	$6	$0	$0	$30

[1] Approximately 2,500 4-kW PV systems.

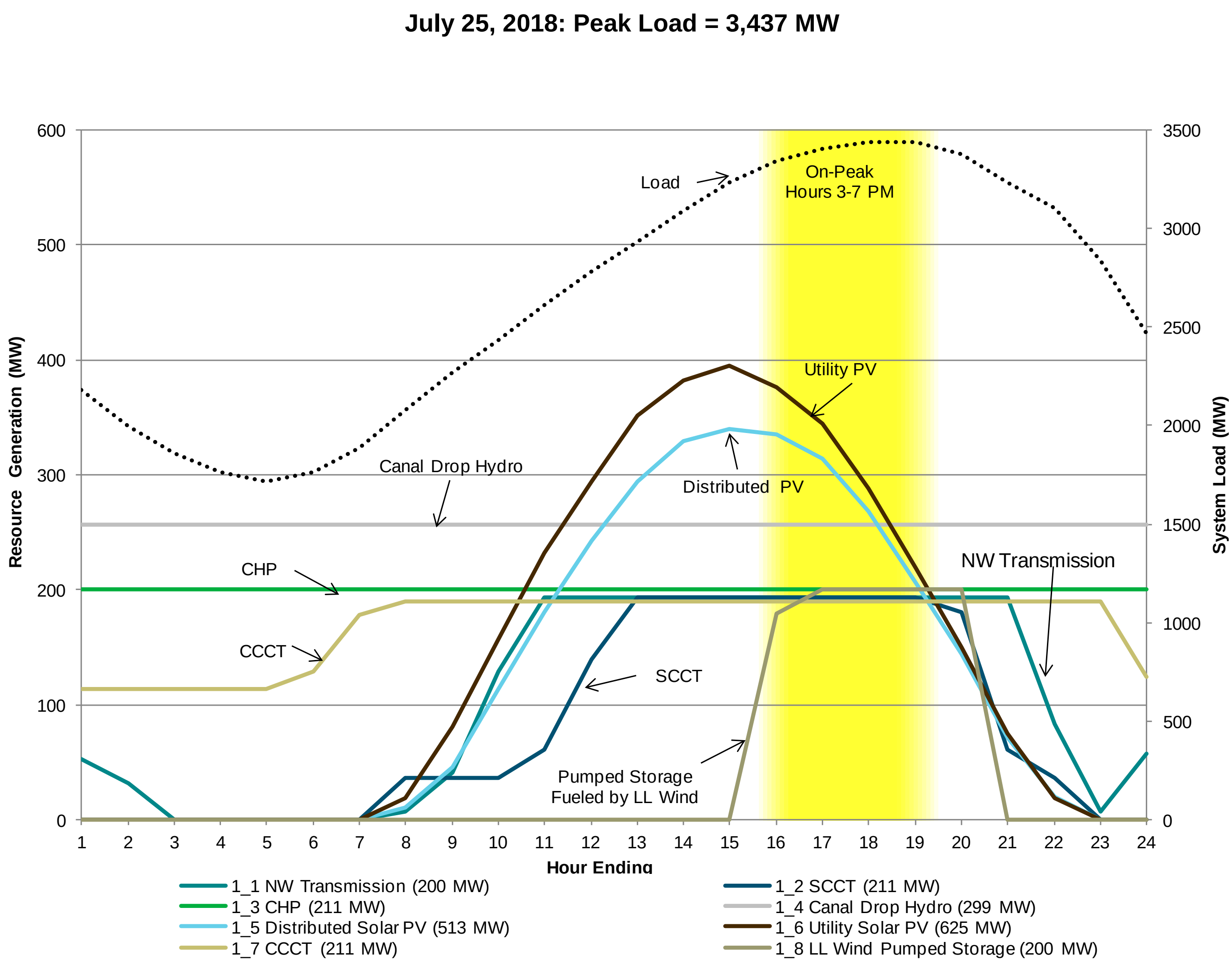
[2] 350-MW average, 500-MW summer, and 200-MW winter.

Resource Advantages and Disadvantages

Resource Type	Advantages	Disadvantages
Biomass	• Renewable resource • No harmful emissions • Minimum fuel risk • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • Uncertainty surrounding future tax incentives • Fuel supply risk
Coal		
Pulverized	• Abundant, low-cost fuel • Less price volatility than natural gas • Proven and reliable technology • Dispatchable resource • Well suited for baseload operations	• Potential lack of public acceptance • Significant particulate and gas emissions, particularly CO_2 • Significant capital investment • Long construction lead times • Lengthy environmental permitting and siting processes
Advanced Technology	• Abundant, low cost fuel • Potentially lower greenhouse gas emissions if CO_2 is sequestered • Potential for financial incentives • Dispatchable resource	• New, unproven technologies • Higher capital costs than pulverized coal • Long construction lead times
Distributed Generation	• Utilize existing backup generators at customer sites • Dispatchable resource • Provides operating reserves	• More expensive than other resource options • Limited number of sites • Fuel price risk and volatility • Existing air quality permits may need to be modified • Small size, many sites would be required
Geothermal	• Renewable resource • No harmful emissions • Minimum fuel risk (once developed) • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • High exploration costs due to drilling risks • Uncertainty surrounding future tax incentives
Hydro	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of sites • Future development is limited to small sites or at existing dams without power generation • Fish and other environmental issues
In-stream Generation	• Renewable resource • No harmful emissions • No fuel cost	• Small size, many sites would be required • Environmental impact and permitting • High maintenance cost

Resource Type	Advantages	Disadvantages
Natural Gas		
CCCT	• Proven and reliable technology • Dispatchable resource • Provides operating reserves necessary for integration of renewable generation • More efficient than a SCCT • Greater than 50% reduction in CO_2 emissions per MWh of output compared to conventional pulverized coal technology	• Fuel price risk and volatility • Potential fuel supply and transportation issues
SCCT	• Dispatchable resource • Proven, reliable resource • Low capital cost • Short construction lead times • Ideal for peaking service	• High variable operating cost • Fuel price risk and volatility • Less efficient than a CCCT
Nuclear	• Forecasted low fuel costs • Forecasted adequate fuel availability • Lack of greenhouse gas emissions • Potential low cost of production • Proven technology (existing reactor types)	• Lack of public acceptance • Safety concerns • Waste disposal • Construction cost uncertainties and the potential for construction cost overruns • Security concerns
Solar (General)	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs • Generation would match well with summer peak loads.	• More expensive than other resource options • Poor generation during winter months • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • 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 • Requires land slope of 1% or less
Parabolic Dish	• Off-grid electricity production in remote areas	• Not suitable for storage options • Unproven technology
Photovoltaic	• Proven & reliable technology • Suitable for distributed generation	• Cloud cover creates a rapid power drop-off • Utility scale projects are only practical up to 10 MW
Transmission	• Provides peak-hour capacity • Can help integrate renewable generation • Lower capital cost compared to other resources • Expanded capacity for off-system sales • Stability associated with possible long-term firm contracts (sales and purchases)	• Siting is difficult with impact to many land owners • Exposure to potential market volatility • Considerable lead times required
Wind	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of good sites in southern Idaho • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • Avian and aesthetic impacts • Uncertainty surrounding future tax incentives

Resource Peak Hour Shape



Capacity Factors for Solar PV

The following tables show capacity factors for solar photovoltaic (PV) panels located in Boise, Idaho. The data is from a tool, PVWatts™, developed by the Nation Renewable Energy Laboratory (NREL). NREL describes PVWatts in the following manner:

> NREL's PVWatts™ calculator determines the energy production and cost savings of grid-connected photovoltaic (PV) energy systems throughout the world. It allows homeowners, installers, manufacturers, and researchers to easily develop estimates of the performance of hypothetical PV installations.
>
> The PVWatts calculator works by creating hour-by-hour performance simulations that provide estimated monthly and annual energy production in kilowatts and energy value. Users can select a location and choose to use default values or their own system parameters for size, electric cost, array type, tilt angle, and azimuth angle. In addition, the PVWatts calculator can provide hourly performance data for the selected location.

> Using typical meteorological year weather data for the selected location, the PVWatts calculator determines the solar radiation incident of the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour is calculated from the PV system DC rating and the incident solar radiation and then corrected for the PV cell temperature. The AC energy for each hour is calculated by multiplying the DC energy by the overall DC-to-AC derate factor and adjusting for inverter efficiency as a function of load. Hourly values of AC energy are then summed to calculate monthly and annual AC energy production.

The following NREL PVWatts data are for a solar PV array in the Boise area. The PV oriented to the southwest is equivalent to a north-based azimuth of 225 degrees. The PV oriented to the south is equivalent to a north-based azimuth of 180 degrees. The following link displays the PVWatts data in Boise: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/US/Idaho/Boise.html.

Capacity Factors for Southerly Oriented PV in Boise

Time	Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12 am–1 am	1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1 am–2 am	2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2 am–3 am	3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3 am–4 am	4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4 am–5 am	5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5 am–6 am	6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6 am–7 am	7	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
7 am–8 am	8	0.0%	0.0%	0.7%	6.4%	9.6%	10.9%	8.1%	6.6%	6.2%	3.5%	0.2%	0.0%
8 am–9 am	9	1.3%	7.4%	15.9%	23.1%	25.7%	26.4%	24.2%	24.8%	24.3%	20.6%	9.8%	1.9%
9 am–10 am	10	15.5%	25.4%	31.1%	38.4%	38.8%	41.6%	39.2%	41.8%	41.5%	36.5%	23.1%	15.3%
10 am–11 am	11	26.1%	39.5%	41.8%	48.0%	49.3%	49.8%	52.6%	51.7%	50.1%	48.0%	36.2%	28.0%
11 am–12 pm	12	33.4%	47.6%	51.3%	55.2%	54.5%	56.2%	59.1%	61.0%	56.2%	54.5%	41.0%	35.9%
12 pm–1 pm	13	36.7%	51.2%	54.6%	54.9%	58.3%	60.6%	62.0%	63.0%	60.7%	59.3%	42.9%	38.9%
1 pm–2 pm	14	39.7%	47.7%	50.9%	56.2%	58.8%	57.9%	62.6%	62.6%	61.8%	52.7%	43.1%	37.6%
2 pm–3 pm	15	32.5%	44.3%	50.2%	54.3%	52.4%	53.1%	58.0%	58.9%	55.5%	49.7%	34.8%	32.3%
3 pm–4 pm	16	25.3%	32.3%	39.8%	42.3%	41.3%	43.9%	49.0%	49.8%	47.1%	38.0%	21.8%	22.1%
4 pm–5 pm	17	11.4%	20.1%	25.6%	28.7%	31.6%	31.3%	34.5%	35.2%	30.7%	21.0%	8.2%	7.4%
5 pm–6 pm	18	0.6%	5.3%	11.4%	14.6%	15.5%	17.0%	18.5%	17.5%	12.6%	4.0%	0.1%	0.0%
6 pm–7 pm	19	0.0%	0.0%	0.1%	0.2%	1.0%	1.8%	1.5%	0.4%	0.0%	0.0%	0.0%	0.0%
7 pm–8 pm	20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8 pm–9 pm	21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9 pm–10 pm	22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10 pm–11 pm	23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11 pm–12 am	24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average		**9.3%**	**13.4%**	**15.6%**	**17.6%**	**18.2%**	**18.8%**	**19.6%**	**19.7%**	**18.6%**	**16.2%**	**10.9%**	**9.1%**
Annual Average		**15.6%**											

All values are in Mountain Standard Time (MST) and have not been adjusted for Daylight Savings Time (DST). DST begins on the second Saturday in March and ends the first Sunday in November.

Capacity Factors for Southwesterly Oriented PV in Boise

Time	Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12 am–1 am	1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1 am–2 am	2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2 am–3 am	3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3 am–4 am	4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4 am–5 am	5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5 am–6 am	6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6 am–7 am	7	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
7 am–8 am	8	0.0%	0.0%	0.0%	1.1%	2.2%	2.8%	1.8%	0.5%	0.1%	0.0%	0.0%	0.0%
8 am–9 am	9	0.0%	0.1%	1.1%	4.4%	5.2%	6.1%	2.8%	1.9%	1.3%	0.4%	0.1%	0.0%
9 am–10 am	10	1.8%	3.3%	11.4%	16.6%	18.7%	18.9%	15.4%	15.2%	14.7%	13.5%	6.9%	1.7%
10 am–11 am	11	14.3%	19.7%	25.2%	31.6%	33.6%	33.5%	33.0%	32.0%	31.1%	29.6%	21.6%	14.9%
11 am–12 pm	12	24.2%	33.2%	38.9%	43.9%	44.7%	45.9%	46.8%	47.7%	43.9%	42.1%	30.8%	25.8%
12 pm–1 pm	13	30.7%	42.3%	47.2%	49.4%	53.6%	55.6%	55.9%	56.1%	53.8%	52.0%	37.0%	32.5%
1 pm–2 pm	14	36.6%	44.0%	48.9%	55.6%	59.6%	58.8%	62.8%	62.0%	60.8%	51.4%	41.3%	35.0%
2 pm–3 pm	15	32.9%	45.2%	53.1%	59.2%	58.8%	59.7%	64.7%	64.7%	60.7%	54.1%	37.1%	33.3%
3 pm–4 pm	16	28.7%	36.8%	46.9%	51.5%	51.8%	55.4%	61.8%	62.0%	58.6%	47.4%	26.6%	26.3%
4 pm–5 pm	17	16.3%	27.3%	35.8%	41.3%	48.8%	47.6%	52.9%	53.4%	47.1%	33.5%	13.8%	11.7%
5 pm–6 pm	18	1.8%	12.2%	24.6%	30.1%	34.1%	38.5%	41.4%	40.3%	32.1%	15.1%	1.0%	0.0%
6 pm–7 pm	19	0.0%	0.0%	8.1%	15.3%	17.5%	23.1%	25.7%	21.7%	10.3%	0.0%	0.0%	0.0%
7 pm–8 pm	20	0.0%	0.0%	0.0%	0.1%	2.9%	6.6%	8.5%	2.7%	0.0%	0.0%	0.0%	0.0%
8 pm–9 pm	21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9 pm–10 pm	22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10 pm–11 pm	23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11 pm–12 am	24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average		**9.3%**	**7.8%**	**11.0%**	**14.2%**	**16.7%**	**18.0%**	**18.9%**	**19.7%**	**19.2%**	**17.3%**	**14.1%**	**9.0%**
Annual Average		**14.5%**											

All values are in MST and have not been adjusted for DST. DST begins on the second Saturday in March and ends the first Sunday in November.

The tables show a PV oriented to the southwest produces more energy in the months of June and July. The PV oriented to the south generates more energy in all other months, and the south orientation generates more energy annually. Annual average capacity factors for a southern PV orientation in Boise is 15.6 percent, and for a southwestern orientation is 14.5 percent.

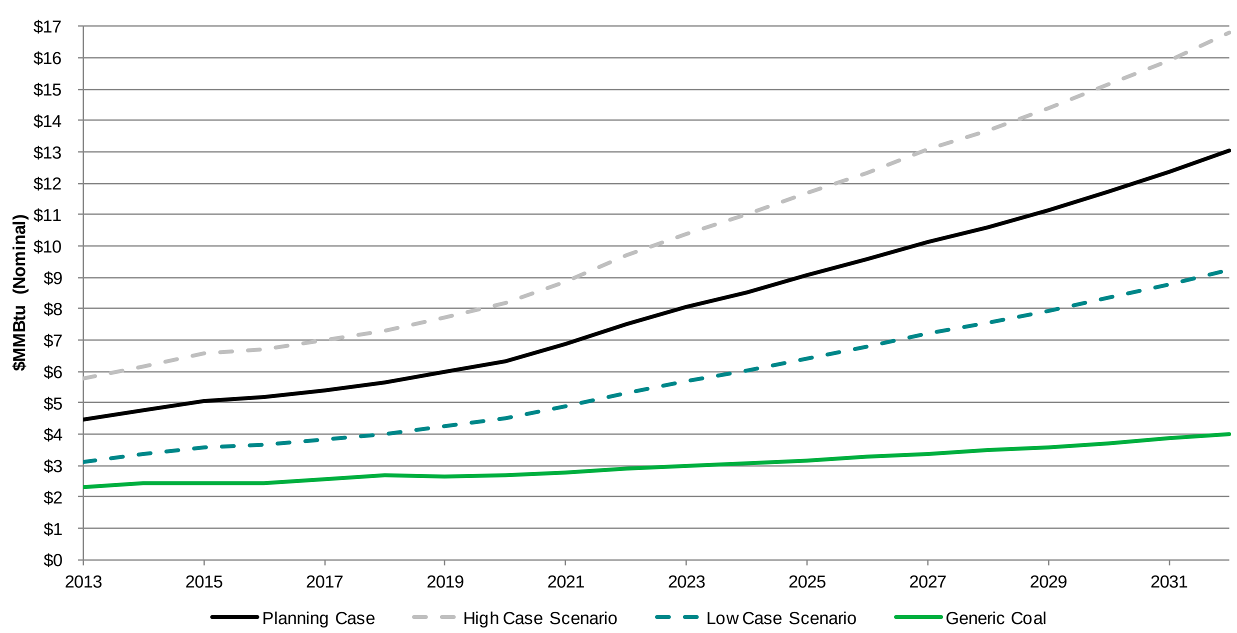
The tables indicate the southwest orientation in Boise has a 25.7 percent capacity factor from 6:00 to 7:00 pm in July and the south orientation has a 1.5 percent capacity factor during the same hour in July. Even though the southwestern exposure has a considerably greater capacity factor in late afternoon in July, the southwestern exposure capacity factor is still only 26 percent during the 6:00 to 7:00 pm hour in July. To meet a 100 MW capacity deficit during the 6:00 to 7:00 pm hour in July would require almost 400 MW of installed nameplate solar PV according to the NREL data. It is likely that the 90th percentile exceedance criteria used by Idaho Power for capacity resource planning would further increase the quantity of solar generation needed to address a capacity deficit.

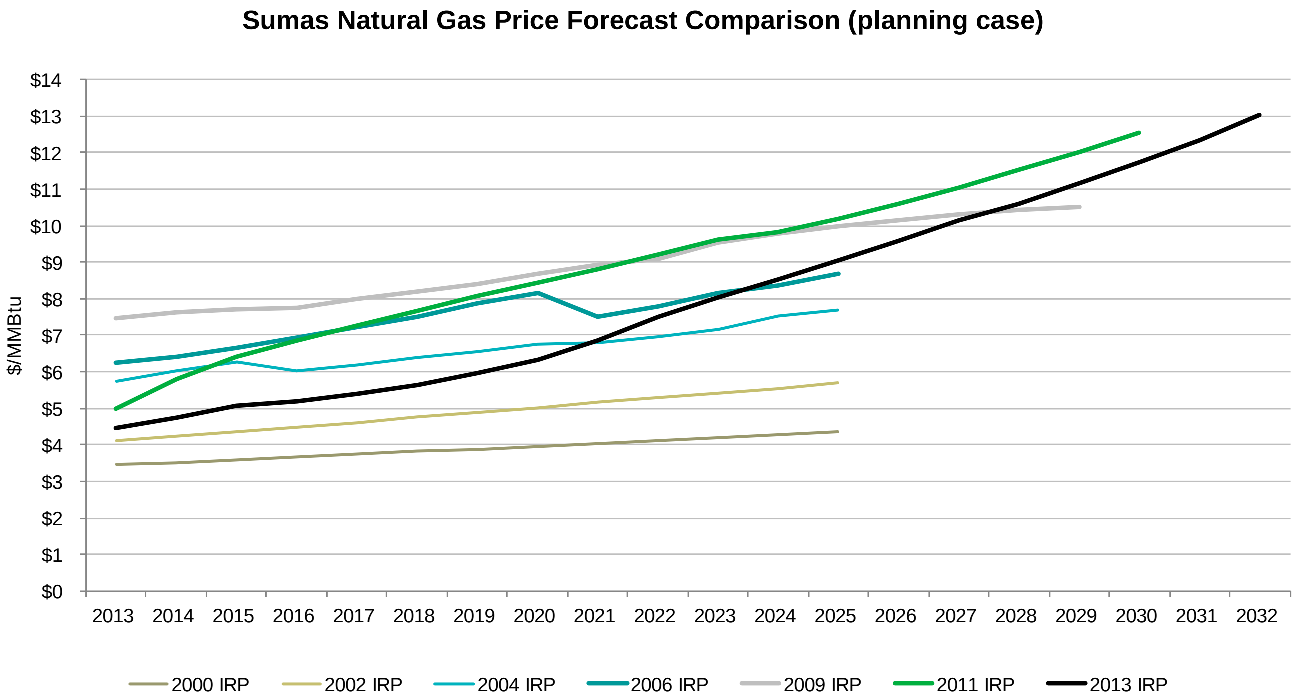
Fuel Data

Natural Gas and Coal Price Forecast

Year	Sumas (Expected)	Sumas (High)	Sumas (Low)	Regional Coal
2013	$4.46	$5.79	$3.13	$2.32
2014	$4.76	$6.17	$3.36	$2.44
2015	$5.06	$6.56	$3.57	$2.42
2016	$5.19	$6.71	$3.66	$2.45
2017	$5.40	$6.98	$3.81	$2.56
2018	$5.64	$7.29	$3.99	$2.68
2019	$5.98	$7.73	$4.23	$2.64
2020	$6.34	$8.18	$4.49	$2.70
2021	$6.87	$8.87	$4.87	$2.79
2022	$7.51	$9.69	$5.32	$2.89
2023	$8.05	$10.40	$5.71	$2.98
2024	$8.52	$11.00	$6.04	$3.07
2025	$9.05	$11.68	$6.42	$3.17
2026	$9.56	$12.34	$6.78	$3.27
2027	$10.14	$13.08	$7.19	$3.38
2028	$10.61	$13.69	$7.53	$3.48
2029	$11.14	$14.38	$7.91	$3.59
2030	$11.74	$15.15	$8.33	$3.71
2031	$12.34	$15.93	$8.76	$3.87
2032	$13.03	$16.81	$9.25	$4.00

Sumas Natural Gas and Coal Price Forecast




Sumas Natural Gas Price Forecast Comparison (planning case)
$/MMBtu
$14
$13
$12
$11
$10
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2000 IRP
2002 IRP
2004 IRP
2006 IRP
2009 IRP
2011 IRP
2013 IRP

EXISTING RESOURCE DATA

Hydroelectric and Thermal Plant Data

Hydroelectric Power Plans	Nameplate kVA	Nameplate kW	Normal Rating kW[4]	Emergency Rating kW[5]
American Falls	102,600	92,340	92,340	106,190
Bliss	86,250	75,000	75,000	84,860
Brownlee	650,444	585,400	585,400	678,040
Cascade	13,800	12,420	12,420	14,280
C.J. Strike	90,000	82,800	82,800	95,420
Clear Lake	3,125	2,500[1]	2,420	2,430
Hells Canyon	435,000	391,500	391,500	449,580
Lower Salmon	70,000	60,000	60,000	69,140
Malad–Lower	15,500	13,500	13,500	13,500
Malad–Upper	9,650	8,270	8,270	8,400
Milner	62,890	59,448	59,448	61,880
Oxbow	211,112	190,000	190,000	218,520
Shoshone Falls	14,900	12,500[1]	12,500	12,500
Swan Falls	28,600	27,170	24,170[3]	24,170
Thousand Springs	11,000	8,800	6,380[2]	6,380
Twin Falls	56,175	52,897	52,561	54,170
Upper Salmon "A"	18,000	18,000	18,000	18,000
Upper Salmon "B"	18,000	16,500	16,500	16,560
Total Hydro	**1,897,046**	**1,709,045**		

Thermal, Natural Gas, and Diesel Power Plans	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC)[6,7] kW	Net Dependable Capability (NDC)[6,7] Summer kW	Net Dependable Capability (NDC)[6,7] Winter kW
Bridger (Idaho Power share)	811,053	770,501		703,667	703,667
Boardman (Idaho Power share)	67,600	64,200		57,800	58,300
Valmy (Idaho Power share)	315,000	283,500		261,000	261,000
Total Thermal	**1,193,653**	**1,118,201**			
Bennett Mountain	192,000	172,800	164,159		
Evander Andrews Unit #1	199,000	179,100	170,955		
Evander Andrews Unit #2	51,000	45,900	45,405		
Evander Andrews Unit #3	51,000	45,900	45,066		
Langley Gulch CT	220,000	187,000	176,880		
Langley Gulch ST	154,650	131,452	122,765		
Total Natural Gas	**867,650**	**762,152**			
Salmon Diesel	6,880	5,000	5,500		
Total IPC Generation	**3,965,229**	**3,594,398**			

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects
Status as of June 17, 2013.

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Hydro Projects							
Arena Drop	0.45	Sep-2010	Sep-2030	Lowline Canal	2.50	May-1985	Apr-2005
Barber Dam	3.70	Apr-1989	Apr-2024	Lowline Midway Hydro	7.97	Aug-2007	Aug-2027
Birch Creek	0.05	Nov-1984	Oct-2019	Lowline #2	2.79	Apr-1988	Apr-2023
Black Canyon #3	0.14	Apr-1984	Apr-2019	Magic Reservoir	9.07	Jun-1989	May-2024
Blind Canyon	1.50	Dec-1994	Dec-2014	Malad River	0.62	May-1984	Apr-2019
Box Canyon	0.36	Feb-1984	Feb-2019	Marco Ranches	1.20	Aug-1985	Jul-2020
Briggs Creek	0.60	Oct-1985	Oct-2020	Mile 28	1.50	Jun-1994	May-2029
Bypass	9.96	Jun-1988	Jun-2023	Mill Creek	0.80	Nov-2011	Jun-2017
Canyon Springs	0.13	Oct-1984	Non firm	Mitchell Butte	2.09	May-1989	May-2024
Cedar Draw	1.55	Jun-1984	May-2019	Mora Drop	1.90	Oct-2006	Sep-2026
Clark Canyon	4.70	Dec-2013	Estimated	Mud Creek S&S	0.52	Feb-1982	Feb-2017
Clear Springs Trout	0.52	Nov-1983	Oct-2018	Mud Creek White	0.21	Jan-1986	Jan-2021
Crystal Springs	2.44	Apr-1986	Mar-2021	Owyhee Dam CSPP	5.00	Aug-1985	Aug-2015
Curry Cattle Company	0.22	Jun-1983	Jun-2018	Pigeon Cove	1.89	Oct-1984	Oct-2019
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pristine Springs	0.13	May-2005	Apr-2015
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3	0.20	May-2005	Apr-2015
Falls River	9.10	Aug-1993	Aug-2028	Reynolds Irrigation	0.26	May-1986	May-2021
Fargo Drop	1.27	Apr-2013	Apr-2033	Rock Creek #1	2.05	Sep-1983	Sep-2018
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #2	1.90	Apr-1989	Mar-2024
Fisheries Development Co	0.26	Jul-1990	Non firm	Sagebrush	0.43	Sep-1985	Aug-2020
Geo Bon #2	0.93	Nov-1986	Nov-2021	Sahko Hydro	0.50	Jun-2006	Feb-2021
Hailey CSPP	0.06	Jun-1985	Jun-2020	Schaffner	0.53	Aug-1986	Jul-2021
Hazelton A	8.10	Jun-1990	Mar-2026	Shingle Creek	0.22	Aug-1983	Jul-2018
Hazelton B	7.60	May-1993	Apr-2028	Shoshone #2	0.58	May-1996	Apr-2031
Horseshoe Bend Hydroelectric	9.50	Sep-1995	Sep-2030	Shoshone CSPP	0.37	Jun-1982	Jun-2017
Jim Knight	0.34	Jun-1985	Jun-2020	Snake River Pottery	0.07	Nov-1984	Nov-2019
Kasel and Witherspoon	0.90	Mar-1984	Feb-2019	Snedigar	0.54	Jan-1985	Dec-2019
Koyle Small Hydro	1.25	Apr-1984	Mar-2019	Tiber Dam	7.50	Jun-2004	May-2024
Lateral # 10	2.06	May-1985	Apr-2020	Trout—Co	0.24	Dec-1986	Nov-2021
Lemoyne	0.08	Jun-1985	Jun-2020	Tunnel #1	7.00	Jun-1993	May-2028
Little Wood Rvr Res	2.85	Feb-1985	Feb-2020	White Water Ranch	0.16	Aug-1985	Jul-2020
Littlewood–Arkoosh	0.87	Aug-1986	Jul-2021	Wilson Lake Hydro	8.40	May-1993	May-2028
Total Hydro Nameplate Rating 147.92 MW							
Thermal Projects							
Magic Valley Natural Gas	10.00	Nov-1996	Nov-2016	TASCO—Nampa Natural Gas	2.00	Sep-2003	Non firm
Magic West Natural Gas	10.00	Dec-1996	Nov-2016	TASCO—Twin Falls Natural Gas	3.00	Aug-2001	Non firm
Simplot Pocatello Cogen	15.90	Mar-2013	Feb-2016				
Total Thermal Nameplate Rating 40.90 MW							

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2009	Aug-2019	Hidden Hollow Landfill Gas	3.20	Oct-2006	Jan-2027
Bettencourt Dry Creek	2.25	Aug-2008	Aug-2018	Pocatello Waste	0.46	Dec-1985	Dec-2020
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	Rock Creek Dairy	4.00	May-2012	Aug-2027
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	5.00	Jun-1983	May-2018
Total Biomass Nameplate Rating 23.19 MW							
Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind	21.30	Feb-2011	Feb-2031	Oregon Trail Wind	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Project	80.00	Dec-2011	Dec-2031
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Golden Valley Wind	12.00	Feb-2011	Feb-2031	Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032	Thousand Springs Wind	12.00	Jan-2011	Jan-2031
High Mesa	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind Park	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	Jun-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2012
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Mainline Windfarm	23.00	Dec-2012	Dec-2032				
Total Wind Nameplate Rating 576.92 MW							
Total Nameplate Rating 788.93 MW							

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of June 17, 2013. In the case of CSPP projects, nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements Status as of April 1, 2013

Project	MW	Contract On-Line Date	Contract End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total wind nameplate MW rating	101		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	September 2012	September 2037
Total geothermal nameplate MW rating	35		
Total nameplate MW rating	136		

Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

Hydro Modeling Results (PDR580)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2013**	**2/2013**	**3/2013**	**4/2013**	**5/2013**	**6/2013**	**7/2013**	**8/2013**	**9/2013**	**10/2013**	**11/2013**	**12/2013**	**aMW**
Brownlee	HCC*	343.1	293.0	343.5	435.3	421.2	424.5	242.8	170.4	215.4	193.2	152.6	253.0	290.7
Oxbow	HCC	143.5	127.9	150.4	181.0	168.9	171.1	103.2	78.0	98.7	88.8	69.4	106.5	123.9
Hells Canyon	HCC	282.0	255.2	304.1	371.7	348.1	345.5	204.8	153.1	193.8	175.2	138.2	211.3	248.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	23.6	24.4	24.3	51.0	80.6	88.2	81.8	67.7	41.1	15.3	0.0	13.5	42.6
Bliss	ROR	49.5	49.5	42.8	49.8	46.8	42.9	35.5	32.1	37.8	40.4	38.3	42.6	42.3
C .J. Strike	ROR	64.4	64.9	57.1	64.4	62.0	53.6	38.3	34.8	45.3	51.5	50.5	55.4	53.5
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.9	35.0	28.5	34.6	33.1	29.2	23.1	19.4	24.2	26.3	24.7	29.5	28.5
Milner	ROR	40.1	40.2	20.7	36.3	31.4	18.2	5.9	6.7	0.0	0.0	4.6	24.3	19.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.7	10.5	12.0	12.0	11.4
Swan Falls	ROR	20.8	21.1	18.6	20.9	20.0	17.5	13.3	12.1	15.2	17.0	16.7	18.1	17.6
Twin Falls	ROR	39.6	39.9	22.4	35.9	32.1	21.7	10.2	11.5	0.0	6.6	9.2	25.9	21.3
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	18.9	14.1	11.5	14.9	16.4	15.1	19.0	16.7
Upper Salmon 3&4	ROR	17.7	17.7	16.5	16.8	17.4	17.4	13.3	11.0	13.9	15.2	14.1	17.5	15.7
HCC Total		**768.6**	**676.1**	**798.0**	**988.0**	**938.1**	**941.1**	**550.8**	**401.5**	**507.9**	**457.2**	**360.2**	**570.8**	**663.2**
ROR Total		**348.3**	**349.8**	**285.5**	**370.9**	**388.0**	**357.5**	**283.2**	**258.3**	**236.1**	**228.4**	**209.3**	**284.5**	**300.0**
Total		**1116.9**	**1025.9**	**1083.5**	**1358.9**	**1326.0**	**1298.6**	**834.0**	**659.8**	**744.0**	**685.6**	**569.5**	**855.3**	**963.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2014**	**2/2014**	**3/2014**	**4/2014**	**5/2014**	**6/2014**	**7/2014**	**8/2014**	**9/2014**	**10/2014**	**11/2014**	**12/2014**	**aMW**
Brownlee	HCC*	342.2	292.5	342.6	435.0	420.5	423.9	242.2	169.8	213.6	194.0	152.9	247.9	289.8
Oxbow	HCC	143.1	127.7	150.0	180.9	168.6	170.9	103.0	77.7	97.7	88.9	69.3	104.3	123.5
Hells Canyon	HCC	281.3	254.9	303.3	371.4	347.5	345.1	204.3	152.6	191.7	175.4	138.1	207.0	247.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	22.3	24.2	23.6	50.7	79.6	88.1	81.8	67.6	41.0	15.2	0.0	11.0	42.1
Bliss	ROR	49.0	49.3	42.3	49.6	46.8	42.8	35.3	31.9	37.6	40.2	38.1	42.4	42.1
C .J. Strike	ROR	64.1	64.6	56.8	64.1	61.8	53.3	38.1	34.6	45.0	51.3	50.3	53.2	53.1
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.5	34.9	27.8	34.4	32.5	29.1	23.0	19.3	24.0	26.2	24.5	28.9	28.3
Milner	ROR	38.2	39.9	18.7	36.0	30.5	18.2	5.9	6.7	0.0	0.0	4.6	20.1	18.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.7	10.5	12.0	12.0	11.4
Swan Falls	ROR	20.5	21.0	18.5	20.8	19.9	17.4	13.3	12.1	15.1	16.9	16.5	17.5	17.5
Twin Falls	ROR	37.9	39.7	21.8	35.7	31.2	21.7	10.2	11.5	0.0	6.6	9.2	22.1	20.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.2	18.8	14.1	11.4	14.8	16.3	15.0	18.5	16.6
Upper Salmon 3&4	ROR	17.7	17.7	16.5	16.8	17.4	17.3	13.2	10.9	13.8	15.1	14.0	17.0	15.6
HCC Total		**766.6**	**675.1**	**795.9**	**987.3**	**936.5**	**939.9**	**549.5**	**400.1**	**502.9**	**458.3**	**360.3**	**559.2**	**661.0**
ROR Total		**341.9**	**348.4**	**280.6**	**369.3**	**384.4**	**356.6**	**282.6**	**257.5**	**235.0**	**227.5**	**208.3**	**269.4**	**296.8**
Total		**1108.5**	**1023.5**	**1076.5**	**1356.6**	**1320.8**	**1296.5**	**832.1**	**657.6**	**737.9**	**685.8**	**568.6**	**828.6**	**957.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50^{th} Percentile Water, 50^{th} Percentile Load

Resource	Type	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015	aMW
Brownlee	HCC*	350.5	292.8	342.1	440.5	435.0	438.7	242.3	169.7	222.1	192.9	152.6	255.1	294.5
Oxbow	HCC	146.5	127.9	149.8	183.1	174.2	176.7	103.0	77.7	100.3	89.0	69.4	107.4	125.4
Hells Canyon	HCC	287.9	255.1	302.9	375.8	358.7	356.4	204.3	152.5	195.9	175.5	138.3	213.1	251.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	24.5	24.6	25.2	59.0	86.2	91.8	82.4	68.5	41.5	17.2	0.0	16.7	44.8
Bliss	ROR	49.8	49.4	42.2	53.0	51.0	44.8	35.3	31.9	37.6	40.4	38.7	46.2	43.4
C .J. Strike	ROR	65.3	65.1	56.9	68.0	66.4	55.2	38.0	34.5	44.9	51.6	50.8	58.6	54.6
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	35.2	34.9	27.8	37.4	36.7	30.2	23.0	19.2	23.9	26.4	24.7	32.1	29.3
Milner	ROR	41.5	40.4	20.5	44.3	40.9	22.9	5.9	6.7	0.0	0.0	5.5	29.7	21.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.7	10.5	12.0	12.0	11.4
Swan Falls	ROR	21.0	21.2	18.6	21.9	21.4	18.0	13.3	12.1	15.1	17.0	16.8	19.0	18.0
Twin Falls	ROR	41.5	40.2	22.1	43.6	40.4	25.5	10.2	11.5	0.0	6.6	9.5	30.6	23.5
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	14.0	11.3	14.7	16.4	15.2	19.2	16.7
Upper Salmon 3&4	ROR	17.7	17.7	16.5	16.8	17.4	17.7	13.2	10.9	13.8	15.2	14.2	17.7	15.7
HCC Total		**784.9**	**675.8**	**794.8**	**999.4**	**967.9**	**971.8**	**549.6**	**399.9**	**518.2**	**457.4**	**360.3**	**575.6**	**671.3**
ROR Total		**354.2**	**350.6**	**284.4**	**405.2**	**424.9**	**375.2**	**283.0**	**258.1**	**235.3**	**230.5**	**211.5**	**308.5**	**310.1**
Total		**1139.1**	**1026.4**	**1079.2**	**1404.6**	**1392.8**	**1347.0**	**832.6**	**658.0**	**753.5**	**687.9**	**571.8**	**884.1**	**981.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50^{th} Percentile Water, 50^{th} Percentile Load

Resource	Type	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016	aMW
Brownlee	HCC*	349.6	295.1	341.2	440.2	434.2	438.2	241.7	156.9	216.9	193.3	152.6	254.6	292.9
Oxbow	HCC	146.1	128.8	149.4	183.0	173.9	176.4	102.7	71.6	99.7	89.1	69.4	107.2	124.8
Hells Canyon	HCC	287.2	257.0	302.1	375.6	358.1	356.0	203.8	141.1	195.7	175.8	138.3	212.6	250.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	24.3	24.4	25.0	58.8	86.0	91.8	82.3	64.3	42.2	17.4	0.0	20.6	44.8
Bliss	ROR	49.5	49.2	42.0	52.9	50.8	44.7	35.2	28.1	37.4	40.4	38.7	48.5	43.1
C .J. Strike	ROR	65.0	64.9	57.2	67.7	66.1	55.0	37.8	29.7	44.7	51.6	51.1	61.8	54.4
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	35.0	34.7	27.6	37.6	36.5	30.1	22.9	16.0	23.8	26.3	24.7	34.1	29.1
Milner	ROR	41.2	40.2	20.1	43.9	40.6	22.5	5.9	0.0	0.0	0.0	5.5	36.0	21.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	21.0	21.1	18.6	21.8	21.3	17.9	13.2	10.4	15.0	17.0	16.9	19.9	17.8
Twin Falls	ROR	41.3	39.9	21.7	43.3	40.2	25.3	10.2	0.0	0.0	6.6	10.0	36.1	22.9
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	13.9	8.8	14.6	16.4	15.1	19.1	16.4
Upper Salmon 3&4	ROR	17.7	17.7	16.4	16.8	17.4	17.7	13.1	8.8	13.7	15.2	14.1	17.7	15.5
HCC Total		**782.9**	**680.9**	**792.7**	**998.8**	**966.2**	**970.6**	**548.2**	**369.6**	**512.2**	**458.2**	**360.3**	**574.4**	**667.9**
ROR Total		**352.7**	**349.2**	**283.2**	**404.0**	**423.4**	**374.1**	**282.2**	**212.5**	**235.1**	**230.6**	**212.2**	**332.5**	**307.6**
Total		**1135.6**	**1030.1**	**1075.9**	**1402.8**	**1389.6**	**1344.7**	**830.4**	**582.1**	**747.3**	**688.8**	**572.5**	**906.9**	**975.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2017**	**2/2017**	**3/2017**	**4/2017**	**5/2017**	**6/2017**	**7/2017**	**8/2017**	**9/2017**	**10/2017**	**11/2017**	**12/2017**	**aMW**
Brownlee	HCC*	349.0	292.0	338.8	440.0	433.1	437.7	241.2	156.4	215.0	193.5	152.4	254.5	292.0
Oxbow	HCC	145.9	127.5	148.4	182.9	173.5	176.3	102.5	71.4	98.7	89.0	69.3	107.2	124.4
Hells Canyon	HCC	286.7	254.5	300.2	375.4	357.2	355.6	203.4	140.6	193.6	175.6	138.0	212.5	249.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	24.1	24.2	24.8	58.2	85.5	91.4	82.2	64.2	42.5	17.3	0.0	20.6	44.6
Bliss	ROR	49.4	49.1	41.8	51.6	50.4	44.6	35.0	28.0	37.3	40.2	38.7	48.2	42.9
C .J. Strike	ROR	64.8	64.7	56.5	66.6	65.6	54.8	37.7	29.5	44.5	51.4	50.9	61.5	54.0
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.8	34.5	27.0	36.7	36.1	30.1	22.8	15.8	23.6	26.2	24.5	33.9	28.8
Milner	ROR	41.0	40.0	18.2	42.1	40.0	22.3	5.9	0.0	0.0	0.0	5.5	36.0	20.9
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	21.1	18.4	21.5	21.2	17.9	13.1	10.4	15.0	16.9	16.8	19.8	17.8
Twin Falls	ROR	41.1	39.6	20.4	41.7	39.6	25.0	10.2	0.0	0.0	6.6	10.0	36.2	22.5
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	13.8	8.7	14.5	16.3	15.0	19.1	16.4
Upper Salmon 3&4	ROR	17.7	17.7	16.1	16.8	17.4	17.7	13.0	8.7	13.6	15.1	14.0	17.7	15.5
HCC Total		**781.6**	**674.0**	**787.4**	**998.3**	**963.8**	**969.6**	**547.1**	**368.4**	**507.2**	**458.1**	**359.7**	**574.2**	**665.8**
ROR Total		**351.5**	**348.0**	**277.8**	**396.4**	**420.3**	**372.9**	**281.4**	**211.7**	**234.8**	**229.7**	**211.5**	**331.7**	**305.6**
Total		**1133.1**	**1022.0**	**1065.2**	**1394.7**	**1384.1**	**1342.5**	**828.5**	**580.1**	**741.9**	**687.8**	**571.2**	**905.9**	**971.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2018**	**2/2018**	**3/2018**	**4/2018**	**5/2018**	**6/2018**	**7/2018**	**8/2018**	**9/2018**	**10/2018**	**11/2018**	**12/2018**	**aMW**
Brownlee	HCC*	348.6	291.7	338.2	439.6	432.8	437.1	240.7	155.8	213.4	193.6	152.5	253.9	291.5
Oxbow	HCC	145.7	127.4	148.2	182.8	173.4	176.0	102.3	71.1	97.8	89.0	69.3	106.9	124.2
Hells Canyon	HCC	286.4	254.2	299.7	375.1	357.0	355.2	203.0	140.1	192.0	175.5	138.1	212.1	249.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	24.1	24.2	24.6	58.0	85.4	91.1	82.1	64.2	42.5	17.3	0.0	17.3	44.2
Bliss	ROR	49.3	49.0	41.2	51.4	49.9	44.5	34.9	27.8	37.2	40.0	38.4	45.7	42.4
C .J. Strike	ROR	64.7	64.5	56.3	66.4	64.8	54.4	37.5	29.3	44.2	51.0	50.5	58.5	53.5
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.8	34.4	26.6	35.4	35.7	30.0	22.6	15.7	23.5	26.0	24.4	31.8	28.4
Milner	ROR	41.0	40.0	15.5	40.1	38.8	22.3	5.9	0.0	0.0	0.0	5.5	30.6	20.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	20.9	18.4	21.4	21.0	17.7	13.1	10.3	14.9	16.9	16.7	19.0	17.6
Twin Falls	ROR	41.2	39.6	19.2	39.3	38.6	24.6	10.2	0.0	0.0	6.6	9.6	31.5	21.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	13.8	8.6	14.3	16.1	14.9	19.2	16.3
Upper Salmon 3&4	ROR	17.7	17.7	15.8	16.8	17.4	17.7	13.0	8.6	13.5	15.0	14.0	17.7	15.4
HCC Total		**780.7**	**673.3**	**786.1**	**997.5**	**963.1**	**968.3**	**546.0**	**367.0**	**503.2**	**458.1**	**359.9**	**572.9**	**664.7**
ROR Total		**351.4**	**347.4**	**272.2**	**390.0**	**416.1**	**371.4**	**280.8**	**210.9**	**233.9**	**228.6**	**210.1**	**310.0**	**301.9**
Total		**1132.1**	**1020.7**	**1058.3**	**1387.5**	**1379.2**	**1339.7**	**826.8**	**577.9**	**737.1**	**686.7**	**570.0**	**882.9**	**966.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2019**	**2/2019**	**3/2019**	**4/2019**	**5/2019**	**6/2019**	**7/2019**	**8/2019**	**9/2019**	**10/2019**	**11/2019**	**12/2019**	**aMW**
Brownlee	HCC*	347.7	291.4	336.7	438.8	432.5	436.6	240.1	155.3	211.9	193.8	152.6	253.5	290.9
Oxbow	HCC	145.4	127.2	147.5	182.5	173.3	175.8	102.1	70.8	97.0	88.9	69.3	106.7	123.9
Hells Canyon	HCC	285.7	253.9	298.4	374.5	356.7	354.8	202.5	139.6	190.4	175.4	138.1	211.7	248.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	23.9	24.0	24.3	57.8	85.2	90.7	82.1	64.1	42.4	17.7	0.0	15.7	44.0
Bliss	ROR	49.1	48.8	40.8	51.0	49.7	44.4	34.7	27.7	37.0	39.9	38.2	44.6	42.2
C .J. Strike	ROR	64.4	64.3	55.7	66.1	64.5	54.1	37.2	29.1	44.0	50.9	49.9	57.0	53.1
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.6	34.2	26.2	34.5	35.5	29.8	22.5	15.5	23.3	25.9	24.1	30.7	28.1
Milner	ROR	40.7	39.6	14.7	36.2	38.6	21.7	5.9	0.0	0.0	0.0	5.5	28.0	19.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.8	20.8	18.2	21.4	20.9	17.7	13.0	10.2	14.8	16.8	16.4	18.6	17.5
Twin Falls	ROR	40.9	39.3	18.4	36.2	38.4	24.2	10.2	0.0	0.0	6.6	9.5	29.1	21.1
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	13.7	8.5	14.2	16.0	14.7	19.2	16.3
Upper Salmon 3&4	ROR	17.7	17.7	15.5	16.8	17.4	17.7	12.9	8.5	13.4	14.9	13.8	17.7	15.3
HCC Total		**778.8**	**672.5**	**782.6**	**995.8**	**962.5**	**967.2**	**544.7**	**365.7**	**499.2**	**458.1**	**360.0**	**571.9**	**663.2**
ROR Total		**349.8**	**345.8**	**268.4**	**381.2**	**414.7**	**369.4**	**279.9**	**210.0**	**232.9**	**228.4**	**208.2**	**299.3**	**299.0**
Total		**1128.6**	**1018.3**	**1051.0**	**1377.0**	**1377.2**	**1336.6**	**824.6**	**575.7**	**732.1**	**686.5**	**568.2**	**871.2**	**962.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2020**	**2/2020**	**3/2020**	**4/2020**	**5/2020**	**6/2020**	**7/2020**	**8/2020**	**9/2020**	**10/2020**	**11/2020**	**12/2020**	**aMW**
Brownlee	HCC*	346.8	290.9	336.4	437.2	432.2	436.0	239.5	154.6	210.5	193.9	152.7	252.9	290.3
Oxbow	HCC	145.0	127.1	147.4	181.8	173.2	175.6	101.8	70.6	96.3	88.9	69.3	106.5	123.6
Hells Canyon	HCC	284.9	253.6	298.2	373.1	356.5	354.3	202.0	139.1	189.0	175.4	138.1	211.2	247.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	23.7	23.7	23.7	56.4	84.9	90.4	82.1	64.0	42.4	17.3	0.0	14.5	43.6
Bliss	ROR	48.8	48.6	40.8	50.6	49.5	44.2	34.6	27.5	36.8	39.8	38.1	43.7	41.9
C .J. Strike	ROR	64.0	64.0	55.6	65.6	64.3	53.8	37.0	28.9	43.7	50.6	49.7	55.7	52.7
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.4	34.0	26.2	34.2	35.3	29.6	22.4	15.4	23.1	25.7	24.0	29.9	27.9
Milner	ROR	40.4	39.3	14.8	35.4	38.3	21.1	5.9	0.0	0.0	0.0	5.5	26.0	18.9
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.4	20.5	18.2	21.2	20.9	17.6	12.9	10.2	14.8	16.8	16.3	18.2	17.3
Twin Falls	ROR	40.6	39.0	18.4	35.2	38.1	24.0	10.2	0.0	0.0	6.6	9.5	27.3	20.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.2	13.6	8.4	14.1	15.9	14.6	19.2	16.2
Upper Salmon 3&4	ROR	17.7	17.7	15.5	16.8	17.4	17.6	12.8	8.4	13.2	14.8	13.7	17.7	15.3
HCC Total		**776.7**	**671.6**	**782.0**	**992.1**	**961.8**	**965.9**	**543.3**	**364.3**	**495.7**	**458.2**	**360.1**	**570.6**	**661.9**
ROR Total		**347.7**	**343.9**	**267.8**	**376.6**	**413.3**	**367.4**	**279.2**	**209.2**	**231.8**	**227.2**	**207.5**	**290.9**	**296.9**
Total		**1124.4**	**1015.5**	**1049.8**	**1368.7**	**1375.0**	**1333.3**	**822.5**	**573.5**	**727.5**	**685.4**	**567.6**	**861.5**	**958.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2021**	**2/2021**	**3/2021**	**4/2021**	**5/2021**	**6/2021**	**7/2021**	**8/2021**	**9/2021**	**10/2021**	**11/2021**	**12/2021**	**aMW**
Brownlee	HCC*	345.7	290.4	335.4	433.8	431.9	435.4	238.8	154.0	207.9	194.5	152.6	252.5	289.4
Oxbow	HCC	144.5	126.8	147.0	180.4	173.0	175.4	101.5	70.2	94.9	88.9	69.2	106.3	123.2
Hells Canyon	HCC	284.1	253.1	297.4	370.5	356.2	353.8	201.5	138.5	186.2	175.4	137.9	210.9	247.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	23.5	23.5	22.3	56.1	84.5	89.8	82.1	63.9	42.2	16.5	0.0	13.2	43.1
Bliss	ROR	48.6	48.3	40.4	50.4	49.3	44.1	34.4	27.3	36.6	39.6	37.7	43.2	41.7
C .J. Strike	ROR	63.7	63.6	55.3	64.4	63.9	53.4	36.8	28.6	43.5	50.4	49.5	54.3	52.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	34.1	33.8	25.9	33.8	35.1	29.5	22.2	15.2	23.0	25.6	23.7	29.4	27.6
Milner	ROR	40.2	38.9	14.1	35.0	37.9	20.8	5.9	0.0	0.0	0.0	5.1	23.8	18.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.3	20.4	18.1	20.9	20.8	17.5	12.9	10.1	14.7	16.7	16.2	17.8	17.2
Twin Falls	ROR	40.3	38.6	17.2	34.8	37.8	23.6	10.2	0.0	0.0	6.6	9.3	25.6	20.3
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.1	13.4	8.2	14.0	15.8	14.4	18.9	16.1
Upper Salmon 3&4	ROR	17.7	17.7	15.3	16.8	17.4	17.6	12.7	8.3	13.1	14.7	13.5	17.4	15.2
HCC Total		**774.3**	**670.3**	**779.8**	**984.7**	**961.1**	**964.6**	**541.8**	**362.7**	**489.0**	**458.8**	**359.7**	**569.7**	**659.7**
ROR Total		**346.1**	**341.9**	**263.2**	**373.4**	**411.3**	**365.3**	**278.3**	**208.0**	**230.9**	**225.6**	**205.5**	**282.3**	**294.3**
Total		**1120.4**	**1012.2**	**1043.0**	**1358.1**	**1372.3**	**1329.9**	**820.1**	**570.7**	**719.8**	**684.4**	**565.2**	**852.0**	**954.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2022**	**2/2022**	**3/2022**	**4/2022**	**5/2022**	**6/2022**	**7/2022**	**8/2022**	**9/2022**	**10/2022**	**11/2022**	**12/2022**	**aMW**
Brownlee	HCC*	344.6	289.9	334.8	433.4	431.5	434.8	238.2	153.3	205.7	194.8	153.0	249.8	288.6
Oxbow	HCC	144.1	126.6	146.7	180.3	172.9	175.1	101.3	69.9	93.7	88.9	69.3	105.2	122.8
Hells Canyon	HCC	283.2	252.7	296.9	370.2	355.9	353.4	201.0	137.9	184.0	175.3	138.1	208.6	246.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	23.3	23.2	22.0	52.2	84.3	89.5	82.1	63.8	42.1	17.3	0.0	11.9	42.6
Bliss	ROR	48.3	48.0	40.1	50.1	49.1	43.9	34.3	27.1	36.4	39.4	37.6	42.2	41.4
C .J. Strike	ROR	63.3	63.3	54.9	64.1	63.6	53.2	36.6	28.4	43.2	50.2	49.2	52.8	51.9
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	33.9	33.6	25.7	33.4	34.9	29.4	22.1	15.1	22.8	25.5	23.6	28.4	27.4
Milner	ROR	39.9	38.5	13.5	34.1	37.6	20.4	5.9	0.0	0.0	0.0	5.1	21.5	18.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.2	20.3	18.0	20.8	20.8	17.4	12.8	10.0	14.6	16.5	16.2	17.4	17.1
Twin Falls	ROR	40.0	38.3	17.2	34.0	37.5	23.3	10.2	0.0	0.0	6.6	9.3	23.4	20.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	19.0	13.3	8.1	13.8	15.7	14.3	18.1	16.0
Upper Salmon 3&4	ROR	17.7	17.7	15.2	16.8	17.4	17.5	12.6	8.2	13.0	14.6	13.4	16.7	15.1
HCC Total		**771.9**	**669.2**	**778.4**	**983.9**	**960.2**	**963.3**	**540.5**	**361.1**	**483.3**	**459.0**	**360.4**	**563.6**	**657.9**
ROR Total		**344.3**	**340.0**	**261.2**	**366.7**	**409.8**	**363.5**	**277.6**	**207.1**	**229.7**	**225.5**	**204.8**	**271.1**	**291.8**
Total		**1116.2**	**1009.2**	**1039.6**	**1350.6**	**1370.0**	**1326.8**	**818.1**	**568.2**	**713.0**	**684.5**	**565.2**	**834.7**	**949.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2023**	**2/2023**	**3/2023**	**4/2023**	**5/2023**	**6/2023**	**7/2023**	**8/2023**	**9/2023**	**10/2023**	**11/2023**	**12/2023**	**aMW**
Brownlee	HCC*	343.4	286.8	334.6	433.1	431.05	434.2	237.6	152.6	203.55	195.2	153	246.4	287.6
Oxbow	HCC	143.6	125.3	146.6	180.1	172.7	174.9	101	69.6	92.5	88.9	69.2	103.7	122.3
Hells Canyon	HCC	282.3	250.1	296.7	369.9	355.6	352.9	200.4	137.3	181.7	175.3	137.9	205.7	245.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	22.7	22.9	21.7	51.9	83.75	89.3	82.1	63.8	41.95	17.1	0	10.4	42.3
Bliss	ROR	48.1	47.8	39.8	49.7	48.8	43.6	34.1	26.9	36.2	39.3	37.3	41.1	41.1
C .J. Strike	ROR	62.9	62.9	54.5	63.7	63.3	53	36.4	28.1	43	50	48.9	52.8	51.6
Cascade	ROR	1.5	1.5	3	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	33.3	33.3	25.1	33.0	34.7	29.3	21.9	14.9	22.7	25.3	23.4	27.5	27.0
Milner	ROR	38.8	38.1	13.0	33.2	36.8	20.0	5.9	0.0	0.0	0.0	5.1	18.8	17.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.1	20.2	17.9	20.4	20.5	17.4	12.8	9.9	14.5	16.4	16.1	17.4	17.0
Twin Falls	ROR	38.5	37.9	16.9	33.2	36.8	23.0	10.2	0.0	0.0	6.6	9.3	21.3	19.5
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.1	19.1	18.9	13.2	8.0	13.7	15.6	14.1	17.4	15.9
Upper Salmon 3&4	ROR	17.7	17.7	14.8	16.8	17.4	17.4	12.5	8.1	12.9	14.5	13.3	16.1	14.9
HCC Total		**769.3**	**662.2**	**777.9**	**983.1**	**959.4**	**962.0**	**539.0**	**359.5**	**477.8**	**459.4**	**360.1**	**555.8**	**655.5**
ROR Total		**339.8**	**337.9**	**258.3**	**363.1**	**406.6**	**361.8**	**276.8**	**206.1**	**228.7**	**224.5**	**203.6**	**261.5**	**289.1**
Total		**1109.1**	**1000.1**	**1036.2**	**1346.2**	**1366.0**	**1323.8**	**815.8**	**565.6**	**706.5**	**683.9**	**563.7**	**817.3**	**944.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2024**	**2/2024**	**3/2024**	**4/2024**	**5/2024**	**6/2024**	**7/2024**	**8/2024**	**9/2024**	**10/2024**	**11/2024**	**12/2024**	**aMW**
Brownlee	HCC*	342.4	286.4	336.0	432.6	430.7	433.6	237.0	152.0	200.9	195.6	153.6	242.5	286.9
Oxbow	HCC	143.2	125.1	147.2	180.0	172.6	174.7	100.7	69.3	91.1	88.8	69.4	102.0	122.0
Hells Canyon	HCC	281.4	249.8	297.9	369.5	355.3	352.5	199.9	136.7	178.9	175.2	138.3	202.5	244.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	22.5	22.6	21.3	51.7	83.5	89.1	82.0	63.6	41.9	16.4	0.0	8.9	42.0
Bliss	ROR	47.5	47.5	39.6	49.3	48.6	43.4	34.0	26.7	36.0	39.1	36.9	40.0	40.7
C .J. Strike	ROR	62.6	62.5	53.4	63.3	63.0	52.8	36.2	27.8	42.7	49.8	48.6	52.0	51.2
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	33.1	33.1	25.0	32.7	34.4	29.1	21.8	14.7	22.5	25.2	23.2	26.5	26.8
Milner	ROR	38.4	37.7	12.6	32.4	36.0	19.3	5.9	0.0	0.0	0.0	5.0	16.1	17.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.0	20.1	17.6	20.3	20.4	17.3	12.7	9.8	14.4	16.3	16.0	17.2	16.8
Twin Falls	ROR	38.2	37.6	16.5	32.5	36.1	22.7	10.2	0.0	0.0	6.6	9.3	19.0	19.1
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.1	18.8	13.8	19.2	19.1	18.8	13.1	7.9	13.6	15.5	14.0	16.6	15.8
Upper Salmon 3&4	ROR	17.7	17.7	14.7	16.8	17.4	17.3	12.4	8.0	12.8	14.5	13.2	15.4	14.8
HCC Total		**767.0**	**661.3**	**781.1**	**982.1**	**958.5**	**960.8**	**537.6**	**358.0**	**470.9**	**459.6**	**361.3**	**547.0**	**653.8**
ROR Total		**337.7**	**335.9**	**255.3**	**360.3**	**403.9**	**359.7**	**276.0**	**204.9**	**227.6**	**223.1**	**202.3**	**250.4**	**286.4**
Total		**1104.7**	**997.2**	**1036.4**	**1342.4**	**1362.4**	**1320.5**	**813.6**	**562.9**	**698.5**	**682.7**	**563.6**	**797.4**	**940.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	340.6	285.9	335.1	432.2	430.4	433.0	236.3	151.2	198.7	196.0	153.5	239.8	286.1
Oxbow	HCC	142.4	124.9	146.9	179.8	172.5	174.4	100.5	68.9	90.0	88.8	69.3	100.8	121.6
Hells Canyon	HCC	280.0	249.4	297.1	369.2	355.1	352.0	199.4	136.0	176.7	175.2	138.0	200.2	244.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	22.3	22.4	21.1	51.4	83.2	89.0	82.0	63.5	41.8	16.1	0.0	7.8	41.7
Bliss	ROR	47.3	47.3	39.3	48.9	48.4	43.1	33.8	26.5	35.8	38.9	37.0	39.1	40.5
C .J. Strike	ROR	62.1	62.2	53.1	63.0	62.8	52.6	36.0	27.6	42.4	49.6	48.4	50.8	50.9
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.9	32.9	25.0	32.5	34.2	29.0	21.7	14.6	22.3	25.0	23.0	25.7	26.6
Milner	ROR	38.1	37.4	12.2	32.1	35.7	18.9	5.9	0.0	0.0	0.0	5.0	14.1	16.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.9	20.0	17.5	20.3	20.3	17.3	12.7	9.8	14.4	16.3	16.0	16.8	16.8
Twin Falls	ROR	37.9	37.3	16.1	32.2	35.8	22.6	10.2	0.0	0.0	6.6	9.3	17.1	18.8
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	18.7	13.0	7.8	13.4	15.4	13.9	16.0	15.7
Upper Salmon 3&4	ROR	17.7	17.7	14.7	16.8	17.4	17.2	12.3	7.9	12.7	14.4	13.1	14.9	14.7
HCC Total		**763.0**	**660.2**	**779.1**	**981.2**	**957.9**	**959.4**	**536.2**	**356.1**	**465.3**	**460.0**	**360.8**	**540.8**	**651.7**
ROR Total		**336.0**	**334.3**	**253.6**	**358.5**	**402.3**	**358.3**	**275.3**	**204.1**	**226.6**	**222.0**	**201.8**	**241.0**	**284.5**
Total		**1099.0**	**994.5**	**1032.7**	**1339.7**	**1360.2**	**1317.7**	**811.5**	**560.2**	**691.8**	**682.0**	**562.6**	**781.8**	**936.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	338.7	285.6	334.1	431.3	430.1	428.0	235.7	150.4	196.5	196.5	153.9	236.7	284.8
Oxbow	HCC	141.7	124.8	146.4	179.4	172.3	172.5	100.2	68.6	88.8	88.8	69.4	99.5	121.0
Hells Canyon	HCC	278.5	249.1	296.3	368.5	354.8	348.2	198.9	135.3	174.4	175.2	138.2	197.6	242.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	22.1	22.2	20.8	51.1	82.8	88.8	82.0	63.4	41.7	17.0	0.0	6.8	41.6
Bliss	ROR	47.0	47.1	39.1	48.5	48.2	42.6	33.6	26.3	35.7	38.8	36.3	38.2	40.1
C .J. Strike	ROR	61.3	61.9	52.8	62.6	62.7	52.4	35.8	27.4	42.2	49.4	48.0	50.0	50.5
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.7	32.7	24.8	32.3	34.0	28.1	21.5	14.4	22.1	24.9	22.9	24.9	26.3
Milner	ROR	37.8	37.1	12.2	31.7	35.4	18.7	5.9	0.0	0.0	0.0	4.6	12.4	16.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.7	19.9	17.4	20.2	20.2	17.2	12.6	9.7	14.3	16.2	15.9	16.5	16.7
Twin Falls	ROR	37.7	37.0	15.7	31.9	35.6	22.5	10.2	0.0	0.0	6.6	9.2	15.5	18.5
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	18.0	12.9	7.6	13.3	15.3	13.7	15.4	15.5
Upper Salmon 3&4	ROR	17.7	17.7	14.6	16.8	17.4	16.6	12.2	7.8	12.6	14.3	12.9	14.4	14.6
HCC Total		**758.9**	**659.5**	**776.8**	**979.2**	**957.2**	**948.7**	**534.8**	**354.3**	**459.6**	**460.5**	**361.5**	**533.8**	**648.7**
ROR Total		**333.8**	**332.7**	**252.0**	**356.4**	**400.9**	**354.8**	**274.4**	**203.0**	**225.7**	**222.2**	**199.6**	**232.8**	**282.4**
Total		**1092.7**	**992.2**	**1028.8**	**1335.6**	**1358.0**	**1303.5**	**809.2**	**557.3**	**685.3**	**682.7**	**561.1**	**766.6**	**931.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2027**	**2/2027**	**3/2027**	**4/2027**	**5/2027**	**6/2027**	**7/2027**	**8/2027**	**9/2027**	**10/2027**	**11/2027**	**12/2027**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.7	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.2**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.3**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2028**	**2/2028**	**3/2028**	**4/2028**	**5/2028**	**6/2028**	**7/2028**	**8/2028**	**9/2028**	**10/2028**	**11/2028**	**12/2028**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.6	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.1**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.2**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.6	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.1**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.2**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.6	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.1**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.2**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.6	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.1**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.2**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	333.8	285.1	333.1	430.4	421.8	423.2	235.1	149.9	194.3	196.8	154.0	234.0	282.6
Oxbow	HCC	139.7	124.6	146.0	187.2	169.1	170.6	100.0	68.3	87.6	88.8	69.3	98.3	120.8
Hells Canyon	HCC	274.6	248.8	295.5	378.4	348.5	344.5	198.4	134.8	172.1	175.2	138.1	195.3	242.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	20.6	21.9	20.6	50.0	82.6	88.7	81.7	63.3	41.6	16.1	0.0	5.6	41.1
Bliss	ROR	46.8	46.8	38.8	48.2	48.0	42.5	33.5	26.2	35.5	38.6	36.2	37.3	39.9
C .J. Strike	ROR	61.0	61.6	52.4	62.1	62.6	52.1	35.6	27.1	41.9	49.2	47.9	49.5	50.3
Cascade	ROR	1.5	1.5	3.0	5.8	5.5	11.1	10.2	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	32.2	32.5	24.6	32.0	33.8	27.9	21.4	14.3	22.0	24.8	22.7	24.1	26.0
Milner	ROR	35.7	36.6	11.7	31.3	35.1	18.2	5.9	0.0	0.0	0.0	4.6	10.5	15.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	19.6	19.8	17.3	20.0	20.2	17.1	12.5	9.6	14.2	16.2	15.8	16.3	16.6
Twin Falls	ROR	35.7	36.6	15.3	31.6	35.3	21.8	10.2	0.0	0.0	6.6	9.2	13.7	18.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	19.2	18.8	13.8	19.2	19.1	17.8	12.8	7.5	13.2	15.2	13.6	14.8	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.4	16.8	17.4	16.5	12.1	7.7	12.5	14.2	12.8	13.8	14.5
HCC Total		**748.1**	**658.5**	**774.6**	**996.0**	**939.3**	**938.3**	**533.5**	**353.0**	**453.9**	**460.8**	**361.4**	**527.6**	**645.4**
ROR Total		**327.1**	**330.6**	**249.7**	**353.3**	**399.5**	**352.5**	**273.4**	**202.1**	**224.7**	**220.6**	**198.9**	**224.3**	**279.7**
Total		**1075.2**	**989.1**	**1024.3**	**1349.3**	**1338.8**	**1290.8**	**806.9**	**555.1**	**678.6**	**681.4**	**560.3**	**751.9**	**925.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2013**	**2/2013**	**3/2013**	**4/2013**	**5/2013**	**6/2013**	**7/2013**	**8/2013**	**9/2013**	**10/2013**	**11/2013**	**12/2013**	**aMW**
Brownlee	HCC*	256.5	264.8	259.1	301.5	390.1	316.6	228.7	162.7	184.9	177.2	156.2	208.7	242.2
Oxbow	HCC	108.2	113.0	110.6	123.5	157.5	127.8	96.9	74.3	84.9	79.2	69.5	87.3	102.7
Hells Canyon	HCC	214.2	225.5	225.7	251.2	320.0	258.2	191.3	145.8	166.4	156.2	138.1	173.1	205.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.7	11.1	33.8	72.6	88.6	83.0	64.1	34.1	11.6	0.0	0.0	33.7
Bliss	ROR	38.3	39.7	37.4	37.2	42.1	40.8	34.8	31.5	37.1	39.3	37.4	37.4	37.8
C .J. Strike	ROR	49.9	52.8	49.0	49.9	52.7	47.0	36.8	33.9	44.3	50.1	48.5	48.5	47.0
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.9	25.0	22.2	23.0	28.5	28.3	22.7	19.1	23.6	25.5	24.0	23.8	24.1
Milner	ROR	8.9	10.6	5.2	3.7	17.0	17.0	5.9	6.7	0.0	0.0	3.6	6.2	7.1
Shoshone Falls	ROR	12.0	12.0	12.0	11.3	12.0	12.0	12.0	12.0	6.7	10.5	12.0	12.0	11.4
Swan Falls	ROR	16.3	17.4	16.2	16.3	17.4	15.5	12.9	11.9	14.9	16.4	16.0	16.0	15.6
Twin Falls	ROR	11.5	13.7	8.6	7.3	19.9	20.6	10.2	11.5	0.0	6.6	8.3	9.5	10.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.7	15.7	13.6	14.2	18.5	18.2	13.8	11.2	14.4	15.8	14.6	14.5	14.9
Upper Salmon 3&4	ROR	13.7	14.6	12.8	13.4	17.1	16.8	13	10.8	13.5	14.7	13.7	13.6	14.0
HCC Total		**578.9**	**603.3**	**595.4**	**676.2**	**867.6**	**702.6**	**516.9**	**382.8**	**436.1**	**412.6**	**363.8**	**469.1**	**550.4**
ROR Total		**215.8**	**233.5**	**215.2**	**235.6**	**327.8**	**336.9**	**278.2**	**251.1**	**224.1**	**219.3**	**202.1**	**208.2**	**245.7**
Total		**794.7**	**836.8**	**810.6**	**911.8**	**1195.4**	**1039.5**	**795.1**	**633.9**	**660.2**	**631.9**	**565.9**	**677.3**	**796.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2014**	**2/2014**	**3/2014**	**4/2014**	**5/2014**	**6/2014**	**7/2014**	**8/2014**	**9/2014**	**10/2014**	**11/2014**	**12/2014**	**aMW**
Brownlee	HCC*	254.6	264.1	258.4	300.2	389.8	315.8	228.2	162.1	184.3	176.1	156.3	207.3	241.4
Oxbow	HCC	107.4	112.7	110.2	123.0	157.3	127.5	96.7	74.0	84.6	78.6	69.6	86.7	102.4
Hells Canyon	HCC	212.7	224.9	225.1	250.2	319.7	257.5	190.8	145.3	165.8	155.2	138.1	171.9	204.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0	0	10.4	32.8	72.6	88.5	83.1	64	34.05	11.6	0	0	33.1
Bliss	ROR	38.2	39.4	36.8	36.1	42	40.6	34.7	31.4	36.9	39.2	37.2	37.1	37.5
C .J. Strike	ROR	49.8	51.8	48.7	48.9	52.6	46.8	36.6	33.7	44.1	49.8	48.3	48	46.6
Cascade	ROR	1.5	1.5	1.3	1.2	2.05	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.8	24.2	22.2	22.6	28.4	28.2	22.5	18.9	23.4	25.4	23.9	23.6	23.9
Milner	ROR	8.9	8.8	4.8	2.3	17	17	5.9	6.7	0	0	3.6	6.2	6.8
Shoshone Falls	ROR	12	12	12	10	12	12	12	12	6.7	10.5	12	12	11.3
Swan Falls	ROR	16.2	17.1	16.1	16.2	17.3	15.5	12.8	11.8	14.8	16.4	15.9	15.9	15.5
Twin Falls	ROR	11.5	12.1	8.3	6.2	19.9	20.6	10.2	11.5	0	6.6	8.3	9.5	10.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.6	15.0	13.6	14.0	18.5	18.1	13.7	11.1	14.3	15.7	14.5	14.4	14.8
Upper Salmon 3&4	ROR	13.7	14.1	12.8	13.1	17.0	16.7	12.9	10.7	13.4	14.6	13.6	13.5	13.8
HCC Total		**574.7**	**601.7**	**593.7**	**673.4**	**866.8**	**700.8**	**515.7**	**381.4**	**434.6**	**409.9**	**364.0**	**465.9**	**548.5**
ROR Total		**215.3**	**220.8**	**212.8**	**227.7**	**327.3**	**336.1**	**277.5**	**250.2**	**223.2**	**218.6**	**201.3**	**206.9**	**243.1**
Total		**790.0**	**822.5**	**806.5**	**901.1**	**1194.1**	**1036.9**	**793.2**	**631.6**	**657.8**	**628.5**	**565.3**	**672.8**	**791.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2015**	**2/2015**	**3/2015**	**4/2015**	**5/2015**	**6/2015**	**7/2015**	**8/2015**	**9/2015**	**10/2015**	**11/2015**	**12/2015**	**aMW**
Brownlee	HCC*	257.8	271.6	260.5	319.5	390.6	317.6	228.2	162.0	184.0	179.2	155.8	213.0	245.0
Oxbow	HCC	108.8	115.9	111.1	130.7	157.6	128.2	96.7	74.0	84.4	80.2	69.5	89.1	103.9
Hells Canyon	HCC	215.3	231.1	226.8	265.1	320.3	259.0	190.9	145.2	165.6	158.1	137.9	176.7	207.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.9	13.5	37.1	72.7	89.4	83.2	65.2	34.9	13.4	0.0	0.0	34.9
Bliss	ROR	38.4	40.8	37.3	38.8	42.5	40.7	34.6	31.3	36.8	39.4	37.6	37.4	38.0
C .J. Strike	ROR	50.1	54.5	48.3	52.7	52.8	47.1	36.6	33.6	44.0	50.1	48.5	49.1	47.3
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	24.4	27.0	22.1	24.9	28.6	28.4	22.5	18.8	23.3	25.6	24.1	23.8	24.5
Milner	ROR	8.9	17.1	4.0	8.5	18.2	18.2	5.9	6.7	0.0	0.0	3.6	6.2	8.1
Shoshone Falls	ROR	12.0	12.0	11.9	12.0	12.0	12.0	12.0	12.0	6.7	10.5	12.0	12.0	11.4
Swan Falls	ROR	16.4	17.7	16.0	17.3	17.4	15.7	12.8	11.8	14.8	16.4	15.9	16.1	15.7
Twin Falls	ROR	11.7	19.5	7.8	11.3	20.6	21.7	10.2	11.5	0.0	6.6	8.3	9.5	11.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	15.0	17.2	13.5	15.8	18.6	18.2	13.7	11.0	14.2	15.8	14.7	14.5	15.2
Upper Salmon 3&4	ROR	14.0	16.0	12.8	14.7	17.1	16.8	12.9	10.6	13.4	14.7	13.8	13.6	14.2
HCC Total		**581.9**	**618.6**	**598.4**	**715.3**	**868.5**	**704.8**	**515.8**	**381.2**	**433.9**	**417.5**	**363.2**	**478.8**	**556.5**
ROR Total		**217.5**	**258.0**	**214.3**	**258.6**	**330.5**	**340.3**	**277.5**	**250.9**	**223.7**	**221.3**	**202.5**	**208.9**	**250.3**
Total		**799.4**	**876.6**	**812.7**	**973.9**	**1199.0**	**1045.1**	**793.3**	**632.1**	**657.6**	**638.8**	**565.7**	**687.7**	**806.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2016**	**2/2016**	**3/2016**	**4/2016**	**5/2016**	**6/2016**	**7/2016**	**8/2016**	**9/2016**	**10/2016**	**11/2016**	**12/2016**	**aMW**
Brownlee	HCC*	257.4	270.8	260.8	318.1	392.0	317.1	227.6	149.1	183.3	178.6	155.9	216.8	244.0
Oxbow	HCC	108.6	115.6	111.3	130.1	158.2	128.0	96.5	67.9	84.1	79.9	69.6	90.8	103.4
Hells Canyon	HCC	214.9	230.5	227.1	264.0	321.5	258.5	190.4	133.7	164.9	157.6	138.1	179.9	206.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	14.0	13.3	38.8	72.7	89.4	83.1	61.2	36.0	13.6	0.0	0.0	35.2
Bliss	ROR	38.5	42.4	36.4	38.9	42.4	40.6	34.5	27.6	36.6	39.2	37.6	37.3	37.7
C .J. Strike	ROR	49.9	54.8	47.7	52.4	52.7	47.0	36.4	28.8	43.7	49.9	48.4	48.9	46.7
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	24.3	29.1	22.2	25.1	28.5	28.2	22.4	15.6	23.2	25.5	23.9	23.8	24.3
Milner	ROR	9.0	24.2	4.6	8.7	18.2	18.2	5.9	0.0	0.0	0.0	3.6	6.2	8.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	16.3	17.9	15.8	17.3	17.4	15.6	12.8	10.1	14.7	16.4	15.9	16.0	15.5
Twin Falls	ROR	12.0	25.6	8.2	11.4	20.6	21.7	10.2	0.0	0.0	6.6	8.3	9.5	11.2
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.9	18.9	13.6	15.9	18.5	18.1	13.5	8.5	14.1	15.7	14.6	14.5	15.1
Upper Salmon 3&4	ROR	14.0	17.4	12.8	14.8	17.1	16.7	12.8	8.5	13.3	14.6	13.7	13.6	14.1
HCC Total		**580.9**	**616.9**	**599.2**	**712.2**	**871.7**	**703.6**	**514.5**	**350.7**	**432.3**	**416.1**	**363.6**	**487.5**	**554.1**
ROR Total		**217.5**	**282.6**	**213.7**	**260.8**	**330.1**	**339.6**	**276.7**	**205.6**	**223.9**	**220.8**	**202.0**	**208.5**	**248.5**
Total		**798.4**	**899.5**	**812.9**	**973.0**	**1201.8**	**1043.2**	**791.2**	**556.3**	**656.1**	**636.9**	**565.6**	**696.0**	**802.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	Type	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017	aMW
Brownlee	HCC*	257.0	270.2	259.3	312.5	389.8	316.5	227.1	148.6	182.7	177.6	156.1	216.4	242.8
Oxbow	HCC	108.4	115.3	110.6	127.9	157.4	127.8	96.3	67.6	83.9	79.4	69.6	90.6	102.9
Hells Canyon	HCC	214.6	230.0	225.8	259.7	319.8	258.1	190.0	133.2	164.5	156.7	138.2	179.5	205.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	12.8	13.2	37.3	72.7	89.3	83.0	61.2	36.0	13.6	0.0	0.0	34.9
Bliss	ROR	38.5	41.7	36.0	37.8	42.4	40.4	34.4	27.4	36.4	39.1	37.4	37.2	37.4
C .J. Strike	ROR	49.8	54.7	47.4	52.0	52.6	46.8	36.2	28.6	43.5	49.8	48.1	48.8	46.5
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	24.2	28.5	21.9	24.1	28.5	28.1	22.3	15.5	23	25.4	23.8	23.7	24.1
Milner	ROR	8.9	22.2	2.4	6.2	18.2	18.2	5.9	0	0	0	3.6	6.2	7.7
Shoshone Falls	ROR	12	12	10.2	12	12	12	12	6.9	6.7	10.5	12	12	10.9
Swan Falls	ROR	16.3	17.9	15.7	17.1	17.3	15.5	12.7	10.1	14.6	16.3	15.9	16	15.5
Twin Falls	ROR	11.7	23.8	6.4	9.5	20.6	21.4	10.2	0	0	6.6	8.4	9.5	10.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.9	18.4	13.4	15.1	18.5	18.0	13.5	8.4	14.0	15.6	14.5	14.4	14.9
Upper Salmon 3&4	ROR	13.9	16.9	12.6	14.1	17.0	16.6	12.7	8.4	13.2	14.6	13.6	13.5	13.9
HCC Total		**580.0**	**615.5**	**595.7**	**700.1**	**867.0**	**702.4**	**513.4**	**349.4**	**431.0**	**413.7**	**363.9**	**486.5**	**551.6**
ROR Total		**216.8**	**275.2**	**206.3**	**250.7**	**329.8**	**338.4**	**276.0**	**204.9**	**222.9**	**220.3**	**201.3**	**208.0**	**245.9**
Total		**796.8**	**890.7**	**802.0**	**950.8**	**1196.8**	**1040.8**	**789.4**	**554.3**	**653.9**	**634.0**	**565.2**	**694.5**	**797.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	Type	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018	aMW
Brownlee	HCC*	256.6	265.8	255.9	311.9	389.4	312.7	226.6	148.0	182.2	176.2	156.1	213.6	241.2
Oxbow	HCC	108.3	113.4	109.2	127.7	157.2	126.3	96.0	67.4	83.6	78.7	69.6	89.4	102.2
Hells Canyon	HCC	214.3	226.3	223.0	259.2	319.5	255.2	189.5	132.7	163.9	155.4	138.1	177.2	204.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0	6	13	37.3	73.35	89.3	83.1	61.1	35.8	13.4	0	0	34.4
Bliss	ROR	38	39.7	35.9	37.6	42.1	40.3	34.3	27.2	36.2	39	37.3	37	37.1
C .J. Strike	ROR	49.7	52.5	47.3	51.9	52.5	46.6	36.1	28.4	43.3	49.5	47.9	48.6	46.2
Cascade	ROR	1.5	1.5	1.3	1.2	2.05	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.9	24.6	21.9	23.9	28.4	28	22.1	15.3	22.9	25.2	23.7	23.5	23.6
Milner	ROR	8.9	11	2.4	6.4	18.2	18.2	5.9	0	0	0	3.6	6.2	6.7
Shoshone Falls	ROR	12	12	10.2	12	12	12	12	6.9	6.7	10.5	12	12	10.9
Swan Falls	ROR	16.3	17.3	15.8	17	17.3	15.4	12.7	10	14.6	16.3	15.8	15.9	15.4
Twin Falls	ROR	11.5	14.1	6.4	9.2	20.6	21	10.2	0	0	6.6	8.4	9.5	9.8
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.7	15.4	13.3	15.0	18.4	17.9	13.4	8.3	13.9	15.5	14.4	14.3	14.5
Upper Salmon 3&4	ROR	13.8	14.4	12.6	14.0	17.0	16.5	12.6	8.3	13.1	14.5	13.5	13.4	13.6
HCC Total		**579.2**	**605.5**	**588.1**	**698.8**	**866.1**	**694.2**	**512.1**	**348.1**	**429.6**	**410.3**	**363.8**	**480.2**	**548.0**
ROR Total		**215.4**	**233.3**	**205.9**	**249.8**	**329.9**	**337.3**	**275.5**	**203.9**	**222.1**	**219.3**	**200.6**	**207.1**	**241.7**
Total		**794.6**	**838.8**	**794.0**	**948.6**	**1196.0**	**1031.5**	**787.6**	**552.0**	**651.7**	**629.6**	**564.4**	**687.3**	**789.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2019**	**2/2019**	**3/2019**	**4/2019**	**5/2019**	**6/2019**	**7/2019**	**8/2019**	**9/2019**	**10/2019**	**11/2019**	**12/2019**	**aMW**
Brownlee	HCC*	256.2	264.3	255.9	310.0	389.1	310.8	226.1	147.4	181.6	167.5	156.0	211.0	239.7
Oxbow	HCC	108.1	112.8	109.2	126.9	157.1	125.5	95.8	67.1	83.3	78.0	69.4	88.3	101.8
Hells Canyon	HCC	214.0	225.0	223.0	257.8	319.2	253.7	189.1	132.2	163.4	153.5	137.9	175.0	203.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0	0	12.5	36.6	73.3	89.2	83.1	60.6	35.2	13.7	0	0	33.7
Bliss	ROR	37.9	39.3	35.8	37.2	42	40.2	34.2	27.1	36.1	38.8	37	36.9	36.9
C .J. Strike	ROR	49.6	51.5	47.2	51.5	52.4	46.4	35.9	28.1	43	49.3	47.7	48.5	45.9
Cascade	ROR	1.5	1.5	1.3	1.2	2.05	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.8	24.3	21.6	22.7	28.3	27.9	22.0	15.2	22.8	25.1	23.5	23.5	23.4
Milner	ROR	8.9	10.1	0.0	4.7	18.2	18.2	5.9	0.0	0.0	0.0	3.6	6.2	6.3
Shoshone Falls	ROR	12.0	12.0	9.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.8
Swan Falls	ROR	16.2	17.0	15.6	16.8	17.3	15.4	12.7	9.9	14.5	16.2	15.7	15.9	15.3
Twin Falls	ROR	11.5	13.3	5.4	8.5	20.6	21.0	10.2	0.0	0.0	6.6	8.4	9.5	9.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.6	15.1	13.1	14.0	18.3	17.8	13.3	8.2	13.8	15.4	14.2	14.3	14.3
Upper Salmon 3&4	ROR	13.7	14.1	12.4	13.2	16.9	16.5	12.6	8.2	13.0	14.4	13.4	13.4	13.5
HCC Total		**578.3**	**602.1**	**588.1**	**694.7**	**865.4**	**690.0**	**511.0**	**346.7**	**428.2**	**399.0**	**363.3**	**474.3**	**545.1**
ROR Total		**214.8**	**223.0**	**199.7**	**242.7**	**329.3**	**336.7**	**275.0**	**202.6**	**220.7**	**218.8**	**199.5**	**206.9**	**239.1**
Total		**793.1**	**825.1**	**787.8**	**937.4**	**1194.7**	**1026.7**	**786.0**	**549.3**	**648.9**	**617.8**	**562.8**	**681.2**	**784.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2020**	**2/2020**	**3/2020**	**4/2020**	**5/2020**	**6/2020**	**7/2020**	**8/2020**	**9/2020**	**10/2020**	**11/2020**	**12/2020**	**aMW**
Brownlee	HCC*	255.7	262.7	255.8	308.3	388.7	309.5	225.5	146.8	180.9	166.0	156.4	208.4	238.7
Oxbow	HCC	107.9	112.1	109.1	126.2	156.9	125.0	95.6	66.8	83.0	77.2	69.6	87.2	101.4
Hells Canyon	HCC	213.6	223.7	222.9	256.5	319.0	252.8	188.6	131.7	162.8	152.0	138.1	172.9	202.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	11.6	36.9	73.3	89.1	83.1	60.5	35.2	13.7	0.0	0.0	33.6
Bliss	ROR	37.7	39.0	35.3	36.1	41.9	40.0	34.0	26.9	35.9	38.6	36.6	36.7	36.6
C .J. Strike	ROR	49.4	51.3	46.8	50.1	52.3	46.2	35.7	27.9	42.8	49.1	47.4	48.2	45.6
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.7	23.9	21.5	22.1	28.2	27.8	21.9	15.0	22.7	25.0	23.4	23.3	23.2
Milner	ROR	8.9	9.1	0.0	3.6	18.2	17.9	5.9	0.0	0.0	0.0	3.6	6.2	6.1
Shoshone Falls	ROR	12.0	12.0	9.1	11.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.7
Swan Falls	ROR	16.2	17.0	15.5	16.5	17.3	15.3	12.6	9.9	14.5	16.2	15.7	15.8	15.2
Twin Falls	ROR	11.5	12.6	5.4	7.7	20.4	21.0	10.2	0.0	0.0	6.6	8.4	9.5	9.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.5	14.8	13.1	13.5	18.3	17.7	13.2	8.1	13.7	15.3	14.1	14.2	14.2
Upper Salmon 3&4	ROR	13.6	13.9	12.4	12.8	16.9	16.4	12.5	8.1	12.9	14.3	13.3	13.3	13.4
HCC Total		**577.2**	**598.5**	**587.8**	**691.0**	**864.6**	**687.3**	**509.7**	**345.3**	**426.6**	**395.2**	**364.1**	**468.5**	**543.0**
ROR Total		**214.1**	**219.9**	**197.8**	**236.5**	**328.8**	**335.5**	**274.2**	**201.7**	**219.9**	**218.1**	**198.5**	**205.9**	**237.6**
Total		**791.3**	**818.4**	**785.6**	**927.5**	**1193.4**	**1022.8**	**783.9**	**547.0**	**646.5**	**613.3**	**562.6**	**674.4**	**780.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2021**	**2/2021**	**3/2021**	**4/2021**	**5/2021**	**6/2021**	**7/2021**	**8/2021**	**9/2021**	**10/2021**	**11/2021**	**12/2021**	**aMW**
Brownlee	HCC*	255.2	260.1	255.7	306.4	388.4	307.9	224.8	146.1	180.1	165.9	156.1	212.9	238.3
Oxbow	HCC	107.7	111.0	109.1	125.5	156.8	124.4	95.3	66.5	82.6	77.1	69.5	89.1	101.2
Hells Canyon	HCC	213.1	221.6	222.9	255.0	318.7	251.5	188.1	131.1	162.1	151.9	138.0	176.6	202.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	10.3	35.6	73.3	88.9	83.0	60.4	35.0	13.7	0.0	0.0	33.3
Bliss	ROR	37.6	38.9	35.1	36.8	41.8	39.9	33.9	26.7	35.7	38.5	36.4	36.5	36.5
C .J. Strike	ROR	49.2	51.2	46.7	49.9	52.2	45.7	35.5	27.6	42.5	48.9	47.2	47.8	45.4
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.3	23.7	21.4	22.5	28.1	27.7	21.7	14.8	22.5	24.8	23.1	23.2	23.1
Milner	ROR	8.9	9.1	0.0	4.6	17.4	17.1	5.9	0.0	0.0	0.0	3.6	6.2	6.1
Shoshone Falls	ROR	12.0	12.0	9.1	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.8
Swan Falls	ROR	16.0	16.9	15.5	16.4	17.2	15.2	12.6	9.8	14.4	16.1	15.6	15.7	15.1
Twin Falls	ROR	11.5	12.6	5.4	8.1	20.1	20.6	10.2	0.0	0.0	6.6	8.4	9.5	9.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.2	14.7	13.0	13.9	18.2	17.6	13.1	8.0	13.6	15.2	13.9	14.1	14.1
Upper Salmon 3&4	ROR	13.4	13.8	12.3	13.1	16.8	16.3	12.4	8.0	12.8	14.2	13.1	13.2	13.3
HCC Total		**576.0**	**592.7**	**587.7**	**686.9**	**863.9**	**683.8**	**508.2**	**343.7**	**424.8**	**394.9**	**363.6**	**478.6**	**542.1**
ROR Total		**212.7**	**219.2**	**195.9**	**238.4**	**327.1**	**333.1**	**273.4**	**200.6**	**218.7**	**217.3**	**197.3**	**204.9**	**236.6**
Total		**788.7**	**811.9**	**783.6**	**925.3**	**1191.0**	**1016.9**	**781.6**	**544.3**	**643.5**	**612.2**	**560.9**	**683.5**	**778.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2022**	**2/2022**	**3/2022**	**4/2022**	**5/2022**	**6/2022**	**7/2022**	**8/2022**	**9/2022**	**10/2022**	**11/2022**	**12/2022**	**aMW**
Brownlee	HCC*	254.7	259.7	255.7	305.5	388.0	307.1	224.2	145.5	179.5	164.3	156.2	209.3	237.5
Oxbow	HCC	107.4	110.8	109.1	125.1	156.7	124.1	95.0	66.2	82.3	76.3	69.4	87.6	100.8
Hells Canyon	HCC	212.7	221.2	222.8	254.3	318.4	250.9	187.5	130.5	161.5	150.4	137.9	173.6	201.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0	0	10.1	35.6	73.3	88.9	83.1	60.3	34.85	13.6	0	0	33.3
Bliss	ROR	37.5	38.6	35	36.6	41.7	39.7	33.7	26.5	35.5	38.3	36.2	36.4	36.3
C .J. Strike	ROR	49.1	50.7	46.6	49.6	52	45.5	35.2	27.4	42.3	48.7	46.9	47.6	45.1
Cascade	ROR	1.5	1.5	1.3	1.2	2.05	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.1	23.6	21.3	22.3	28.1	27.5	21.6	14.7	22.3	24.6	22.9	23.1	22.9
Milner	ROR	8.9	9.1	0.0	2.7	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.9
Shoshone Falls	ROR	12.0	12.0	8.6	11.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.6
Swan Falls	ROR	16.0	16.8	15.5	16.3	17.2	15.4	12.5	9.7	14.3	16.0	15.5	15.7	15.1
Twin Falls	ROR	11.5	12.6	4.8	7.1	20.1	20.6	10.2	0.0	0.0	6.6	8.4	9.5	9.3
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.1	14.6	12.9	13.7	18.2	17.5	12.9	7.8	13.4	15.1	13.8	14.0	14.0
Upper Salmon 3&4	ROR	13.2	13.7	12.2	12.9	16.8	16.2	12.3	7.9	12.7	14.1	13.0	13.1	13.2
HCC Total		**574.8**	**591.7**	**587.6**	**684.9**	**863.1**	**682.1**	**506.7**	**342.2**	**423.2**	**391.0**	**363.5**	**470.5**	**540.1**
ROR Total		**212.0**	**218.0**	**194.1**	**233.3**	**326.4**	**332.4**	**272.5**	**199.6**	**217.6**	**216.3**	**196.3**	**204.3**	**235.2**
Total		**786.8**	**809.7**	**781.7**	**918.2**	**1189.5**	**1014.5**	**779.2**	**541.8**	**640.8**	**607.3**	**559.8**	**674.8**	**775.3**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load

Resource	Type	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023	aMW
Brownlee	HCC*	254.2	259.4	255.6	304.3	387.6	306.6	223.5	144.8	178.9	162.6	156.6	205.8	236.7
Oxbow	HCC	107.2	110.7	109.0	124.6	156.5	123.9	94.7	65.9	82.1	75.4	69.5	86.1	100.5
Hells Canyon	HCC	212.3	221.0	222.7	253.3	318.1	250.5	187.0	129.9	161.0	148.7	138.1	170.7	201.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	9.1	36.0	73.3	88.9	83.1	60.3	34.8	13.6	0.0	0.0	33.3
Bliss	ROR	37.3	37.6	34.9	35.8	41.6	39.6	33.5	26.3	35.3	38.1	36.0	36.2	36.0
C .J. Strike	ROR	48.6	49.7	46.5	49.3	51.9	45.3	35.0	27.1	42.0	48.5	46.6	46.8	44.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	23.0	23.5	21.3	21.8	28.0	27.3	21.4	14.5	22.1	24.5	22.7	22.8	22.7
Milner	ROR	8.9	8.7	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.6
Shoshone Falls	ROR	12.0	12.0	8.6	8.1	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.4
Swan Falls	ROR	15.9	16.3	15.3	16.3	17.2	15.3	12.4	9.7	14.2	16.0	15.4	15.5	15.0
Twin Falls	ROR	11.5	11.8	4.8	4.4	20.1	20.6	10.2	0.0	0.0	6.6	8.4	9.5	9.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	14.0	14.5	12.9	13.3	18.1	17.4	12.8	7.7	13.3	14.9	13.6	13.8	13.9
Upper Salmon 3&4	ROR	13.2	13.6	12.2	12.6	16.7	16.1	12.2	7.8	12.6	14.0	12.8	13.0	13.1
HCC Total		**573.7**	**591.1**	**587.3**	**682.2**	**862.2**	**681.0**	**505.2**	**340.6**	**421.9**	**386.7**	**364.2**	**462.6**	**538.2**
ROR Total		**211.0**	**214.0**	**192.7**	**223.1**	**325.9**	**331.6**	**271.6**	**198.7**	**216.6**	**215.5**	**195.1**	**202.5**	**233.2**
Total		**784.7**	**805.1**	**780.0**	**905.3**	**1188.1**	**1012.6**	**776.8**	**539.3**	**638.4**	**602.2**	**559.3**	**665.1**	**771.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load

Resource	Type	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024	aMW
Brownlee	HCC*	253.7	259.0	255.5	302.0	387.2	305.9	222.9	144.2	178.6	161.3	156.7	203.7	235.9
Oxbow	HCC	107.0	110.5	109.0	123.7	156.3	123.6	94.5	65.6	81.9	74.7	69.5	85.2	100.1
Hells Canyon	HCC	211.9	220.6	222.7	251.6	317.8	250.0	186.5	129.3	160.7	147.4	138.0	168.9	200.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	8.0	35.6	73.3	88.9	83.1	60.2	34.8	13.5	0.0	0.0	33.1
Bliss	ROR	37.2	37.5	34.8	35.5	41.5	39.4	33.4	26.1	35.1	38.0	35.8	35.9	35.9
C .J. Strike	ROR	47.8	49.4	46.5	48.2	51.8	45.2	34.8	26.9	41.7	48.3	46.4	46.6	44.5
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.8	23.4	21.0	20.9	27.9	27.2	21.3	14.3	22.0	24.4	22.5	22.6	22.5
Milner	ROR	8.2	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.5
Shoshone Falls	ROR	12.0	12.0	8.5	4.8	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.7	16.2	15.3	16.0	17.1	15.3	12.4	9.6	14.1	15.9	15.4	15.5	14.9
Twin Falls	ROR	11.5	11.2	4.8	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.8	14.4	12.7	12.7	18.0	17.2	12.7	7.6	13.2	14.9	13.5	13.6	13.7
Upper Salmon 3&4	ROR	13.0	13.5	12.0	12.0	16.7	16.0	12.1	7.7	12.5	13.9	12.7	12.8	12.9
HCC Total		**572.6**	**590.1**	**587.2**	**677.3**	**861.3**	**679.5**	**503.9**	**339.1**	**421.1**	**383.4**	**364.2**	**457.8**	**536.5**
ROR Total		**208.6**	**212.2**	**190.7**	**211.2**	**325.2**	**330.9**	**271.0**	**197.7**	**215.6**	**214.8**	**194.3**	**201.4**	**231.1**
Total		**781.2**	**802.3**	**777.9**	**888.5**	**1186.5**	**1010.4**	**774.9**	**536.8**	**636.7**	**598.2**	**558.5**	**659.2**	**767.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	253.2	258.4	255.4	297.3	386.9	305.3	222.2	143.5	178.1	159.6	156.9	203.1	235.0
Oxbow	HCC	106.8	110.3	109.0	121.9	156.2	123.4	94.2	65.3	81.7	73.8	69.6	84.9	99.8
Hells Canyon	HCC	211.5	220.2	222.6	247.9	317.5	249.6	185.9	128.8	160.2	145.7	138.1	168.5	199.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	8.0	35.5	73.3	88.8	83.0	60.2	34.8	13.5	0.0	0.0	33.1
Bliss	ROR	36.7	37.4	34.7	34.8	41.4	39.3	33.2	25.9	34.9	37.8	35.6	35.8	35.6
C .J. Strike	ROR	47.6	49.3	46.2	48.0	51.7	45.0	34.6	26.7	41.4	48.0	46.1	46.2	44.2
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.7	23.3	21	20.7	27.8	27	21.2	14.2	21.8	24.3	22.4	22.5	22.4
Milner	ROR	8.2	8.3	0	0	17	17	5.9	0	0	0	3.6	6.2	5.5
Shoshone Falls	ROR	12	12	8.5	4.8	12	12	12	6.9	6.7	10.5	12	12	10.1
Swan Falls	ROR	15.6	16.2	15.3	15.9	17.1	15.2	12.3	9.5	14.1	15.9	15.3	15.4	14.8
Twin Falls	ROR	11.5	11.2	4.8	0	19.9	20.6	10.2	0	0	6.6	8.4	9.5	8.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.8	14.3	12.6	12.5	18.0	17.2	12.6	7.5	13.0	14.8	13.4	13.5	13.6
Upper Salmon 3&4	ROR	13.0	13.5	12.0	11.9	16.6	15.9	12.0	7.6	12.4	13.9	12.6	12.7	12.8
HCC Total		**571.5**	**588.9**	**587.0**	**667.1**	**860.6**	**678.3**	**502.3**	**337.6**	**419.9**	**379.1**	**364.6**	**456.5**	**534.5**
ROR Total		**207.7**	**211.8**	**190.2**	**209.6**	**324.8**	**330.1**	**270.1**	**196.9**	**214.6**	**214.1**	**193.4**	**200.5**	**230.3**
Total		**779.2**	**800.7**	**777.2**	**876.7**	**1185.4**	**1008.4**	**772.4**	**534.5**	**634.5**	**593.2**	**558.0**	**657.0**	**764.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	252.3	257.9	255.2	297.0	386.5	304.7	221.6	142.9	177.5	157.9	157.0	203.0	234.5
Oxbow	HCC	106.4	110.1	108.9	121.7	156.1	123.1	93.9	65.0	81.4	73.0	69.5	84.9	99.5
Hells Canyon	HCC	210.8	219.8	222.4	247.7	317.3	249.1	185.4	128.2	159.7	144.1	138.1	168.4	199.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.8	83.0	60.1	34.8	13.5	0.0	0.0	33.0
Bliss	ROR	36.5	37.3	34.6	34.7	41.3	39.2	33.0	25.7	34.7	37.7	35.4	35.6	35.5
C .J. Strike	ROR	47.4	49.1	45.9	47.9	51.6	44.8	34.4	26.4	41.2	47.8	45.9	46.1	44.0
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.5	23.2	20.9	20.7	27.8	26.9	21.0	14.0	21.6	24.2	22.2	22.3	22.3
Milner	ROR	7.6	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.5
Shoshone Falls	ROR	12.0	12.0	8.5	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.6	16.1	15.2	15.8	17.1	15.2	12.2	9.4	14.1	15.8	15.2	15.3	14.8
Twin Falls	ROR	10.6	11.2	4.8	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.5
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.6	14.3	12.6	12.4	17.9	17.0	12.5	7.3	12.9	14.7	13.2	13.4	13.5
Upper Salmon 3&4	ROR	12.8	13.4	12.0	11.8	16.6	15.8	11.9	7.5	12.2	13.8	12.5	12.7	12.8
HCC Total		**569.5**	**587.8**	**586.5**	**666.4**	**859.9**	**676.9**	**500.9**	**336.1**	**418.6**	**375.0**	**364.6**	**456.3**	**533.2**
ROR Total		**205.2**	**211.2**	**188.6**	**209.0**	**324.5**	**329.4**	**269.2**	**195.7**	**213.7**	**213.4**	**192.4**	**199.8**	**229.3**
Total		**774.7**	**799.0**	**775.1**	**875.4**	**1184.4**	**1006.3**	**770.1**	**531.8**	**632.3**	**588.4**	**557.0**	**656.1**	**762.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2027**	**2/2027**	**3/2027**	**4/2027**	**5/2027**	**6/2027**	**7/2027**	**8/2027**	**9/2027**	**10/2027**	**11/2027**	**12/2027**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17.0	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2028**	**2/2028**	**3/2028**	**4/2028**	**5/2028**	**6/2028**	**7/2028**	**8/2028**	**9/2028**	**10/2028**	**11/2028**	**12/2028**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17.0	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17.0	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17.0	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	248.9	257.4	255.0	296.6	386.1	304.1	221.0	142.3	176.9	156.8	157.1	202.4	233.7
Oxbow	HCC	105.0	109.8	108.8	121.5	155.9	122.9	93.7	64.7	81.1	72.4	69.5	84.6	99.2
Hells Canyon	HCC	208.0	219.3	222.3	247.3	316.9	248.6	184.9	127.6	159.2	143.1	138.1	167.9	198.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	35.5	73.3	88.7	82.9	60.0	34.7	13.5	0.0	0.0	33.0
Bliss	ROR	36.3	37.0	34.5	34.6	41.0	38.7	32.9	25.5	34.6	37.5	35.2	35.5	35.3
C .J. Strike	ROR	47.1	49.0	45.6	47.5	51.5	44.5	34.2	26.2	41.0	47.6	45.6	45.9	43.8
Cascade	ROR	1.5	1.5	1.3	1.2	2.1	5.3	7.6	12.2	7.3	1.5	1.3	1.4	3.7
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	23.1	20.8	20.6	27.7	26.8	20.9	13.9	21.5	24.0	22.1	22.2	22.2
Milner	ROR	6.9	8.3	0.0	0.0	17.0	17.0	5.9	0.0	0.0	0.0	3.6	6.2	5.4
Shoshone Falls	ROR	12.0	12.0	8.0	4.7	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	10.1
Swan Falls	ROR	15.5	16.1	15.4	15.8	17.0	15.1	12.2	9.3	14.0	15.7	15.4	15.3	14.7
Twin Falls	ROR	10.0	11.2	4.4	0.0	19.9	20.6	10.2	0.0	0.0	6.6	8.4	9.5	8.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	14.2	12.5	12.4	17.9	17.0	12.4	7.2	12.8	14.6	13.1	13.3	13.4
Upper Salmon 3&4	ROR	12.7	13.3	11.9	11.8	16.5	15.7	11.8	7.4	12.1	13.7	12.4	12.6	12.7
HCC Total		**561.9**	**586.5**	**586.1**	**665.4**	**858.9**	**675.6**	**499.6**	**334.6**	**417.1**	**372.3**	**364.7**	**454.9**	**531.5**
ROR Total		**203.0**	**210.5**	**187.2**	**208.4**	**323.8**	**328.2**	**268.5**	**194.8**	**213.0**	**212.5**	**191.8**	**199.2**	**228.4**
Total		**764.9**	**797.0**	**773.3**	**873.8**	**1182.7**	**1003.8**	**768.1**	**529.4**	**630.1**	**584.8**	**556.5**	**654.1**	**759.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	Type	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	aMW
Brownlee	HCC*	200.7	199.7	244.5	251.3	294.0	213.0	214.2	150.3	152.4	156.4	158.7	194.2	202.5
Oxbow	HCC	83.5	82.9	101.7	104.6	119.0	88.3	90.4	68.4	70.1	71.0	69.7	80.9	85.9
Hells Canyon	HCC	165.2	165.0	205.8	212.3	241.6	177.7	177.7	134.2	137.5	140.0	138.1	159.9	171.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	0.0	29.7	71.0	86.4	83.8	56.4	25.7	9.1	0.0	0.0	30.2
Bliss	ROR	35.3	35.3	33.9	32.7	38.8	37.6	33.7	30.4	35.3	37.8	36.1	35.8	35.2
C .J. Strike	ROR	44.7	44.3	43.8	42.1	45.1	41.1	33.0	32.4	40.6	45.8	45.5	44.4	41.9
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.6	22.8	20.8	20.3	26.1	25.5	22.0	18.4	22.5	24.4	23.3	23.0	22.6
Milner	ROR	6.3	6.2	0.0	0.0	14.2	14.2	5.9	6.7	0.0	0.0	1.7	5.0	5.0
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	12.0	6.5	8.8	11.0	12.0	10.1
Swan Falls	ROR	15.1	15.0	14.9	14.4	15.4	14.3	11.9	11.4	13.7	15.4	15.4	15.2	14.3
Twin Falls	ROR	9.4	9.0	3.8	0.0	17.0	17.8	10.0	11.0	0.0	5.2	7.1	8.8	8.3
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.6	13.9	12.5	12.2	16.7	16.0	13.2	10.7	13.6	14.9	14.0	13.9	13.8
Upper Salmon 3&4	ROR	12.9	13.1	11.9	11.6	15.5	14.9	12.5	10.3	12.8	14.0	13.2	13.1	13.0
HCC Total		**449.4**	**447.6**	**552.0**	**568.2**	**654.6**	**479.0**	**482.3**	**352.9**	**360.0**	**367.4**	**366.5**	**435.0**	**459.6**
ROR Total		**198.4**	**197.8**	**176.0**	**192.5**	**301.3**	**310.8**	**270.5**	**236.2**	**205.4**	**204.1**	**191.3**	**197.8**	**223.5**
Total		**647.8**	**645.4**	**728.0**	**760.7**	**955.9**	**789.8**	**752.8**	**589.1**	**565.4**	**571.5**	**557.8**	**632.8**	**683.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	Type	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014	aMW
Brownlee	HCC*	200.2	198.4	243.1	251.0	293.7	212.4	213.6	149.6	151.7	155.3	158.9	193.6	201.8
Oxbow	HCC	83.3	82.4	101.1	104.5	118.9	88.0	90.2	68.0	69.8	70.4	69.7	80.6	85.6
Hells Canyon	HCC	164.8	163.9	204.6	212.0	241.4	177.2	177.2	133.6	136.9	138.9	138.1	159.4	170.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	0.0	29.9	71.0	86.0	83.8	56.4	25.6	9.0	0.0	0.0	30.1
Bliss	ROR	35.2	35.2	33.7	32.5	38.3	37.1	33.6	30.3	35.2	37.6	35.9	35.7	35.0
C .J. Strike	ROR	44.6	44.1	43.4	41.9	45.1	40.7	32.8	32.2	40.5	45.6	45.3	44.3	41.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.5	22.5	20.7	20.1	25.7	25.4	21.8	18.2	22.3	24.3	23.1	22.9	22.5
Milner	ROR	6.3	6.2	0.0	0.0	12.6	12.6	5.9	6.7	0.0	0.0	1.7	4.9	4.7
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	12.0	6.5	8.8	10.7	12.0	10.1
Swan Falls	ROR	15.0	15.0	14.8	14.3	15.3	14.1	11.9	11.2	13.7	15.3	15.3	15.1	14.3
Twin Falls	ROR	9.4	9.0	3.8	0.0	16.2	16.6	10.0	11.0	0.0	5.2	6.8	8.7	8.1
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.6	13.7	12.4	12	16.3	15.9	13.1	10.5	13.4	14.8	13.9	13.8	13.6
Upper Salmon 3&4	ROR	12.8	12.9	11.8	11.5	15.2	14.8	12.4	10.2	12.7	13.8	13.1	13	12.9
HCC Total		**448.3**	**444.7**	**548.8**	**567.5**	**654.0**	**477.6**	**481.0**	**351.2**	**358.4**	**364.6**	**366.7**	**433.6**	**458.0**
ROR Total		**197.9**	**196.8**	**175.0**	**191.7**	**297.1**	**306.2**	**269.8**	**235.2**	**204.6**	**203.1**	**189.8**	**197.0**	**222.0**
Total		**646.2**	**641.5**	**723.8**	**759.2**	**951.1**	**783.8**	**750.8**	**586.4**	**563.0**	**567.7**	**556.5**	**630.6**	**680.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2015**	**2/2015**	**3/2015**	**4/2015**	**5/2015**	**6/2015**	**7/2015**	**8/2015**	**9/2015**	**10/2015**	**11/2015**	**12/2015**	**aMW**
Brownlee	HCC*	200.9	198.7	245.8	251.4	294.2	212.6	213.6	149.4	151.5	156.3	158.5	193.9	202.2
Oxbow	HCC	83.5	82.5	102.2	104.6	119.1	88.1	90.2	68.0	69.7	70.9	69.6	80.8	85.8
Hells Canyon	HCC	165.3	164.2	206.8	212.4	241.8	177.4	177.2	133.5	136.7	139.8	137.9	159.7	171.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.9	30.7	71.2	87.6	84.4	58.9	25.9	10.1	0.0	0.0	31.3
Bliss	ROR	35.2	35.4	33.9	32.8	39.6	38.3	33.5	30.2	35.2	37.7	35.9	35.6	35.3
C .J. Strike	ROR	44.5	44.1	43.9	41.9	46.6	42.3	32.8	32.1	40.5	46.0	45.2	44.6	42.0
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.5	22.7	20.8	20.3	26.8	25.8	21.8	18.1	22.3	24.5	23.3	22.9	22.7
Milner	ROR	6.3	6.3	0.0	0.0	15.5	15.5	5.9	6.7	0.0	0.0	2.4	5.0	5.3
Shoshone Falls	ROR	12.0	12.0	7.3	4.0	12.0	12.0	12.0	12.0	6.5	9.7	11.4	12.0	10.2
Swan Falls	ROR	15.1	14.9	14.9	14.3	15.8	14.5	11.9	11.2	13.7	15.4	15.3	15.2	14.4
Twin Falls	ROR	9.4	9.2	3.8	0.0	18.3	19.1	10.0	11.0	0.0	6.0	7.5	8.9	8.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.6	13.9	12.5	12.2	17.1	16.2	13.1	10.5	13.5	15.0	14.1	13.8	13.8
Upper Salmon 3&4	ROR	12.8	13.1	11.9	11.6	15.9	15.1	12.4	10.2	12.7	14.0	13.2	13.0	13.0
HCC Total		**449.7**	**445.4**	**554.8**	**568.4**	**655.1**	**478.1**	**481.0**	**350.9**	**357.9**	**367.0**	**366.0**	**434.4**	**459.1**
ROR Total		**197.9**	**197.8**	**183.0**	**193.4**	**308.3**	**317.4**	**270.3**	**237.4**	**205.0**	**207.1**	**192.3**	**197.6**	**225.6**
Total		**647.6**	**643.2**	**737.8**	**761.8**	**963.4**	**795.5**	**751.3**	**588.3**	**562.9**	**574.1**	**558.3**	**632.0**	**684.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2016**	**2/2016**	**3/2016**	**4/2016**	**5/2016**	**6/2016**	**7/2016**	**8/2016**	**9/2016**	**10/2016**	**11/2016**	**12/2016**	**aMW**
Brownlee	HCC*	200.5	199.1	245.2	251.1	293.9	212.1	213.1	136.5	150.8	155.4	158.7	193.4	200.8
Oxbow	HCC	83.4	82.7	102.0	104.5	118.9	87.9	89.9	61.9	69.4	70.4	69.7	80.5	85.1
Hells Canyon	HCC	165.0	164.5	206.3	212.1	241.6	177.0	176.7	122.0	136.0	139.0	138.0	159.3	169.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.9	30.5	71.3	87.6	84.3	55.9	27.5	10.2	0.0	0.0	31.2
Bliss	ROR	35.1	35.4	33.8	32.7	39.6	38.3	33.5	26.5	35.2	37.6	35.8	35.5	34.9
C .J. Strike	ROR	44.4	44.0	43.9	41.4	46.5	42.2	32.7	27.3	40.4	45.8	45.1	44.5	41.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.4	22.8	20.7	20.3	26.8	25.7	21.7	14.9	22.3	24.4	23.2	22.8	22.3
Milner	ROR	6.3	7.3	0.0	0.0	15.5	15.5	5.9	0.0	0.0	0.0	2.5	5.1	4.8
Shoshone Falls	ROR	12.0	12.0	7.3	4.0	12.0	12.0	12.0	6.6	6.5	9.8	11.5	12.0	9.8
Swan Falls	ROR	15.0	14.9	15.0	14.1	15.8	14.5	11.8	9.7	13.6	15.4	15.3	15.2	14.2
Twin Falls	ROR	9.4	9.7	3.8	0.0	18.3	19.2	10.0	0.0	0.0	6.1	7.5	9.0	7.8
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.5	13.9	12.4	12.2	17.2	16.1	13.0	8.0	13.4	14.9	14.0	13.7	13.5
Upper Salmon 3&4	ROR	12.7	13.1	11.8	11.6	15.9	15.0	12.3	8.1	12.7	13.9	13.1	13.0	12.8
HCC Total		**448.9**	**446.3**	**553.5**	**567.7**	**654.4**	**477.0**	**479.7**	**320.4**	**356.2**	**364.8**	**366.4**	**433.2**	**455.7**
ROR Total		**197.3**	**199.3**	**182.7**	**192.4**	**308.4**	**317.1**	**269.7**	**193.5**	**206.3**	**206.8**	**192.0**	**197.4**	**221.9**
Total		**646.2**	**645.6**	**736.2**	**760.1**	**962.8**	**794.1**	**749.4**	**513.9**	**562.5**	**571.6**	**558.4**	**630.6**	**677.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017	aMW
Brownlee	HCC*	200.1	198.8	244.6	250.8	293.6	211.6	212.6	136.0	150.2	154.4	159.0	192.9	200.4
Oxbow	HCC	83.2	82.6	101.7	104.4	118.8	87.7	89.7	61.7	69.1	69.9	69.8	80.4	84.9
Hells Canyon	HCC	164.7	164.2	205.8	211.9	241.4	176.6	176.3	121.5	135.5	138.0	138.2	158.9	169.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.0	30.5	71.1	87.1	84.3	55.9	27.7	10.1	0.0	0.0	31.1
Bliss	ROR	35.0	35.2	33.8	32.7	39.3	38.0	33.3	26.3	35.1	37.5	35.7	35.4	34.8
C .J. Strike	ROR	44.3	43.9	43.7	41.1	46.4	42.1	32.5	27.1	40.3	45.8	44.9	44.4	41.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.3	22.7	20.7	20.2	26.5	25.6	21.6	14.8	22.1	24.3	23.0	22.7	22.2
Milner	ROR	6.3	6.3	0.0	0.0	15.0	15.0	5.9	0.0	0.0	0.0	2.5	5.2	4.7
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	9.8	11.5	12.0	9.8
Swan Falls	ROR	15.0	14.9	14.9	14.2	15.7	14.4	11.8	9.6	13.5	15.4	15.2	15.1	14.1
Twin Falls	ROR	9.5	9.2	3.8	0.0	17.9	18.3	10.0	0.0	0.0	6.1	7.5	9.0	7.6
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.4	13.9	12.4	12.1	17.0	16.0	12.9	7.9	13.3	14.8	13.9	13.7	13.4
Upper Salmon 3&4	ROR	12.7	13.1	11.8	11.6	15.7	14.9	12.3	8.0	12.6	13.9	13.1	12.9	12.7
HCC Total		**448.0**	**445.6**	**552.1**	**567.1**	**653.8**	**475.9**	**478.6**	**319.2**	**354.8**	**362.3**	**367.0**	**432.2**	**454.7**
ROR Total		**197.0**	**197.4**	**182.5**	**191.9**	**306.1**	**314.4**	**269.1**	**192.7**	**205.8**	**206.4**	**191.3**	**197.0**	**221.0**
Total		**645.0**	**643.0**	**734.6**	**759.0**	**959.9**	**790.3**	**747.7**	**511.9**	**560.6**	**568.7**	**558.3**	**629.2**	**675.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018	aMW
Brownlee	HCC*	199.5	197.4	242.0	250.4	293.4	211.1	212.0	135.3	149.5	153.6	158.9	192.5	199.6
Oxbow	HCC	83.0	82.0	100.6	104.2	118.7	87.5	89.5	61.3	68.8	69.6	69.7	80.2	84.6
Hells Canyon	HCC	164.2	163.1	203.7	211.6	241.2	176.2	175.9	120.9	134.9	137.3	138.0	158.6	168.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.9	31.4	70.9	86.2	84.3	55.8	27.6	10.1	0.0	0.0	31.1
Bliss	ROR	34.9	35.2	33.7	32.6	38.8	37.3	33.1	26.1	34.8	37.3	35.4	35.2	34.5
C .J. Strike	ROR	44.1	43.7	43.6	41.1	45.8	41.3	32.3	26.9	40.2	45.7	44.6	44.3	41.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.2	22.5	20.6	20.1	26.3	25.4	21.4	14.6	21.9	24.2	22.9	22.5	22.1
Milner	ROR	6.3	6.3	0.0	0.0	13.9	13.9	5.9	0.0	0.0	0.0	2.6	5.0	4.5
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	9.5	11.6	12.0	9.8
Swan Falls	ROR	15.0	14.8	14.8	14.1	15.4	14.1	11.7	9.5	13.4	15.3	15.1	15.1	14.0
Twin Falls	ROR	9.5	9.2	3.8	0.0	16.8	17.4	10.0	0.0	0.0	5.7	7.6	8.9	7.4
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.4	13.7	12.3	12.0	16.8	15.9	12.8	7.8	13.1	14.7	13.7	13.6	13.3
Upper Salmon 3&4	ROR	12.6	12.9	11.8	11.5	15.6	14.8	12.2	7.9	12.4	13.8	12.9	12.8	12.6
HCC Total		**446.7**	**442.5**	**546.3**	**566.2**	**653.3**	**474.8**	**477.4**	**317.5**	**353.2**	**360.5**	**366.6**	**431.3**	**453.0**
ROR Total		**196.5**	**196.5**	**181.9**	**192.3**	**301.8**	**309.3**	**268.2**	**191.7**	**204.6**	**205.0**	**190.4**	**196.0**	**219.5**
Total		**643.2**	**639.0**	**728.2**	**758.5**	**955.1**	**784.1**	**745.6**	**509.2**	**557.8**	**565.5**	**557.0**	**627.3**	**672.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019	aMW
Brownlee	HCC*	199.1	197.1	240.6	250.1	293.0	210.6	211.5	134.7	148.9	152.2	159.2	192.0	199.1
Oxbow	HCC	82.8	81.8	100.0	104.1	118.6	87.3	89.3	61.1	68.5	68.9	69.8	79.9	84.3
Hells Canyon	HCC	163.9	162.8	202.6	211.4	240.9	175.8	175.4	120.4	134.4	136.0	138.2	158.1	168.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	7.2	30.2	70.5	85.9	84.2	55.8	27.4	10.3	0.0	0.0	31.0
Bliss	ROR	34.8	35.1	33.6	32.5	38.6	37.1	32.9	25.9	34.7	37.2	35.3	35.1	34.4
C .J. Strike	ROR	43.9	43.6	43.5	40.9	44.9	40.8	32.1	26.7	40.0	45.5	44.4	43.8	40.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.1	22.4	20.6	20.0	26.1	25.3	21.3	14.5	21.7	24.1	22.6	22.4	21.9
Milner	ROR	6.3	6.3	0.0	0.0	12.7	12.7	5.9	0.0	0.0	0.0	2.0	5.0	4.2
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	9.5	11.3	12.0	9.8
Swan Falls	ROR	15.0	14.8	14.8	14.1	15.4	13.9	11.6	9.5	13.4	15.3	15.0	14.9	14.0
Twin Falls	ROR	9.5	9.2	3.8	0.0	15.9	16.5	10.0	0.0	0.0	5.7	7.4	8.9	7.2
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.3	13.6	12.3	12.0	16.7	15.8	12.7	7.7	13.0	14.6	13.5	13.4	13.2
Upper Salmon 3&4	ROR	12.6	12.9	11.7	11.4	15.5	14.7	12.1	7.8	12.3	13.7	12.8	12.7	12.5
HCC Total		**445.8**	**441.7**	**543.2**	**565.6**	**652.5**	**473.7**	**476.2**	**316.2**	**351.8**	**357.1**	**367.2**	**430.0**	**451.8**
ROR Total		**196.0**	**196.1**	**181.9**	**190.6**	**297.8**	**305.7**	**267.3**	**191.0**	**203.7**	**204.6**	**188.3**	**194.8**	**218.1**
Total		**641.8**	**637.8**	**725.1**	**756.2**	**950.3**	**779.4**	**743.5**	**507.2**	**555.5**	**561.7**	**555.5**	**624.8**	**669.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020	aMW
Brownlee	HCC*	198.0	196.6	240.2	249.8	292.7	210.0	210.9	134.1	148.3	150.7	159.1	191.9	198.5
Oxbow	HCC	82.4	81.6	99.9	104.0	118.5	87.0	89.0	60.8	68.2	68.1	69.7	79.9	84.1
Hells Canyon	HCC	163.0	162.4	202.3	211.1	240.6	175.3	174.9	119.8	133.8	134.6	138.0	158.0	167.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.9	30.2	70.3	85.8	84.2	55.8	27.1	10.3	0.0	0.0	30.9
Bliss	ROR	34.7	34.8	33.5	32.4	38.4	36.8	32.8	25.8	34.5	37.2	35.1	34.9	34.2
C .J. Strike	ROR	43.8	43.4	43.4	40.8	44.7	40.4	31.9	26.4	39.9	45.4	44.2	43.6	40.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	22.0	22.2	20.5	20.0	25.8	25.1	21.1	14.3	21.5	23.9	22.4	22.2	21.8
Milner	ROR	6.3	5.8	0.0	0.0	12.3	12.3	5.9	0.0	0.0	0.0	1.8	5.0	4.1
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	9.5	11.3	12.0	9.8
Swan Falls	ROR	14.8	14.7	14.8	14.0	15.3	13.8	11.6	9.4	13.3	15.2	15.0	14.9	13.9
Twin Falls	ROR	9.5	8.9	3.8	0.0	15.1	15.8	10.0	0.0	0.0	5.7	7.4	8.8	7.1
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.2	13.5	12.3	11.9	16.4	15.7	12.6	7.5	12.8	14.5	13.4	13.3	13.1
Upper Salmon 3&4	ROR	12.5	12.8	11.7	11.4	15.2	14.6	12.0	7.7	12.2	13.6	12.6	12.6	12.4
HCC Total		**443.4**	**440.6**	**542.4**	**564.9**	**651.8**	**472.3**	**474.8**	**314.7**	**350.3**	**353.4**	**366.8**	**429.8**	**450.4**
ROR Total		**195.3**	**194.3**	**181.3**	**190.2**	**295.0**	**303.3**	**266.6**	**190.0**	**202.5**	**204.0**	**187.2**	**193.9**	**217.0**
Total		**638.7**	**634.9**	**723.7**	**755.1**	**946.8**	**775.6**	**741.4**	**504.7**	**552.8**	**557.4**	**554.0**	**623.7**	**667.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021	aMW
Brownlee	HCC*	197.5	196.1	239.9	249.4	292.3	209.3	210.2	133.5	147.5	148.5	159.3	191.2	197.9
Oxbow	HCC	82.2	81.4	99.7	103.8	118.3	86.7	88.7	60.5	67.8	67.0	69.7	79.6	83.8
Hells Canyon	HCC	162.6	162.1	202.0	210.7	240.4	174.7	174.4	119.3	133.1	132.5	138.1	157.4	167.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.8	30.8	70.3	85.6	84.1	55.3	26.9	9.9	0.0	0.0	30.8
Bliss	ROR	34.5	34.8	33.4	32.4	38.1	36.6	32.6	25.6	34.2	37.1	34.8	34.8	34.1
C .J. Strike	ROR	43.6	43.3	43.3	40.8	44.5	40.0	31.7	26.2	39.7	45.1	43.8	43.4	40.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.9	22.1	20.4	19.9	25.6	25.0	21.0	14.1	21.3	23.7	22.2	22.1	21.6
Milner	ROR	6.3	6.2	0.0	0.0	12.3	12.3	5.9	0.0	0.0	0.0	1.8	4.9	4.1
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	9.4	11.1	12.0	9.7
Swan Falls	ROR	14.8	14.7	14.7	14.1	15.2	13.7	11.5	9.3	13.3	15.2	14.9	14.8	13.9
Twin Falls	ROR	9.5	9.0	3.8	0.0	15.5	16.6	10.0	0.0	0.0	5.7	7.2	8.8	7.2
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.1	13.4	12.2	11.8	16.3	15.6	12.5	7.4	12.7	14.3	13.2	13.2	13.0
Upper Salmon 3&4	ROR	12.4	12.7	11.6	11.3	15.1	14.5	11.9	7.6	12.0	13.5	12.5	12.5	12.3
HCC Total		**442.3**	**439.6**	**541.6**	**563.9**	**651.0**	**470.7**	**473.3**	**313.3**	**348.4**	**348.0**	**367.1**	**428.2**	**449.0**
ROR Total		**194.6**	**194.4**	**180.6**	**190.6**	**294.3**	**302.9**	**265.7**	**188.6**	**201.3**	**202.6**	**185.5**	**193.1**	**216.2**
Total		**636.9**	**634.0**	**722.2**	**754.5**	**945.3**	**773.6**	**739.0**	**501.9**	**549.7**	**550.6**	**552.6**	**621.3**	**665.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022	aMW
Brownlee	HCC*	196.9	195.6	238.9	248.9	292.0	208.7	209.5	132.7	146.8	146.8	159.5	190.5	197.2
Oxbow	HCC	81.9	81.2	99.3	103.6	118.2	86.5	88.4	60.1	67.5	66.2	69.8	79.3	83.5
Hells Canyon	HCC	162.1	161.7	201.2	210.4	240.1	174.2	173.8	118.6	132.5	131.0	138.2	156.9	166.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.6	30.6	70.0	85.5	84.2	55.3	26.9	9.9	0.0	0.0	30.7
Bliss	ROR	34.4	34.6	33.3	32.1	38.1	36.2	32.3	25.4	34.0	37.0	34.7	34.7	33.9
C .J. Strike	ROR	43.4	43.1	43.0	40.7	44.4	39.5	31.4	25.9	39.5	44.9	43.5	43.2	40.2
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.8	22.0	20.3	19.5	25.4	24.7	20.8	14.0	21.1	23.5	22.0	22.0	21.4
Milner	ROR	6.3	5.8	0.0	0.0	12.2	12.2	5.9	0.0	0.0	0.0	1.7	4.9	4.1
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.9	12.0	9.7
Swan Falls	ROR	14.7	14.7	14.7	14.0	15.2	13.6	11.4	9.2	13.2	15.1	14.8	14.8	13.8
Twin Falls	ROR	9.5	8.9	3.8	0.0	15.0	16.0	10.0	0.0	0.0	5.2	7.0	8.8	7.0
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	13.0	13.3	12.1	11.5	16.1	15.4	12.3	7.3	12.5	14.2	13.1	13.1	12.8
Upper Salmon 3&4	ROR	12.3	12.6	11.6	11.1	15.0	14.3	11.7	7.5	11.9	13.4	12.4	12.4	12.2
HCC Total		**440.9**	**438.5**	**539.4**	**562.9**	**650.3**	**469.4**	**471.7**	**311.4**	**346.8**	**344.0**	**367.5**	**426.7**	**447.5**
ROR Total		**193.9**	**193.2**	**179.8**	**189.0**	**292.9**	**300.4**	**264.5**	**187.7**	**200.3**	**200.7**	**184.1**	**192.5**	**214.9**
Total		**634.8**	**631.7**	**719.2**	**751.9**	**943.2**	**769.8**	**736.2**	**499.1**	**547.1**	**544.7**	**551.6**	**619.2**	**662.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2023**	**2/2023**	**3/2023**	**4/2023**	**5/2023**	**6/2023**	**7/2023**	**8/2023**	**9/2023**	**10/2023**	**11/2023**	**12/2023**	**aMW**
Brownlee	HCC*	196.1	195.2	239.1	248.6	291.6	208.1	208.9	131.9	146.2	146.3	159.4	190.1	196.8
Oxbow	HCC	81.5	81.1	99.4	103.5	118.0	86.2	88.2	59.8	67.2	66.0	69.7	79.1	83.3
Hells Canyon	HCC	161.4	161.3	201.4	210.1	239.8	173.8	173.3	117.9	131.9	130.5	138.1	156.5	166.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.6	30.5	69.8	85.2	84.3	55.1	26.9	10.1	0.0	0.0	30.7
Bliss	ROR	34.3	34.5	33.2	32.0	38.0	35.9	32.1	25.2	33.8	36.9	34.5	34.5	33.7
C .J. Strike	ROR	43.1	43.0	43.0	40.7	44.2	38.8	31.2	25.7	39.2	44.6	43.3	43.0	40.0
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.7	21.9	20.2	19.4	25.2	24.4	20.6	13.8	20.9	23.3	21.9	21.9	21.3
Milner	ROR	6.2	5.8	0.0	0.0	11.3	11.3	5.9	0.0	0.0	0.0	1.7	4.9	3.9
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	11.1	12.0	9.7
Swan Falls	ROR	14.7	14.7	14.6	13.9	15.0	13.3	11.4	9.1	13.2	15.0	14.7	14.7	13.7
Twin Falls	ROR	9.4	8.9	3.8	0.0	14.0	15.1	10.0	0.0	0.0	5.2	7.2	8.8	6.9
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.9	13.3	12.1	11.5	15.9	15.1	12.2	7.2	12.3	14.1	13.0	13.0	12.7
Upper Salmon 3&4	ROR	12.3	12.6	11.5	11.0	14.8	14.1	11.6	7.4	11.8	13.2	12.3	12.3	12.1
HCC Total		**439.0**	**437.6**	**539.9**	**562.2**	**649.4**	**468.1**	**470.4**	**309.6**	**345.3**	**342.8**	**367.2**	**425.7**	**446.4**
ROR Total		**193.1**	**192.9**	**179.4**	**188.5**	**289.6**	**296.2**	**263.8**	**186.6**	**199.3**	**199.9**	**183.7**	**191.7**	**213.7**
Total		**632.1**	**630.5**	**719.3**	**750.7**	**939.0**	**764.3**	**734.2**	**496.2**	**544.6**	**542.7**	**550.9**	**617.4**	**660.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2024**	**2/2024**	**3/2024**	**4/2024**	**5/2024**	**6/2024**	**7/2024**	**8/2024**	**9/2024**	**10/2024**	**11/2024**	**12/2024**	**aMW**
Brownlee	HCC*	195.5	194.7	238.8	248.2	283.1	207.5	208.3	131.2	145.5	144.8	159.3	189.9	195.6
Oxbow	HCC	81.3	80.8	99.3	103.3	117.9	86.0	87.9	59.4	66.9	65.2	69.6	79.0	83.1
Hells Canyon	HCC	160.9	160.9	201.1	209.8	241.3	173.3	172.8	117.2	131.3	129.1	137.9	156.4	166.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0	0	6.6	30.2	69.35	85.1	84.3	54.5	26.8	9.9	0	0	30.6
Bliss	ROR	34.2	34.4	33.1	31.9	38	35.8	32	25	33.6	36.7	34.3	34.3	33.6
C .J. Strike	ROR	43	42.8	42.9	40.4	44	38.5	31	25.4	39	44.4	43	42.8	39.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7	10.3	6.45	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.6	21.8	20.2	19.3	25.1	24.2	20.4	13.6	20.7	23.2	21.7	21.7	21.1
Milner	ROR	6.0	5.8	0.0	0.0	10.9	10.9	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.9	12.0	9.7
Swan Falls	ROR	14.6	14.6	14.6	13.9	14.9	13.2	11.2	9.0	13.2	15.0	14.6	14.6	13.6
Twin Falls	ROR	9.4	8.9	3.8	0.0	13.7	14.7	10.0	0.0	0.0	5.2	7.0	8.8	6.8
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.9	13.2	12.0	11.4	15.9	15.0	12.0	7.0	12.2	13.9	12.8	12.9	12.6
Upper Salmon 3&4	ROR	12.2	12.5	11.5	10.9	14.8	14.0	11.5	7.3	11.6	13.1	12.2	12.2	12.0
HCC Total		**437.7**	**436.4**	**539.2**	**561.3**	**642.3**	**466.8**	**469.0**	**307.8**	**343.7**	**339.1**	**366.8**	**425.3**	**444.6**
ROR Total		**192.4**	**192.2**	**179.1**	**187.5**	**288.1**	**294.4**	**262.8**	**184.9**	**198.3**	**198.9**	**182.2**	**190.8**	**212.6**
Total		**630.1**	**628.6**	**718.3**	**748.8**	**930.4**	**761.2**	**731.8**	**492.7**	**542.0**	**538.0**	**549.0**	**616.1**	**657.3**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	195.0	194.1	238.3	247.7	282.7	206.9	207.6	130.4	144.8	143.6	159.4	189.4	195.0
Oxbow	HCC	81.1	80.6	99.1	103.1	117.7	85.7	87.6	59.1	66.5	64.6	69.7	78.8	82.8
Hells Canyon	HCC	160.5	160.4	200.8	209.4	241.1	172.8	172.2	116.5	130.7	127.9	138.0	155.9	165.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.6	30.0	69.2	85.0	84.4	54.4	26.8	9.8	0.0	0.0	30.5
Bliss	ROR	34.0	34.2	33.0	31.8	37.8	35.7	31.7	24.8	33.4	36.5	34.1	34.2	33.4
C .J. Strike	ROR	43.0	42.7	42.8	40.3	43.1	37.8	30.8	25.2	38.7	44.3	42.8	42.6	39.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.5	21.7	20.1	19.2	25	24.1	20.3	13.5	20.5	23.1	21.5	21.6	21.0
Milner	ROR	6	5.8	0	0	10.7	10.7	5.9	0	0	0	1.7	4.9	3.8
Shoshone Falls	ROR	12	12	7.3	3.9	12	12	12	6.6	6.5	8.8	10.8	12	9.7
Swan Falls	ROR	14.6	14.6	14.6	13.8	14.7	13	11.2	8.9	13.1	14.9	14.5	14.6	13.5
Twin Falls	ROR	9.4	8.9	3.8	0	13.5	14.5	10	0	0	5.2	6.9	8.8	6.8
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.8	13.1	12.0	11.3	15.8	14.9	11.9	6.9	12.0	13.9	12.7	12.8	12.5
Upper Salmon 3&4	ROR	12.1	12.4	11.4	10.9	14.7	13.9	11.4	7.2	11.5	13.1	12.0	12.1	11.9
HCC Total		**436.6**	**435.1**	**538.2**	**560.2**	**641.5**	**465.4**	**467.4**	**306.0**	**342.0**	**336.1**	**367.1**	**424.1**	**443.3**
ROR Total		**191.9**	**191.6**	**178.7**	**186.8**	**285.9**	**292.6**	**262.1**	**184.0**	**197.2**	**198.3**	**181.0**	**190.2**	**211.7**
Total		**628.5**	**626.7**	**716.9**	**747.0**	**927.4**	**758.0**	**729.5**	**490.0**	**539.2**	**534.4**	**548.1**	**614.3**	**655.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	194.2	193.2	237.5	247.4	282.4	206.3	207.0	129.8	144.1	142.0	159.9	188.5	194.4
Oxbow	HCC	80.7	80.2	98.7	103.0	117.6	85.5	87.3	58.8	66.2	63.9	69.8	78.4	82.5
Hells Canyon	HCC	159.9	159.7	200.1	209.2	240.8	172.3	171.7	116.0	130.0	126.5	138.3	155.2	165.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.6	29.9	68.8	84.6	84.4	54.4	26.7	9.6	0.0	0.0	30.4
Bliss	ROR	33.7	34.2	32.9	31.7	37.3	35.4	31.5	24.6	33.2	36.4	33.9	34.1	33.2
C .J. Strike	ROR	42.9	42.5	42.7	40.2	42.1	37.6	30.6	24.9	38.5	44.1	42.5	42.4	39.3
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.3	21.5	20.0	19.1	24.4	23.7	20.2	13.3	20.3	23.0	21.4	21.4	20.8
Milner	ROR	6.0	5.8	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.8	14.6	12.9	11.1	8.9	13.1	14.8	14.4	14.5	13.5
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.7	12.9	11.9	11.3	15.3	14.6	11.8	6.8	11.9	13.8	12.6	12.7	12.4
Upper Salmon 3&4	ROR	12	12.3	11.4	10.8	14.3	13.7	11.3	7.1	11.4	13	12	12.1	11.8
HCC Total		**434.8**	**433.1**	**536.3**	**559.6**	**640.8**	**464.1**	**466.0**	**304.6**	**340.3**	**332.4**	**368.0**	**422.1**	**441.8**
ROR Total		**191.0**	**190.7**	**178.2**	**186.3**	**282.4**	**290.7**	**261.3**	**183.1**	**196.3**	**197.4**	**180.0**	**189.5**	**210.6**
Total		**625.8**	**623.8**	**714.5**	**745.9**	**923.2**	**754.8**	**727.3**	**487.7**	**536.6**	**529.8**	**548.0**	**611.6**	**652.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027	aMW
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028	aMW
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

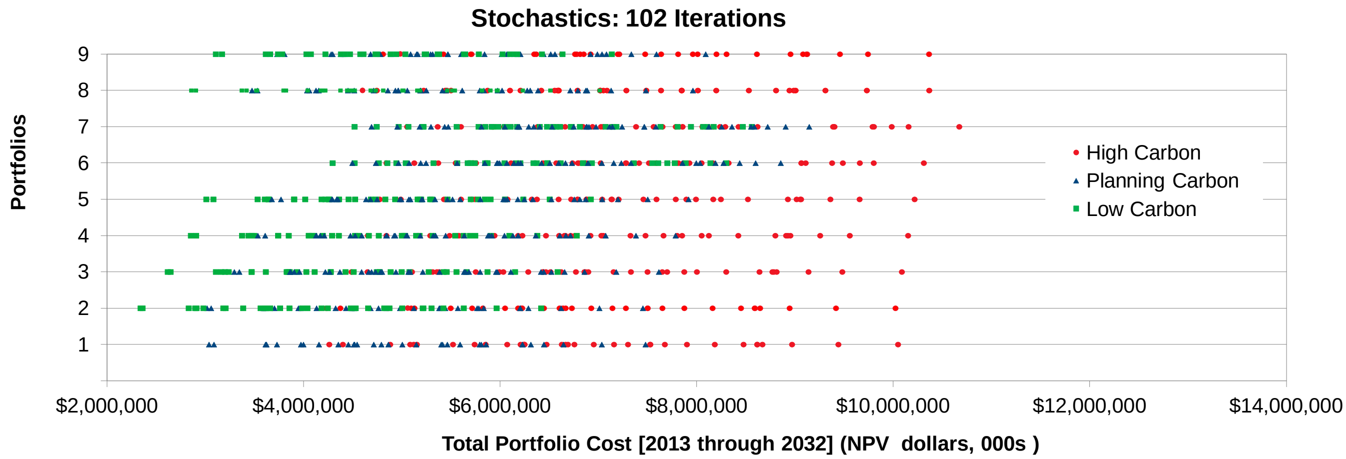
*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	193.8	192.8	236.6	247.0	282.1	205.7	206.3	129.1	143.4	140.9	160.0	180.8	193.2
Oxbow	HCC	80.6	80.1	98.4	102.8	117.4	85.3	87.1	58.5	65.9	63.3	69.9	78.2	82.3
Hells Canyon	HCC	159.5	159.4	199.4	208.9	240.5	171.9	171.2	115.4	129.4	125.4	138.3	154.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	6.5	29.8	68.8	84.4	84.1	54.3	26.7	9.7	0.0	0.0	30.4
Bliss	ROR	33.6	34.0	32.8	31.6	36.9	35.2	31.4	24.4	33.0	36.2	33.7	33.9	33.1
C .J. Strike	ROR	42.8	42.4	42.5	40.0	41.9	37.4	30.4	24.6	38.2	43.9	42.3	42.2	39.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.5	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.7	1.6	1.6	1.4	1.6	1.4	1.4	1.5	1.6	1.7	1.5	1.7	1.6
Lower Malad	ROR	11.1	11.2	11.9	11.3	13.0	12.0	11.7	12.0	13.0	12.8	10.1	11.2	11.8
Lowe Salmon	ROR	21.2	21.4	19.9	19.1	24.3	23.5	20.0	13.2	20.2	22.8	21.2	21.3	20.7
Milner	ROR	6.0	5.5	0.0	0.0	10.7	10.7	5.9	0.0	0.0	0.0	1.7	4.9	3.8
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.6	6.5	8.8	10.7	12.0	9.7
Swan Falls	ROR	14.5	14.5	14.5	13.7	14.5	12.9	11.0	8.8	13.1	14.8	14.4	14.5	13.4
Twin Falls	ROR	9.4	8.8	3.8	0.0	13.5	14.5	10.0	0.0	0.0	5.2	6.8	8.8	6.7
Upper Malad	ROR	6.3	6.2	6.6	6.3	7.7	7.3	6.7	6.7	7.2	6.5	5.6	6.3	6.6
Upper Salmon 1&2	ROR	12.6	12.9	11.8	11.2	15.3	14.4	11.7	6.7	11.8	13.7	12.4	12.6	12.3
Upper Salmon 3&4	ROR	11.9	12.2	11.3	10.8	14.2	13.5	11.2	7.0	11.3	12.9	11.8	12.0	11.7
HCC Total		**433.9**	**432.3**	**534.4**	**558.7**	**640.0**	**462.9**	**464.6**	**303.0**	**338.7**	**329.6**	**368.2**	**413.4**	**440.0**
ROR Total		**190.5**	**189.9**	**177.5**	**185.7**	**281.5**	**289.5**	**260.2**	**182.1**	**195.5**	**196.7**	**179.0**	**188.8**	**209.7**
Total		**624.4**	**622.2**	**711.9**	**744.4**	**921.5**	**752.4**	**724.8**	**485.1**	**534.2**	**526.3**	**547.2**	**602.2**	**649.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

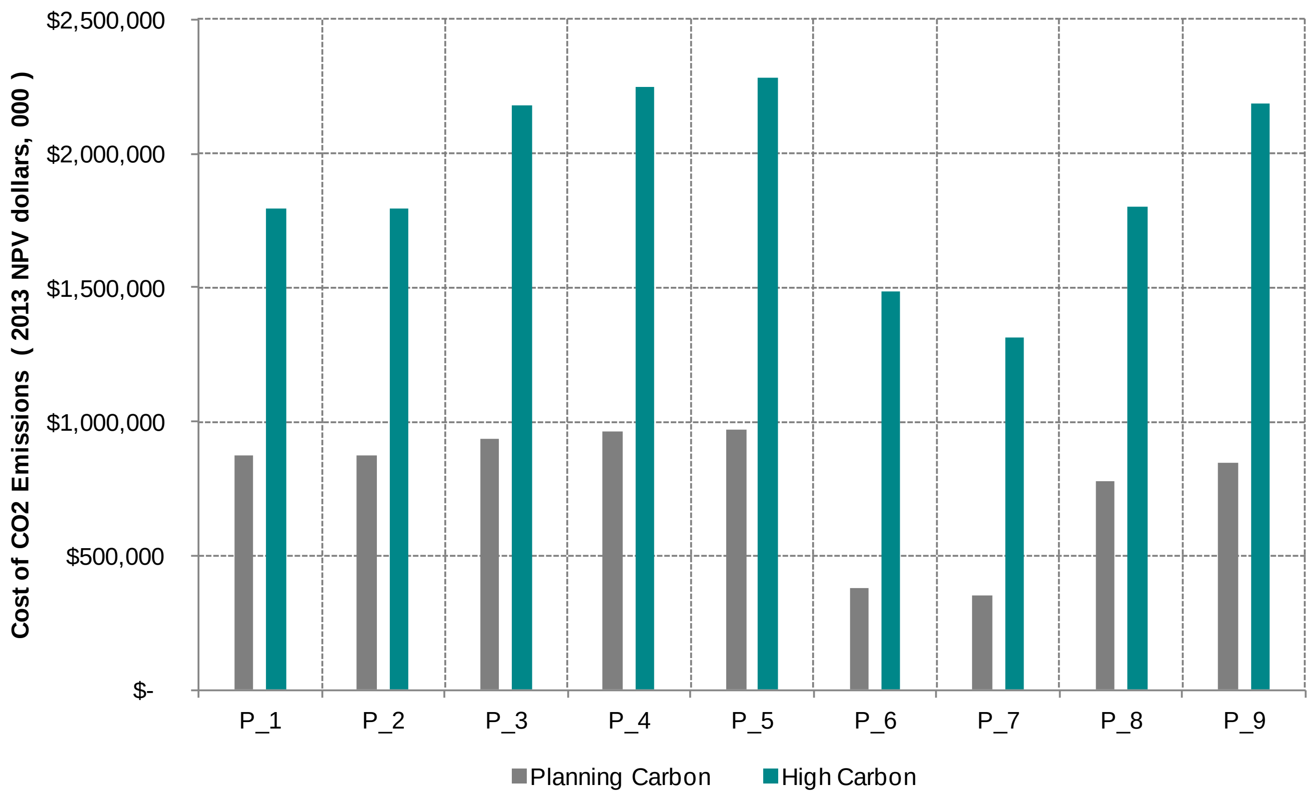
PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

Stochastic Dispersion Plot



Regulatory Environmental Compliance Costs

Portfolio Analysis Cost of CO_2 Emissions



Note: Instead of assuming NOx, Hg, and SO_2 emissions adders, the 2013 IRP used the Idaho Power coal study to calculate the variable and fixed environmental compliance costs attributed to these emission types.

Loss of Load Expectation Analysis

Loss of Load Expectation Summary Data*–Portfolio 1

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
2021	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2022	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2023	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2024	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00
2025	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.00	0.00
2026	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.00	0.01
2027	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.01
2028	0.29	0.00	0.00	0.00	0.00	0.00	0.01	0.26	0.00	0.00	0.00	0.00	0.02
2029	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
2030	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
2031	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
2032	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 2

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
2021	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2022	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2023	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2024	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2025	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00
2026	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.01
2027	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.01
2028	0.21	0.00	0.00	0.00	0.00	0.00	0.01	0.18	0.00	0.00	0.00	0.00	0.02
2029	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00
2030	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.00
2031	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.90	0.00	0.00	0.00	0.00	0.00
2032	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.01

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 3

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.74	0.00	0.00	0.00	0.00	0.00	0.03	0.69	0.01	0.01	0.00	0.00	0.00
2014	1.24	0.00	0.00	0.00	0.00	0.00	0.01	1.21	0.01	0.00	0.00	0.00	0.01
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.97	0.00	0.00	0.00	0.00	0.01	0.44	0.30	0.18	0.02	0.00	0.00	0.01
2019	1.42	0.00	0.00	0.00	0.00	0.04	0.36	0.57	0.37	0.08	0.00	0.00	0.01
2020	3.30	0.00	0.00	0.00	0.00	0.10	0.26	1.19	1.68	0.04	0.00	0.00	0.02
2021	2.61	0.01	0.00	0.00	0.00	0.05	0.25	1.59	0.52	0.11	0.00	0.00	0.07
2022	0.28	0.00	0.00	0.00	0.00	0.01	0.06	0.14	0.05	0.01	0.00	0.00	0.01
2023	0.46	0.00	0.00	0.00	0.00	0.01	0.09	0.28	0.06	0.01	0.00	0.00	0.01
2024	0.94	0.00	0.00	0.00	0.00	0.01	0.07	0.69	0.08	0.09	0.00	0.00	0.01
2025	2.01	0.00	0.00	0.00	0.00	0.00	0.03	1.86	0.06	0.05	0.00	0.00	0.01
2026	2.01	0.00	0.00	0.00	0.00	0.01	0.04	1.83	0.10	0.02	0.00	0.00	0.01
2027	1.35	0.00	0.00	0.00	0.00	0.00	0.05	1.22	0.05	0.01	0.00	0.00	0.02
2028	2.30	0.00	0.00	0.00	0.00	0.01	0.14	2.06	0.05	0.02	0.00	0.00	0.02
2029	1.05	0.00	0.00	0.00	0.00	0.00	0.05	0.98	0.01	0.01	0.00	0.00	0.01
2030	2.55	0.00	0.00	0.00	0.00	0.00	0.06	2.45	0.02	0.01	0.00	0.00	0.01
2031	6.75	0.00	0.00	0.00	0.00	0.00	0.05	6.67	0.03	0.00	0.00	0.00	0.01
2032	3.28	0.00	0.00	0.00	0.00	0.00	0.08	3.15	0.02	0.00	0.00	0.00	0.02

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 4													
Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.14	0.00	0.00	0.00	0.00	0.00	0.05	0.07	0.02	0.00	0.00	0.00	0.00
2019	0.20	0.00	0.00	0.00	0.00	0.00	0.04	0.12	0.04	0.01	0.00	0.00	0.00
2020	0.47	0.00	0.00	0.00	0.00	0.01	0.03	0.24	0.19	0.00	0.00	0.00	0.00
2021	0.29	0.00	0.00	0.00	0.00	0.00	0.03	0.19	0.05	0.01	0.00	0.00	0.01
2022	0.29	0.00	0.00	0.00	0.00	0.01	0.06	0.16	0.05	0.01	0.00	0.00	0.01
2023	0.49	0.00	0.00	0.00	0.00	0.01	0.09	0.32	0.06	0.01	0.00	0.00	0.01
2024	1.01	0.00	0.00	0.00	0.00	0.01	0.07	0.76	0.08	0.09	0.00	0.00	0.01
2025	2.18	0.00	0.00	0.00	0.00	0.00	0.03	2.03	0.06	0.05	0.00	0.00	0.01
2026	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.01	0.00	0.00	0.00	0.00
2027	0.18	0.00	0.00	0.00	0.00	0.00	0.01	0.17	0.00	0.00	0.00	0.00	0.00
2028	0.32	0.00	0.00	0.00	0.00	0.00	0.01	0.30	0.01	0.00	0.00	0.00	0.00
2029	0.55	0.00	0.00	0.00	0.00	0.00	0.02	0.51	0.01	0.00	0.00	0.00	0.00
2030	1.33	0.00	0.00	0.00	0.00	0.00	0.03	1.28	0.01	0.00	0.00	0.00	0.00
2031	3.63	0.00	0.00	0.00	0.00	0.00	0.02	3.59	0.01	0.00	0.00	0.00	0.00
2032	1.75	0.00	0.00	0.00	0.00	0.00	0.04	1.69	0.01	0.00	0.00	0.00	0.01

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 5													
Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.14	0.00	0.00	0.00	0.00	0.00	0.05	0.07	0.02	0.00	0.00	0.00	0.00
2019	0.20	0.00	0.00	0.00	0.00	0.00	0.04	0.12	0.04	0.01	0.00	0.00	0.00
2020	0.47	0.00	0.00	0.00	0.00	0.01	0.03	0.24	0.19	0.00	0.00	0.00	0.00
2021	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.01	0.00	0.00	0.00	0.00
2022	0.05	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.01	0.00	0.00	0.00	0.00
2023	0.09	0.00	0.00	0.00	0.00	0.00	0.01	0.08	0.01	0.00	0.00	0.00	0.00
2024	0.20	0.00	0.00	0.00	0.00	0.00	0.01	0.18	0.01	0.01	0.00	0.00	0.00
2025	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.01	0.00	0.00	0.00	0.00
2026	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.01	0.00	0.00	0.00	0.00
2027	0.18	0.00	0.00	0.00	0.00	0.00	0.01	0.17	0.00	0.00	0.00	0.00	0.00
2028	0.32	0.00	0.00	0.00	0.00	0.00	0.01	0.30	0.01	0.00	0.00	0.00	0.00
2029	0.55	0.00	0.00	0.00	0.00	0.00	0.02	0.51	0.01	0.00	0.00	0.00	0.00
2030	1.33	0.00	0.00	0.00	0.00	0.00	0.03	1.28	0.01	0.00	0.00	0.00	0.00
2031	3.63	0.00	0.00	0.00	0.00	0.00	0.02	3.59	0.01	0.00	0.00	0.00	0.00
2032	1.75	0.00	0.00	0.00	0.00	0.00	0.04	1.69	0.01	0.00	0.00	0.00	0.01

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 6

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.45	0.00	0.00	0.00	0.00	0.00	0.01	0.41	0.00	0.00	0.00	0.00	0.01
2017	2.59	0.01	0.00	0.00	0.00	0.00	0.16	2.29	0.04	0.01	0.00	0.00	0.07
2018	0.04	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.00
2019	0.06	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.01	0.00	0.00	0.00	0.00
2020	0.15	0.00	0.00	0.00	0.00	0.00	0.01	0.07	0.06	0.00	0.00	0.00	0.01
2021	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.02
2022	0.07	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.01	0.00	0.00	0.00	0.02
2023	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.01	0.00	0.00	0.00	0.02
2024	0.22	0.01	0.00	0.00	0.00	0.00	0.01	0.15	0.01	0.02	0.00	0.00	0.02
2025	0.44	0.00	0.00	0.00	0.00	0.00	0.01	0.39	0.01	0.01	0.00	0.00	0.02
2026	0.44	0.00	0.00	0.00	0.00	0.00	0.01	0.38	0.02	0.00	0.00	0.00	0.03
2027	0.34	0.01	0.00	0.00	0.00	0.00	0.01	0.27	0.01	0.00	0.00	0.00	0.05
2028	0.55	0.01	0.00	0.00	0.00	0.00	0.02	0.44	0.01	0.00	0.00	0.00	0.06
2029	0.90	0.01	0.00	0.00	0.00	0.00	0.04	0.76	0.01	0.01	0.00	0.00	0.07
2030	2.18	0.01	0.00	0.00	0.00	0.00	0.05	2.03	0.02	0.01	0.00	0.00	0.07
2031	3.97	0.01	0.00	0.00	0.00	0.00	0.03	3.85	0.01	0.00	0.00	0.00	0.06
2032	2.03	0.01	0.00	0.00	0.00	0.00	0.05	1.85	0.01	0.00	0.00	0.00	0.11

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 7

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.78	0.00	0.00	0.00	0.00	0.00	0.01	0.75	0.01	0.00	0.00	0.00	0.01
2016	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2017	0.31	0.00	0.00	0.00	0.00	0.00	0.02	0.28	0.00	0.00	0.00	0.00	0.01
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
2021	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.00	0.01
2022	0.06	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.02
2023	0.09	0.00	0.00	0.00	0.00	0.00	0.01	0.05	0.01	0.00	0.00	0.00	0.02
2024	0.18	0.01	0.00	0.00	0.00	0.00	0.01	0.12	0.01	0.01	0.00	0.00	0.02
2025	0.36	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.01	0.01	0.00	0.00	0.02
2026	0.36	0.00	0.00	0.00	0.00	0.00	0.01	0.31	0.02	0.00	0.00	0.00	0.02
2027	0.28	0.01	0.00	0.00	0.00	0.00	0.01	0.21	0.01	0.00	0.00	0.00	0.04
2028	0.44	0.01	0.00	0.00	0.00	0.00	0.02	0.36	0.01	0.00	0.00	0.00	0.05
2029	0.73	0.01	0.00	0.00	0.00	0.00	0.03	0.61	0.01	0.00	0.00	0.00	0.06
2030	1.68	0.01	0.00	0.00	0.00	0.00	0.04	1.55	0.01	0.01	0.00	0.00	0.05
2031	3.95	0.01	0.00	0.00	0.00	0.00	0.03	3.81	0.02	0.00	0.00	0.00	0.08
2032	2.20	0.02	0.00	0.00	0.00	0.00	0.05	1.97	0.02	0.00	0.00	0.00	0.14

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 8

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
2021	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2022	0.06	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.01	0.00	0.00	0.00	0.02
2023	0.10	0.00	0.00	0.00	0.00	0.00	0.02	0.05	0.01	0.00	0.00	0.00	0.02
2024	0.19	0.00	0.00	0.00	0.00	0.00	0.01	0.14	0.01	0.01	0.00	0.00	0.02
2025	0.51	0.00	0.00	0.00	0.00	0.00	0.01	0.47	0.01	0.01	0.00	0.00	0.02
2026	1.70	0.01	0.00	0.00	0.00	0.00	0.03	1.49	0.06	0.01	0.00	0.00	0.09
2027	0.14	0.01	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.02
2028	0.21	0.00	0.00	0.00	0.00	0.00	0.01	0.18	0.00	0.00	0.00	0.00	0.02
2029	0.39	0.00	0.00	0.00	0.00	0.00	0.01	0.34	0.00	0.00	0.00	0.00	0.02
2030	0.98	0.00	0.00	0.00	0.00	0.00	0.02	0.94	0.00	0.00	0.00	0.00	0.02
2031	3.02	0.00	0.00	0.00	0.00	0.00	0.01	2.96	0.01	0.00	0.00	0.00	0.03
2032	1.34	0.00	0.00	0.00	0.00	0.00	0.02	1.24	0.01	0.00	0.00	0.00	0.06

* With CBM@330 MW

Loss of Load Expectation Summary Data*–Portfolio 9

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013	0.42	0.00	0.00	0.00	0.00	0.00	0.01	0.40	0.00	0.00	0.00	0.00	0.00
2014	0.79	0.00	0.00	0.00	0.00	0.00	0.01	0.78	0.00	0.00	0.00	0.00	0.00
2015	0.63	0.00	0.00	0.00	0.00	0.00	0.01	0.61	0.01	0.00	0.00	0.00	0.00
2016	0.35	0.00	0.00	0.00	0.00	0.00	0.01	0.32	0.00	0.00	0.00	0.00	0.01
2017	0.58	0.00	0.00	0.00	0.00	0.00	0.03	0.53	0.01	0.00	0.00	0.00	0.01
2018	0.97	0.00	0.00	0.00	0.00	0.01	0.44	0.30	0.18	0.02	0.00	0.00	0.01
2019	1.42	0.00	0.00	0.00	0.00	0.04	0.36	0.57	0.37	0.08	0.00	0.00	0.01
2020	3.30	0.00	0.00	0.00	0.00	0.10	0.26	1.19	1.68	0.04	0.00	0.00	0.02
2021	2.61	0.01	0.00	0.00	0.00	0.05	0.25	1.59	0.52	0.11	0.00	0.00	0.07
2022	1.14	0.05	0.01	0.00	0.00	0.28	0.17	0.42	0.15	0.03	0.00	0.00	0.03
2023	1.33	0.00	0.00	0.00	0.00	0.02	0.25	0.81	0.17	0.05	0.00	0.00	0.03
2024	2.56	0.01	0.00	0.00	0.00	0.03	0.20	1.82	0.22	0.25	0.00	0.00	0.02
2025	0.68	0.00	0.00	0.00	0.00	0.01	0.01	0.62	0.02	0.02	0.00	0.00	0.00
2026	1.90	0.00	0.00	0.00	0.00	0.01	0.04	1.70	0.11	0.02	0.00	0.00	0.01
2027	1.37	0.03	0.00	0.00	0.00	0.05	0.05	1.14	0.05	0.02	0.00	0.00	0.02
2028	2.14	0.00	0.00	0.00	0.00	0.01	0.12	1.90	0.06	0.02	0.00	0.00	0.03
2029	3.46	0.00	0.00	0.00	0.00	0.01	0.21	3.12	0.05	0.03	0.00	0.00	0.03
2030	2.37	0.01	0.00	0.00	0.00	0.00	0.06	2.26	0.02	0.01	0.00	0.00	0.01
2031	6.06	0.00	0.00	0.00	0.00	0.00	0.05	5.97	0.03	0.00	0.00	0.00	0.01
2032	3.00	0.00	0.00	0.00	0.00	0.00	0.09	2.87	0.03	0.00	0.00	0.00	0.02

* With CBM@330 MW

State of Oregon IRP Guidelines

ORDER NO. 07-047

ENTERED 02/09/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1056

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF OREGON	)	ERRATA ORDER
	)	
Investigation Into Integrated Resource Planning.	)	

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 0 9 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. *All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. *Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*

  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and* *associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Guideline 2: Procedural Requirements.

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

ORDER NO. 07-047

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

Guideline 3: Plan Filing, Review, and Updates.

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

APPENDIX A
PAGE 3 OF 7

ORDER NO. 07-047

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

APPENDIX A
PAGE 4 OF 7

ORDER NO. 07-047

f. *Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

g. *Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

h. *Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

i. *Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

j. *Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

k. *Analysis of the uncertainties associated with each portfolio evaluated;*

l. *Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

m. *Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

n. *An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote

APPENDIX A
PAGE 5 OF 7

ORDER NO. 07-047

locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

APPENDIX A
PAGE 6 OF 7

ORDER NO. 07-047

Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. *An electric utility should, in its IRP:*

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

APPENDIX A
PAGE 7 OF 7

Compliance with State of Oregon IRP Guidelines

Oregon Order 07-047 Action Items	2013 IRP
Guideline 1: Substantive Requirements a. All resources must be evaluated on a consistent and comparable basis. • All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response. • Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling. • Consistent assumptions and methods should be used for evaluation of all resources. • The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. b. Risk and uncertainty must be considered. • At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions. 2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions. • Utilities should identify in their plans any additional sources of risk and uncertainty. c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. • The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource. • Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases. • To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging. • The utility should explain in its plan how its resource choices appropriately balance cost and risk. d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3. Idaho Power Today, section *Existing Supply-Side Resources*, pages 25–36. Demand-side options for meeting the utility's load are discussed in Chapter 4. Demand-Side Resources, pages 37–45. a-2) Different resource alternatives results are compared in Chapter 7. Resource Alternatives Analysis, Table 7.1 on page 84. Different resource portfolios results are compared in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98. a-3) The consistent modeling method for evaluating all resource alternatives is explained in Chapter 7. Resource Alternatives Analysis, pages 83-85. The consistent modeling method for evaluating all resource portfolios are explained in Chapter 9. Modeling Analysis and Results, pages 97–99. a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9. Modeling Analysis and Results, in Table 9.1 Financial Assumptions, on page 97. b-1) Electric utility risk and uncertainty factors (carbon, NG and water conditions) for resource alternatives are considered in Chapter 7. Resource Alternatives Analysis, section *Risk Analysis and Results,* pages 86–87. Electric utility risk and uncertainty factors (load, carbon, NG and water conditions) for resource alternatives are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis*, pages 103–105 (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). An additional analysis for CO_2 emissions costs can be found in the *2013 IRP Technical Appendix*, section *Regulatory Environmental Compliance Costs,* page 131. Note: Plant forced outages for resource alternatives and resource portfolios are not discussed in the IRP document or *2013 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis. b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2. Political, Regulatory, and Operational Issues the following sections: *FERC Relicensing*, page 12; *Idaho Water Issues*, page 13; *Northwest Power Pool Energy Imbalance Market*, page 17; and *Federal Energy Legislation*, page 19. Also, the uncertainty in transmission planning process is described in Chapter 6. Transmission Planning, pages 72–73. A tipping-point analyses for carbon adder and dispatch cost is analyzed in Chapter 5. Planning Period Forecasts, section *Carbon Adder Generation Dispatch Analysis,* pages 69–70. c-1) The IRP methodology and its' subsequent planning horizon of 20 years are discussed in Chapter 1. Summary, section *IRP Methodology,* fourth paragraph on page 4. c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the expected NPV for resource alternative costs are found in Chapter 7. Resource Alternative Analysis, Table 7.1 on page 84. The summary of the expected NPV for total portfolio costs are found in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98.

Oregon Order 07-047 Action Items	2013 IRP
	c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. A plot of stochastic dispersion is shown in the *2013 IRP Technical Appendix*, S*tochastic Dispersion Plot* on page 131. c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1. Summary, in the last paragraph of section Introduction, on page 2. Idaho Power explains how its resource choices appropriately balance cost and risk in a twofold process: Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87. For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96. d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2. Political, Regulatory, and Operational Issues, beginning pages 11–19 as well as in Chapter 1. Summary, section *Public Advisory Process*, pages 2–3.
Guideline 2: Procedural Requirements. a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution. b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission. c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011 and 2013 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the 2004, 2006, 2009, 2011 and 2013 IRPs. The IRP Advisory Council meetings are open to the public, on a limited basis due to space constraints. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan. As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2013 IRP, the 2013 Load and Sales Forecast and in the 2013 Technical Appendix. As set forth in Guideline 2, part c., Idaho Power provided a draft 2013 IRP for public review on Friday, June 6, 2013, via a hard copy to members of IRP Advisory Committee and public attendees of the 2013 IRP Advisory Committee meetings. June 17, 2013 was the deadline for getting IRP Advisory Committee and public comments back on the draft plan.

Oregon Order 07-047 Action Items	2013 IRP
Guideline 3: Plan Filing, Review, and Updates. a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission. b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment. c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing. d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order. e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP. f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update. g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	a. The OPUC acknowledged Idaho Power's 2011 IRP on May 21, 2012 in Order 12-177. Idaho Power plans to file the 2013 IRP on June 28, 2013. b. Idaho Power will schedule a public meeting at the OPUC after the 2013 IRP has been filed. c. No action needed. d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan. e. In ORDER NO. 12-013, the OPUC provided direction on IRP flexible resource guidelines for EV. In ORDER NO. 12-177, the OPUC noted 12 action items regarding Idaho Power's 2011 IRP. Idaho Power has addressed these action items in the 2013 IRP. f. Idaho Power submitted an update to the 2011 IRP in February 2013. g. No action needed.

Oregon Order 07-047 Action Items	2013 IRP
Guideline 4: Plan Components. At a minimum, the plan must include the following elements: a. An explanation of how the utility met each of the substantive and procedural requirements; b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions; c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested; d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources; e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology; f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs; g. Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered; h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system; i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results; k. Analysis of the uncertainties associated with each portfolio evaluated; l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff. b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 5. Planning Period Forecasts, section *Load Forecast,* beginning on page 47. High- and low-growth scenarios in addition to stochastic load risk analysis are discussed in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. c. Peaking capacity and energy capability for each year of the plan are discussed in Chapter 5. Planning Period Forecasts, sections *Average Monthly Energy Planning* and *Peak-Hour Planning,* pages 60–61. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios,* beginning on page 80. d. Not applicable. e. Supply-side resources and their levelized costs and technologies are covered in Chapter 5. Planning Period Forecasts on figures 5.7 and 5.8, pages 66 and 67 respectively. Demand-side resources and their levelized costs and technologies are covered in Chapter 4. Demand-Side Resources, in Table 4.2 on page 43. f. Resource reliability is covered in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* on pages 110111. g. Fuel price forecasts are discussed in Chapter 5. Planning Period Forecasts, section *Coal Resources* (coal price forecast and environmental compliance cost analysis), pages 5859, section *Natural Gas Price Forecast,* on page 62. Environmental compliance costs are also discussed in section *Emissions Adders for Fossil Fuel-Based Resources,* pages 63–64. Alternative scenarios are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. h. Construction of resource portfolios are made in a twofold process: 1) Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87. 2) For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96. i. The resource portfolios are evaluated against various risks in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. j. The portfolios are evaluated and ranked in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98. k. The uncertainties associated with each portfolio are evaluated in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98 and Figure 9.6 on page *104*. m. No inconsistencies were identified. n. An annual near-term action plan is described in Chapter 1. Summary, section *Near-Term Action Plan*, starting on page 9.

Oregon Order 07-047 Action Items	2013 IRP
Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	The transmission required for each resource being considered is described in the *2013 IRP Technical Appendix*, section *Transmission Cost Assumptions* on page 86. The transmission required for each resource portfolio being considered is also described in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios*, pages 80–81. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. Transmission facilities were analyzed as a resource option in Chapter 7. Resource Alternatives Analysis, pages 83–84. All the resource portfolios contained the Boardman to Hemingway Transmission Line as a resource option as discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96.
Guideline 6: Conservation. a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory. b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets. c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: • Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and • Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	a. Idaho Power periodically studies conservation potential and a summary of the company's conservation (DSM) philosophy is described in Chapter 4. Demand-Side Resources, pages 37–38. b. Cost-effectiveness of energy efficiency programs are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Performances,* pages 38–44. c. As described in Chapter 4. Demand-Side Resources, third paragraph of page 37, due to the indirect nature of savings from regional market transformation activities, Idaho Power's outside party administrator Northwest Energy Efficiency Alliance (NEEA) impacts are not accounted for in the 2013 IRP.
Guideline 7: Demand Response. Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Demand response resources are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Resources* on page 44.
Guideline 8: Environmental Costs. Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO^2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.	Idaho Power discusses the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources,* pages 63–64. The costs are shown in the *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131. Idaho Power performed a base case, upper case, and zero-cost case and for the compliance cost of CO_2 and is discussed in Chapter 5. Planning Period Forecasts, section *Carbon Adder,* pages 68–69. Idaho Power discusses the sensitivity analysis on a range of reasonably possible cost adders (low and high case) for nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources* on page 64. The costs are shown in *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131.
Guideline 9: Direct Access Loads. An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2013 IRP 20-year planning period.
Guideline 10: Multi-state Utilities. Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	Idaho Power intends to file the 2013 IRP in both the Idaho and Oregon jurisdictions.

Oregon Order 07-047 Action Items	2013 IRP
Guideline 11: Reliability. Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Idaho Power discussed the capacity planning margin in Chapter 9. Modeling Analysis and Results, section *Capacity Planning Margin*, pages 106–108, and the loss of load probability in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* pages 110–111.
Guideline 12: Distributed Generation. Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Idaho Power evaluated distributed generation technologies in the following sections: Load shed, grid sync, and distributed PV: in Chapter 5. Planning Period Forecasts, Figure 5.7 and 5.8, pages 66 and 67, respectively. Distributed PV: in Chapter 7. Resource Alternatives, pages 83–87.
Guideline 13: Resource Acquisition. a. An electric utility should, in its IRP: • Identify its proposed acquisition strategy for each resource in its action plan. • Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. • Identify any Benchmark Resources it plans to consider in competitive bidding. b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order 06-446 issued on August 10, 2006. Idaho Power discussed asset ownership in Chapter 10 Action Plan, section *Acton Plan (2013–2032)*, last paragraph on page 114. In the next 10 years, the Boardman to Hemingway Transmission Line is the only new IRP resource identified. Idaho Power is currently permitting this project and plans to contract the construction work.

STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1461

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation of matters related to Electric Vehicle Charging.	ORDER

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

ORDER NO. 12 013

2. *Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

D. Integrated Resource Planning Flexible Resources Guidelines

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

1. *Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

16

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

2. Resolution

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

ORDER NO. 12 013

2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

20

Compliance with EV Guidelines

Oregon Order 12-013 Guideline	2013 IRP
Guideline 1: Forecast the Demand for Flexible Capacity. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;	Forecasting the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110.
Guideline 2: Forecast the Supply for Flexible Capacity. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;	Forecasting the balancing reserves available at different time intervals from existing generating resources is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110.
Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	Evaluating all resource options, including the use of EVs, is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110.

STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2011 IRP

ORDER NO. 12 177

ENTERED MAY 21 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 53

In the Matter of IDAHO POWER COMPANY 2011 Integrated Resource Plan.	ORDER

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be

[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a public meeting. A technical workshop was held for parties on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

IV. DISCUSSION

A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected–case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

ORDER NO. 12 177

Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

B. Objections to Idaho Power's 2011 IRP

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

1. Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as

3

ORDER NO. 12 177

well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

Resolution

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

2. Boardman to Hemingway Transmission (Action Item 7)

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

Resolution

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

3. Conservation Voltage Reduction (Action Item 4)

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

4

ORDER NO. 12 177

Resolution

We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:

> <u>Action Item 4 – Conservation Voltage Reduction</u> – The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

4. Demand Response (Action Item 3)

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

Resolution

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

5. Energy Efficiency (Action Items 1 and 2)

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

Resolution

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

ORDER NO. 12 177

6. Alternative Portfolio (Action Items 8 and 9)

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

Resolution

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

7. Long Term Action Items (Action Item 12)

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

Resolution

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

8. Load Forecast

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

Resolution

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

6

ORDER NO. 12 177

9 *Risk Analysis*

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

Resolution

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

10. *Wind Integration Study*

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

Resolution

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

11. *Solar Photovoltaic Analysis*

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

Resolution

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

12. Adherence of Plan to Integrated Resource Planning Guidelines

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

Resolution

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

---

[4] IRP Guideline 1(c) prescribes the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future environmental compliance costs.

ORDER NO. 12 177

IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 31 day of May, 2012, at Salem, Oregon.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

9

Compliance with State of Oregon Action Items Regarding Idaho Power's 2011 IRP

Oregon Order 12-177 Action Items	2013 IRP
Action Item 1: Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11) Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years. CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments. Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings. Staff shares CUB's and RNP 's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.	Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman Plant in Oregon that is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*. In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.
Action Item 2: Boardman to Hemingway Transmission (Action Item 7) RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.	Idaho Power analyzed Boardman to Hemingway as uncommitted resource in two ways: 1) Resource Alternatives: eight resources were analyzed side-by-side to achieve a 200-MW capacity of peak-hour contribution. The Resource Alternatives analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87. 2) Resource Portfolios: Boardman to Hemingway was in all nine portfolios. The results of the Resource Portfolio analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98. Progress on Boardman to Hemingway was discussed in the *Boardman to Hemingway* section of Chapter 6. Transmission Planning, pages 77–78.
Action Item 3: Conservation Voltage Reduction (Action Item 4) Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management. We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows: Action Item 4 - Conservation Voltage Reduction- The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.	Idaho Power included an assessment of the available cost-effective CVR resource potential in its service area. This can be found in the *Conservation Voltage Reduction* section of Chapter 4 Demand-Side Resources on page 45.

Oregon Order 12-177 Action Items	2013 IRP
Action Item 4: Demand Response (Action Item 3) In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.	Chapter 4. Demand-Side Resources, pages 37–45. provides a detailed discussion and analysis of the company's DSM programs. All nine resource portfolios include Demand Response. Resource portfolios are described in the *Portfolio Design and Selection* section of Chapter 8. Planning Criteria And Portfolio Selection, pages 90–96.
Action Item 5: Energy Efficiency (Action Items 1 and 2) Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.	Energy efficiency performance is discussed in Chapter 4 Demand-Side Resources, section Energy Efficiency Performance, pages 38-39. New energy efficiency programs are discussed in Chapter 4 Demand-Side Resources, section New Energy Efficiency Resources, pages 41-44.
Action Item 6: Alternative Portfolio (Action Items 8 and 9) RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.	Eight resources, including four renewable resources, were analyzed side-by-side to achieve 200 MW of peak-hour contribution. The analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87. Four resource portfolios were constructed where Idaho Power ceased operations at some or all of the Idaho Power coal-fired generation facilities. One of the portfolios was jointly designed by the Idaho Conservation League and Boise State University. Portfolio design is discussed in the *Portfolio Design and Selection* section of Chapter 8. Planning, pages 90–96.
Action Item 7: Long Term Action Items (Action Item 12) In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.	Idaho Power provides its action plan in Chapter 10. Action Plan, pages 113–115.
Action Item 8: Load Forecast Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staffs concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.	Idaho Power's load forecast is discussed in detail in Chapter 5. Planning Period Forecasts, section *Load Forecast*, pages 47–55. Lingering economic conditions are discussed in detail, pages 48–50.
Action Item 9: Risk Analysis Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.	Idaho Power incorporated hydro generation variability as a risk factor. Idaho Power also used the AURORA model to perform stochastic risk analyses. Stochastic analysis is discussed in the *Stochastic Analysis* section of Chapter 9. Modeling Analysis and Results, pages 103–105.
Action Item 10: Wind Integration Study RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.	Idaho Power filed a wind integration study in February 2013. The wind integration study included an independent technical review. The wind integration study can be found on the Idaho Power website: www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf
Action Item 11: Solar Photovoltaic Analysis RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.	Idaho Power evaluated the performance of solar PV generation as a class. The PV analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87.

Oregon Order 12-177 Action Items	2013 IRP
Action Item 12: Adherence of Plan to Integrated Resource Planning Guidelines Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1 (c) and 4(g), 4 because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard. In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations. Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.	Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman plant in Oregon which is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*. In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.The OPUC is currently reviewing the Idaho Power coal study as part of Oregon Docket No. LC 57. 1. Idaho Power provides a concise listing of action items in Chapter 10. Action Plan, pages 113–114.

This page left blank intentionally.