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June 30, 2017

VIA EMAIL AND OVERNIGHT DELIVERY

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket LC ___ - Idaho Power Company's 2017 Integrated Resource Plan ("IRP")

Enclosed for filing in the above-identified docket are twenty copies of Idaho Power Company's Application of the 2017 Integrated Resource Plan.

Please contact this office with any questions

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC ______

In the Matter of IDAHO POWER COMPANY'S 2017 Integrated Resource Plan.	))))))	**APPLICATION**

I. INTRODUCTION

Idaho Power Company (Idaho Power or Company), in accordance with the Public Utility Commission of Oregon's (Commission) Order Nos. 89-507, 07-002, 07-747, and 12-013, hereby requests that the Commission issue an order acknowledging the Company's 2017 Integrated Resource Plan (IRP or Plan).

Idaho Power requests that the following people receive notices and communications with respect to this Application:

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II. BACKGROUND

Idaho Power's 2017 IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and an Action Plan that details the steps the Company plans to take to implement the action plan items described in the 2017 IRP.

The complete 2017 IRP consists of four separate documents: (1) the 2017 Integrated Resource Plan; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2017 Annual Report; and (4) Appendix C – Technical Report. A copy of the complete 2017 IRP is provided as Attachment 1 and can also be found on the Company's website at www.idahopower.com. Interested persons may also request a printed copy of the 2017 IRP by contacting irp@idahopower.com.

Idaho Power has worked with stakeholders over the last year to develop the 2017 IRP. To incorporate stakeholder and public input, the Company worked with the Integrated Resource Plan Advisory Council ("IRPAC"), comprised of members of the environmental community, major industrial customers, agricultural interests, representatives from both the Commission and Idaho Public Utilities Commission, representatives from the Idaho Governor's Office of Energy and Mineral Resources, representatives from the Northwest Power and Conservation Council, and others.[1] A list of the 2017 IRPAC members can be found in Appendix C – Technical Report. For the 2017 IRP, Idaho Power conducted eight IRPAC meetings, including a workshop designed to explore the potential for distributed generation to defer grid investment.

III. IRP GOALS AND ASSUMPTIONS

The primary goals of Idaho Power's 2017 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period (2017-2036); (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give balanced treatment to both supply-side resources and demand-side measures; and (4) involve the public in the planning process in a meaningful way.

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[1] Idaho Power informed members of the public interested in the Boardman to Hemingway Transmission Line Project about participating in the IRPAC process, and many B2H stakeholders attended IRPAC meetings —including B2H stakeholders from Oregon residing outside of Idaho Power's service area.

The 2017 IRP assumes that during the 20-year planning period, Idaho Power will continue to be responsible for acquiring resources sufficient to serve its retail customers in its Idaho and Oregon service areas and will continue to operate as a vertically integrated electric utility. During this period, average system load is forecasted to grow by 0.9 percent per year and 1.4 percent per year for peak-hour demand. Total number of customers is expected to increase from 534,000 in 2016 to 756,000 by 2036. Idaho Power continues to use 70th percentile water conditions and 70th percentile average load for energy planning. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load. Based on the forecasted demand and energy over the 20-year planning period and including expanded demand-side measures, additional resources will be needed to meet these increased demands.

IV. IRP METHODOLOGY

Preparation of Idaho Power's 2017 IRP began with the forecast of future customer demand. Existing generation resources, demand-side resources, and transmission import capacity were combined with forecasted customer demand to create a load and resource balance for energy and capacity over the 20-year planning period. Idaho Power then evaluated new energy efficiency programs and the expansion of existing DSM programs to revise energy and capacity deficits. A baseline assumption for the 2017 IRP was Idaho Power's exit from coal-fired operations of North Valmy Unit 1 and Unit 2 at the end of 2019 and 2025, respectively. Idaho Power designed the portfolio analysis for the 2017 IRP to inform the IRP's action plan with respect to two key resource actions: 1) selective catalytic reduction (SCR) investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively, and 2) the B2H transmission line. Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance, transmission

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upgrades, projected wholesale market purchases, integration costs, and anticipated environmental controls. The financial benefits include economic resource operations, projected wholesale market sales, transmission revenue, and the availability and market value of renewable energy certificates.

Idaho Power is part of the larger northwestern 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 regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds customer demand and transmission export capacity, and the Company must curtail generation on its system.

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 now known as the Boardman to Hemingway Transmission Line Project ("B2H"). Idaho Power again evaluated B2H as an uncommitted resource in the 2017 resource plan to ensure the transmission addition remains a prudent resource acquisition.

V. PREFERRED RESOURCE PORTFOLIO

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The preferred portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost and risk over the 2017 to 2036 planning period. While the preferred resource portfolio represents current resource acquisition targets, it is important to note that the actual resource portfolio may differ from the quantities and types of resources outlined in the IRP depending on the changing needs of Idaho Power and its customers.

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Analysis for the 2017 IRP indicates favorable economics associated with two significant resource actions: (1) the acquisition of the B2H transmission line; and (2) the early retirement of the Jim Bridger Plant -- unit 2 in 2028 and unit 1 in 2032 -- without the installation of SCRs. These two resource actions are central to portfolio 7 (P7), the 2017 IRP's preferred resource portfolio. P7 contains no other resource actions through the end of the 2020s, but adds 36-MW reciprocating engine resources in 2031 and in 2032, a 300-MW combined-cycle combustion turbine in 2033, and 54-MW reciprocating engine resources in 2035 and 2036.

VI. ACTION PLAN (2017-2021)

Consistent with the Commission's direction in Order No. 14-253, the 2017 IRP includes an action plan with resource activities that the Company plans to take in the next two to four years.[2] The Action Plan for the 2017 to 2021 period (2017 IRP Action Plan) includes items specifically related to the preferred portfolio P7, and other items included in all portfolios. The following items are significant:

- The 2017 IRP Action Plan includes Idaho Power's continued planning to enter the western Energy Imbalance Market (EIM) in April of 2018. Since its inception, the EIM has resulted in significant cost savings for its participants and Idaho Power expects that its participation will similarly result in net power supply savings for its customers.
- The 2017 IRP Action Plan includes planning and coordination with NV Energy (Idaho Power's co-owner) for Idaho Power's exit from coal-fired operations of North Valmy Unit 1 by year-end 2019 and North Valmy Unit 2 by 2025, and the planning and negotiation with PacifiCorp (Idaho Power's co-owner) and

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[2] *In re Idaho Power's 2013 Integrated Resource Plan*, LC 58, Order No. 14-253 (July 8, 2014) at 17. As discussed below, Idaho Power has extended the action plan window for the B2H transmission line to include activities from 2017 to 2026, given the unusually lengthy timeline for permitting and constructing this 300-mile 500 kV transmission line.

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applicable environmental regulators to achieve early retirements of Jim Bridger Unit 2 by 2028, and Unit 1 by 2032.

- The 2017 IRP Action Plan includes the on-going permitting and acquisition (construction) of B2H from 2017 to 2026.[3] The Company has included a longer action plan "window" for B2H given the length of time required to permit and construct the 300-mile 500 kV transmission line. The pursuit of these items over the relevant action plan periods is critical to the successful and timely implementation of the preferred portfolio. Note that as part of its permitting activities, Idaho Power is seeking a site certificate for the construction of B2H from Oregon's Energy Facility Siting Council (EFSC). The Commission's acknowledgement of Idaho Power's acquisition of B2H in the Action Plan will serve as the Company's satisfaction of EFSC's "Need" standard under its Least Cost Plan Rule.[4]
- The Gateway West transmission line remains a beneficial future upgrade to Idaho Power and the region, creating additional capacity and promoting continued grid reliability in a time of expanding variable energy resources. Therefore, the 2017 IRP Action Plan includes continued permitting and planning associated with the Gateway West project.
- Finally, Clean Air Act (CAA) Section 111(d) could potentially have a pronounced impact on coal and natural gas-fired power plant operations on Idaho Power's system and throughout the nation. Due to ongoing litigation about the legality of the rule, Idaho Power will continue to monitor and assess the impacts of CAA Section 111(d) on the preferred portfolio.

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[3] The Company anticipates a B2H project in-service date of 2024 or later – subject to coordination of activities with project co-participants.

[4] *See* OAR 345-023-0005(1) and 345-023-0020.

In addition to continued transmission permitting efforts and evaluation of potential changes in thermal fleet operations at North Valmy and Jim Bridger, the 2017 IRP Action Plan also includes the following items:

- Investigation of solar photovoltaic (PV) contribution to peak and loss-of-load probability analysis.
- Continued pursuit of cost-effective energy efficiency.
- Continued coordination with Portland General Electric to achieve cessation of coal-fired operations at the Boardman plant by year-end 2020.

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Below is a summary of the 2017 IRP's Action Plan:

Year	Resource	Action	Action Number
2017–2018	EIM	Continue planning for western EIM participation beginning in April 2018.	1
2017–2018	Loss-of-load and solar contribution to peak	Investigate solar PV contribution to peak and loss-of-load probability analysis.	2
2017–2019	North Valmy Unit 1	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.	3
2017–2021	Jim Bridger units 1 and 2	Plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.	4
2017–2020	B2H	Conduct ongoing permitting, planning studies, and regulatory filings.	5
2018–2026[5]	B2H	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	6
2017–2021	Boardman	Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.	7
2017–2021	Gateway West	Conduct ongoing permitting, planning studies, and regulatory filings.	8
2017–2021	Energy efficiency	Continue the pursuit of cost-effective energy efficiency.	9
2017–2021	Carbon emission regulations	Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.	10
2017–2021	North Valmy Unit 2	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.	11

VII. COMPLIANCE WITH ORDER NO. 16-160

In Order No. 16-160 issued in Idaho Power's 2015 IRP[6], the Commission adopted Staff's recommendation to acknowledge the IRP as modified by Staff's presentation made at the public meeting at which the IRP was considered.[7] In doing so, the Commission implicitly adopted Staff's three recommendations as to the specific analysis that should be included in the 2017 IRP.

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[5] The Company anticipates a B2H in-service date of 2024 or later, subject to coordination of activities with project co-participants.

[6] *In Re Idaho Power Company's 2015 Integrated Resource Plan,* LC 63, Order No. 16-160, April 28, 2016.

[7] Order No. 16-160 at 1.

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Staff's first two recommendations concerned Idaho Power's analysis of the Environmental Protection Agency's (EPA) June 2, 2014 release of a proposal to regulate CO2 emissions from existing power plans under the Clean Air Act Section 111(d) (Clean Power Plan). Because the 2015 IRP was published prior to the release of the final rules under Section 111(d), Staff recommended that the Company prepare specific analyses as to the impact of these rules in the 2017 IRP. Staff recommended that in the 2017 IRP the Company:

1. *Analyze alternative Section 111 (d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path in the 2017 IRP; and*
2. *Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.*[8]

Idaho Power notes that there is now a final rule implementing 111(d), published in the Federal Register on October 23, 2015. For that reason, modeling alternative paths is not necessary. Consistent with the 111(d) rules, Idaho Power modeled compliance in each portfolio assuming a state-by-state mass-based approach. The Langley Gulch generating plant was assumed to be unconstrained, and units at North Valmy were largely unaffected because of the assumed retirement in 2019 and 2025.

Idaho Power believes that carbon-emission regulation in some form is likely during the next 20 years. Under a non-carbon-constrained future, the SCR investments at the Jim Bridger plant would likely result in a better financial outcome for customers, while the opposite is true if carbon is constrained. While uncertainty exists regarding carbon regulation, Idaho Power is not inclined to pursue a direction toward making the SCR investments. The additional SCR investments are counter to the findings of the portfolio

[8] Order No. 16-160, Appendix A, pp. 7-8.

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analysis, in which portfolios without SCRs on Jim Bridger units 1 and 2 generally performed better.

In addition, in the 2015 IRP, the Citizens' Utility Board (CUB) and Staff raised concerns over the Company's reliance on qualitative risks to support the selection of its preferred portfolio over several lower cost portfolios. In particular, Staff was concerned that some of the lower-cost, lower-risk portfolios also afforded the same qualitative risk benefits the Company attributes to the preferred portfolio. Staff stated its appreciation of Idaho Power's "broader assessment" of qualitative risks, but found that Idaho Power's IRP lacked a comprehensive evaluation of qualitative risks of all other portfolios besides the preferred portfolio.[9] For this reason, Staff recommended that, in the 2017 IRP, the Company:

> *Include a more systematic evaluation of the qualitative risks and benefits of the resource portfolios that Idaho Power analyzes in the company's 2017 IRP.*[10]

In response to Staff's recommendation for a more systematic evaluation of the qualitative risks, the 2017 IRP qualitative risk analysis identifies each of the 12-portfolio's exposure to selected qualitative risk factors *and* benefits relative to the lowest-cost portfolio's (P7) exposure to the same risk factors and benefits. This comparative analysis recognizes that differing exposure to qualitative risks can lead to the selection of a preferred portfolio different from the portfolio emerging as the lowest-cost portfolio from the quantitative analysis. This contrasts with the qualitative risk analysis presented in the 2015 IRP which highlighted specific risks within the portfolios and Idaho Power's interpretation of how the preferred portfolio reduced exposure to certain qualitative risks. The findings of the qualitative risk analysis in the 2017 IRP indicate that portfolio P7 does not carry greater exposure to qualitative risk factors relative to other resource portfolios. In fact, P7 has unique qualitative benefits in a future where the electric grid is a critical element to the

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[9] Order No. 16, 160, Appendix A, p. 11.

[10] Order No. 16, 160, Appendix A, p. 11.

successful development of automated energy markets and the integration of expanded intermittent renewable resources. Tables providing the assessment of qualitative risks and benefits are provided on page 123 of the IRP.

VIII. REQUEST FOR ACKNOWLEDGMENT

Idaho Power respectfully requests that the Commission issue an order acknowledging the Company's 2017 IRP and finding that the 2017 IRP meets both the procedural and substantive requirements of Order Nos. 89-507, 07-002, 07-747, and 12-013. The Company also requests that the Commission specifically acknowledge Idaho Power's acquisition of B2H in the Action Plan to satisfy EFSC's "Need" standard under its Least Cost Plan Rule.[11]

DATED this 30th day of June 2017.

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[11] *See* OAR 345-023-0005(1) and 345-023-0020.

INTEGRATED RESOURCE PLAN

IDAHO POWER®
An IDACORP Company

2017 IRP

LOOKING AHEAD

JUNE • 2017

SAFE HARBOR STATEMENT

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

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2017 IRP

LOOKING FORWARD

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) 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 2017 IRP. 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 IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP 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 idahopower.com.

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Glossary of Acronyms

A/C—Air Conditioning
AC—Alternating Current
AEG—Applied Energy Group
AEO—Annual Energy Outlook
AFUDC—Allowance for Funds Used During Construction
AgI—Silver Iodide
akW—Average Kilowatt
aMW—Average Megawatt
ATC—Available Transmission Capacity
B2H—Boardman to Hemingway
BLM—Bureau of Land Management
BPA—Bonneville Power Administration
BSER—Best System of Emissions Reduction
CAA—*Clean Air Act of 1970*
CAISO—California Independent System Operator
CAMP—Comprehensive Aquifer Management Plan
CCCT—Combined-Cycle Combustion Turbine
cfs—Cubic Feet per Second
CHP—Combined Heat and Power
CHQ—Corporate headquarters
Clatskanie PUD—Clatskanie People's Utility District
CO_2—Carbon Dioxide
COE—United States Army Corps of Engineers
CREP—Conservation Reserve Enhancement Program
CSPP—Cogeneration and Small-Power Producers
CWA—*Clean Water Act of 1972*
D.C.—District of Columbia
DC—Direct Current
DER—Distributed Energy Resources
DOE—Department of Energy
DSM—Demand Side Management
EEAG—Energy Efficiency Advisory Group
EGU—Electric Generating Unit
EIA—Energy Information Administration
EIM—Energy Imbalance Market
EIS—Environmental Impact Statement
EPA—Environmental Protection Agency
ESA—*Endangered Species Act of 1973*

ESPA—Eastern Snake River Plain Aquifer
ESPAM—Enhanced Snake River Plain Aquifer Model
F—Fahrenheit
FCRPS—Federal Columbia River Power System
FERC—Federal Energy Regulatory Commission
FPA—*Federal Power Act of 1920*
FWS—US Fish and Wildlife Service
GWh—Gigawatt-Hour
GWMA—Ground Water Management Area
HCC—Hells Canyon Complex
HRSG—Heat Recovery Steam Generator
IDWR—Idaho Department of Water Resources
IGCC—Integrated Gasification Combined Cycle
INL—Idaho National Laboratory
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
IWRB—Idaho Water Resource Board
kV—Kilovolt
kW—Kilowatt
kWh—Kilowatt-Hour
LCOC—Levelized Cost of Capacity
LCOE—Levelized Cost of Energy
LiDAR—Light Detection and Ranging
LOLE—Loss-of-Load Expectation
LOLP—Loss-of-Load Probability
LTP—Local Transmission Plan
m2—Square Meters
MATL—Montana–Alberta Tie Line
MOU—Memorandum of Understanding
MSA—Metropolitan Statistical Area
MW—Megawatt
MWh—Megawatt-Hour
NEEA—Northwest Energy Efficiency Alliance
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NOx—Nitrogen Oxide
NPV—Net Present Value
NREL—National Renewable Energy Laboratory
NTTG—Northern Tier Transmission Group

NWPCC—Northwest Power and Conservation Council
NWPP—Northwest Power Pool
O&M—Operation and Maintenance
OATT—Open Access Transmission Tariff
ODEQ—Oregon Department of Environmental Quality
ODOE—Oregon Department of Energy
OEMR—Office of Energy and Mineral Resources
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statue
pASC—Preliminary Application for Site Certificate
PCA—Power Cost Adjustment
PGE—Portland General Electric
PM&E—Protection, Mitigation, and Enhancement
PPA—Power Purchase Agreement
PURPA—*Public Utility Regulatory Policies Act of 1978*
PV—Photovoltaic
QA—Quality Assurance
QF—Qualifying Facility
RAAC—Resource Adequacy Advisory Committee
REC—Renewable Energy Certificate
RFP—Request for Proposal
RH BART—Regional Haze Best Available Retrofit Technology
ROD—Record of Decision
ROI—Return on Investment
ROR—Run-of-River
ROW—Right-of-Way
RPS—Renewable Portfolio Standard
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SIP—State Implementation Plan
SMR—Small Modular Reactor
SO_2—Sulfur Dioxide
SRBA—Snake River Basin Adjudication
SRPM—Snake River Planning Model
T&D—Transmission and Distribution
TEPPC—Transmission Expansion Planning Policy Committee
TES—Thermal Energy Storage
TRC—Total Resource Cost
UAMPS—Utah Associated Municipal Power Systems
US—United States
USBR—Bureau of Reclamation
USFS—United States Forest Service

VRB—Vanadium Redox-Flow Battery
WDEQ—Wyoming Department of Environmental Quality
WECC—Western Electricity Coordinating Council

1. Summary

Introduction

The *2017 Integrated Resource Plan* (IRP) is Idaho Power's 13th 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). Idaho Power's resource planning process has four primary goals:

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

The 2017 IRP evaluates the 20-year planning period from 2017 through 2036. During this period, load is forecasted to grow by 0.9 percent per year for average energy demand and 1.4 percent per year for peak-hour demand. Total customers are expected to increase to 756,000 by 2036 from 534,000 in 2016. Additional company-owned resources will be needed to meet these increased demands.[1]

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. Hydroelectric generation is a large part of Idaho Power's generation fleet; however, hydroelectric plants are subject to variable water and weather conditions. Public and regulatory input encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP. In response to this input, Idaho Power continues to develop more conservative streamflow projections and planning criteria for use in resource adequacy planning. Idaho Power has an obligation to serve customer loads regardless of water and weather conditions. Further discussion of Idaho Power's IRP planning criteria can be found in Chapter 7.

[1] Recent company disclosures forecast load growth during the 2016 to 2035 planning period at 1 percent for average energy demand and 1.4 percent for peak-hour demand.

Other resources relied on for planning include demand-side management (DSM) and transmission resources. The goal of DSM programs is to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response programs. Idaho Power also strives to provide customers with tools and information to help them manage their own energy usage. The company achieves these objectives through the implementation and careful management of incentive programs and through outreach and education.

Idaho Power's resource planning process also includes evaluating additional transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and their 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 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[2] and Idaho Power retail customers.[3] The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the *Energy Risk Management Policy* and *Energy Risk Management 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 *Energy Risk Management Standards* specifies an 18-month load and resource review period, and Idaho Power assesses the resulting operations plan monthly.

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

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

Public Advisory Process


IRPAC meeting, May 2017

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 (IRPAC). The IRPAC meets most months during the development of the resource plan, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2017 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2017 IRP, Idaho Power conducted eight IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment.

Idaho Power believes working with members of the IRPAC and the public improves the IRP. Idaho Power and the members of the IRPAC recognize that final decisions on the resource plan are made by Idaho Power. However, Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2017 IRP and the resource planning process in general.

IRP Methodology

A primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand over the 20-year planning period. A tool critical to assessing resource sufficiency is the load and resource balance, which compares projected customer demand with system resources available for meeting demand. An effective IRP methodology identifies deficiencies in the 20-year load and resource balance and analyzes options for satisfying the identified resource deficiencies. The practical implication of successful integrated resource planning is that system operators of the future are equipped with a system having sufficient resources to maintain reliable electrical service to Idaho Power's customers.

Resource sufficiency is assessed for energy and capacity. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand response resources are included in the capacity resource sufficiency assessment as well. Idaho Power then includes the IRP target amount of cost-effective and achievable energy efficiency, which reflects expansion of existing energy-savings potential.

Based on identified resource deficiencies over the planning period, Idaho Power conducts a financial analysis of various resources and all portfolios to quantitatively evaluate the individual resources and resulting portfolios designed to remediate any energy or capacity deficiency over the planning period. Within the financial analysis, Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), transmission upgrades associated with interconnecting new resource options, and anticipated environmental controls. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy certificates (REC) for REC-eligible resources.

The Idaho Power balancing area is part of the larger western interconnect. Idaho Power must balance loads and generation per North American Electric Reliability Corporation (NERC) system reliability standards. During times of acute oversupply, Idaho Power must rely on available system resources to regain intra-hour balance and must sometimes curtail intermittent resources like wind and solar. Power markets are available via transmission lines to purchase or sell power inter-hour to balance the system.

An additional transmission connection to the Pacific Northwest has been part of Idaho Power's 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 (B2H) Transmission Line Project. Idaho Power again evaluated the B2H transmission line in the 2017 IRP to ensure the transmission addition remains a prudent resource acquisition.

Greenhouse Gas Emissions

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 CO_2 emissions intensity (pounds per megawatt-hour [MWh] generation) and total CO_2 emissions (tons) (Figure 1.1 and Figure 1.2).

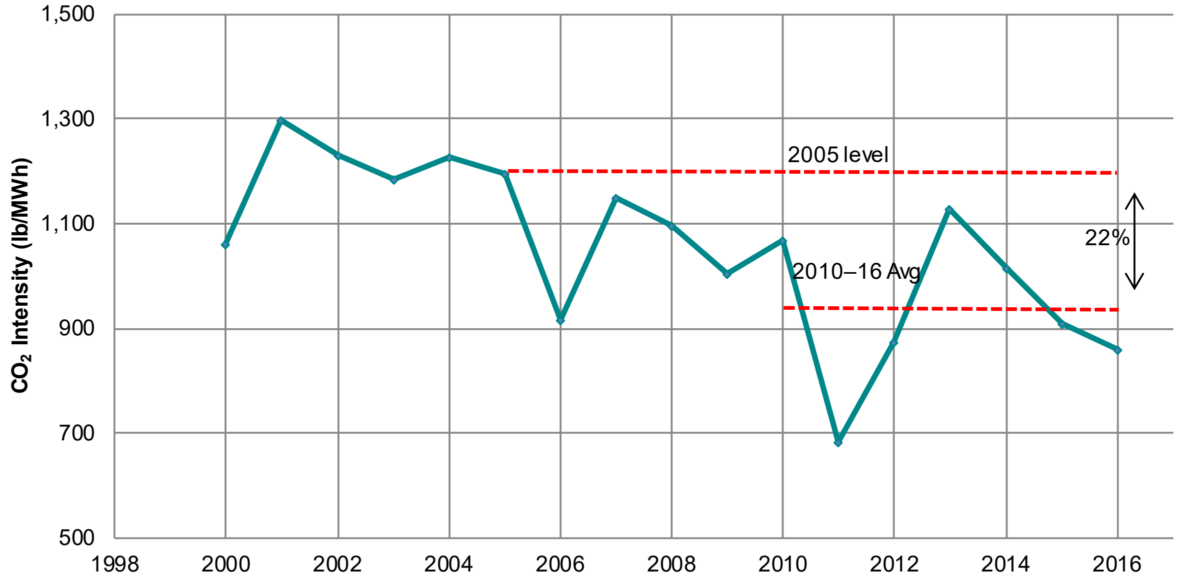

Figure 1.1 Estimated Idaho Power CO_2 emissions intensity

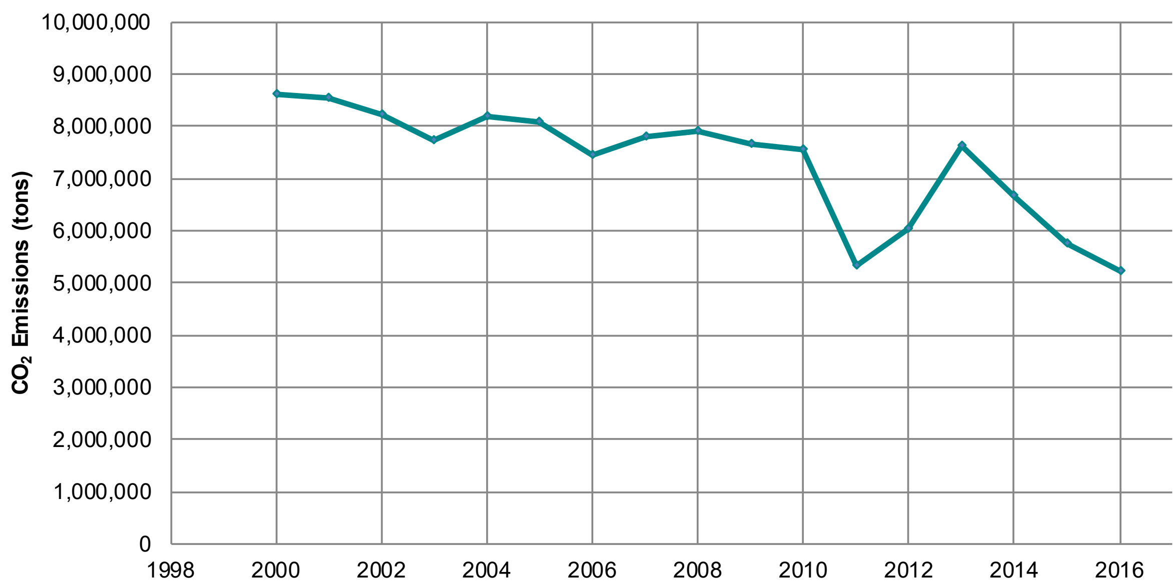

Figure 1.2 Estimated Idaho Power CO_2 emissions

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.

Generation and emissions from company-owned resources are included in the CO_2 emissions 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.[4] Information related to Idaho Power's CO_2 emissions, voluntarily reported annually, is also available through the Carbon Disclosure Project at cdp.net.

In November 2012, the Board of Directors approved an extension of the company's 2010 to 2013 goal for reducing CO_2 emissions intensity. The goal as restated in 2012 was to achieve a CO_2 emissions intensity 10 to 15 percent below the 2005 CO_2 emissions intensity from 2010 to 2015. That goal was met.

In May 2017, the Board of Directors approved the current CO_2 emissions intensity goal, which extends the target CO_2 emissions intensity of 15 to 20 percent below the 2005 CO_2 emissions intensity through 2020. As of the end of 2016, the company's CO_2 emissions intensity was 858 pounds per MWh, 28 percent below the 2005 CO_2 emissions intensity.

The portfolio analysis performed for the 2017 IRP assumes all resource portfolios comply with state-by-state mass-based emission limits detailed in the Clean Power Plan Final Rule filed in the Federal Register in October 2015. Further discussion of these CO_2 emission constraints is provided in Chapter 9. Projected CO_2 emissions for each analyzed resource portfolio are provided in *Appendix C—Technical Appendix*.

Portfolio Analysis Summary

Idaho Power designed the portfolio analysis for the 2017 IRP to inform the IRP's action plan with respect to two key resource actions: 1) selective catalytic reduction (SCR) investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively, and 2) the B2H transmission line. To achieve this objective, portfolios were formulated such that the effects of these two resource actions, or factors, could be isolated. This portfolio design approximates a controlled experiment using a factorial experimental design. This design is an effective statistical technique for studying differences between two (or more) factors, each factor having more than one possible level. An outline of the factorial design specifically in the context of the 2017 IRP is as follows:

- **Factor 1:** Treatment of Jim Bridger units 1 and 2
    - Level 1: Invest in SCRs and operate through 2036
    - Level 2: Retire Unit 1 in 2028 and Unit 2 in 2024 (without investing in SCRs)
    - Level 3: Retire Unit 1 in 2032 and Unit 2 in 2028 (without investing in SCRs)
    - Level 4: Retire Unit 1 in 2022 and Unit 2 in 2021 (without investing in SCRs)

[4] idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm

- **Factor 2:** Primary portfolio element(s)
  - Level 1: B2H
  - Level 2: Solar PV/natural gas-fired generation
  - Level 3: Natural gas-fired generation

Table 1.1 provides a matrix of the factorial design with the portfolios corresponding to each factorial combination.

Table 1.1 Factorial design applied to portfolios

	Primary Portfolio Element(s)		
Treatment of Jim Bridger Units 1 and 2	**B2H**	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

The IRP emphasizes that the validity of the factorial design relies on by-column and by-row uniformity; that is, all portfolios within a given row in the above table must uniformly reflect the same SCR investment scenario, and similarly all portfolios within a given column must uniformly reflect the same primary portfolio element(s). This uniformity is critical to yielding meaningful inferences from the factorial design.

The 12 resource portfolios formulated were analyzed under planning-case conditions for natural gas price, hydroelectric production, and system load. The analysis also included a range of eight natural gas sensitivities and a stochastic risk analysis. The stochastic risk analysis modeled 100 iterations (or futures) on the selected stochastic risk variables: natural gas price, hydroelectric production, and system load. These analyses are described in more detail in Chapter 9. The top performing portfolio from the quantitative portfolio analysis is portfolio 7 (P7). Table 1.1 demonstrates P7 is a portfolio with B2H as the primary element and assumes retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively. The resource additions with dates for P7 are provided in Table 1.2.

Table 1.2 P7 resource additions

Date	Resource	Installed Capacity
2026	B2H	500 megawatts (MW) transfer capacity Apr–Sep, 200 MW transfer capacity Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	Combined-cycle combustion turbine (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

The qualitative risk analysis supports the selection of P7, finding that P7 does not carry greater exposure to qualitative risk factors than other portfolios. In fact, P7 has unique qualitative benefits associated with Idaho Power's participation in an energy imbalance market (EIM) and with expanded penetrations of intermittent renewable energy sources. P7 is also consistent with Idaho Power's goals related to responsibly transitioning away from coal-fired generating capacity.

Action Plan

Table 1.3 provides the schedule of action items Idaho Power anticipates over the next four years. Further discussion surrounding the action plan is provided in Chapter 10.

Table 1.3 Action plan[5]

Year	Resource	Action	Action Number
2017–2018	EIM	Continue planning for western EIM participation beginning in April 2018.	1
2017–2018	Loss-of-load and solar contribution to peak	Investigate solar PV contribution to peak and loss-of-load probability analysis.	2
2017–2019	North Valmy Unit 1	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.	3
2017–2021	Jim Bridger units 1 and 2	Plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.	4
2017–2020	B2H	Conduct ongoing permitting, planning studies, and regulatory filings.	5
2018–2026[6]	B2H	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	6
2017–2021	Boardman	Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.	7
2017–2021	Gateway West	Conduct ongoing permitting, planning studies, and regulatory filings.	8
2017–2021	Energy efficiency	Continue the pursuit of cost-effective energy efficiency.	9
2017–2021	Carbon emission regulations	Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.	10
2017–2021	North Valmy Unit 2	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.	11

[5] The B2H short-term action plan is 2017 to 2026. All other action plan items are for 2017 to 2021.

[6] B2H in-service date of 2024 or later, subject to coordination of activities with project co-participants.

2. Political, Regulatory, and Operational Issues

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor's Office of Energy and Mineral Resources (OEMR), the Idaho Strategic Energy Alliance allows various stakeholders to represent and participate in developing energy plans and strategies for Idaho's energy future. The Idaho Strategic Energy Alliance is Idaho's primary mechanism for advancing energy production, energy efficiency, and energy business in Idaho.

The purpose of the Idaho Strategic Energy Alliance is to develop a sound energy portfolio for Idaho that includes diverse energy resources and production methods; the highest value to the citizens of Idaho; quality stewardship of environmental resources; and an effective, secure, and stable energy system.

Idaho Power representatives serve on both the Idaho Strategic Energy Alliance Board of Directors and several volunteer task forces on the following topics:

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

Idaho Energy Primer

In 2016, the Idaho Strategic Energy Alliance prepared the 2016 Idaho Energy Primer (Primer). The Primer is a resource to help citizens of Idaho better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.

The Primer provides information about energy resources, production, distribution, and use in the state. Having reliable, affordable, and sustainable energy for individuals, families, and businesses while protecting the environment is critical to achieving sustainable economic growth and maintaining our quality of life.

The 2016 Idaho Energy Primer finds that, despite Idaho's reliance on imported energy, Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy. In a year with average hydroelectric generation, about 65 percent of Idaho's electricity is generated in Idaho. The other 35 percent comes primarily from coal-fired power plants located in neighboring states. Idaho has the fifth lowest carbon dioxide output of any state because of its abundant hydropower, wind, biomass, and other renewable energy sources.

State of Oregon Biennial Energy Plan: 2015–2017

The Oregon Department of Energy (ODOE) completes a Biennial Energy Plan every two years. The ODOE's Biennial Energy Plan provides information on Oregon's energy supply and consumption, shows how long-term energy costs have been reduced, and highlights current energy issues and trends.

The ODOE 2015–2017 Biennial Energy Plan highlights some of the current challenges and opportunities for Oregon, including the following:

- Accelerated demand for energy efficiency due to a growing population in Oregon that drives increases in demand and energy use
- Continued development of clean energy that can help reduce the environmental impact of energy use
- Reduction of carbon emissions
- Energy supply due to numerous market forces that affect the type, number, and geographic diversity of energy siting projects

The 2015–2017 Biennial Energy Plan showed Oregon's energy supply consisting of primarily hydroelectric power, followed by coal and natural gas. The most significant change in electricity consumption from 2005 to 2010 is the growth of natural gas, from 3.3 percent to 16.24 percent. Wind has also grown consistently, increasing from 0.25 percent to 4.31 percent. Oregon's generation mix includes power generated outside of the state and delivered to Oregon consumers.

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.

Bayha Island

Idaho Power's remaining and most significant ongoing relicensing effort is for 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 in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under annual licenses issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC has been 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 1973* (ESA); the *Clean Water Act of 1972* (CWA); and other applicable federal laws. FERC is currently waiting for Oregon and Idaho to issue Section 401 certifications under the CWA. The certifications are expected on or before April 13, 2018.

Efforts to obtain a new multi-year license for the HCC are expected to continue until a new license is issued, which Idaho Power estimates will occur no earlier than 2021. Considering the costs incurred and the considerable passage of time, in December 2016 Idaho Power filed an application with the IPUC requesting a determination that Idaho Power relicensing expenditures of $220.8 million through year-end 2015 were prudently incurred and therefore eligible for inclusion in retail rates. After a new multi-year 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 on resource and legal matters

3. Preparing and conducting studies on fish, wildlife, recreation, archaeological resources, historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes

4. Analyzing data and reporting study results

5. Preparing all necessary reports, exhibits, and filings to support ongoing regulatory processes related to the relicensing effort.

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the 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 2017 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. The company is dedicated to the vigorous defense of its water rights. Idaho Power's ongoing participation in water-right issues and ongoing studies are intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power, along with other Snake River Basin water-right holders, was 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. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of the State of Idaho in October 1984. Idaho Power filed claims for all its hydroelectric water rights in the SRBA. As a result of the SRBA, the company's water rights were adjudicated, resulting in the issuance of partial water-right decrees. The Final Unified Decree for the SRBA was signed on August 25, 2014.

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 of Idaho. 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 the water rights held in trust by the State of Idaho are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the State of Idaho 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.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program in the upper Snake River Basin and has cooperatively expanded the existing weather modification operational program, along with forecasting and meteorological data support. The company has a long-term plan to continue the expansion of this program. In 2014, Idaho Power expanded its cloud-seeding program to the Boise and Wood River basins, in collaboration with basin water users and the Idaho Water Resource Board (IWRB). Wood River cloud seeding, along with the upper Snake River activities, will benefit the Eastern Snake River Plain Aquifer (ESPA) Comprehensive Aquifer Management Plan (CAMP) implementation through additional water supply.

Water management activities for the ESPA are currently being driven by the recent agreement between the Surface Water Coalition and the Idaho Ground Water Appropriators. This agreement settled a call by the Surface Water Coalition against groundwater appropriators for delivery of water to its members at Minidoka Dam and Milner Dam. The agreement provides a plan for the management of groundwater resources on the ESPA with the goal of improving aquifer levels and spring discharge upstream of Milner Dam. The plan provides short-term and long-term aquifer level goals that must be met to ensure a sufficient water supply for the Surface Water Coalition. The plan also references ongoing management activities, such as aquifer recharge. The plan provided the framework for modeling future management activities on the ESPA. These management activities were included in the modeling to develop the flow file for assessing hydropower production through the IRP planning horizon.

On November 4, 2016, Idaho Department of Water Resources (IDWR) Director Gary Spackman signed an order creating a Ground Water Management Area (GWMA) for the ESPA. Spackman told the Idaho Water Users Association at their November 2016 Water Law Seminar:

> By designating a groundwater management area in the Eastern Snake Plain Aquifer region, we bring all of the water users into the fold—cities, water districts and others—who may be affecting aquifer levels through their consumptive use. […] As we've continued to collect and analyze water data through the years, we don't see recovery happening in the ESPA. We're losing 200,000 acre-feet of water per year.

Spackman said creating a GWMA will embrace the terms of a historic water settlement between the Surface Water Coalition and groundwater users, but the GWMA for the ESPA will also seek to bring other water users under management who have not joined a groundwater district, including some cities.

Renewable Integration Costs

Idaho Power has completed two wind integration studies and two solar integration studies since the mid-2000s. These studies increased the company's understanding of the impacts and costs associated with integrating variable and intermittent resources without compromising reliability. The variable and uncertain production from wind and solar resources requires Idaho Power to provide additional balancing reserves from existing dispatchable generating resources, which results in opportunity costs and corresponding increases in power-supply expenses. Idaho Power completed the most recent wind integration study in 2013 and the most recent solar integration study in 2016. The costs found by these studies are the basis for renewable integration costs as provided in Idaho Schedule 87 and Oregon Schedule 85.

The results of the integration studies show periods of low customer demand to be the most difficult to cost-effectively integrate intermittent resources. During low demand periods, other existing resources are often already running at minimum levels or may already be shut off. Under these conditions, curtailment of the variable resources may be necessary to keep generation balanced with customer load. The integration studies also demonstrate the frequency of curtailment events is expected to increase as additional variable resources are added to the system.

For the IRP, integration costs for existing wind and solar resources are common to all portfolios analyzed and are not included in the portfolio cost accounting. However, portfolios with new solar resources include costs consistent with schedules 87 (Idaho) and 85 (Oregon) for the new resources. The schedule of integration costs is provided in *Appendix C—Technical Appendix*.

Community Solar Pilot Program

In the 2009 IRP, Idaho Power proposed a solar PV pilot project. Due to a few extenuating circumstances, as detailed in the 2015 IRP, the pilot project was not pursued. However, customer interest in distributed solar generation continued to grow and was the subject of many 2015 IRP discussions. Late in the 2015 IRP public process, Idaho Power was approached by several interested parties and asked to consider sponsoring a community solar project.

In response to customer interest, in June 2016 Idaho Power filed an application with the IPUC requesting an order authorizing Idaho Power to implement an optional Community Solar Pilot Program.

For the pilot program, the company proposed to build and own a 500-kilowatt (kW) single-axis tracking community solar array in southeast Boise that would allow a limited number of Idaho Power's Idaho customers to voluntarily subscribe to the generation output on a first-come basis. Participating customers would be required to pay a one-time, upfront subscription fee, and in return would receive a monthly bill credit for their designated share of the energy produced from the array. Because the company's 2015 IRP did not reflect a load-serving need for the proposed solar resource, the overall program design was intended to result in program participants covering the full cost of the project with nominal impact to non-participating customers.

The IPUC approved the pilot program on October 31, 2016, and marketing efforts for customer subscription began immediately. At the time of publishing, the Community Solar Pilot Program was not fully subscribed, with only 15.5 percent of the allotted subscriptions purchased. The company is currently evaluating the future of the Community Solar Pilot Program.

Energy Imbalance Market

In November 2014, the California Independent System Operator (CAISO) and PacifiCorp created the western EIM to enhance real-time coordination of market trading activity. The western EIM is a five-minute market administered by a single market operator, CAISO, which uses an automatic economic dispatch model to find and determine the least-cost energy resources to serve real-time customer demand across a wide geographic area. The western EIM focuses solely on real-time imbalances and allows EIM participants to retain all balancing responsibilities and transmission provider duties. In addition, the western EIM uses generating resources from market participants to meet real-time load efficiently and cost-effectively across the entire western EIM footprint.

Idaho Power is scheduled to begin participating in the western EIM in April 2018, at which time the western EIM participants will include PacifiCorp, CAISO, NV Energy, Puget Sound Energy, Arizona Public Service Company, and PGE. Market participants voluntarily bid resources into the western EIM, and the market operator provides least-cost dispatch instructions and generates a locational marginal price to be used for energy imbalances, factoring in load, available generation, and existing transmission constraints. Benefits to joining the western EIM include the following:

- The economic efficiency of an automated dispatch model for both generation and transmission line congestion
- Savings due to diversity of loads and variability of resources within the expanded footprint
- Reduced operational risk due to enhanced system reliability
- The ability to better support the integration of renewable resources

Since its inception, the western EIM has resulted in significant cost savings for its participants. Idaho Power expects its participation in the western EIM will similarly result in net power-supply expense savings for customers.

Renewable Energy Certificates

RECs, also known as green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents the renewable attributes associated with the production of 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The purchase of a REC buys the renewable attributes, or “greenness,” of that energy.

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1 MWh of electricity produced. RECs and the electricity produced by a certified renewable resource can either be sold together (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level renewable portfolio standard (RPS). A RPS is a policy requiring a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy. Retired RECs also enable the retiring entity to claim the renewable energy attributes of the corresponding amount of energy delivered to customers.

A certifying tracking system gives each REC a unique identification number to facilitate tracking purchases, sales, and retirements. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used (retired), held (banked), or traded (sold).

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- REC supply/demand
- Whether the REC is certified for RPS compliance
- The generation type (e.g., wind, solar, geothermal)
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds 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. Idaho Power cannot claim the renewable attributes associated with RECs that are sold. The new REC owner has purchased the rights to claim the renewable attributes of that energy.

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, each dollar of green power purchased represents 100 kilowatt-hours (kWh) of renewable energy delivered to the regional power grid, providing the Green Power Program participant associated claims for the renewable energy. Most the participant funds are used to purchase green power from renewable projects in the Northwest and to support Solar 4R Schools, a program designed to educate students about renewable energy by placing solar installations on school property. A portion of the funds are used to market the program, with the prospect of increasing participation in the program. On behalf of program participants, Idaho Power obtains and retires RECs. In 2016, Idaho Power purchased and subsequently retired 15,360 RECs on behalf of Green Power participants. Green Power is sourced from renewable energy projects in Idaho, Oregon, and Washington.

Renewable Portfolio Standard

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established an RPS for electric utilities and retail electricity suppliers. 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. In 2015, per Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.3 percent of Oregon's total electric sales. As a smaller utility, Idaho Power will have to meet a 5- or 10-percent RPS requirement beginning in 2025. In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25 percent by 2025 to 50 percent renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change.

The State of Idaho does not currently have an RPS.

Clean Power Plan

Rule History

On June 2, 2014, the Environmental Protection Agency (EPA), under President Obama's Climate Action Plan, released a proposal to regulate CO_2 emissions from existing power plants under the CAA Section 111(d) (Clean Power Plan). EPA's proposed Clean Power Plan included ambitious, mandatory CO_2 reduction targets for each state designed to achieve nationwide 30-percent CO_2 emission reductions over 2005 levels by 2030. On October 23, 2015, the final Clean Power Plan was published in the Federal Register, and the EPA proposed a Federal Implementation Plan.

Due to ongoing litigation about the legality of the rule, on February 9, 2016, the U.S. Supreme Court issued orders staying the Clean Power Plan pending resolution of challenges to the rule. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) heard oral arguments en banc before a panel of 10 judges on September 27, 2016.

On March 28, 2017, President Donald Trump issued an Executive Order on Energy Independence that, among other things, directs the EPA to review and, if appropriate, suspend, revise, or rescind the Clean Power Plan. On March 31, 2017, Scott Pruitt, the Director of the EPA, notified each state's governor that if any deadlines under the Clean Power Plan become relevant in the future, the EPA will toll its requirement for states to comply with the regulation.

On April 28, 2017, the D.C. Circuit Court approved an EPA motion to hold the Clean Power Plan case in abeyance for 60 days, or until June 27, 2017. According to the EPA's motion, "EPA should be afforded the opportunity to fully review the Clean Power Plan and respond to the President's direction in a manner that is consistent with the terms of the Executive Order, the Clean Air Act, and the agency's inherent authority to reconsider past decisions."[7] In the order granting the abeyance, the EPA was directed to file status reports every 30 days. The court also ordered the parties to file supplemental briefs on or before May 15, 2017, addressing whether the challenge should be remanded to the EPA rather than held in abeyance.

Clean Power Plan Final Rule

The final Clean Power Plan establishes interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired electric generating units (EGU):

- Fossil fuel-fired EGUs (coal- and oil-fired power plants)
- Natural gas-fired combined cycle generating units

[7] *West Virginia v. EPA*, No. 15-1363 (D.C. Cir. March 28, 2017).

To maximize the range of choices available to states in implementing the standards and to utilities meeting them, the EPA has established interim and final statewide goals in three forms:

1. A rate-based state goal measured in pounds per MWh
2. A mass-based state goal measured in total short tons of CO_2
3. A mass-based state goal with a new source complement measured in short tons of CO_2

States must develop and implement plans that ensure the power plants in their state—individually, collectively, or in combination with other measures—achieve the interim CO_2 emission performance rates from 2022 to 2029 and the final CO_2 emission performance rates for their state by 2030.

In the final Clean Power Plan, the EPA determined the best system of emissions reduction (BSER) to reduce CO_2 from fossil fuel-fired power plants consisted of three building blocks:

1. Building Block 1—Improve efficiency in existing coal-fired power plants.
2. Building Block 2—Re-dispatch generation from existing coal-fired power plants to natural gas combined-cycle plants.
3. Building Block 3—Increase generation from non-CO_2-emitting resources.

The EPA applied the building blocks to all coal and natural gas power plants in each region to produce a regional emission performance rate for each category. From the resulting regional coal and natural gas power plant rates, the EPA chose the most readily achievable rate for each category to arrive at equitable CO_2 emission performance rates that represent the BSER. The same CO_2 emission performance rates were then applied to all affected sources in each state to arrive at individual statewide rate- and mass-based goals. Each state has a different goal based on its own mix of affected sources.

The final rule also gives states the option to work with other states on multi-state approaches, including emissions trading.

While specific actions based on the EPA's review of the Clean Power Plan are forthcoming, each resource portfolio in the 2017 IRP is compliant with the final Clean Power Plan mass-based emission limits. Due to the executive order and the Pruitt letter, Idaho Power anticipates more stringent compliance measures will not be required under the Clean Power Plan.

Further discussion of these CO_2 emission constraints is provided in Chapter 9. Projected CO_2 emissions for each analyzed resource portfolio are provided in *Appendix C—Technical Appendix*.

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3. Idaho Power Today

Customer Load and Growth

Construction in downtown Boise.

In 1992, Idaho Power served approximately 306,000 general business customers. Today, Idaho Power serves nearly 534,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,164 MW in 1992 to over 3,400 MW. On July 2, 2013, the peak-hour load reached 3,407 MW—the system peak-hour record, nearly matched in 2015 (3,402 MW).

Average firm load increased from 1,280 average MW (aMW) in 1992 to 1,750 aMW in 2016 (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. The data in Table 3.1 suggests each new customer adds over 5.5 kW to the peak-hour load and over 2 average kW (akW) to the average load.

Since 1992, Idaho Power's total nameplate generation has increased from 2,694 MW to 3,594 MW. The 900-MW increase in capacity represents enough generation to serve nearly 161,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1992.

Idaho Power has added about 228,000 new customers since 1992. The peak-hour and average-energy calculations mentioned earlier suggest the additional 228,000 customers require about 1,250 to 1,300 MW of additional peak-hour capacity and about 450 to 500 aMW of energy.

Idaho Power anticipates adding approximately 11,100 customers each year throughout the 20-year planning period. The expected-case load forecast for the entire system predicts summer peak-hour load requirements will grow over 50 MW per year, and the average-energy requirement is forecast to grow over 15 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

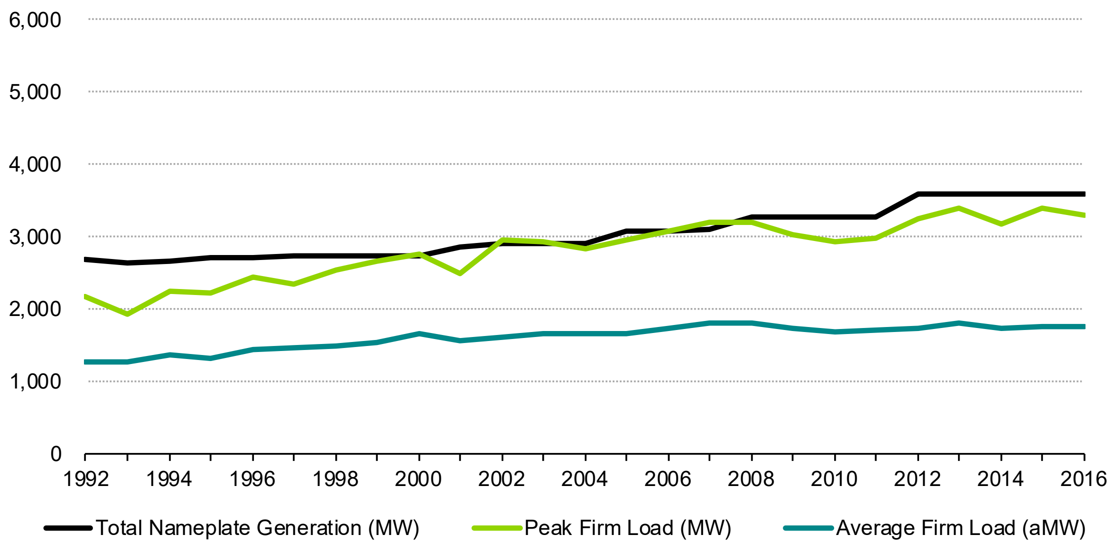

Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
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	1,654	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,623	414,062
2003	2,912	2,944	1,658	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,661	456,104
2006	3,085	3,084	1,747	470,950
2007	3,093	3,193	1,810	480,523
2008	3,276	3,214	1,816	486,048
2009	3,276	3,031	1,744	488,813
2010	3,276	2,930	1,680	491,368
2011	3,276	2,973	1,712	495,122
2012	3,594	3,245	1,746	500,731
2013	3,594	3,407	1,801	508,051
2014	3,594	3,184	1,739	515,262
2015	3,594	3,402	1,748	524,325
2016	3,594	3,299	1,750	534,528

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

2016 Energy Sources

Idaho Power's energy sources for 2016 are shown in Figure 3.2. Idaho Power-owned generating capacity was the source for 73 percent of the energy delivered to customers. Hydroelectric production from company-owned projects was the largest single source of energy at 39 percent of the total. Coal contributed 24 percent, and natural gas- and diesel-fired generation contributed 10 percent. Purchased power comprised 27 percent of the total energy delivered to customers. Of the purchased power, about a third, or 9 percent of the total delivered energy, was from the wholesale electric market. The remaining purchased power was from long-term energy contracts (*Public Utility Regulatory Policies Act of 1978* [PURPA] and power purchase agreements [PPA]) primarily from wind, hydro, geothermal, biomass, and solar projects (in order of decreasing percentage). While Idaho Power enables production from PURPA and PPA projects, the company sells RECs associated with the production and does not represent the energy from these projects as energy delivered to customers.

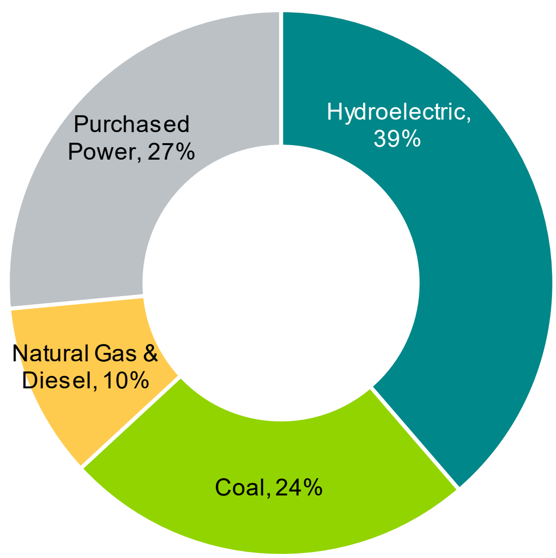

Figure 3.2 2016 energy sources

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 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 3.2 shows all of Idaho Power's existing company-owned resources, nameplate capacities, and general locations.

Table 3.2 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
North 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**	

*Combined-cycle combustion turbine
**Simple-cycle combustion turbine

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

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects 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 enough energy to meet over 30 percent of the energy demand of retail customers. 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 annual 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 Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

Brownlee Reservoir is the main 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 1 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 its primary purpose is to provide a stable power source, Brownlee Reservoir is also used for system flood control, 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 (COE) as outlined in Article 42 of the existing FERC license.

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

The US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River Basin 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 River (mid-Snake) projects, with all 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 Program adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During fall Chinook 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. These three projects are operated within the FERC license requirements to coincide with daily system peak demand when 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 relicense the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power annually alternated operating the Bliss and Lower Salmon facilities under 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 has been 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 hydroelectric production is needed are especially beneficial.

Acquiring water through the water bank also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC. The company does not currently have any water lease agreements but plans to continue to evaluate potential water-lease opportunities in the future.

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 Basin above Milner Dam. Idaho Power has continued to work with the stakeholders in the upper Snake River to expand the program and has recently collaborated with irrigators in the Boise and Wood river basins to expand the target area to include those watersheds.

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 abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation. 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 both methods provides the most flexibility to successfully introduce 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 nuclei, allowing 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.[8] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 28 percent annually, with an annual average of 14 percent. Idaho Power estimates cloud seeding provides an additional 346,000 acre-feet from the upper Snake River and 272,000 acre-feet from the Payette River. At program build-out, Idaho Power estimates additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,000,000 acre-feet. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

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[8] weathermodification.org/images/AGI_toxicity.pdf

For the 2016 to 2017 winter season, Idaho Power continued to collaborate with the State of Idaho and water users to augment water supplies with cloud seeding. The program included 30 remote-controlled, ground-based generators and two aircraft for Idaho Power-operated cloud seeding in the west-central mountains of Idaho (Payette, Boise, and Wood River basins). The Upper Snake River Basin program included 25 remote-controlled, ground-based generators and one aircraft operated by Idaho Power targeting the Upper Snake, as well as 25 manual, ground-based generators operated by a coalition of stakeholders in the Upper Snake. The 2016 to 2017 season provided abundant storms and seeding opportunities. Suspension criteria were met in some areas in early February, and operations were suspended for the season for all target areas by early March.

Coal 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. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

The 2017 IRP considers a range of scenarios for Jim Bridger units 1 and 2. The scenarios relate to varying options for capital investments into environmental retrofits. The scenarios are described in Chapter 7.

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. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

A baseline assumption of the 2017 IRP has Idaho Power retiring its share of North Valmy Unit 1 at year-end 2019 and its share of North Valmy Unit 2 at year-end 2025. Further discussion surrounding this assumption is provided in Chapter 7.

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. PGE has 90 percent ownership and is the operator of the Boardman facility.

The 2017 IRP assumes Idaho Power's share of the 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 EPA related to compliance with

Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NOx) emissions.

Natural Gas Facilities

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, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012.

Langley Gulch Power Plant

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 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 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.

In 2015, Idaho Power installed a 50-kW solar array at its new Twin Falls Operations Center. The array came on-line in October 2016.

Idaho Power also has solar lights in its parking lot and 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 and owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events.

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 March 1, 2017, there were 1,045 solar PV systems were interconnected through the company's net metering service with a total capacity of 8.079 MW. At that time, the company had received completed applications for an additional 110 net metered solar PV systems, representing an incremental capacity of 1.376 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.3 and Table 3.4.

Table 3.3 Net metering service customer count as of March 1, 2017

Resource Type	Active	Pending	Total
Solar PV	1,045	110	1,155
Wind	62	2	64
Other/hydroelectric	10	1	11
Total	**1,117**	**113**	**1,230**

Table 3.4 Net metering service generation capacity (MW) as of March 1, 2017

Resource Type	Active	Pending	Total
Solar PV	8.079	1.3760	9.455
Wind	0.378	0.0016	0.380
Other/hydroelectric	0.147	0.0120	0.159
Total	**8.604**	**1.3900**	**9.994**

Oregon Solar PV Pilot Program and Oregon Solar PV Capacity Standard

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 acquired 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 2011 enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In 2013, the Oregon Legislature passed House Bill 2893, which increased Idaho Power's required capacity amount by 55 kW. An enrollment period was held in April 2014, and all capacity was allocated, bringing Idaho Power's total capacity in the program to 455 kW.

Under the previously required Oregon Solar PV Capacity Standard, Idaho Power was required to either own or purchase the generation from a 500-kW utility-scale solar PV facility by 2020. This requirement was repealed, effective March 8, 2016, pursuant to Oregon Senate Bill 1547.

PURPA

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 IPUC rules and regulations for all PURPA facilities located in Idaho, and to OPUC rules and regulations for all PURPA facilities located in Oregon. The rules and regulations are similar but not identical for the two states.

Under PURPA, Idaho Power is required to pay for generation at the utility's avoided cost, which is defined by FERC as the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source. The process to request an Energy Sales Agreement for Idaho QFs is described in Schedule 73, and for Oregon QFs, Schedule 85. QFs also have the option to sell energy "as-available" under Schedule 86.

As of April 1, 2017, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,135 MW of nameplate capacity. These PURPA contracts are for hydroelectric projects, cogeneration projects, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power generation facilities. Of the 133 contracts, 128 were on-line as of April 1, 2017, with a cumulative nameplate rating of approximately 1,115 MW. Figure 3.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

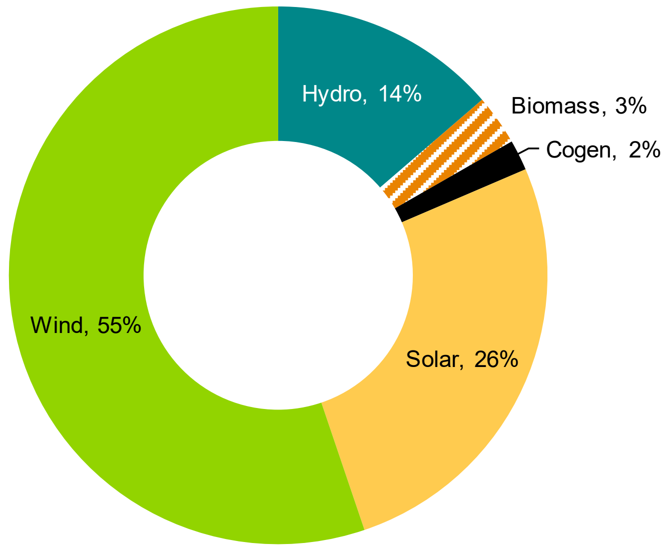


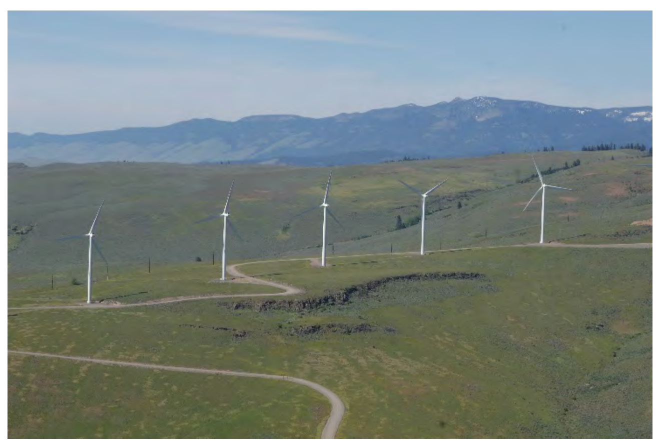
Figure 3.3 PURPA contracts by resource type

Idaho Power cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process. Generation from PURPA contracts is forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2017 IRP was completed in December 2016.

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.



Elkhorn Valley Wind Project, Union County, Oregon

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 rarely exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is currently receiving negligible RECs from the 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.

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, with the initial exchange agreement with Idaho Power ending in 2015. At the end of the initial term, Idaho Power exercised its right to extend the agreement through 2020. Idaho Power holds one more option to extend through 2025, exercisable in 2020. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Wholesale Contracts

Idaho Power currently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts).

Power Market Purchases and Sales

Idaho Power relies on regional power 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 power market purchases during peak-load periods. The existing transmission system is used to import the power purchases. A reliance on regional power markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

Transmission MW Import Rights

Idaho Power's interconnected transmission system facilitates market purchases to access resources to serve load. Five transmission paths connect Idaho Power to neighboring utilities:

1. Idaho–Northwest (Path 14)
2. Idaho–Nevada (Path 16)
3. Idaho–Montana (Path 18)
4. Idaho–Wyoming (Path 19)
5. Idaho–Utah (Path 20).

However, Idaho Power does not own exclusive rights to all the transmission capacity available on each path. Idaho Power is either a partial owner of a path shared with other partners, or other entities have acquired long-term purchased capacity for a portion of a path. Idaho Power is allowed to set aside portions of its transmission capacity to import energy for load service. Beyond the existing set-aside capacity and contractual obligations, Idaho Power's import capacity on these paths is fully allocated, except for 86 MW of available capacity on Path 19.

4. Future Supply-Side Generation and Storage Resources

Generation Resources

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. As discussed in Chapter 5, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources and storage technologies considered when Idaho Power developed the resource portfolios for the 2017 IRP. While a variety of resource options was analyzed, the portfolio design for the IRP allowed the selection of a subset for inclusion in resource portfolios.

The primary source of cost information for the 2017 IRP is *Lazard's Levelized Cost of Energy Analysis*.[9] Lazard, a leading independent financial advisory and asset management firm, issued the levelized cost report in December 2016. Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the age of the information. Refer to Chapter 7 for a full list of all the resources considered and cost information. All cost information presented is in 2017 dollars.

Renewable Resources

Renewable energy resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. Renewable resources are discussed in general terms in the following sections.

Solar

The primary types of solar technology are utility-scale PV and distributed PV. In general, PV technology converts solar energy collected from sunlight shining on panels of solar cells into electricity. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy passes through an inverter, converting it to alternating current (AC) that can be used on-site or sent to the grid. Even on cloudy days, a solar PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter (m^2)

[9] Lazard. 2016. Lazard's levelized cost of energy analysis 10.0 (LCOE 10.0). https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the southwest desert has the highest solar potential in the US.

In designing resource portfolios that included solar resources, Idaho Power chose the utility-scale PV technology because of its compliance to EPA's proposed CAA Section 111(d) regulation, its flexibility, and its lower overall cost. Modern solar PV technology has existed for several years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPSs, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2017 IRP for utility-scale PV resources is based on the Lazard report, which estimates a cost of $1,375 per kW for PV with a single-axis tracking system. The 25-year levelized cost of energy for PV with single-axis tracking is $74 per MWh with a 27-percent annual capacity factor.

Rooftop solar was considered in two forms as part of the 2017 IRP. The capital-cost estimate used in the 2017 IRP for residential rooftop solar PV resources is based on the Lazard report, which estimates a cost of $2,400 per kW for PV on residential rooftops. The 25-year levelized cost of energy for residential rooftop solar PV resources is $153 per MWh with a 21-percent annual capacity factor. The capital-cost estimate used for commercial and industrial rooftop solar PV resources is based on the Lazard report, which estimates a cost of $2,925 per kW for PV on commercial and industrial rooftops. The 25-year levelized cost of energy for commercial and industrial rooftop solar PV resources is $179 per MWh with a 21-percent annual capacity factor. The cost of rooftop solar PV resources is recognized to vary by region, and the Lazard-reported costs are not indicative of solar PV costs in Idaho Power's service area.[10] Rooftop solar PV cost estimates vary by source, and based on Idaho Power's review of sources, the Lazard-reported costs are toward the lower end of the cost range. For example, the Department of Energy (DOE) Tracking the Sun study indicates rooftop solar pricing of approximately $4,000 per kW for residential installations and $3,000 per kW for non-residential installations.[11]

Energy production from solar PV arrays declines over time. This is known as PV degradation. For the 2017 IRP, Idaho Power assumes a 0.5 percent annual degradation rate of energy production from solar PV arrays.

[10] The Open PV Project, NREL, https://openpv.nrel.gov/.

[11] DOE. August 2016. Tracking the sun IX, the installed price of residential and non-residential photovoltaic systems in the United States. https://emp.lbl.gov/sites/default/files/tracking_the_sun_ix_report.pdf.

Solar Capacity Credit

Idaho Power applied the solar capacity credit calculations derived from the 2015 IRP. As part of the 2015 IRP process, Idaho Power, interested members of the IRPAC, and interested members of the public formed a study group separate from the IRPAC to evaluate solar peak-hour capacity factors. The group formally met and conducted meetings and conversations with members of the study group. Idaho Power updated the solar PV peak-hour capacity factors based on guidance from members of the solar work group.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to the Idaho Power system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2017 IRP are reported in Table 4.1.

Table 4.1 Solar capacity credit values

PV System Description	Peak-Hour Capacity Credit
South orientation	28.4%
Southwest orientation	45.5%
Tracking	51.3%

Geothermal

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

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flashed-steam plants are applicable for geothermal resources where the fluid temperature is 300º Fahrenheit (F) or greater. Binary-cycle technology is used for lower-temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface and passed through a heat exchanger where the geothermal energy is transferred to a low-boiling-point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine/generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters used for binary-cycle geothermal generation in the 2017 IRP are based on data from the Northwest Power and Conservation Council (NWPCC) Seventh Power Plan. The capital-cost estimate used in the 2017 IRP for geothermal resources is $4,675 per kW, and the 25-year levelized cost of energy is $111 per MWh based on an 88-percent annual capacity factor.

Hydroelectric

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

Small Hydroelectric

Small hydroelectric projects, such as ROR and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital-cost estimate used in the 2017 IRP for small hydroelectric resources is $3,753 per kW, and the 75-year levelized cost of energy is $165 per MWh.

Wind

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

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain regions, as evidenced by the number of existing projects. Wind resources present operational challenges for utilities due to the variable and intermittent nature of wind generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2017 IRP, Idaho Power used an annual average capacity factor of 28 percent and an on-peak capacity factor of 5 percent for peak-hour planning. The capital-cost estimate used in the IRP for wind resources is $1,475 per kW, and the 25-year levelized cost of energy is $111 per MWh, which includes a wind integration cost of $16.33 per MWh.

Biomass

Biomass resource types considered in the 2017 IRP include wood-burning resources and anaerobic digesters. Wood-burning resources typically rely on a steady supply of woody residue collected from forested areas. Fuel supply can be an issue for these types of plants as the radius of the area used to collect fuel is expanded. Several anaerobic digesters have been built in southern Idaho due to the size of the dairy industry and the quantity of fuel available. The 2017 IRP considered anaerobic digesters as a best fit for the service area.

The capital-cost estimate used in the 2017 IRP for an anaerobic digester project is $6,522 per kW for a 35-MW facility. The anaerobic digester is expected to have an annual capacity factor of 85 percent. Based on the annual capacity factors, the 30-year levelized cost of energy is $133 per MWh for the anaerobic digester.

Conventional Resources

While much attention has been paid to renewable resources over the past few years, conventional generation resources are essential to provide dispatchable capacity, which is critical in maintaining the reliability of an electrical power system. These conventional generation technologies include natural gas-fired resources, nuclear, and coal.

Natural Gas-Fired Resources

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

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. The additional cost as necessary for expanded gas pipeline allocation is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial, dispatchable power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits fewer emissions when compared to coal, therefore requiring fewer pollution controls. Modern CCCT facilities are highly efficient and can achieve efficiencies of approximately 60 percent (lower heating value).

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

Several CCCT plants, similar to Idaho Power's Langley Gulch project, are planned in the region due to a sustained depression in natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate intermittent resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the IRP for a CCCT (1 x 1) resource is $1,246 per kW, and the 30-year levelized cost of energy at a 70-percent annual capacity factor is $64 per MWh.

Simple-Cycle Combustion Turbines

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

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

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

The 2017 IRP evaluated a 170-MW industrial-frame (F class) SCCT unit. The capital-cost estimate used in the 2017 IRP is $878 per kW. The industrial-frame unit is expected to have an annual capacity factor of 10 percent.

Based on an annual capacity factor of 10 percent, the 35-year levelized cost of energy is $197 per MWh for the industrial-frame SCCT unit. If Idaho Power were to identify the need for a SCCT, it would evaluate SCCT technologies in greater detail prior to issuing a request for proposal (RFP) to determine which technology would provide the greatest benefit.

Reciprocating Engines

Reciprocating engine generation sets are typically multi-fuel engines connected to a generator through a flywheel and coupling. They are typically capable of burning natural gas. Because they are mounted on a common baseframe, the entire unit can be assembled, tuned, and tested in the factory before being delivered to the power plant location, which minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple, identical units, which allows each unit to run at its best efficiency point once started. As more generation is needed, additional units are started. This configuration also allows for relatively inexpensive future expansion of the plant capacity. Reciprocating engines provide unique benefits to the electrical grid. They are extremely flexible in the sense that they can provide ancillary services to the grid in a few minutes. Engines can go from a cold start to full-load in 10 minutes.

For the IRP, Idaho Power modeled a reciprocating engine similar to the 34SG model manufactured by Wärtsilä with a nameplate rating of approximately 18 MW. The capital-cost estimate used for a reciprocating engine resource is $775 per kW, and the 40-year levelized cost of energy at a 25-percent annual capacity factor is $94 per MWh.

Combined Heat and Power

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

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

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

Recognizing the actual cost of a CHP resource varies depending on the specific facility being considered, the capital-cost estimate used in the 2017 IRP for CHP is $2,213 per kW, and the 40-year levelized cost of energy evaluated at an annual capacity factor of 80 percent is $71 per MWh.

Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for some time, and Idaho Power has continued to evaluate various technologies in the IRP. Due to the Idaho National Laboratory (INL) site in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor (SMR) could be built on the site. For the 2017 IRP, high capital costs coupled with a great amount of uncertainty in waste-disposal issues prevented a nuclear resource from being included in the portfolio analysis. Recent large-scale nuclear development in the US has proven to be fraught with project delays and projected construction cost overruns exceeding $1 billion. In addition, the 2011 earthquake and tsunami in Japan, and the impact on the Fukushima nuclear plant, created a global concern over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to know the full impact this disaster will have on the future of nuclear power generation. While Idaho Power does not currently view traditional nuclear resources as a viable supply-side resource option for the company, it continues to monitor the advancement of SMR technology and will evaluate it in the future as the Nuclear Regulatory Commission reviews proposed SMR designs in the coming years.

For the 2017 IRP, a 50-MW small modular plant was analyzed. The capital-cost estimate used in the IRP for an advanced SMR nuclear resource is $6,126 per kW, and the 40-year levelized cost of energy, evaluated at an annual capacity factor of 90 percent, is $163 per MWh.

Coal Resources

Conventional coal resources have been a part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over global warming and climate change coupled with historic low natural gas prices have made it impractical to consider building new conventional coal resources.

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

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

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

Carbon sequestration involves taking captured CO_2 and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. No new coal-based energy resources were modeled as part of the 2017 IRP.

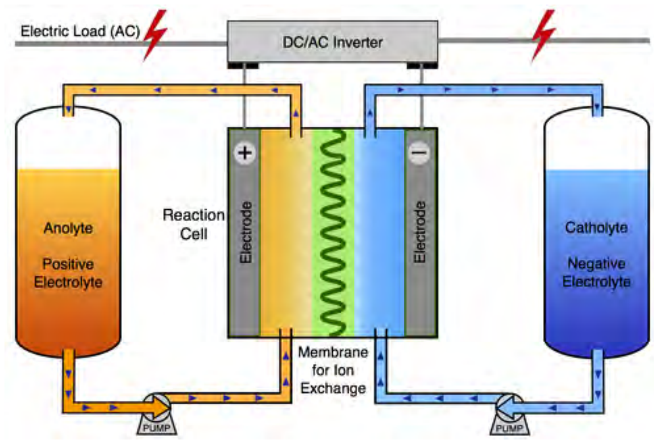
Storage Resources

RPSs and PURPA have spurred the development of renewable resources in the Pacific Northwest, leading to periodic oversupply of energy in the region. Mid-Columbia wholesale market prices for electricity continue to remain relatively low. At the same time, retail rates for electricity continue to grow, as utilities must pass the cost of building these resources on to customers. The oversupply issue has grown to the point where at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to decrease into negative values.

As more intermittent renewable resources like wind and solar continue to be built within the region, the need for energy storage is amplified. Many storage technologies are at various stages of development, such as hydrogen storage, compressed air, and flywheels. The 2017 IRP considered and evaluated multiple energy storage technologies, including battery storage, ice-based thermal energy storage (TES), and pumped hydro storage.

Battery Storage

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery storage technologies at various stages of development. The 2017 IRP analyzed the vanadium redox-flow battery (VRB), lithium-ion battery systems and zinc battery systems.



Basic illustration of a flow battery.[12]

Advantages of the VRB technology include its low cost, long life, and scalability to utility/grid applications. Most battery technologies are not a good fit for utility-scale applications because they cannot be easily or economically scaled to much larger sizes. The VRB overcomes much of this issue because the capacity of the battery can be increased by increasing the size of the tanks that contain the electrolytes, which also helps keep the cost relatively low.

VRB technology also has an advantage in maintenance and replacement costs, as only certain components need to be replaced about every 10 years, whereas other battery technologies require a complete and often more frequent replacement of the battery depending on the duty cycle. For the IRP, the capital-cost estimate for the VRB is $3,736 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 4 percent, is $2,010 per MWh. Idaho Power recognizes the continued technological development of VRB batteries used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and the scalability of this technology in the coming years.

In recent months, lithium-ion battery systems have gone on-line commercially in the US on the west coast. Lithium-ion battery storage systems realize high charging and discharging efficiencies. Lithium-based energy storage devices present possible safety concerns due to overheating.

For the IRP, the capital-cost estimate for lithium-ion battery storage is $3,114 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 14 percent, is $476 per MWh. Idaho Power recognizes the continued technological development of lithium-ion batteries

12 Source: http://wernerantweiler.ca/blog.php?item=2014-09-28

used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and the scalability of this technology in the coming years.

A third type of battery storage system analyzed in the 2017 IRP was zinc battery storage. Zinc battery storage systems are capable of deep discharge cycles and are relatively low cost due to the abundance of the primary metals in a zinc battery. Zinc-based energy storage devices do present concerns due to their lack of proven utility-scale application. Zinc battery systems are typically less efficient than other types of battery storage technologies.

For the IRP, the capital-cost estimate for zinc battery storage is $2,010 per kW, and the 10-year levelized cost of energy, evaluated at an annual capacity factor of 7 percent, is $621 per MWh. Idaho Power recognizes the continued technological development of Zinc batteries and will continue to monitor price trends and the technical viability of this technology in the coming years.

Ice-Based TES

Ice-based TES is a concept developed to take advantage of the air conditioning (A/C) needs of mid-sized to large commercial buildings. The general concept is to create ice during low-load/low-price times (light load hours), then to use the ice for A/C needs during the high-load/higher-price times (heavy-load hours). While this concept does not specifically store electricity, it does shift the time the energy is consumed, with the overall goal of reducing peak daytime demand.

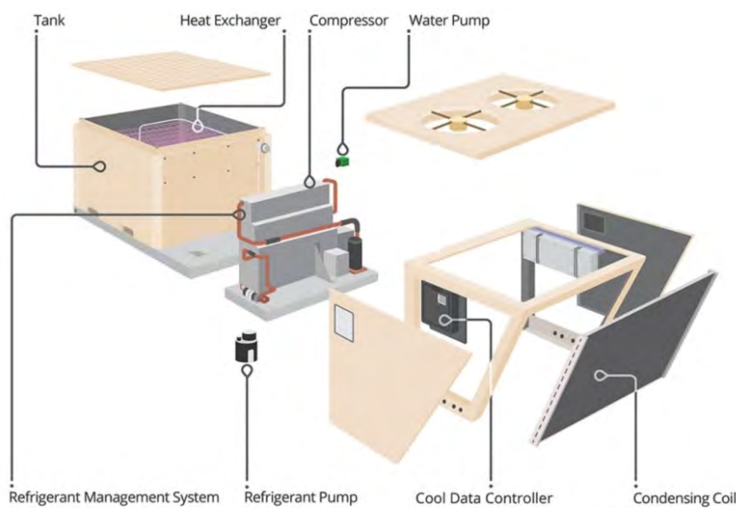


Illustration of an ice-based TES system.[13]

One company currently commercializing the ice-based TES technology is Ice Energy with their Ice Bear Energy Storage System. Requirements in California to develop energy storage have allowed several utilities to begin installing and testing this technology, with several installations of 5 MW to 15 MW in size. For the IRP, the capital-cost estimate used for this technology is

[13] Source: http://www.ice-energy.com/technology/ice-bear-energy-storage-system

$2,000 per kW, and the 20-year levelized cost of energy, evaluated at an annual capacity factor of 6 percent, is $508 per MWh.

Pumped Hydro Storage

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

For pumped storage to be economical, there must be a significant differential (arbitrage) in the price of electricity between peak and off-peak times to overcome the costs incurred due to efficiency. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, Idaho Power continues to monitor the viability of pumped storage projects in the region. The capital-cost estimate used in the IRP for pumped storage is $2,352 per kW, and the 50-year levelized cost of energy, evaluated at an annual capacity factor of 20 percent, is $229 per MWh.

5. Demand-Side Resources

DSM Program Overview

Demand-side resources are the first selected resources in each IRP. No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective, achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. In the 2017 IRP, demand response provides 390 MW of committed peak summer capacity, while energy efficiency will reduce average annual loads by 273 aMW and 483 MW of peak reduction by the year 2036.

The Shade Tree Project provides free trees for residential customers in select counties to shade their homes. Shade trees, properly grown on the west side of a home, can help reduce energy needed for summer cooling by 15 percent or more. In 2016, Idaho Power distributed 2,070 trees.

Changes from the 2015 IRP

Methods for incorporating and accounting for energy efficiency and demand response resources in the 2017 IRP were similar to methods used in the 2015 IRP. As in the 2013 and 2015 IRPs, the planning case for energy efficiency as a resource potential was determined by a third-party consultant. Notably, the company's 20-year load forecast for the 2017 IRP accounted for all accumulated potential energy efficiency savings. As a result, over the last seven years of the IRP planning period (2030–2036), no adjustments to forecast loads were required to reflect incremental energy efficiency savings potential determined by the third party but not included in the load forecast. The alignment of the energy efficiency savings potential forecasts is a result of sharing data and assumptions from the 2015 potential study and the early results of the 2017 potential study. Another highlight for the 2017 IRP is the continued improvement in estimating peak contribution from energy efficiency that was first estimated using hourly load shapes in the 2015 IRP. Prior to the 2015 IRP, peak contribution from energy efficiency was estimated using average monthly energy values.

Program Screening

All DSM programs and measures included in Idaho Power's current programs and the forecast have been screened for cost-effectiveness. Cost-effectiveness analyses of DSM forecasts for the 2017 IRP are presented in more detail in *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2016 Annual Report* contains a detailed description of Idaho Power's 2016 energy efficiency programs, along with historical program performance. A complete review of Idaho Power's DSM programs, evaluations, and cost-effectiveness can be found in the

2016 annual report, *Demand-Side Management 2016 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*, which are available on Idaho Power's website at idahopower.com/EnergyEfficiency/reports.cfm.

DSM Program Performance

While the IRP planning process primarily looks forward, recent DSM performance is a good predictor of near-term performance for the 2017 IRP. Accumulated annual savings from energy efficiency investments grow over time based on measure lives of the efficient equipment and measures adopted and installed by customers each year. Additionally, past performance of demand response programs has changed over time as the design and use of the programs have evolved.

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 209 aMW, or over 1.6 million MWh, of reduced supply-side energy production to customers through 2016. Figure 5.1 shows the cumulative annual growth in energy efficiency effects over the 13-year period from 2002 through 2016, along with the associated IRP targets developed as part of the IRP process since 2004.

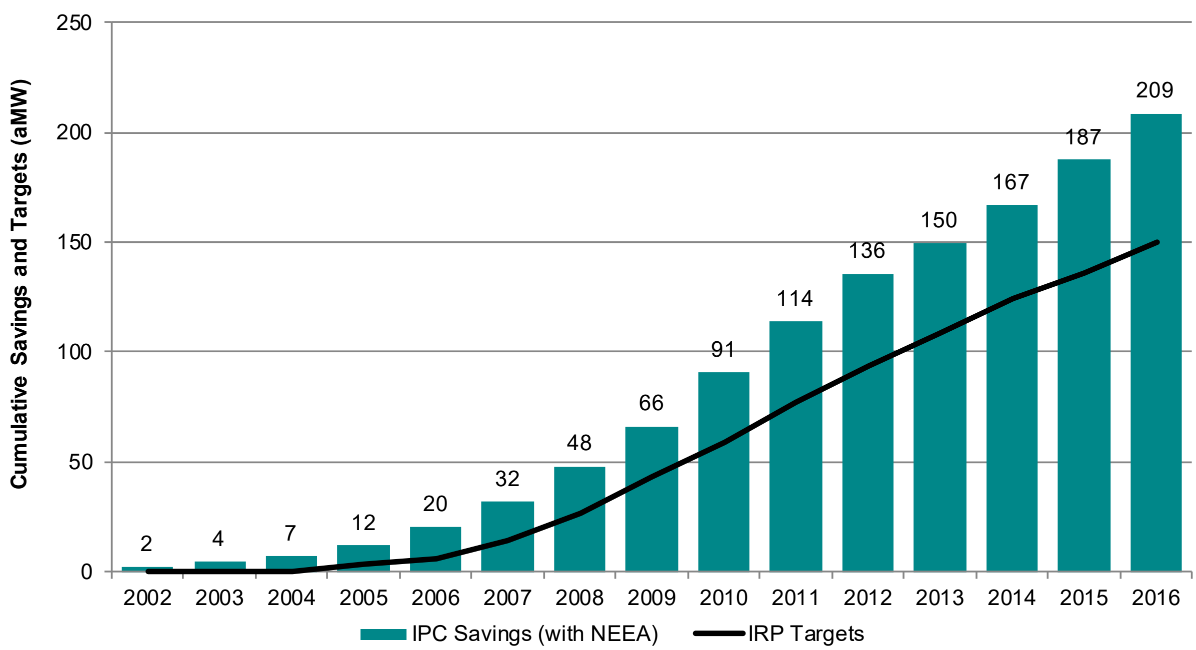


Figure 5.1 Cumulative annual growth in energy efficiency

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three programs that work together as one resource. Each program targets a different customer class. Table 5.1 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2016 summer season, Irrigation Peak Rewards participants contributed 81 percent of the total potential demand-reduction capacity, or 317 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2016 Annual Report*.

Table 5.1 Demand response programs

Program	Customer Class	Reduction Technology	2016 Total Demand Response Capacity (MW)	Percent of Total 2016 Peak Performance*
A/C Cool Credit	Residential	Central A/C	34	9%
Irrigation Peak Rewards	Irrigation	Pumps	317	81%
Flex Peak Program	Commercial, industrial	Various	42	11%
		Total	**392**	

*Values may not add to 100 percent due to rounding.

Figure 5.2 shows the historical annual demand response program capacity between 2004 and 2016 along with associated IRP targets between 2006 and 2012 and 2015 through 2016. There were no demand response targets for 2013 to 2014 in the 2013 IRP. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning most the Irrigation Peak Rewards participants to a dispatchable program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity, respectively, from the Irrigation Peak Rewards program, which was not used based on the lack of need and the variable cost to dispatch the program. The reported demand response capacity value was lower in 2013 because of the one-year suspension of both the irrigation and residential programs.

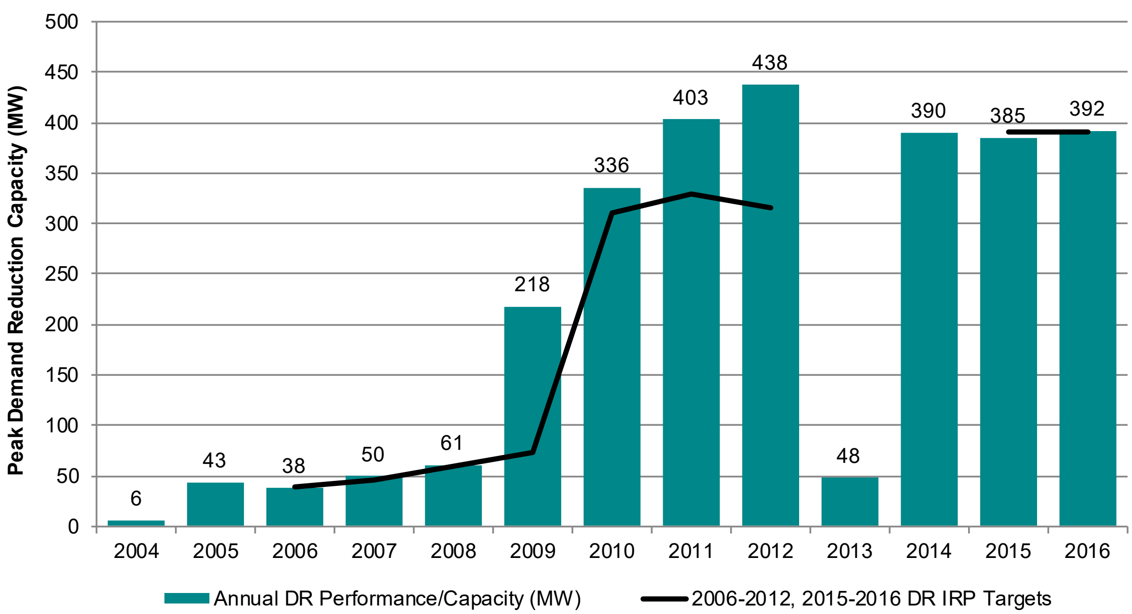


Figure 5.2 Historical annual demand response programs

Committed Energy Efficiency Forecast

Typical irrigation pivots

For the 2017 IRP, Applied Energy Group (AEG) was retained to update the previous study prepared for the 2015 IRP and provide an updated 20-year comprehensive view of Idaho Power's energy efficiency potential.

AEG developed three levels of potential: technical, economic, and achievable. Technical and economic potential are both theoretical limits to efficiency savings, while achievable savings become the planning case forecast for energy efficiency in the 2017 IRP. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. The three levels of potential are described below.

- *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 other applicable measure available. The retrofit measures are phased in over several years, which is increased for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, AEG applies the total resource cost (TRC) test for cost-effectiveness, which compares lifetime energy and capacity benefits to the incremental cost of the measure. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential considers 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 market characterization study bundles industries and building types into homogenous groupings. Idaho Power's 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 combined customer group's history of participation along with the near-term projected projects.

AEG provides the annual savings potential forecast to Idaho Power in gigawatt-hours (GWh), where it is converted to hourly, then monthly, average energy reduction (aMW) to compare with supply-side resources for the IRP analysis. The savings are shaped by end-use load shapes that spread the forecasted savings across all hours of the year. The load shapes used to allocate savings by end use were provided by AEG as part of the study deliverables. All reported energy efficiency and demand response forecasts are expressed at generation level and therefore include line losses of 9.6 percent for energy and 9.7 percent for peak demand to account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the meter level.

Table 5.2 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2017 to 2036 in five-year blocks in terms of cumulative average annual energy reduction (aMW) by customer class. Detailed annual forecast values can be found in *Appendix C—Technical Appendix*.

Table 5.2 Total energy efficiency portfolio forecasted effects (2017–2036) (aMW)

Customer Class	2017	2021	2026	2031	2036
Industrial/commercial/special contracts	9	51	105	140	175
Residential	2	14	27	46	66
Irrigation	2	8	16	23	31
Total*	**13**	**73**	**147**	**208**	**273**

*Totals may not add exactly due to rounding.

Table 5.3 shows the 20-year cost-effectiveness summary based on the AEG potential study and preliminary DSM alternative costs. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficient technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings with the DSM preliminary alternative costs.

Table 5.3 Total energy efficiency portfolio cost-effectiveness summary

Customer Class	2036 Load Reduction (aMW)	2036 Peak-Load Reduction (MW)*	Resource Costs ($000s) 20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	66	–	$155,425	$295,479	1.9	6.7
Industrial/commercial/ special contract	176	–	$302,559	$567,923	1.9	3.9
Irrigation	31	–	$81,981	$133,498	1.6	6.7
Total	**273**	**483**	**$539,965**	**$996,900**	**1.8**	**4.8**

*Final peak-reduction estimates were calculated only for the portfolio as a whole.

The completed energy efficiency forecast is included in the IRP planning horizon and the load and resource balance analysis after ensuring all future energy efficiency was properly accounted for and netted out of future loads prior to portfolio analysis. As noted earlier in this chapter, the company's IRP load forecast accounted for all of the accumulated 20-year potential energy efficiency savings, exceeding the AEG-determined potential over the last seven years of the IRP planning period (2030–2036). Portfolios for the IRP were developed based on the assumption that for 2030 to 2036, the amount of energy efficiency in the load and resource balance is the amount accounted for in the company's load forecast, rather than the smaller amount determined by AEG in the potential study. For the energy load and resource balance, the accumulated energy efficiency in the company's load forecast is 300 aMW, rather than the 273 aMW load reduction provided in Table 5.3 above. The accumulated peak-load reduction in the company's load forecast is 531 MW, rather than the 483 MW noted in Table 5.3.

The amount of energy efficiency determined by the DSM potential study to be cost-effective and achievable sets an appropriate and prudent target for energy efficiency for the 2017 IRP; this amount of energy efficiency is included in all analyzed portfolios before all other resources. Idaho Power recognizes that the amount of energy efficiency achieved in practice may ultimately exceed the 2017 IRP target amount as a result of implementation efforts of the company and the Energy Efficiency Advisory Group (EEAG). The achievable potential is in no way considered a ceiling for funding or the company's efforts.

Further, the company recognizes that alternative (or avoided) costs used for the cost-effectiveness evaluation are likely to change in the interim between the 2017 IRP and 2019 IRP as key drivers of these costs (e.g., natural gas price) vary. Thus, it is the company's view that the DSM potential study-determined cost-effective and achievable energy efficiency sets the target for the amount of energy efficiency available in this IRP. This target does not represent a ceiling or finite amount for actual energy efficiency activities. It is emphasized that neither the cost-effectiveness nor the achievability of this target is fixed; both attributes can change following completion of this IRP, and future analysis (e.g., the 2019 IRP) will reflect these changes.

Transmission and Distribution Deferral Benefits Associated with Energy Efficiency

The transmission and distribution (T&D) deferral benefits associated with energy efficiency were determined using all growth projects from Idaho Power's officer-reviewed three-year budget for 2016. Transmission, substation, and distribution projects were represented. The limiting capacity (determined by feeder or transformer) was identified for each project along with the anticipated in-service date, projected cost, peak loading, and projected growth rate.

The forecast for the penetration of energy efficiency was incorporated into the formula. Independent energy efficiency demand reduction forecasts for different rate classes were applied at summer and winter peak. If the adjusted forecast was below the limiting capacity, it was assumed the project could be deferred. The financial savings of deferring the project were then calculated.

The total savings from all the deferrable projects were divided by the total annual energy efficiency reduction forecast over the service area. A sensitivity analysis was conducted with an energy efficiency forecast multiplier of 0 to 10 times the existing forecast. Based on the analysis, a value of $3.76 per kW per year will be used as the T&D deferral value.

Committed Demand Response Forecast

Under the current program design and participation levels, demand response from all programs is forecast to provide 390 MW of peak capacity during July throughout the IRP planning period, with additional program potential available during June and August. The committed demand response included in the IRP has a capacity cost of $29 per kW per year.

Additional Demand Response

As part of the IRP's expressed strategy to set the highest standard for evaluating B2H cost-effectiveness, B2H alternative portfolios include an additional 50 MW of demand response in 25 MW increments in 2021 and 2026. The achievement of this additional 50 MW is reasonable and consistent with the role of demand response as a cost-effective capacity resource available to shift peak loading for a finite number of hours. While the B2H-based portfolios did not include the added demand response for the purpose of focusing the costs and benefits of these portfolios on B2H, the company does not view B2H as precluding the continued evaluation and as-needed expansion of demand response resources.

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6. Transmission Planning

Past and Present Transmission

500-kilovolt (kV) transmission line near Melba, Idaho

High-voltage transmission lines are 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 serve southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects in the 1950s and 1960s. In the 1970s and 1980s, transmission lines facilitated partnerships in the three coal-fired power plants located in neighboring states that deliver energy to Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its intermittent resources with access to wholesale energy markets.

Idaho Power's transmission interconnections provide economic benefits and improve reliability through the flexibility to move electricity between utilities to serve load and to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience peak loads during the winter; as a result, Idaho Power can purchase energy from the Mid-Columbia energy trading market to meet peak summer load and sell excess energy to Pacific Northwest utilities during the winter and spring. Additional regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers in the following ways:

- The construction of additional 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.
- System reliability is increased.
- Increased capacity can help integrate intermittent resources, such as wind and solar.

- Improve the ability to more efficiently implement advanced market tools, such as the EIM.

Transmission Planning Process

FERC mandates 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

The expansion planning of Idaho Power's transmission network occurs through the biennial local transmission planning (LTP) process which identifies the transmission required to interconnect 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 third-party 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.

Idaho Power develops long-term, local-area transmission plans for various load centers within Idaho Power's service area by applying a local-area transmission advisory process. This process uses community advisory committees and is performed every 10 years for each area. 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. The plans account for land-use limits 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 the following load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Eastern Treasure Valley
5. Western Treasure Valley
6. West Central Mountains

Regional Transmission Planning

Idaho Power is active in regional transmission planning through the NTTG. The NTTG was formed in early 2007 to improve 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), Montana–Alberta Tie Line (MATL), and the Utah Associated Municipal Power Systems (UAMPS). Biennially, the NTTG develops a regional transmission plan using 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

The WECC Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three 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 NERC reporting, transmission security studies, and the transmission line rating process.

Existing Transmission System

Idaho Power's transmission system extends 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 specific southern Idaho load centers. Idaho Power's transmission system and paths are shown in Figure 6.1.

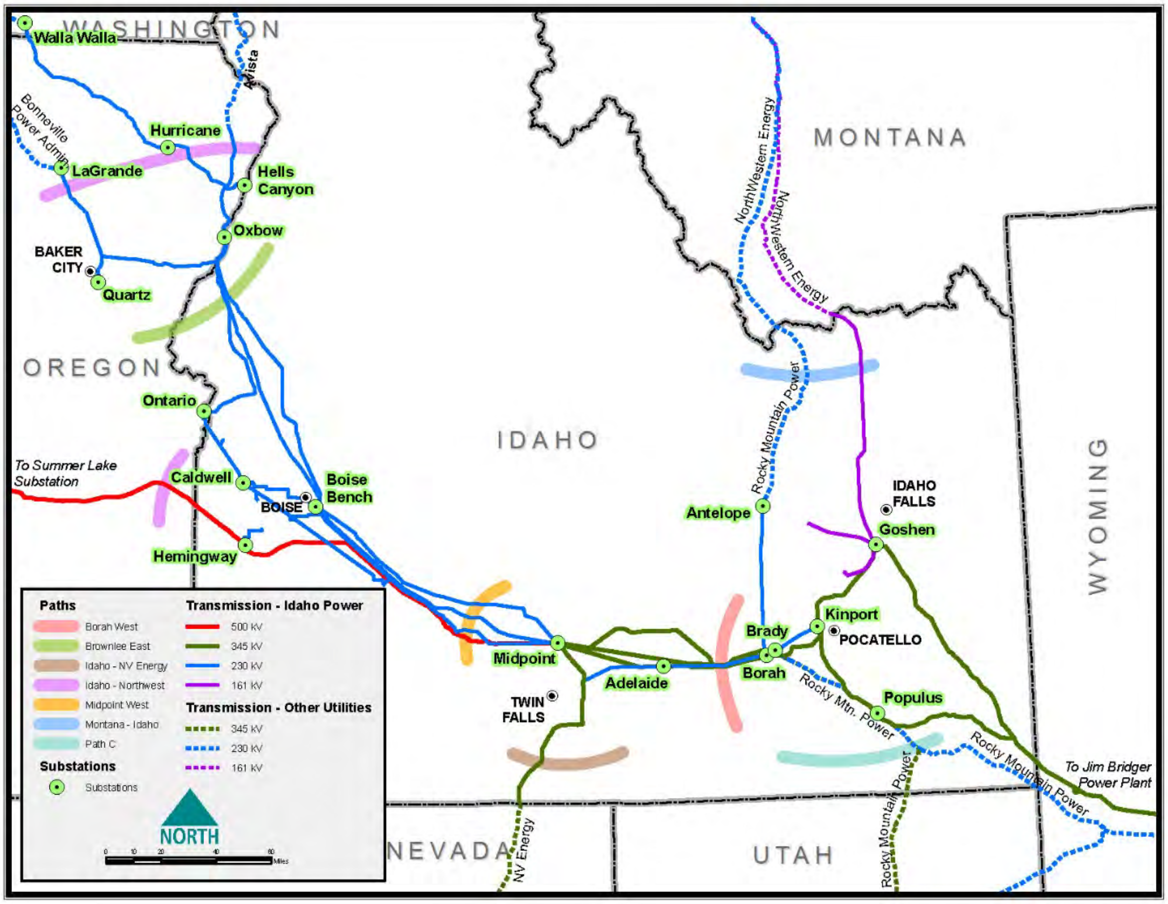

Figure 6.1 **Idaho Power transmission system map**

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 capacity-limited during summer months due to energy imports from the Pacific Northwest to serve Idaho Power retail load and transmission-wheeling obligations for the BPA load in eastern Oregon and southern Idaho. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's 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 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 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.

Montana–Idaho Path

The Montana–Idaho transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The Montana–Idaho 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 Idaho Power's system and is jointly owned between Idaho Power and PacifiCorp. Idaho Power owns 1,467 MW of the path, and PacifiCorp owns 1,090 MW of the path. 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 energy from east-side resources and imports from Montana, Wyoming, and Utah. 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 transmission path is internal to Idaho Power's system and is a jointly owned path between Idaho Power and PacifiCorp. Idaho Power owns 1,710 MW of the path and PacifiCorp owns 1,090 MW of the path (all on the Midpoint–Hemingway 500-kV line). The path is comprised of 500-kV, 230-kV, and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. Like 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 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns 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 the transmission lines. 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 summarizes the import capability for paths impacting Idaho Power operations and lists their total capacity and available capacity; most of paths are completely allocated with no capacity remaining.

Table 6.1 Transmission import 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	383	0
Brownlee East	West to east	1,915	Internal Path
Midpoint West	East to west	1,710	Internal Path
Borah West	East to west	2,557	Internal Path
Idaho–Wyoming (Bridger West)	East to west	2,400	86 (Idaho Power Share)
Idaho–Utah (Path C)	South to north	1,250	PacifiCorp Path

* The available transmission capacity (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).

B2H

In the 2006 IRP process, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a 230-kV line interconnecting at the McNary Substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including evaluating upgrade options of existing transmission lines, evaluating terminus locations, and sizing the project to economically meet projected demand. The project identified in 2006 has evolved into what is currently the B2H project. The project involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn Station near Boardman, Oregon, and the existing Hemingway Substation in southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to economically serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and resiliency
- Reduced capacity limitations on the regional transmission system as demands on the system continue to grow
- Flexibility to integrate renewable resources and more efficiently implement advanced market tools, such as the EIM

The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, 2013, and 2015 IRPs.

The B2H project is a regionally significant project. The project has been identified as producing a more efficient or cost-effective plan in the NTTG's 2007, 2009, 2011, 2013, and 2015 biennial regional transmission plans.[14] NTTG regional transmission plans aim to produce a more efficient or cost-effective regional transmission plan that meets the transmission requirements associated with the load and resource needs of the NTTG footprint.

Additionally, the B2H project is a nationally recognized project. The project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money.[15]

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[14] nttg.biz/site/

[15] boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf

Project Participants

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 B2H project. Table 6.2 shows each party's B2H capacity and permitting cost allocation.

Table 6.2 B2H 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 serve eastern Idaho load from the Hemingway Substation. BPA identified six solutions—including two B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publicly announced the preferred solution to be the B2H project. The participation of three large utilities working toward the permitting of B2H further demonstrates the regional significance and regional benefits of the project.

Permitting Update

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), US Forest Service (USFS), Department of the Navy, and ODOE. The federal permitting process is dictated primarily by the *Federal Land Policy Management Act* and *National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On November 25, 2016, BLM published the Final Environmental Impact Statement (EIS). Figure 6.2 shows the proposed transmission line routes included in the Final EIS with the agency preferred route. Idaho Power expects the BLM to issue a Record of Decision (ROD) by summer 2017.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE in February 2013. Idaho Power plans to submit an amended pASC in summer 2017.

Given the ongoing permitting requirements, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2024 or beyond.

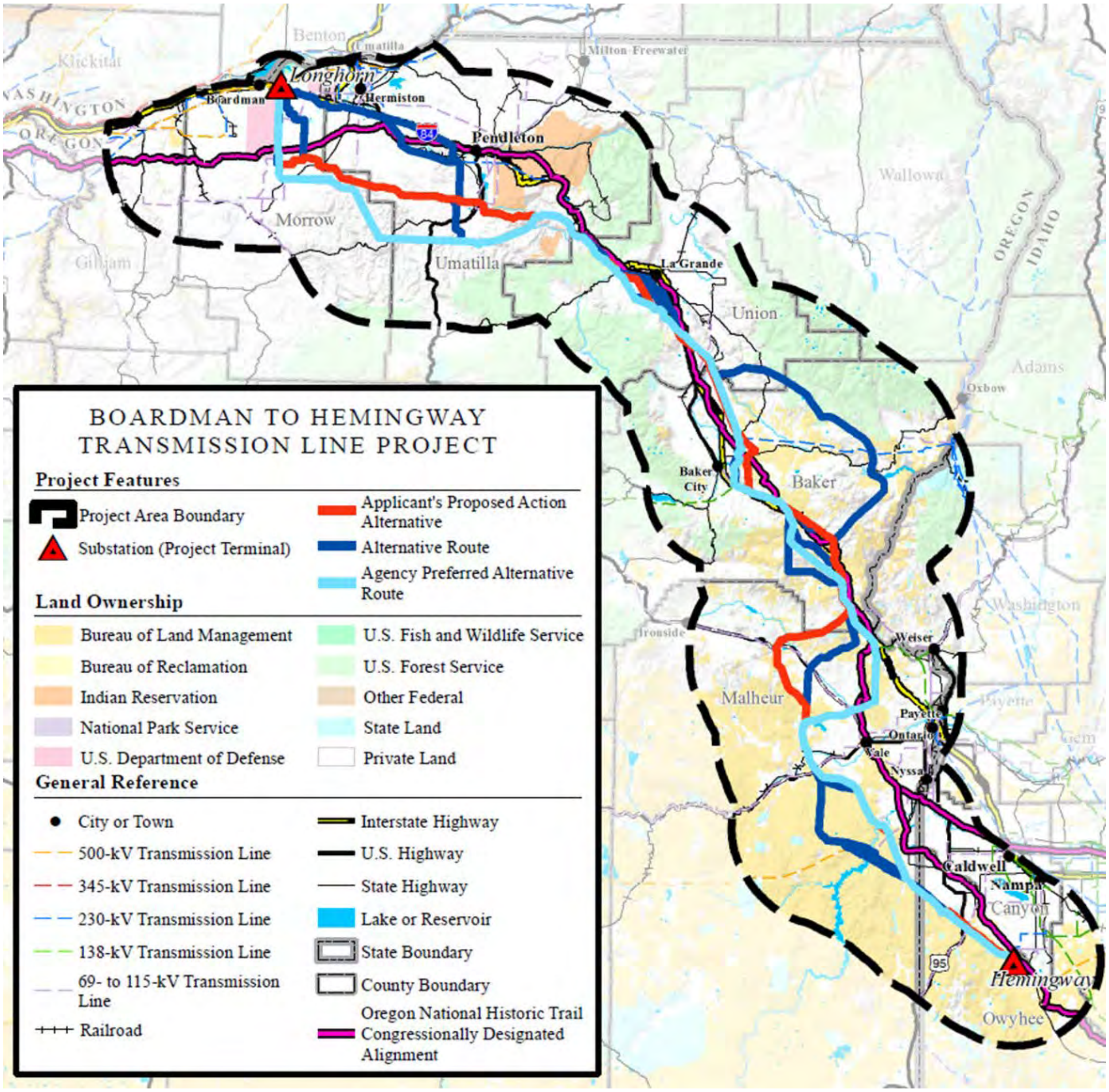


Figure 6.2 **B2H routes with the agency-preferred alternative**

Activities after BLM ROD

After the BLM issues a ROD and the amended pASC has been submitted to the ODOE and deemed complete, sufficient route certainty will exist to begin preliminary construction activities. These activities include, but are not limited to, the following:

- Geotechnical surveys
- Detailed ground surveys (light detection and ranging [LiDAR] surveys)
- Sectional surveys

- Right-of-way (ROW) activities
- Detailed design
- Construction bid package development

After the Oregon permitting process concludes, construction activities would commence. Construction activities include, but are not limited to, the following:

- Long-lead material acquisition
- Transmission line construction
- Substation construction or upgrades

The specific timing of each of the preliminary construction and construction activities will be coordinated with the project co-participants. Additional project information is available at boardmantohemingway.com.

B2H Cost Treatment in the IRP

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. However, historically, additional transmission wheeling revenue has not been quantified for a transmission capacity addition. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project.
After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system. In the IRP modeling, the estimated incremental transmission wheeling revenue from non-native load customers was modeled as an annual revenue credit for B2H portfolios.

Northwest Seasonal Resource Availability Forecast

The assessment of regional resource adequacy is part of the regional transmission planning process, and the review of adequacy assessments is useful in understanding the liquidity of regional wholesale electric markets. For the 2017 IRP, Idaho Power has reviewed two recent assessments and their respective characterizations of regional resource adequacy in the Pacific Northwest: 1) the adequacy assessment conducted by the NWPCC Resource Adequacy Advisory Committee (RAAC) and 2) the adequacy assessment conducted by the BPA.

In July 2013, the NWPCC approved a charter for the RAAC, which provided that the RAAC's purpose is to assess power-supply adequacy in the Northwest. Idaho Power has participated in the RAAC since its inception, and also in the NWPCC's Resource Adequacy Forum, which preceded the RAAC.

The NWPCC adopted an adequacy standard used by the RAAC as a metric for assessing resource adequacy. 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 regional utilities when preparing their individual IRPs. The statistic used to assess compliance with the adequacy standard is the likelihood of supply shortage, which is commonly known as the loss-of-load probability (LOLP). Under the adequacy standard, the LOLP is held to a maximum level of 5 percent.

The RAAC issued a report in September 2016 on resource adequacy for the 2021 operating year.[16] The 2021 operating year follows the 2020 retirement of 1,330 MW of coal-fired generating capacity at Centralia (Washington) Unit 1 and the Boardman power plant. The RAAC adequacy assessment reports the LOLP for operating year 2021 is 10 percent, and that to maintain resource adequacy at the maximum level of 5 percent the Pacific Northwest needs to add slightly more than 1,000 MW of new capacity. The RAAC also reports that the retirement of approximately 600 MW of coal-fired generating capacity at Colstrip units 1 and 2, currently anticipated for summer 2022, would increase the LOLP to approximately 13 percent if the retirement of the Colstrip units was moved up to earlier than operating year 2021. The adequacy assessment demonstrates Pacific Northwest adequacy concerns in both winter and summer. Winter LOLP exceeds summer LOLP, except for the analysis assuming pre-2021 retirement of Colstrip units 1 and 2, wherein late summer LOLP exceeds winter LOLP. Under both assumptions for Colstrip units 1 and 2, the LOLP in June and July is zero. The RAAC is currently conducting an updated adequacy assessment for the 2022 operating year. Preliminary results of the updated assessment released by the RAAC indicate a lowered LOLP for operating year 2022 of just under 8 percent. A report on the updated adequacy assessment from the RAAC is anticipated in 2017.

BPA annually assesses regional resource adequacy in its Pacific Northwest load and resource study. The BPA assessment accounts for forecast load growth in the Pacific Northwest (including Idaho and Montana), existing generation, planned new generation considered as highly certain, and committed generation retirements. In their assessment, BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly

[16] NWPCC. Pacific Northwest power supply adequacy assessment for 2021. 2016. Document 2016-10. https://www.nwcouncil.org/media/7150591/2016-10.pdf. Accessed on: April 25, 2017.

production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937).

The most recent BPA adequacy assessment report was released in December 2016 and evaluates resource adequacy from 2018 through 2027.[17] Monthly capacity adequacy is analyzed from the perspective of one-hour capacity and 120-hour sustained capacity. In the 2016 assessment, the Pacific Northwest region is projected in 2027 to have summer surpluses from the one-hour perspective in June through the first half of August, then a deficit of nearly 200 MW in the second half of August. From the 120-hour sustained capacity perspective, the Pacific Northwest region is projected in 2027 to have a surplus in June, then to be in deficit for July and August. However, the projected 120-hour deficits in July and the first half of August are less than half those predicted for the winter months, suggesting the addition of sustained capacity needed to address winter deficits would be available as surplus capacity to the summer wholesale market in the region.

The Pacific Northwest was historically characterized as an energy-constrained region, rather than capacity constrained. Load-serving entities could typically serve capacity needs, but during periodic low water conditions may encounter energy constraints. However, over time the region has trended toward becoming capacity constrained, as shown by the RAAC and BPA adequacy assessments. While the regional adequacy assessments suggest potential capacity inadequacies, these inadequacies for both assessments are shifted from the timing of Idaho Power's peak needs. Specifically, the adequacy assessments find summer inadequacies in the region occur in the late summer, by which time demand for energy from Idaho Power's irrigation customers has substantially declined from its late-June through early-July peak. Further, the RAAC adequacy assessment acknowledges that its assessment does not include generating capacity not yet sited or licensed, or generating capacity additions driven by RPS requirements. Known new generating capacity planned by 2021 of about 550 MW, along with RPS requirements in Washington, Oregon, and California, will drive resource expansion. The regional resource adequacy assessments are consistent with Idaho Power's view that expanded transmission interconnection to the Pacific Northwest (i.e., B2H) provides access to a market with capacity for meeting its summer load needs and abundant low-cost energy, and that expanded transmission is critical in a future with automated energy markets (i.e., western EIM) and high penetrations of renewable intermittent resources.

[17] BPA. 2016 Pacific Northwest loads and resources study (2016 white book). https://www.bpa.gov/power/pgp/whitebook/2016/index.shtml. Accessed on: May 19, 2017.

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and PacifiCorp 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. PacifiCorp has been designated 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 currently authorized routes in the federal permitting process based on the BLM's November 2013 ROD for segments 1 through 7 and 10. Segments 8 and 9 were further considered through a Supplemental EIS by the BLM. The BLM issued a ROD for segments 8 and 9 on January 20, 2017. In March 2017, this ROD was rescinded by the BLM for further consideration. On May 5, 2017, the *Morley Nelson Snake River Birds of Prey National Conservation Area Boundary Modification Act of 2017* (H.R. 2104) was enacted. H.R. 2104 authorized the Gateway West route through the Birds of Prey area that was proposed by Idaho Power and PacifiCorp and supported by the Idaho Governor's Office, Owyhee County and certain other constituents. Per this legislation, the Secretary of the Interior must issue a ROW for Idaho Power's proposed routes for segments 8 and 9 by early August 2017.

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 (segment 6), which is an existing transmission line operated at 345 kV but constructed at 500 kV.

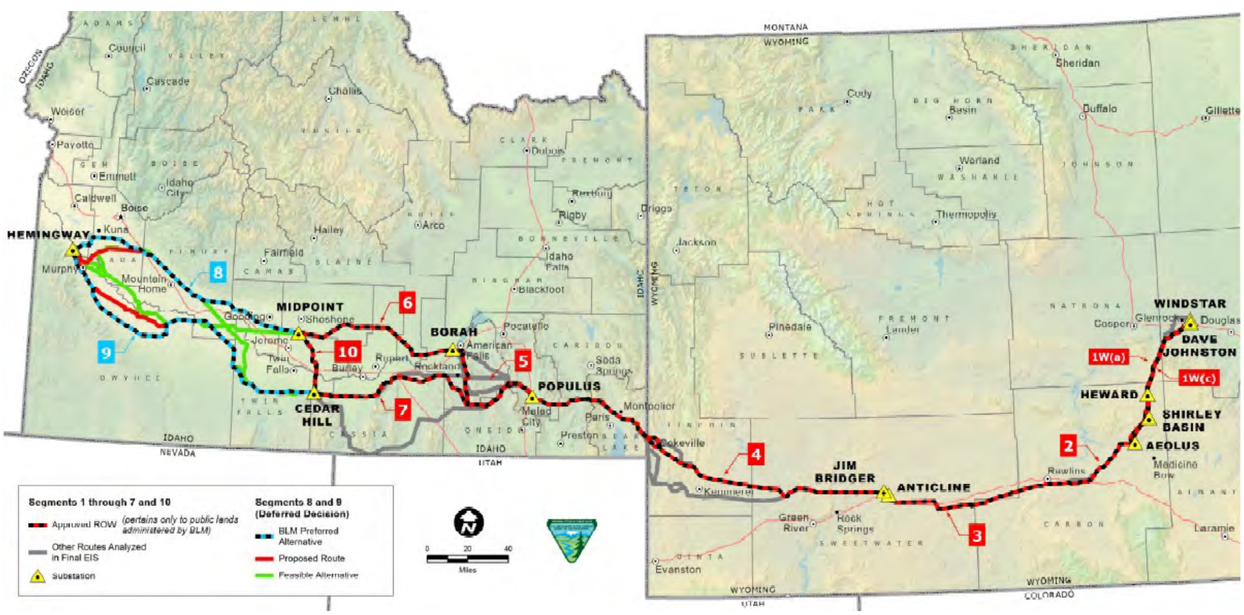


Figure 6.3 Gateway West map

The Gateway West project will provide many benefits to Idaho Power customers, including the following:

1. Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's core transmission system, connecting two major Idaho Power load centers.
2. Provide the option to locate future generation resources east of the Treasure Valley.
3. Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation.
4. Help meet the transmission needs of the future, including transmission needs associated with intermittent resources.

Phase 1 of the Gateway West project is expected to provide up to 1,500 MW of additional transfer capacity between Midpoint and Hemingway. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Idaho Power has a one-third interest in these capacity additions.

The Gateway West and B2H projects are complementary and will provide upgraded transmission paths from the Pacific Northwest across Idaho and into eastern Wyoming.

More information about the Gateway West project can be found at gatewaywestproject.com.

Nevada without North Valmy

The Idaho–Nevada transmission path is co-owned by Idaho Power and NV Energy, with Idaho Power having full allocation of northbound capacity and NV Energy having full allocation of southbound capacity. As noted earlier in this chapter, the northbound capacity of the path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

In its evaluation of North Valmy retirement options, Idaho Power has reviewed the potential to import wholesale energy across the Idaho–Nevada transmission path following retirement of North Valmy generating capacity. Idaho Power has principally participated in the Mid-Columbia wholesale power market to the northwest and considers the availability of wholesale energy for import across the Idaho–Nevada path as less certain. In particular, the frequent import of wholesale energy from Nevada is likely to encounter scarcity and/or costly energy. Therefore, while Nevada is not considered a viable source for abundant wholesale energy, it may have potential to source seldom-needed capacity during peak-loading periods. For this reason, Idaho Power is assuming for the 2017 IRP that the retirement of North Valmy generating capacity can be adequately replaced with infrequent wholesale capacity imports across the Idaho–Nevada transmission path.

Idaho Power recognizes the uncertainty of assuming wholesale capacity imports from Nevada can replace North Valmy generating capacity. The viability of the Idaho–Nevada path can be evaluated as the company continues to transition away from coal in a measured and responsible manner. Idaho Power expects to develop greater understanding of the viability of the Idaho–Nevada path with participation in the western EIM beginning in spring 2018. As it continues its evaluation, Idaho Power recognizes the assumption that wholesale capacity imports from Nevada can replace North Valmy generating capacity may prove unfounded, and future IRPs may need to reflect such a change.

Transmission Assumptions in the IRP Portfolios

Transmission lines leading from Danskin Power Plant

Idaho Power makes resource location assumptions to determine 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 assumptions about the geographic area where supply-side resources are developed determine the transmission upgrades required.

Table 6.3 Transmission assumptions and requirements

Resource	Capacity	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Biomass indirect—Anaerobic digester	35	Assume distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	Assume $3.5 million of distribution feeder upgrades and $1.2 million in substation upgrades.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Geothermal (binary-cycle)—Idaho	35	Assume Raft River area location; displaces equivalent MW of portfolio resources in same region.	Requires 5-mile 138-kV line to nearby station with new 138-kV substation line terminal bay.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Hydro—Canal drop (seasonal)	1	Assume Magic Valley location connecting to 46-kV sub-transmission or local feeder.	Assume 4 miles of distribution rebuild at $150,000 per mile plus $100,000 in substation upgrades.	No backbone upgrades required.

Resource	Capacity	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Natural gas—SCCT frame F class (Idaho Power's peaker plants use this technology)	170	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2-mile 230-kV line required to connect to nearby station.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—Reciprocating gas engine Wärtsilä 34SG	18	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at 230-kV Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (1x1) F class with duct firing	300	Assume Langley Gulch location; displaces equivalent MW of portfolio resources in same region.	New LGSY–GARNET 230-kV line w/ Garnet 230/138 transformer and Garnet 138-kV tap line. Bundle conductor on the LGSY–CDWL 230-kV line. Reconductor CDWL–LNDN.	No additional backbone upgrades required.
Natural gas—CCCT (1x1) F class with duct firing	300	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2-mile 230-kV line required to connect to nearby station.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Natural gas—CCCT (2x1) F class	550	Build new facility south of Boise (assume Simco Road area).	New 230-kV switching station with a 22-mile 230-kV line to Boise Bench Substation and wrap 230-kV Danskin Power Plant to Hubbard line into new station.	Rebuild Rattle Snake to DRAM 230-kV line, rebuild Boise Bench to DRAM 230-kV line, rebuild Micron to Boise Bench 138-kV line.
Natural gas—CHP	35	Assume location in Treasure Valley.	Assume 1-mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—SMR	50	Assume tie into ANTS 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise.	Two 2-mile 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at Antelope Substation.	New parallel 55-mile 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Pumped storage—New upper reservoir and new generation/ pumping plant	100	Assume Anderson Ranch location; displaces equivalent MW of portfolio resources in same region.	18-mile 230-kV line to connect to Rattle Snake Substation.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Solar PV—Utility-scale 1-axis tracking	30	Assume Magic Valley location; displaces equivalent MW of portfolio resources in same region.	Assume 1-mile 230-kV line and associated stations equipment.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.
Wind—Idaho	100	Assume location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region.	Assume 5-mile 230-kV transmission from Midpoint Substation to project site.	Assigns pro-rata share for transmission upgrades identified for resources east of Boise.

7. Planning Period Forecasts

The IRP process requires Idaho Power to prepare numerous forecasts and estimates, which can be grouped into four main categories:

1. Load forecasts
2. Generation forecast for existing resources
3. Natural gas price forecast
4. Resource cost estimates

Pedestrians at the Drive Electric Week event in Boise.

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 2017 IRP.

Load Forecast

Each year, Idaho Power prepares a forecast of sales and demand of electricity using the company's electrical T&D network. This forecast is a product of historical system data and trends in electricity usage along with numerous external economic and demographic factors.

Idaho Power has its annual peak demand in the summer, with peak loads driven by irrigation pumps and A/C in June, July, and August. Historically, Idaho Power's growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. Both measures are important in planning future resources and are part of the load forecast prepared for the 2017 IRP.

The expected case (median) load forecasts for peak-hour and average energy (average load) represent Idaho Power's most probable outcome for load growth during the planning period. In addition, Idaho Power prepared two probabilistic load forecasts that address the load variability associated with abnormal weather trends. The 70^{th}-percentile and 90^{th}-percentile load forecasts were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to variable weather conditions.

The expected case forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*.

For example, the expected annual average system load growth of 0.9 percent (over the period 2017 through 2036) is comprised of a residential load growth of 1.2 percent, a commercial load growth of 0.7 percent, an irrigation load growth of 0.6 percent, an industrial load growth of 0.7 percent, and an additional firm load growth of 0.7 percent.

The number of residential customers in Idaho Power's service area is expected to increase 1.8 percent annually from 444,000 at the end of 2016 to nearly 632,000 by the end of the planning period in 2036. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.2-percent average residential load-growth rate.

Significant factors and considerations that influenced the outcome of the 2017 IRP load forecast include the following:

- The load forecast used for the 2017 IRP reflects the continuing recovery of the service-area economy following a severe recession in 2008 and 2009. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed growth. By 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

- The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflects the impact of additional plant investments and associated variable costs of integrating new resources identified in the 2015 IRP preferred portfolio, including the expected cost to comply with carbon-emission regulations. Compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yields lower future prices. The retail prices are most evident after the first two years of the planning period and can impact the sales forecast positively, 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 expected load forecast reflects only those industrial customers that have made a sufficient and significant binding investment indicating a commitment of the highest probability of locating in the service area. The large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area 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, and other naturally occurring efficiencies 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 (i.e., are treated as a supply-side peaking resource). 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 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, occurring as a result of growth in the dairy industry. The irrigation sales forecast is higher also as a consequence of renewed production from high-lift acreage. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to efforts to reduce labor costs.

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 were analyzed to address load variability due to weather—70th-percentile and 90th-percentile load forecasts. 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.

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

Economic Effects

Numerous external factors influence the sales and load forecast that are primarily economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, metropolitan statistical area (MSA) and county economic and demographic 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. Additional data sources used to substantiate Moody's data include, but are not limited to, the US Census Bureau, the Bureau of Labor Statistics, the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve Economic Databases.

The number of households in Idaho is projected to grow at an annual 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 is projected to grow faster than the remainder of the state over the planning period. The number of households in the Boise City–Nampa MSA is projected to grow faster than the rest of Idaho, at an annual rate of 1.6 percent during the forecast period. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. In addition, the number of households, incomes, employment, economic output, electricity prices, and customer consumption patterns are used to develop load projections.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period. This 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's 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 2017 IRP average annual system load forecast reflects continued improvement in the service-area economy. While economic conditions during the development of the 2015 IRP were positive, the resulting sales forecast was more optimistic than the actual performance experienced in the interim period leading up to the 2017 IRP. The improving economic and demographic variables driving the 2017 forecast are reflected by a positive sales outlook throughout the planning period. However, the 2017 IRP forecast is more moderate, and the growth path is less steep.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 7.1 and Table 7.1 show the results of the three forecasts used in the 2017 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70th-percentile forecast, and a 10-percent probability of load exceeding the 90th-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 0.9 percent over the 2017 through 2036 period.

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

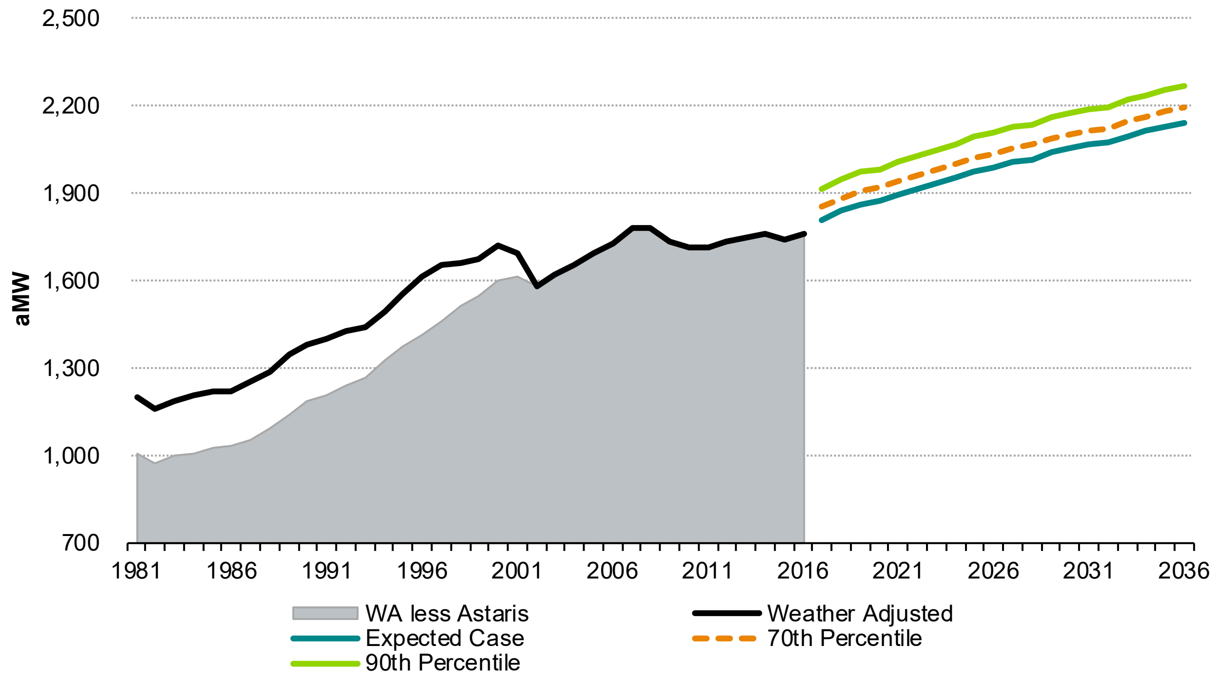


Figure 7.1 Average monthly load-growth forecast

Table 7.1 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2017	1,810	1,853	1,917
2018	1,840	1,883	1,948
2019	1,864	1,907	1,973
2020	1,874	1,918	1,984
2021	1,894	1,939	2,006
2022	1,914	1,959	2,027
2023	1,935	1,981	2,049
2024	1,955	2,001	2,070
2025	1,975	2,022	2,092
2026	1,990	2,037	2,108
2027	2,007	2,054	2,126
2028	2,018	2,066	2,137
2029	2,039	2,087	2,160
2030	2,053	2,102	2,175
2031	2,067	2,116	2,190
2032	2,074	2,123	2,197
2033	2,095	2,145	2,220
2034	2,112	2,162	2,237
2035	2,129	2,179	2,255
2036	2,142	2,193	2,269
Growth Rate (2017–2036)	**0.9%**	**0.9%**	**0.9%**

Peak-Hour Load Forecast

As average demands as discussed in the preceding section are an integral component to the load forecast so is the impact of peak-hour demands on the system. Peak-hour forecasts are expressed as a function of the sales forecast, as well as the impact of peak-day temperatures.

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—3,407 MW—was recorded on July 2, 2013, at 4:00 p.m. The system peak-hour load record was nearly matched on June 30, 2015, at 4:00 p.m., when the system peak reached 3,402 MW. 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 summer have also had a significant effect on reducing peak demand. The 2017 IRP load forecast projects peak-hour load to grow by over 50 MW per year throughout the planning period in the 95th-percentile case. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance in a manner similar to a supply-side resource.

Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m., matching the previous record peak dated December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summer 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.

Figure 7.2 and Table 7.2 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th percentile, and 95th percentile. 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. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

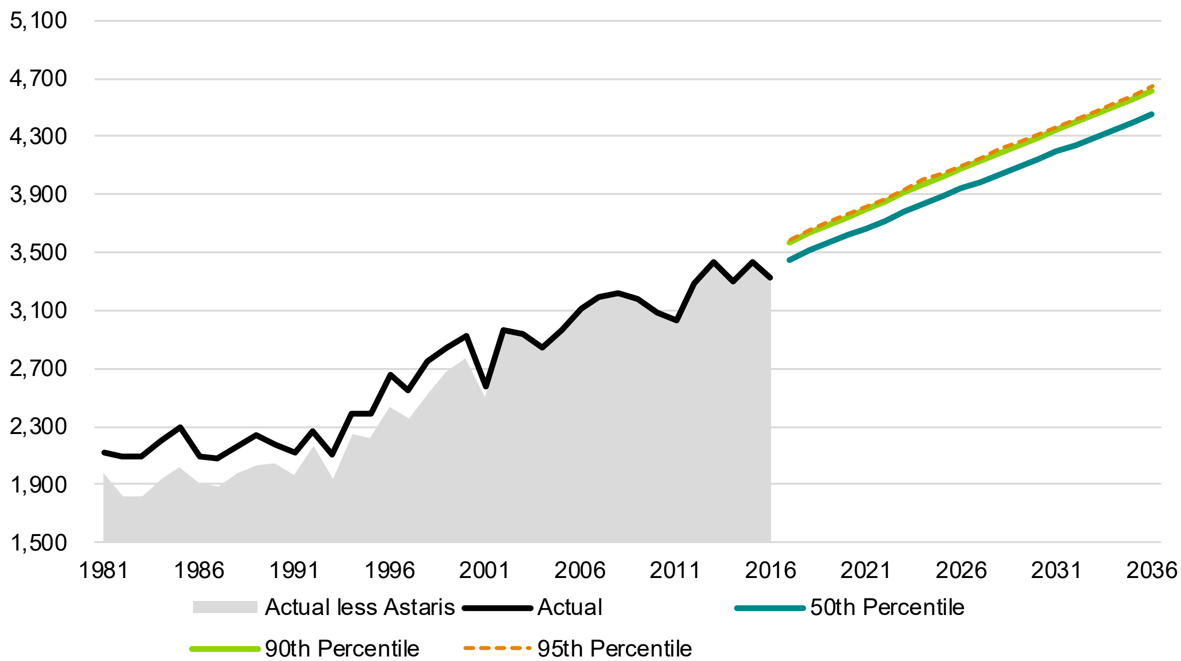


Figure 7.2 Peak-hour load-growth forecast (MW)

Table 7.2 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2016 (Actual)	3,327	3,327	3,327
2017	3,446	3,566	3,586
2018	3,508	3,630	3,651
2019	3,567	3,692	3,713
2020	3,618	3,745	3,766
2021	3,668	3,797	3,819
2022	3,722	3,854	3,876
2023	3,778	3,912	3,934
2024	3,838	3,974	3,998
2025	3,888	4,026	4,050
2026	3,937	4,078	4,102
2027	3,989	4,132	4,157
2028	4,042	4,187	4,212
2029	4,092	4,240	4,265
2030	4,141	4,292	4,317
2031	4,192	4,344	4,370
2032	4,239	4,394	4,420
2033	4,289	4,447	4,474
2034	4,342	4,502	4,529
2035	4,395	4,557	4,584
2036	4,449	4,613	4,641
Growth Rate (2017–2036)	**1.4%**	**1.4%**	**1.4%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,446 MW in 2017 to 4,449 MW in 2036—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 3,586 MW in 2017 to 4,641 MW in 2036. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 7.2.

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company to 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.

Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the INL. These three special-contract customers comprise the entire forecast category labeled additional firm load.

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 (QA); systems integration; and related manufacturing, corporate, and general services. Micron Technology's electricity use is a function of 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 through 2017, then stay flat throughout the remainder of the planning period.

INL

The INL is part of the DOE's complex of national laboratories. The INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2036 for the INL. The forecast calls for loads to increase through 2024, then levelize through the remainder of the forecast period.

Generation Forecast for Existing Resources

Hells Canyon Dam

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 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 provide a description of Idaho Power's hydroelectric, thermal, and transmission resources and how they are accounted for in the load and resource balance.

Hydroelectric Resources

For the 2017 IRP, Idaho Power continues the practice of using 70th-percentile future 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 50th-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 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2017 IRP is included in *Appendix C—Technical Appendix.*

A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface-water outflow from the river basin. The current water-use practices driving the steady decline over recent years are expected to continue, resulting in declining basin outflows assumed to persist well into the 2030s. The declining basin outflows for this IRP are assumed to continue through the planning period.

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. 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 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Additionally, yearly flow augmentation shortages from the upper Snake River Basin are filled from the Boise River Basin if adequate water is available.

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 the peak-hour analysis, a review of historical (2001—2016) operations was performed to estimate the maximum HCC output achieved on an annual basis with 90-percent probability.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April through July runoff period. Figure 7.3 shows historical April through 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 continue through the planning period.

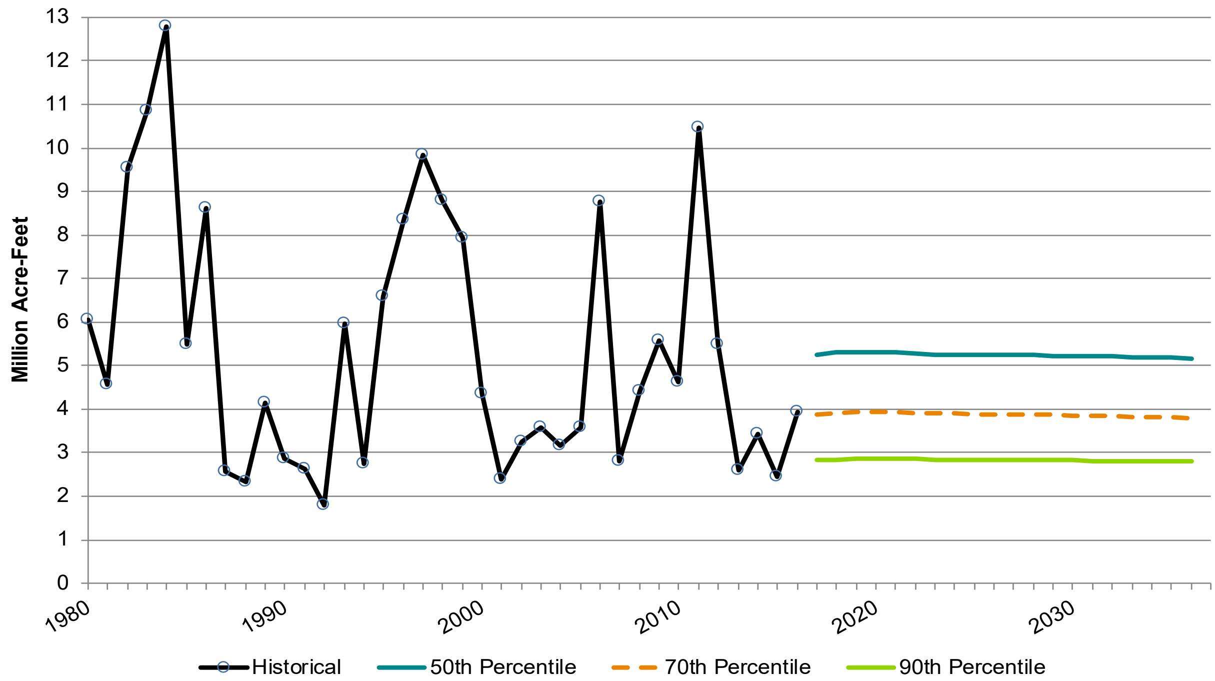


Figure 7.3 Brownlee historical and forecast inflows, April through July

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes too much uncertainty exists 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 2017 IRP. Further discussion of climate change and expectations of possible effects on Snake River water supply is available starting on page 64 of the IDACORP Inc. 2016 Form 10-K.

Coal Resources

Idaho Power's coal-fired power plants continue to deliver generating capacity during high-demand periods. However, production of baseload energy from the company's coal plants has declined over recent years, a trend mirrored by coal plants across the region and nation. The decline in baseload energy production is primarily viewed as driven by low natural gas prices and the expansion of renewable generating capacity; because of the low natural gas prices and expanded renewable generating capacity, wholesale electric market prices over recent years have frequently been too low to merit economic dispatch of coal generating capacity. The challenging economics posed by low wholesale electric market prices, particularly when coupled with the need for capital investments for environmental retrofits, have increasingly led owners of coal-fired power plants to evaluate the cost-effectiveness of continued capital expenditure and continued operation. For the 2017 IRP, Idaho Power makes such economic evaluations for the Jim Bridger and North Valmy coal-fired power plants, as described in the following sections.

While coal-fired power plants over recent years are less frequently dispatched for baseload energy production, the projected monthly average energy output from the coal plants in the load and resource balance continues to reflect typical baseload output levels. Because the load and resource balance is a tool for assessing resource adequacy, rather than a forecast of actual resource output, it is appropriate to include the amount of production a resource can produce. With respect to peak-hour output, the capacity load and resource balance includes the coal-fired power plants at their 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*.

Boardman Retirement

The 2017 IRP assumes Idaho Power's share of the Boardman plant will not be available for coal-fired operations after December 31, 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with regional-haze regulations on particulate matter, SO_2, and NOx emissions.

North Valmy

The preferred portfolio from the 2015 IRP included retirement of both North Valmy units year-end 2025. The baseline assumption for North Valmy for the 2017 IRP is updated to reflect retirement of Unit 1 year-end 2019 and Unit 2 year-end 2025. The selection of the preferred portfolio for the 2015 IRP, including the 2025 retirement of both North Valmy units, was consistent with strategies to manage exposure to qualitative risk factors. The qualitative risk factors considered in selecting the preferred portfolio for the 2015 IRP included PURPA contract uncertainty, cooperation with NV Energy on retirement planning, B2H execution, and the Clean Power Plan. For the 2017 IRP, these qualitative risks have diminished.

A review of a North Valmy Unit 1 shutdown year-end 2019 determined the likelihood of customer economic benefits associated with the 2019 retirement outweighs the diminished 2015 IRP qualitative risks. The 2017 IRP load and resource balance impact of retiring North Valmy units 1 and 2 in 2019 and 2025, respectively, is mitigated by the assumption that import capacity across the Idaho–Nevada transmission path will be available. For the 2017 IRP, Idaho Power assumed new resources will not be required to replace retiring North Valmy units, as the existing transmission path can satisfy hourly peak needs. Further discussion of the viability of wholesale capacity imports across the Idaho–Nevada transmission path is included in Chapter 6.

Jim Bridger Units 1 and 2 Scenarios

Each of the four Jim Bridger units requires capital investment for retrofitting to comply with regional-haze regulations. The implementation of these regulations is stipulated in a state implementation plan (SIP). PacifiCorp and Idaho Power, as joint owners of the Jim Bridger plant, with the Wyoming Department of Environmental Quality (WDEQ), have developed a plan to implement the regional-haze regulation. The current SIP stipulates installation of SCR retrofitting on Jim Bridger units 3 and 4 in 2015 and 2016, and on units 1 and 2 in 2022 and 2021, respectively. The installation of SCRs on Jim Bridger Units 3 and 4 is complete, and as a baseline assumption, units 3 and 4 are operating resources through the 20-year IRP planning period.

The 2017 IRP analyzes four scenarios related to SCR installation on Jim Bridger units 1 and 2. The scenarios include one in which the SCR investments are made by the required dates in 2021 and 2022, and three alternative scenarios in which units 1 and 2 are retired early at varying dates within the 20-year IRP planning period. The three early-retirement scenarios are analyzed to evaluate the economics of alternatives to SCR installation and to help guide future discussions with the WDEQ in developing a SIP for regional-haze compliance. The four scenarios are as follows:

1. Make the SCR investments and operate Jim Bridger units 1 and 2 through the end of the planning period.
2. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2028 and year-end 2024, respectively.
3. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2032 and year-end 2028, respectively.
4. Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

The four Jim Bridger scenarios are discussed further in Chapter 8.

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 peak-load events in the summer and winter. 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 235 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 280 aMW, with an on-demand peaking capacity of 300 MW.

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. For the 2017 IRP, Idaho Power is continuing to use the EIA as the source for the natural gas price forecast. Idaho Power reviewed two natural gas price forecast cases reported by the EIA in the 2016 Annual Energy Outlook (AEO): 1) the Reference Case and 2) the High Oil and Gas Resource and Technology Case. These forecasts are reported by the EIA at Henry Hub, which is an important natural gas distribution hub and pricing point in Louisiana. A graph of historical Henry Hub prices and the reviewed EIA forecasts is provided in Figure 7.4.

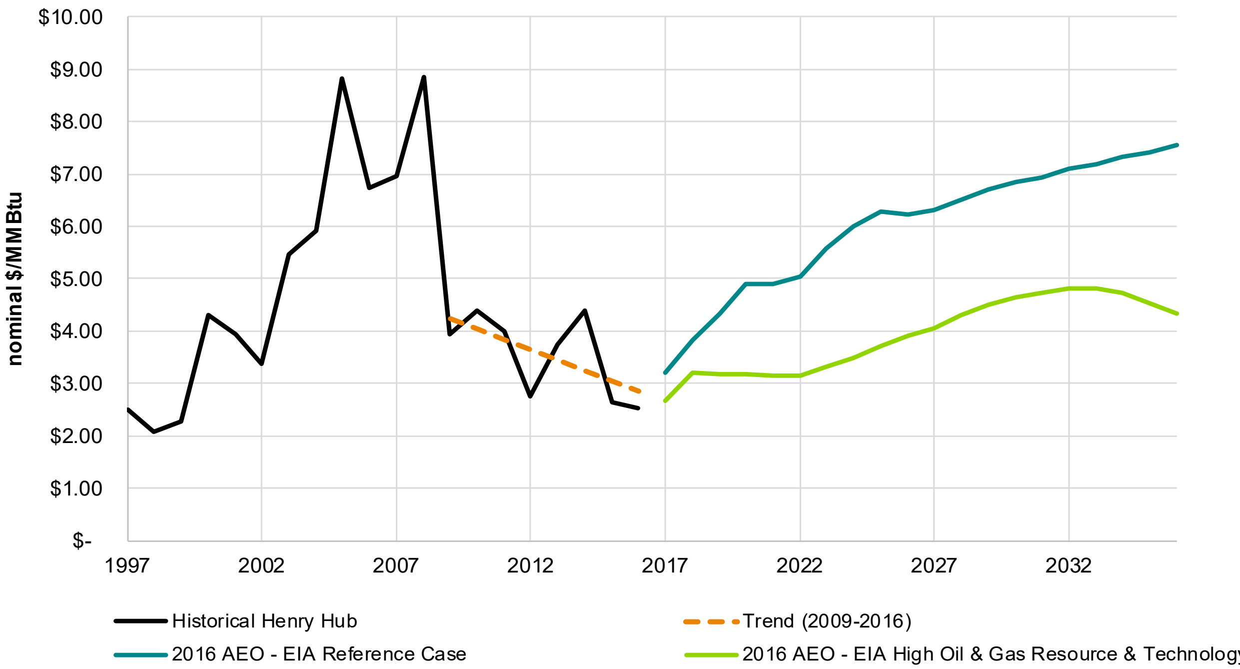


Figure 7.4 Henry Hub natural gas spot price

Importantly, historical Henry Hub prices beginning in 2009 have remained relatively stable and have even trended slightly downward; the illustrated trendline fit to the annual prices for 2009 through 2016 declines at a rate of $0.20 per year. The natural gas price trends since 2009 are highly related to marked expansion of natural gas production from shale. Based on natural gas price trends since 2009 and the coincident expansion of shale gas production, Idaho Power uses the High Oil and Gas Resource and Technology Case as the planning case natural gas price forecast for the 2017 IRP; this case is more consistent with recent price trends than the reference case.

A sensitivity analysis using alternative natural gas price forecasts is described in Chapter 9. The natural gas price is also included as a risk variable in the stochastic risk analysis performed on the IRP resource portfolios.

Idaho Power applies a Sumas basis adjustment and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in *Appendix C—Technical Appendix.*

Analysis of IRP Resources

The electrical energy sector has experienced considerable transformation during the past decade. Variable energy resources, such as wind and solar, have markedly expanded their market penetration during this period, and through this expansion they have affected the wholesale market for electrical energy. The expansion of variable energy resources has also highlighted the need for flexible capacity resources to provide balancing. A consequence of the expanded penetration of variable energy resources is periodic energy oversupply alternating with energy undersupply. Flexible capacity is provided by multiple resources. Dispatchable natural gas-fired generating capacity is commonly designated as cost-effectively providing flexible capacity, particularly during the recent era of low natural gas prices. Transmission resources can be used to provide balancing by the locational moving of energy from parts of the regional grid experiencing oversupply to parts experiencing undersupply. Storage resources can provide balancing by the temporal moving of energy from oversupply periods to undersupply periods. Demand response resources can also provide balancing by temporally moving the demand for energy from periods of undersupply to periods of oversupply.

For the 2017 IRP, Idaho Power continues to analyze resources on the basis of cost, specifically the cost of a resource to provide energy and capacity to the system. The IRP also qualitatively analyzes resources on the basis of their system attributes. In addition to the capability to provide flexible capacity, the system attributes analyzed include the capability to provide dispatchable capacity, non-dispatchable (i.e., coincidental) capacity, and energy. Importantly, energy in this qualitative analysis is considered to include not only baseload-type resources but also resources, such as wind and solar, that provide relatively predictable output when averaged over long periods (i.e., monthly or longer). The resource attribute analysis also designates those resources whose intermittent production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are compared using two cost metrics: levelized cost of capacity (fixed) (LCOC) and levelized cost of energy (LCOE). These metrics are discussed later in this section. The resource cost analysis performed for the IRP assumes Idaho Power incurs all costs of ownership and operation, even for resources for which this ownership paradigm has historically not been typical, such as for geothermal, wind, and solar resources. The assumption that Idaho Power incurs the total resource costs of ownership and operation allows a like-versus-like comparison between resources.

In resource cost calculations, Idaho Power assumes potential IRP resources have varying economic lives. Financial analysis for the IRP assumes the annual depreciation expense of capital costs is based on an apportionment of the capital costs over the entire economic life of a given resource.

The levelized costs for the various resource alternatives analyzed include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs of resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, plant construction costs, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an 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 B2H resource includes an offsetting cost associated with estimated transmission tariff revenue.

The levelized costs for demand-side resource options include annual program administrative and marketing costs, 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 provided in *Appendix C—Technical Appendix*.

LCOC—IRP Resources

The annual fixed revenue requirements in nominal dollars for each resource are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month. Included in these LCOCs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic lives, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. The LCOCs for the potential IRP resources are provided in Figure 7.5. B2H, after netting out transmission tariff revenue, is the lowest-cost resource in terms of LCOC. Other resources among those having a lower LCOC include demand response, reciprocating gas engines, and SCCTs.

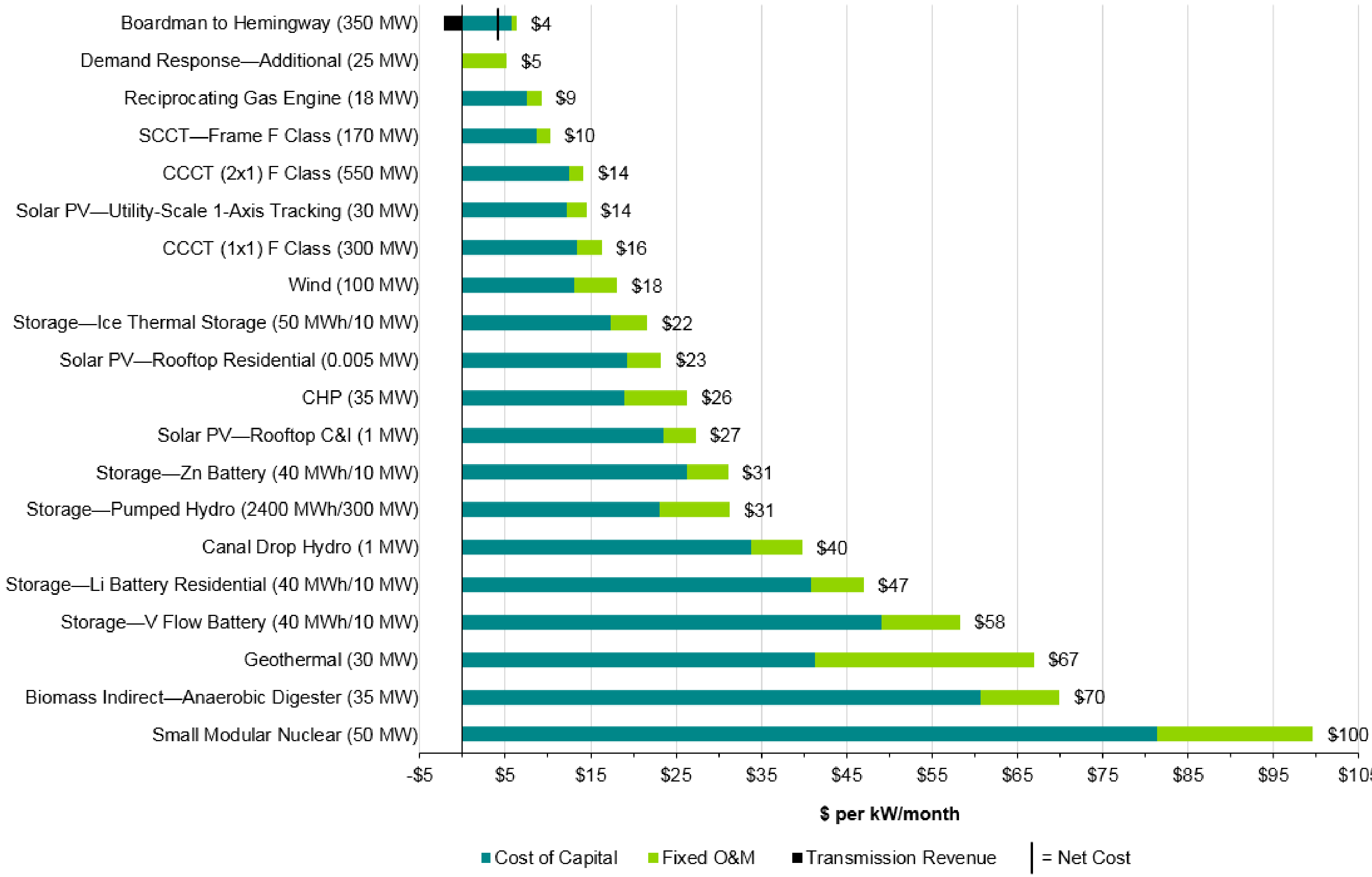


Figure 7.5 Levelized capacity (fixed) costs

LCOE—IRP Resources

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 (or zero) operating costs. The LCOE metric represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource. The nominal LCOE assuming the expected capacity factors for each resource is shown in Figure 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, integration costs, and wholesale energy for transmission and storage resources. Variable costs are offset by transmission tariff revenue for B2H, steam sales for CHP, and RECs for renewable-qualifying resources. B2H is the lowest-cost energy resource, followed by energy efficiency and natural gas-fired generation (CCCT).

When comparing LCOEs between resources, consistent assumptions for the computations must be used. The LCOE metric is the annual cost of energy over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; however, 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 LCOE calculation is the assumed level of annual energy output over the life of the resource being analyzed. The energy output is commonly expressed as a capacity factor. At a higher capacity factor, the LCOE is reduced as a result of spreading resource fixed costs over more MWh. Conversely, lower capacity-factor assumptions reduce the MWh over which resource fixed costs are spread, resulting in a higher LCOE.

For the portfolio cost analysis, resource fixed costs are annualized over the assumed economic life for each resource and are applied only to the years of output within the IRP planning period, thereby accounting for end effects.

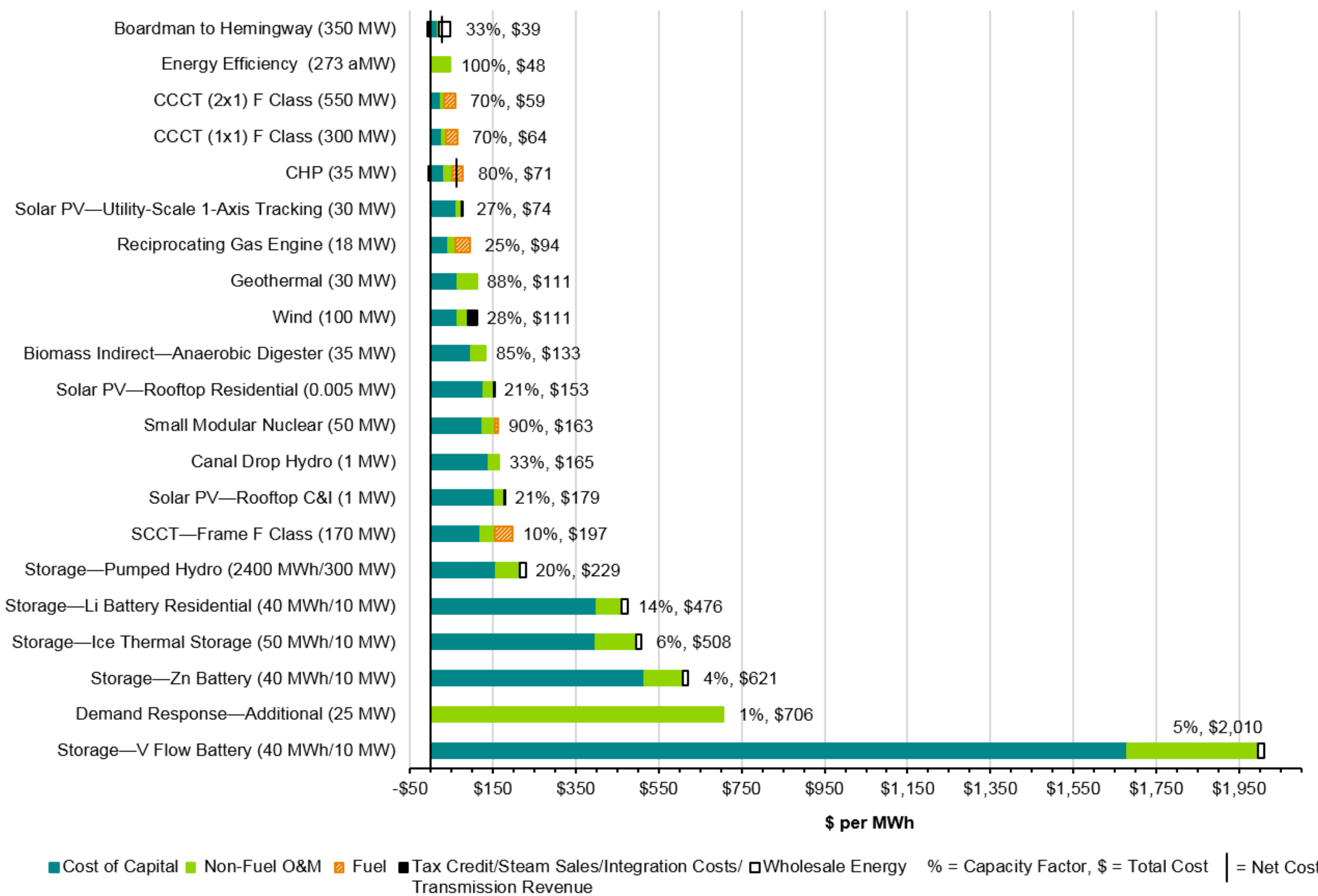


Figure 7.6 LCOE (as stated capacity factors)

Resource Attributes—IRP Resources

While the cost metrics described in this section are informative, caution must be exercised when comparing costs for resources providing different attributes or qualities to the power system. For the LCOC metric, this critical distinction arises because of differences for some resources between *installed* capacity and *on-peak* capacity. Specifically, for intermittent renewable resources, an installed capacity of 1 kW equates to an on-peak capacity of less than 1 kW. For example, wind is estimated to have an LCOC of $18 per month per kW of installed capacity.[18] However, assuming wind delivers on-peak capacity equal to 5 percent of installed capacity, the LCOC ($18/month/kW) converts to $360 per month per kW of on-peak capacity.

For the LCOE metric, the critical distinction between resources arises because of differences for some resources with respect to the timing at which MWh are delivered. For example, wind and geothermal have effectively equivalent LCOEs. However, the energy output from geothermal generating facilities tends to be delivered in a steady and predictable manner, including relatively dependably during peak-loading periods. Conversely, wind tends to less dependably deliver during the high-value peak-loading periods; in effect, the energy delivered from wind tends to be of lesser value than that delivered from geothermal, and because of this difference caution should be exercised when comparing LCOEs for these resources.

In recognition of differences between resource attributes, potential IRP resources for the 2017 IRP are classified based on their attributes or qualities. The following resource attributes are considered in this analysis:

- *Intermittent renewable*—Renewable resources, such as wind and solar, characterized by intermittent output and causing an increased need for resources providing balancing or flexibility
- *Dispatchable capacity-providing*—Resources that can be dispatched as needed to provide capacity during periods of peak-hour loading or to provide output during generally high-value periods
- *Non-dispatchable (coincidental) capacity-providing*—Resources whose output tends to naturally occur with moderate likelihood during periods of peak-hour loading or during generally high-value periods

[18] The units of the denominator can be expressed in reverse order from the cost estimates provided in Figure 7.5 without mathematically changing the cost estimate.

- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from intermittent renewable resources
- *Energy-providing*—Resources producing relatively predictable energy when averaged over long time periods (i.e., monthly or longer).

Table 7.3 provides classification of potential IRP resources with respect to the above attributes. The table also provides cost information as graphed previously and the estimated size potential and scalability for each resource.

Table 7.3 Resource attributes

Resource	Intermittent Renewable	Dispatchable Capacity-Providing	Non-Dispatchable (Coincidental) Capacity-Providing	Balancing/ Flexibility-Providing	Energy-Providing	LCOE ($/MWh)	LCOC ($/kW/Month)	Size Potential
Biomass Indirect—Anaerobic Digester		✓			✓	$133	$70	Scalable up to about 50 MW
B2H		✓		✓	✓	$39	$4	(200 Oct–March, 500 April–Sep)
Canal Drop Hydro		✓			✓	$165	$40	Scalable up to about 50 MW
CCCT (1x1)		✓		✓	✓	$64	$16	300-MW increments
CCCT (2x1)		✓		✓	✓	$59	$14	550-MW increments
CHP		✓			✓	$71	$26	Scalable up to about 50 MW
Demand Response—Additional		✓				$706	$5	Scalable up to achievable MW
Energy Efficiency			✓		✓	$48	N/A	Scalable up to achievable MWh
Geothermal		✓			✓	$111	$67	Scalable up to about 50 MW
Reciprocating Gas Engine		✓		✓	✓	$94	$9	18-MW increments
SCCT—Frame F Class		✓		✓		$197	$10	170-MW increments
Small Modular Nuclear		✓			✓	$163	$100	50-MW increments
Solar PV—Rooftop Commercial & Industrial	✓		✓		✓	$179	$27	Scalable
Solar PV—Rooftop Residential	✓		✓		✓	$153	$23	Scalable
Solar PV—Utility-Scale 1-Axis Tracking	✓		✓		✓	$74	$14	Scalable
Storage—Ice Thermal Storage		✓				$508	$22	Scalable
Storage—Lithium Battery Residential		✓		✓		$476	$47	Scalable
Storage—Pumped Hydro		✓		✓	✓	$229	$31	Scalable beyond about 100 MW
Storage—V Flow Battery		✓		✓		$2,010	$58	Scalable
Storage—Zinc Battery		✓		✓		$621	$31	Scalable
Wind	✓				✓	$111	$18	Scalable

IRP Resources and Portfolio Design

As described in the following chapter, the portfolio design for the 2017 IRP focuses on evaluating two key resource actions: the capital investment in environmental retrofits at Jim Bridger units 1 and 2, and the B2H transmission line. This portfolio design allows the 2017 IRP resource portfolios to be composed of resources that most cost competitively test the key resource actions while providing the necessary system attributes to ensure continued reliability. Based on Idaho Power's assessment of resource costs and resource attributes, the analysis of IRP resource portfolios containing natural gas-fired generating capacity (reciprocating engines and CCCTs), expanded demand response, and single-axis tracking solar PV is consistent with the portfolio design objectives of the 2017 IRP.

Idaho Power recognizes that resources attaining modest market penetration to date, particularly electrochemical energy storage technologies (i.e., battery technologies), may become increasingly cost competitive and in future IRPs outcompete natural gas-fired generating capacity. Idaho Power values the discussions held during IRPAC meetings related to emerging technologies and understands that the analysis of a variety of resource technologies, supply- and demand-side, is vital to long-term planning. The focused portfolio design of the 2017 IRP permits the development of portfolios containing resources demonstrated by today's analysis to be most cost competitive.

T&D Deferral Benefit Associated with DERs

The T&D deferral benefits associated with solar distributed energy resources (DER) were discussed at the T&D Deferral Workshop on December 19, 2016. The main considerations in determining the potential for solar DERs to defer T&D investments were discussed. Idaho Power performed a preliminary analysis to determine locations where solar DERs could result in an asset replacement deferral opportunity.

Several criteria were considered to determine viable candidates for asset deferral:

- Summer-peaking assets
- Peak loads that occur before 4:00 p.m.
- Assets that have a use factor at peak greater than or equal to 90 percent
- Load growth rate
- Cost of alternatives

Only two substation transformers and two feeders in Idaho Power's service area fit the criteria, representing approximately 0.5 percent of the total transformers and feeders.

However, Idaho Power is aware that the rapid decrease in the cost of solar PV and energy storage may provide future opportunities for asset replacement deferral. Idaho Power will continue to look for opportunities where DERs may result in cost-effective asset replacement deferral opportunities in the next few years.

Load and Resource Balance

Idaho Power assumes 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 sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for generation from all the company's existing resources and planned purchases. For the 2017 IRP, load and resource balances were developed for each of the four scenarios for Jim Bridger units 1 and 2. A baseline assumption in the load and resource balances is the early retirement of Valmy units 1 and 2 in 2019 and 2025, respectively. North Valmy units are assumed to be replaced with market purchases imported across the Idaho–Nevada path. Each Jim Bridger scenario will include a load and resource balance using average monthly energy planning assumptions and peak-hour planning assumptions.

Average-energy surpluses and deficits are determined using 70th-percentile water and 70th-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity.

Peak-hour load deficits are determined using 90th-percentile water and 95th-percentile peak-hour load conditions. 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.

All load and resource balances include the following:

- Existing demand reduction due to the demand response programs and the forecast effect of existing energy efficiency programs.
- Expected generation from all Idaho Power-owned resources. The Boardman coal plant has a planned retirement date of 2020. Additionally, the 2017 IRP includes a baseline assumption for the early retirement of Valmy Unit 1 at the end of 2019 and Valmy Unit 2 at the end of 2025.

- Firm Pacific Northwest import capability, including import capacity over the Idaho–Nevada path. The northbound capacity of this line has historically been fully subscribed with Idaho Power's share of energy from the North Valmy generation plant. The load and resource balance scenarios do not include the import capacity from the B2H transmission line or the Gateway West transmission line.

- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. The agreement with Elkhorn Valley Wind expires at the end of 2027, and a replacement contract is not contemplated. The agreement with Raft River Geothermal expires at the end of 2033 and is expected to be replaced. The agreement with Neal Hot Springs does not expire within the planning period.

- Existing PURPA projects and contracts. The 2017 IRP forecast includes all contracts completed by December 9, 2016. Since that time, one biomass project with a nameplate of 5 MW has been added and is scheduled to come on-line in 2018. Idaho Power assumes all PURPA contracts, except for wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the replacement contracts are negotiated.
  Wind projects are not expected to be renewed. Currently, 627 MW of wind are under PURPA contract, and contract expirations begin in October 2025. By February 2033, the total wind under contract drops to 130 MW and remains at that level through the end of the planning period.

At times of peak summer load, Idaho Power is using all ATC from the Pacific Northwest. If Idaho Power encountered 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.

Idaho Power's customers reach a maximum energy demand in the summer. From a resource adequacy perspective, July has historically been the month during which Idaho Power's system is most constrained. Based on projections for the 2017 IRP, July is likely to remain the most resource-constrained month. Table 7.4 provides the monthly average energy deficits, and Table 7.5 provides the monthly peak-hour deficits for July for each of the Jim Bridger futures considered in the 2017 IRP. Darker shading in the tables corresponds with larger deficits, which occur more in later years and begin earlier with the retirement of units 1 and 2 in 2021 and 2022, respectively. Surplus positions are not specified in the tables. Because no deficits exist prior to 2023, the tables include data only for the period 2023 to 2036.

Table 7.4 July monthly average energy deficits (aMW) by Bridger coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)

Energy Deficits (aMW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	0	0	0	0	(9)	(80)	(107)	(173)	(200)	(226)	(256)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	0	(11)	(41)	(105)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	0	0	0	(143)	(177)	(248)	(276)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2021, 2022	0	(16)	(38)	(180)	(209)	(273)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)

Note: Darker shading indicates increasing deficit values.

Table 7.5 July monthly peak-hour capacity deficits (MW) by Bridger coal future with existing and committed supply- and demand side resources (90th-percentile water and 95th-percentile load)

Capacity Deficits (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	(34)	(94)	(159)	(222)	(282)	(346)	(399)	(464)	(521)	(576)	(635)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	(152)	(210)	(270)	(335)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	(34)	(94)	(159)	(397)	(458)	(521)	(574)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2021, 2022	(213)	(275)	(328)	(386)	(445)	(510)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)

Note: Darker shading indicates increasing deficit values.

8. Portfolios

Portfolio Design

Idaho Power designed the portfolio analysis for the 2017 IRP with the objective of informing the IRP's Action Plan with respect to two key resource actions: 1) SCR investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively, and 2) the B2H transmission line. To achieve this objective, the portfolio design consisted of four Jim Bridger SCR investment scenarios, with three resource portfolios formulated within each scenario, resulting in 12 resource portfolios. The SCR investment scenarios study a range of early retirement scenarios at Jim Bridger units 1 and 2 versus a scenario in which the SCR investments are made. The three resource portfolios formulated within each SCR investment scenario include one B2H-focused portfolio and two B2H alternative portfolios. The portfolio design is considered to approximate a controlled experiment isolating two key factors: 1) the cost-effectiveness of making the SCR investments versus practicable early retirement alternatives and 2) the cost-effectiveness of B2H in meeting resource needs versus practicable resource alternatives. This type of portfolio design is also described as a factorial experimental design. Further discussion of the portfolio design is provided in Chapter 1 and at the end of this chapter.

To analyze the SCR investments for Jim Bridger, four scenarios were analyzed:

1. *Scenario* 1—Install SCRs and operate Jim Bridger units 1 and 2 through the end of the planning period.
2. *Scenario 2*—Do not make SCR investments and retire Jim Bridger units 1 and 2 at year-end 2028 and year-end 2024, respectively.
3. *Scenario 3*—Do not make SCR investments are retire Jim Bridger units 1 and 2 at year-end 2032 and year-end 2028, respectively.
4. *Scenario 4*—Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

The B2H alternative portfolios within each Jim Bridger SCR investment scenario have similar characteristics: an alternative portfolio containing a mix of solar- and natural gas-powered generating capacity, and a second alternative containing solely natural gas-powered generating capacity. Demand response capacity is also added to the B2H alternative portfolios in two steps in the early- to mid-2020s. The supply- and demand-side resources composing the B2H alternative portfolios set the highest standard for B2H economics based on current costs. The portfolio design objective is to determine whether a B2H-based portfolio can be outperformed based on current cost estimates of alternative resources. The resources judged to practicably set the highest standard for B2H cost-effectiveness included expanded demand response, flexible capacity-providing natural gas-fired reciprocating engines, single-axis solar

PV, and natural gas-fired CCCTs. Other potential IRP resources were analyzed and considered for inclusion in portfolios. However, the inclusion of less cost-effective resources would lower the standard for the evaluation of B2H.

Capacity needs require the addition of natural gas-powered generating capacity to the B2H-based portfolios; however, this added generating capacity is relatively small compared to B2H, and the costs and benefits of the B2H-based portfolios are considered primarily driven by B2H as a portfolio element. Detailed portfolio descriptions are provided later in this chapter.

The SCR compliance alternatives considered in this IRP are in recognition of past negotiations between owners of coal-powered generating units, regulators, and other stakeholders that yielded a resolution permitting extended operation in exchange for early unit retirement. Idaho Power views the analyzed compliance alternatives as placeholder assumptions representing negotiated resolutions permitting varying operation extensions. The company does not presuppose extensions will be necessarily negotiated, nor that specific alternatives analyzed in this IRP are more likely outcomes than other possible early retirement dates.

Energy savings achieved from implementing cost-effective energy efficiency programs and measures are included in all portfolios prior to the inclusion of supply-side resources. The forecasted energy savings are based on the assessment performed by AEG for Idaho Power. The AEG assessment and the projected energy savings are discussed in Chapter 5.

Studied Portfolios

The following sections describe the portfolios analyzed for each Jim Bridger scenario. All portfolios are designed to balance forecast load with available or additional resources to eliminate energy and capacity deficits according to the IRP planning criteria described in Chapter 7. The energy and capacity deficits for the Jim Bridger scenarios are also provided in Chapter 7.

Jim Bridger Scenario 1

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are made and Jim Bridger units 1 and 2 are operable through the end of the planning period. P1 is the B2H-based portfolio. P2 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity. The reciprocating engine generating capacity of P2 is considered to provide the flexible capacity necessary to reliably integrate the solar-powered capacity of the portfolio. The single-axis solar PV generating capacity is assumed to deliver peak-hour capacity equal to 51.3 percent of installed (AC) nameplate capacity. The analysis supporting the assumed peak-hour capacity for solar-powered PV generating capacity is discussed in Chapter 4. P3 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P2 and P3 include added demand response capacity developed in two steps in 2021 and 2026.

P1

Table 8.1 P1 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2034	Reciprocating engines	36	36
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total	**644**	**644**

Table 8.2 P1 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	144

P2

Table 8.3 P2 timeline

Date	Resource	Installed Capacity	Peak-Hour Capacity
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	25	13
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	50	26
2029	Reciprocating engines	36	36
2029	Single-axis solar PV	50	26
2030	Reciprocating engines	36	36
2030	Single-axis solar PV	50	26
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	50	26
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	35	18
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	60	31
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	45	23
2035	Reciprocating engines	36	36
2035	Single-axis solar PV	40	21
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	45	23
	Total*	**860**	**643**

*Includes demand response

Table 8.4 P2 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	450
Natural gas	360

P3

Table 8.5 P3 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	54	54
2028	Reciprocating engines	54	54
2029	Reciprocating engines	72	72
2030	Reciprocating engines	54	54
2031	CCCT (1x1)	300	300
2036	Reciprocating engines	54	54
	Total*	**638**	**638**

*Includes demand response

Table 8.6 P3 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	588

Jim Bridger Scenario 2

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are permitted to operate through 2028 and 2024, respectively. Within this scenario, P4 is the B2H-based portfolio. P5 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including a 300 MW CCCT. P6 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P5 and P6 include added demand response capacity developed in two steps in 2021 and 2026.

P4

Table 8.7 P4 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2029	Reciprocating engines	72	72
2030	Reciprocating engines	72	72
2031	Reciprocating engines	54	54
2032	Reciprocating engines	54	54
2033	Reciprocating engines	72	72
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	36	36
	Total	**968**	**968**

Table 8.8 P4 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	468

P5

Table 8.9 P5 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2025	Reciprocating engines	54	54
2025	Single-axis solar PV	140	72
2026	Demand response	25	25
2026	Reciprocating engines	18	18
2026	Single-axis solar PV	35	18
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	45	23
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	55	28
2029	Reciprocating engines	300	300
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	55	28
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	40	21
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	55	28

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	45	23
2035	Reciprocating engines	36	36
2035	Single-axis solar PV	25	13
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	25	13
	Total*	**1,230**	**977**

*Includes demand response

Table 8.10 P5 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	520
Natural gas	660

P6

Table 8.11 P6 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2025	Reciprocating engines	126	126
2026	Demand response	25	25
2026	Reciprocating engines	36	36
2027	Reciprocating engines	72	72
2028	Reciprocating engines	54	54
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	72	72
2032	Reciprocating engines	54	54
2033	Reciprocating engines	54	54
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total*	**980**	**980**

*Includes demand response

Table 8.12 Resource P6 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	930

Jim Bridger Scenario 3

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are permitted to operate through 2032 and 2028, respectively. Within this scenario, P7 is the B2H-based portfolio. P8 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including two 300-MW CCCTs. P9 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P8 and P9 include added demand response capacity developed in two steps in 2021 and 2026.

P7

Table 8.13 P7 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2031	Reciprocating engines	36	36
2032	Reciprocating engines	36	36
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
	Total	**980**	**980**

Table 8.14 P7 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	480

P8

Table 8.15 P8 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	25	13
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	50	26
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	50	26

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	35	18
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	18	18
2035	Single-axis solar PV	55	28
2036	Reciprocating engines	18	18
2036	Single-axis solar PV	60	31
	Total*	**1,105**	**972**

*Includes demand response

Table 8.16 P8 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	275
Natural gas	780

P9

Table 8.17 P9 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2026	Demand response	25	25
2027	Reciprocating engines	54	54
2028	Reciprocating engines	54	54
2029	CCCT (1x1)	300	300
2031	Reciprocating engines	72	72
2032	Reciprocating engines	54	54
2033	CCCT (1x1)	300	300
2035	Reciprocating engines	36	36
2036	Reciprocating engines	54	54
	Total*	**974**	**974**

*Includes demand response

Table 8.18 P9 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	924

Jim Bridger Scenario 4

Three portfolios were developed for the Jim Bridger scenario in which the SCR investments are not made and Jim Bridger units 1 and 2 are retired on their respective compliance dates of year 2022 and year-end 2021. Within this scenario, P10 is the B2H-based portfolio. P11 is the B2H alternative portfolio containing a blend of solar- and natural gas-powered generating capacity, including two 300-MW CCCTs. P12 is the B2H alternative portfolio composed of natural gas-powered generating capacity. In addition to supply-side capacity, P11 and P12 include added demand response capacity developed in two steps in 2021 and 2026.

P10

Table 8.19 P10 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2023	Reciprocating engines	216	216
2024	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2032	Reciprocating engines	54	54
2033	Reciprocating engines	54	54
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	36	36
	Total	**968**	**968**

Table 8.20 P10 resource summary

Resource	Installed Capacity (MW)
B2H (Apr–Sep capacity)	500
Natural gas	468

P11

Table 8.21 P11 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2023	Reciprocating engines	108	108
2023	Single-axis solar PV	155	80
2024	Reciprocating engines	36	36
2024	Single-axis solar PV	55	28
2025	Reciprocating engines	36	36
2025	Single-axis solar PV	30	15
2026	Demand response	25	36
2026	Reciprocating engines	18	18
2026	Single-axis solar PV	30	15
2027	Reciprocating engines	36	36
2027	Single-axis solar PV	50	26
2028	Reciprocating engines	36	36
2028	Single-axis solar PV	60	31
2029	Reciprocating engines	36	36
2029	Single-axis solar PV	50	26
2030	Reciprocating engines	36	36
2030	Single-axis solar PV	50	26
2031	Reciprocating engines	36	36
2031	Single-axis solar PV	55	28
2032	Reciprocating engines	36	36
2032	Single-axis solar PV	40	21
2033	Reciprocating engines	36	36
2033	Single-axis solar PV	55	28
2034	Reciprocating engines	36	36
2034	Single-axis solar PV	50	26
2035	Reciprocating engines	18	18
2035	Single-axis solar PV	60	31
2036	Reciprocating engines	36	36
2036	Single-axis solar PV	25	13
	Total*	**1,355**	**995**

*Includes demand response

Table 8.22 P11 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Solar	765
Natural gas	540

P12

Table 8.23 P12 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2021	Demand response	25	25
2023	CCCT (1x1)	300	300
2026	Demand response	25	25
2026	Reciprocating engines	36	36
2027	Reciprocating engines	72	72
2028	Reciprocating engines	54	54
2029	Reciprocating engines	72	72
2030	Reciprocating engines	54	54
2031	CCCT (1x1)	300	300
2036	Reciprocating engines	36	36
	Total*	**974**	**974**

*Includes demand response

Table 8.24 P12 resource summary

Resource	Installed Capacity (MW)
Demand response	50
Natural gas	924

Portfolio Design with Two Factors

The portfolio analysis for the 2017 IRP is described as a factorial design. This type of experimental design allows an analysis isolating on two (or more) factors, each factor having more than one level describing it. The two factors studied in the portfolio analysis with their respective levels are as follows:

- **Factor 1:** Treatment of Jim Bridger units 1 and 2
    - Level 1: Invest in SCRs and operate through 2036
    - Level 2: Retire Unit 1 in 2028 and Unit 2 in 2024 (without investing in SCRs)
    - Level 3: Retire Unit 1 in 2032 and Unit 2 in 2028 (without investing in SCRs)
    - Level 4: Retire Unit 1 in 2022 and Unit 2 in 2021 (without investing in SCRs)

- **Factor 2:** Primary portfolio element(s)
    - Level 1: B2H
    - Level 2: Solar PV/natural gas-fired generation
    - Level 3: Natural gas-fired generation

Table 8.25 provides a matrix of the factorial design with the portfolios corresponding to each factorial combination.

Table 8.25 Factorial design applied to portfolios

	Primary Portfolio Element(s)		
Treatment of Jim Bridger Units 1 and 2	**B2H**	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

Importantly, to validate this design, portfolios must be devised so they can be categorized according to the studied factor levels. For example, P4, P5, and P6 must all include retirement of Jim Bridger units 1 and 2 in 2028 and 2024, respectively. Similarly, P2, P5, P8, and P11 must all be characterized as having solar PV and natural gas-fired generation as their primary portfolio elements. A tabulation of the portfolio analysis results in the form of the factorial design is provided in Chapter 9.

9. Modeling Analysis and Results

Planning Case Portfolio Analysis

Idaho Power evaluated the net present value (NPV) costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to serve customer load using all resources in the portfolio.

The IRP portfolio costs consist of fixed and variable components. The fixed component includes annualized capital costs for new portfolio resources, including transmission interconnection costs for new generating facilities, fixed O&M costs, and return on investment (ROI). Capital costs for new resources are annualized over the resource's estimated economic life. Annualized capital costs beyond the IRP planning window (2017–2036) are not included in portfolio costs.

Portfolios that consider early retirement of coal units include costs for the accelerated recovery of depreciation expenses and accelerated recovery of estimated decommissioning and demolition costs (net of salvage). The costs of coal-retirement portfolios are countered by savings from avoiding future coal plant capital upgrades and fixed operating expenses beyond the early retirement dates, including avoidance of environmental retrofit upgrades where applicable.

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

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

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results.

Portfolio costs are calculated as the NPV of the 20-year stream of annualized costs, fixed and variable, for each portfolio. 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 capital cost)	6.74%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	2.10%
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)	7.72%

Idaho Power is limiting the CAA Section 111(d) analysis to a state-by-state mass-based approach. Under state-by-state mass-based compliance, CAA Section 111(d) proposed state-specific target reductions are the basis for compliance. Langley Gulch is assumed to be unconstrained. The proposed target reductions are defined in Table 9.2.

Table 9.2 Proposed target reductions for state-by-state mass-based compliance (Idaho Power share)

Affected Source	2022–2024 Target MWh	2025–2027 Target MWh	2028–2029 Target MWh	2030 and Beyond Target MWh
Jim Bridger Below 2012	3,499,795 (-23%)	3,176,356 (-30%)	2,986,317 (-34%)	2,873,560 (-37%)
North Valmy Below 2012	790,247 (-3%)	737,627 (-9%)	715,611 (-12%)	708,848 (-13%)

The planning case natural gas price variable costs, the new resource fixed costs, and the Bridger units 1 and 2 fixed costs are shown in Table 9.3.

Table 9.3 2017 IRP Portfolios, NPV years 2017–2036 ($ x 1,000)

Portfolio Details				Variable Costs			New Resource Fixed Costs			Bridger	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)	Operating (AURORA) (5)	Rank (6)	Relative Difference (7)	Portfolio Fixed Costs (8)	Rank (9)	Relative Difference (10)	Bridger Fixed Costs (11)	Total Fixed + Variable Costs (12) = (5) + (8) + (11)	Lowest Cost Rank (13)	Lowest Cost Relative Difference (14)
P1	SCR invest, B2H, recips	✓		$5,782,181	10	$252,923	$91,266	1	–	$527,249	$6,400,696	4	$64,925
P2	SCR invest, DR, recips, solar			$5,670,820	4	$141,562	$299,436	5	$208,169	$527,249	$6,497,505	6	$161,733
P3	SCR invest, DR, recips, CCCT			$5,731,938	8	$202,679	$271,669	4	$180,403	$527,249	$6,530,856	9	$195,084
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	$5,796,035	11	$266,777	$207,739	2	$116,473	$334,909	$6,338,683	2	$2,912
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	$5,577,721	2	$48,463	$653,937	10	$562,671	$334,909	$6,566,567	10	$230,796
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	$5,729,526	7	$200,267	$443,808	8	$352,541	$334,909	$6,508,242	8	$172,470
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	$5,755,589	9	$226,331	$214,229	3	$122,963	$365,952	$6,335,771	1	–
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	$5,654,210	3	$124,951	$483,362	9	$392,096	$365,952	$6,503,524	7	$167,753
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	$5,701,053	6	$171,794	$415,995	7	$324,729	$365,952	$6,483,000	5	$147,229
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	$5,807,951	12	$278,693	$309,227	6	$217,961	$283,328	$6,400,507	3	$64,736
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	$5,529,258	1	–	$767,183	12	$675,917	$283,328	$6,579,769	11	$243,998
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	$5,689,172	5	$159,914	$699,009	11	$607,743	$283,328	$6,671,510	12	$335,739

Under the planning case natural gas price, P7 has a total fixed and variable 20-year NPV cost of $6,335,771,000 and a lowest cost rank of 1.

Natural Gas Price Sensitivities

The planning case natural gas shown in Table 9.3 reflects a 2017 IRP lower bound of future gas prices. An additional eight natural gas price sensitivities described as 125, 150, 175, 200, 225, 250, 300, and 400 percent of the planning case price were modeled for each of the 12 portfolios. The natural gas price sensitivities represent a phasing-in of the named percentage over the years 2017 to 2026 and the full named percentage escalation for 2027 to 2036.

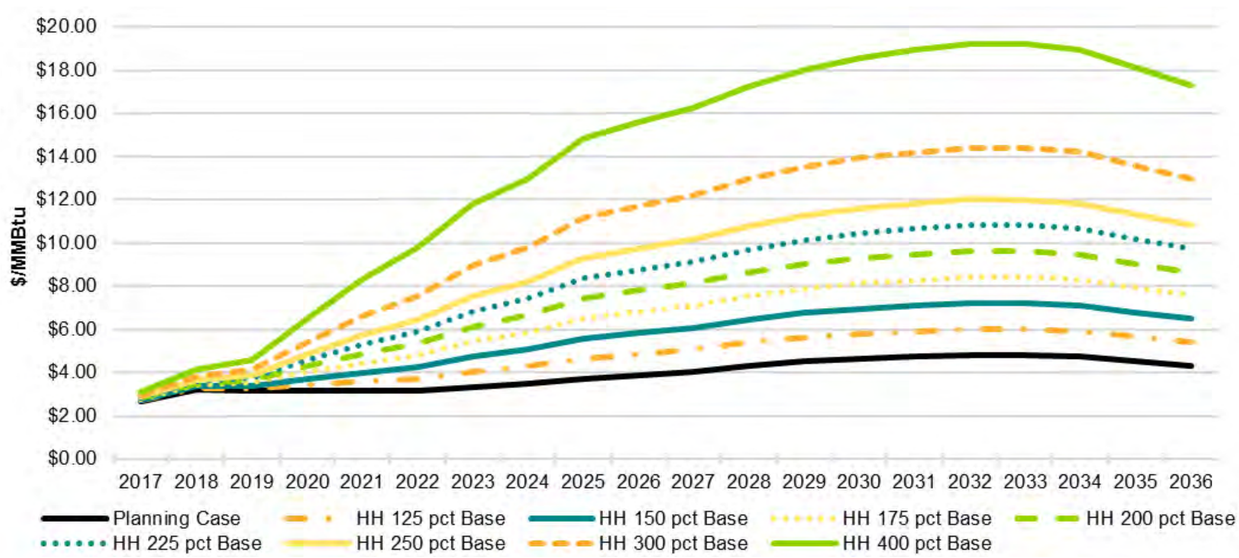


Figure 9.1 Natural gas planning case and eight sensitivities (nominal $)

The relative difference between the NPV of the lowest-cost portfolio under the natural gas price planning case and eight higher natural gas sensitivities, along with the rankings of the 12 portfolios under the nine Natural Gas Price forecasts, are shown in Table 9.4 and Table 9.5.

Table 9.4 Portfolio relative costs under nine natural gas price forecasts, NPV years 2017–2036 ($ x 1,000)

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	$64,925	$161,733	$195,084	$2,912	$230,796	$172,470	–	$167,753	$147,229	$64,736	$243,998	$335,739
HH 125 Percent	$58,058	$142,953	$188,386	$7,376	$207,186	$173,025	–	$155,281	$142,220	$85,896	$229,666	$352,890
HH 150 Percent	$58,142	$129,040	$186,163	$13,472	$183,556	$172,346	–	$143,472	$138,386	$105,611	$212,513	$363,972
HH 175 Percent	$63,386	$120,284	$187,910	$19,377	$162,044	$174,491	–	$133,714	$136,153	$127,583	$196,759	$374,576
HH 200 Percent	$60,514	$102,090	$182,606	$23,856	$135,130	$171,846	–	$119,610	$128,671	$143,776	$174,778	$378,449
HH 225 Percent	$61,904	$92,582	$180,551	$28,388	$110,252	$172,598	–	$106,629	$125,133	$162,122	$154,081	$384,389
HH 250 Percent	$60,720	$76,879	$177,400	$31,620	$84,098	$167,438	–	$93,640	$118,182	$178,368	$130,579	$388,352
HH 300 Percent	$60,257	$50,595	$174,637	$44,796	$35,071	$168,937	–	$72,161	$114,453	$215,307	$89,851	$404,734
HH 400 Percent	$114,023	$50,128	$216,370	$126,783	–	$230,108	$61,658	$82,446	$156,364	$342,022	$61,587	$494,597

Note: Darker shading indicates increasing values.

Table 9.5 Portfolio rankings under nine natural gas price forecasts

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	4	6	9	2	10	8	1	7	5	3	11	12
HH 125 Percent	3	6	9	2	10	8	1	7	5	4	11	12
HH 150 Percent	3	5	10	2	9	8	1	7	6	4	11	12
HH 175 Percent	3	4	10	2	8	9	1	6	7	5	11	12
HH 200 Percent	3	4	11	2	7	9	1	5	6	8	10	12
HH 225 Percent	3	4	11	2	6	10	1	5	7	9	8	12
HH 250 Percent	3	4	10	2	5	9	1	6	7	11	8	12
HH 300 Percent	5	4	10	3	2	9	1	6	8	11	7	12
HH 400 Percent	6	2	9	7	1	10	4	5	8	11	3	12

Note: Darker shading indicates increasing values.

P7 ranks first under eight of the nine natural gas price escalation sensitivities. P5 ranks first under the highest natural gas price sensitivity.

Stochastic Risk Analysis

The stochastic analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and the degree to which they can affect the analysis results (i.e., portfolio costs).

Idaho Power identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Natural gas prices follow a log-normal distribution adjusted upward from the planning case gas price forecast, which is shown as the dashed line in Figure 9.2. Natural gas prices are adjusted upward from the planning case to capture upward risk in natural gas prices. The correlation factor used for the year-to-year variability is 0.60, which is based on historic values from 1997 through 2015.

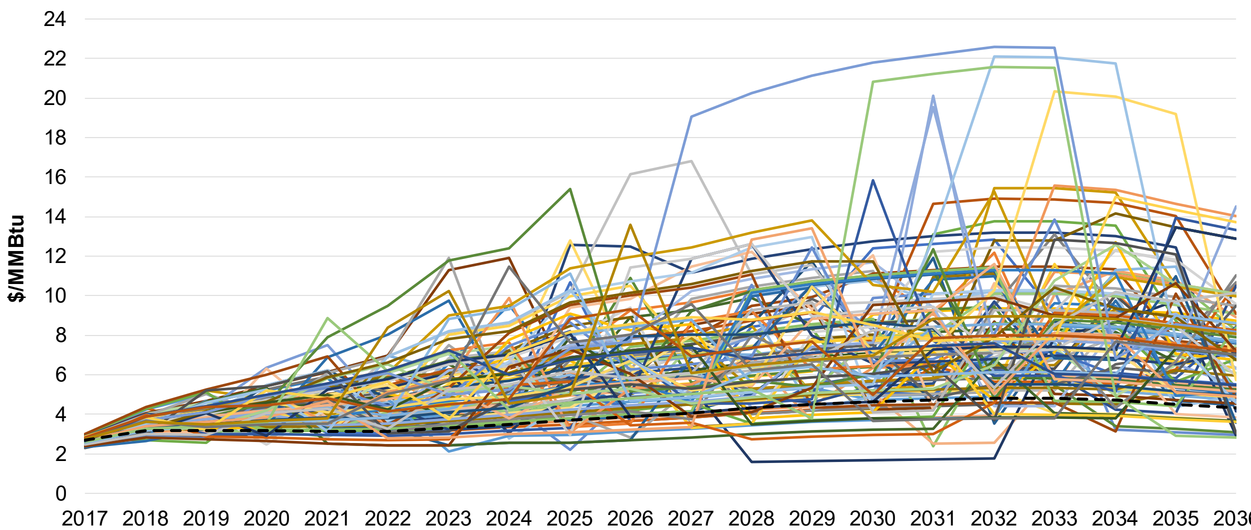


Figure 9.2 Natural gas sampling (Nominal $/MMBtu)

2. *Customer load*—Customer load follows a normal distribution and is adjusted around the planning case load forecast, which is shown as the dashed line in Figure 9.3.

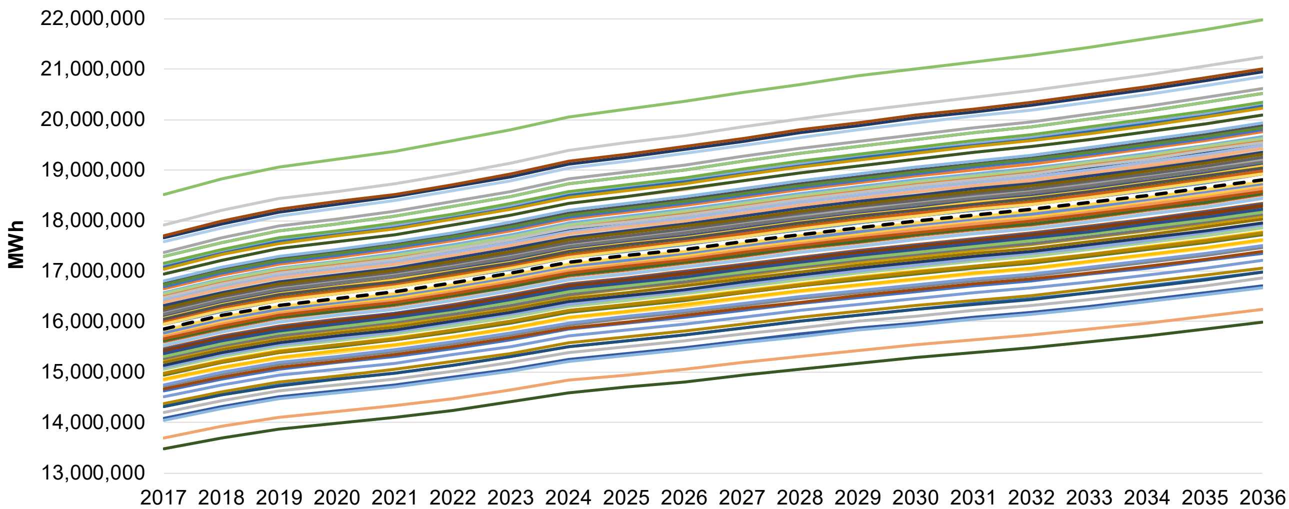


Figure 9.3 Customer load sampling (annual MWh)

3. *Hydroelectric variability*—Hydroelectric variability follows a log-normal distribution and is adjusted around the planning case hydroelectric generation forecast, which is shown as the black dashed line in Figure 9.4. The correlation factor used for the year-to-year variability is 0.50, which is based on historic values from 1975 through 2015.

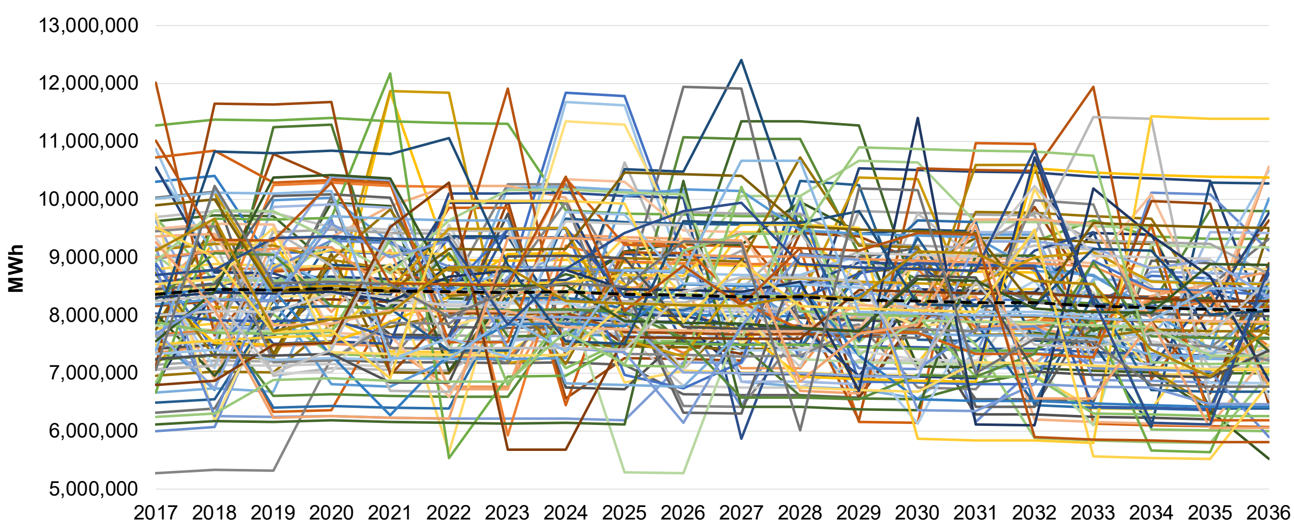


Figure 9.4 Hydro generation sampling (annual MWh)

The three selected stochastic variables are key drivers of variability in year-to-year power-supply costs and therefore provide suitable stochastic shocks to allow differentiated results for analysis.

The purpose of the analysis is to understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations) and how the ranges for portfolios differ.

Idaho Power created a set of 100 iterations based on the three stochastic variables (hydro condition, load, and natural gas price). Idaho Power then calculated the 20-year NPV portfolio cost for each of the 100 iterations for all 12 portfolios. The distribution of 20-year NPV portfolio costs for all 12 portfolios is shown in Figure 9.5.

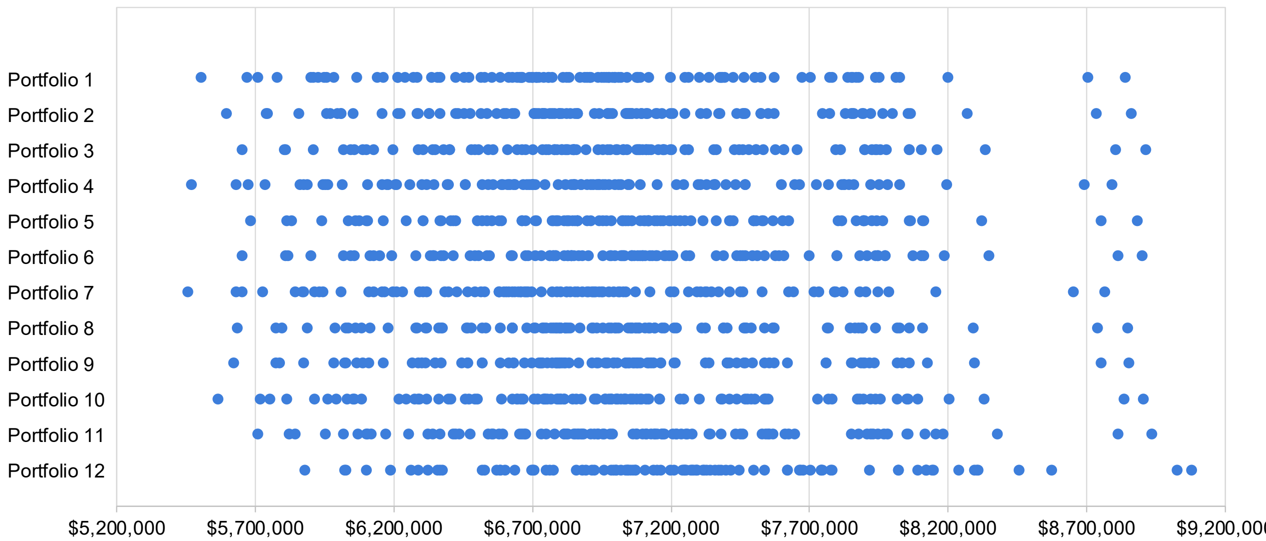


Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2017–2036 ($ x 1,000)

The horizontal axis on Figure 9.5 represents the portfolio cost (NPV) in millions of dollars, and the 12 portfolios are represented by their designation on the vertical axis. Each portfolio has 100 dots for the 100 different stochastic iterations scattered across different NPV ranges. P7 is the lowest-cost portfolio for 92 of the 100 stochastic iterations. P4 is the lowest-cost portfolio for the remaining eight stochastic iterations.

Table 9.6 is a descriptive statistical table for all 12 portfolios after the NPV is calculated for each of the 100 stochastic iterations. When calculated for the 100 iterations, P7 ranked the lowest in average, median, lowest minimum value, and lowest maximum value. P5 ranked the lowest in the standard deviation value. While P5, with 520 MW of installed solar PV capacity, has the lowest standard deviation, the approximately $20 million difference between its standard deviation and that for P7 is small when compared to the $175 million by which average portfolio costs for P7 are lower than those for P5. The difference in median portfolio costs between P7 and P5 is even greater at approximately $195 million.

Table 9.6 AURORA variable + fixed costs, NPV years 2017–2036 ($ x 1,000)

Portfolio	Average	Rank	Median	Rank	Standard Deviation	Rank	Minimum	Rank	Maximum	Rank
P1	$6,918,595	3	$6,894,944	3	$658,486	10	$5,505,259	3	$8,839,719	3
P2	$6,975,320	4	$6,956,065	4	$648,415	7	$5,597,752	5	$8,862,931	6
P3	$7,036,514	8	$7,005,725	8	$648,272	6	$5,651,871	8	$8,913,532	10
P4	$6,888,487	2	$6,854,217	2	$661,474	11	$5,469,530	2	$8,794,886	2
P5	$7,041,812	10	$7,026,159	10	$634,864	1	$5,686,144	10	$8,882,295	7
P6	$7,040,185	9	$7,021,875	9	$649,384	8	$5,654,847	9	$8,903,320	8
P7	$6,867,722	1	$6,831,522	1	$655,351	9	$5,458,222	1	$8,766,645	1
P8	$7,003,716	7	$6,980,730	7	$639,107	2	$5,638,058	7	$8,850,010	4
P9	$7,000,725	6	$6,970,350	5	$643,279	3	$5,623,483	6	$8,852,332	5
P10	$6,991,750	5	$6,971,770	6	$671,318	12	$5,566,108	4	$8,907,014	9
P11	$7,073,118	11	$7,071,434	11	$644,490	4	$5,708,125	11	$8,934,737	11
P12	$7,249,564	12	$7,244,615	12	$647,536	5	$5,880,258	12	$9,078,774	12

Portfolio Analysis Results in Factorial Design Format

As discussed in Chapter 8, the portfolio analysis for the 2017 IRP uses a factorial design. Table 9.7 presents the results of the design.

Table 9.7 2017 IRP portfolios, NPV years 2017–2036 ($ x 1,000)

	Primary Portfolio Element(s)				
Treatment of Jim Bridger Units 1 and 2	B2H	Solar PV/ Natural Gas	Natural Gas	Average	Rank
Invest in SCR	$6,400,696	$6,497,505	$6,530,856	$6,476,352	3
Retire Unit 1 in 2028 and Unit 2 in 2024	$6,338,683	$6,566,567	$6,508,242	$6,471,164	2
Retire Unit 1 in 2032 and Unit 2 in 2028	$6,335,771	$6,503,524	$6,483,000	$6,440,765	1
Retire Unit 1 in 2022 and Unit 2 in 2021	$6,400,507	$6,579,769	$6,671,510	$6,550,595	4
Average	$6,368,915	$6,536,842	$6,548,402		
Rank	1	2	3		

A review of the row averages indicates the lowest-cost level of the factor related to the treatment of Jim Bridger units 1 and 2 is the 2032 (Unit 1) and 2028 (Unit 2) retirement scenario. Similarly, reviewing the column averages indicates the B2H-based portfolios are low cost. These findings support P7 as the low-cost portfolio, but they are also instrumental in allowing the IRP's portfolio analysis to inform the action plan with respect to the cost-effectiveness of the SCR investments and B2H.

Solar Tipping-Point Analysis

At the direction of the IRPAC, a solar tipping-point analysis was performed to evaluate the sensitivity of the portfolio rankings to a reduction in solar cost. The solar tipping-point analysis reduces the capital cost of the solar PV included in P2, P5, P8, and P11 by 50 percent and 100 percent from the base-case capital cost of $1,375 per kW. The impact of the reduced solar capital costs on the NPV ranking of portfolios is shown in Table 9.8.

Assuming solar capital costs are reduced by 50 percent, P7 and P4 remain the two lowest-cost portfolios. P11, with 765 MW of installed solar capacity, is the third lowest in the 50-percent reduction case, moving up eight positions from its ranking under base-case capital costs. Assuming solar capital costs are reduced by 100 percent (i.e., free solar), P11, P5 (520 MW installed solar), and P2 (450 MW installed solar) are the lowest-ranked portfolios. P7 is the fourth lowest-cost portfolio in the 100-percent reduction case.

The conclusion is the economic performance of P7 under a reduction in solar costs is very robust.

Table 9.8 2017 IRP portfolios, NPV years 2017–2036 ($ x 1,000)

Portfolio Details				Planning Case		50% Reduction		100% Reduction	
Portfolio Index	Portfolio Description	B2H	Bridger Capacity Retirement	Rank	Lowest Cost Relative Difference	Rank	Lowest Cost Relative Difference	Rank	Lowest Cost Relative Difference
P1	SCR invest, B2H, recips	✓		4	$64,925	5	$64,925	7	$290,518
P2	SCR invest, DR, recips, solar			6	$161,733	6	$85,878	3	$219,766
P3	SCR invest, DR, recips, CCCT			9	$195,084	11	$195,084	11	$420,678
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	2	$2,912	2	$2,912	5	$228,505
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	10	$230,796	7	$101,391	2	$170,539
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	8	$172,470	10	$172,470	10	$398,064
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	1	–	1	–	4	$225,593
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	7	$167,753	8	$125,487	8	$299,982
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	5	$147,229	9	$147,229	9	$372,822
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	3	$64,736	4	$64,736	6	$290,329
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	11	$243,998	3	$31,413	1	–
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	12	$335,739	12	$335,739	12	$561,332

Qualitative Risk Analysis

The quantitative portfolio cost analysis indicates P7 as the lowest-cost portfolio. For the 2017 IRP, Idaho Power is assessing qualitative risk in terms of each portfolio's exposure to selected qualitative risk factors relative to P7's exposure to the same risk factors.
This comparative analysis recognizes that differing exposure to qualitative risks can lead to the selection of a preferred portfolio different from the portfolio emerging as the lowest-cost portfolio from the quantitative analysis. Idaho Power has expanded the qualitative analysis to not only assess differing exposure to qualitative risks but also differing exposure to qualitative benefits. The considered qualitative risks and benefits are described in the following sections.

Qualitative Risks

Hydro—Water Supply Risk

The long-term sustainability of the Snake River Basin streamflows is important for Idaho Power to sustain hydro generation as a resource to meet future demand. Several assumptions related to the management of streamflows were made in developing the 20-year streamflow forecasts for the IRP. These assumptions include the following:

- The implementation of aquifer management practices on the ESPA, including aquifer recharge, system conversions, and the Conservation Reserve Enhancement Program (CREP)
- Future irrigation demand and return flows
- Declines in reach gains tributary to the Snake River
- Expansion of weather-modification efforts (i.e., cloud seeding).

The assumptions used in developing the 20-year streamflow forecast are carefully planned and based on the current knowledge of Idaho Power staff in consultation with other stakeholders. Those assumptions are also subject to the limitations of the current forecasting models.

Additional risks to future hydro generation not included in the development of the 20-year streamflow outlook consist of the following:

- Changes in the timing and demand for irrigation water due to climate variability
- Changes to the sources of flow augmentation water and the potential for overestimation of flow augmentation availability in low-water years
- Long-term changes in the timing of flood control releases at Brownlee Reservoir in response to earlier snowmelt

- The potential for underestimation of the decline in reach gains within the Snake River Basin
- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

Relicensing Risk

Working within the constraints of the original FERC licenses, the HCC has historically provided operational flexibility that has benefited Idaho Power's customers. The operational flexibility of the HCC is increasingly critical to the successful integration of variable-energy resources. As a result of the FERC relicensing process, operational requirements, such as minimum reservoir elevations, minimum flows, and limitations on ramping rates, may become more stringent. The loss of operational flexibility will limit Idaho Power's ability to optimally manage the HCC, making the integration of variable-energy resources more challenging and ultimately increasing power-supply costs.

Regulatory Risk

Idaho Power is a regulated utility with an obligation to serve customer load in its service area and is therefore subject to regulatory risk. Idaho Power expects future resource additions and removals will be approved for inclusion in the rate base and it will be allowed to earn a fair rate of ROIs related to resource actions of the IRP portfolios. Idaho Power includes public involvement in the IRP process through an IRPAC and by opening the IRPAC meetings to the public. The open public process allows a public discussion of the IRP and establishes a foundation of customer understanding and support for resource additions and removals when the plan is submitted for approval. The open public process reduces the regulatory risk associated with developing a resource plan.

NOx Compliance Alternatives Risk

Six of the 12 portfolios, including P7, assume Jim Bridger units 1 and 2 will be permitted to operate beyond their regional-haze compliance dates without installation of SCRs. The remaining six portfolios either assume SCR installation or retirement of the units in 2021 (Unit 2) and 2022 (Unit 1) as stipulated by regional-haze requirements. While agreements permitting operating extensions have been reached in the past, uncertainty remains that such agreements can be reached for Jim Bridger units 1 and 2. An inability to successfully achieve permitting consistent with the assumptions of these compliance alternatives would likely have a significant effect on the costs and feasibility of portfolios with extended operations without SCR installation.

Permitting/Siting Risk

Significant challenges are often encountered during permitting and siting for energy resources. While these challenges are not uniform for all resources or for all proposed resource locations, it is nevertheless reasonable to assume all portfolios are exposed to permitting/siting risk, and no portfolio is markedly less exposed than P7; B2H planners have been collaborating with stakeholders for several years on resolving permitting/siting issues, and while challenges remain, much progress has been made.

Regional Resource Adequacy

B2H-based portfolios have higher exposure to potential regional resource inadequacies. However, Idaho Power's review of regional resource adequacy assessments conducted by the NWPCC and BPA indicates B2H will provide access to a wholesale electric market with capacity for meeting summer load needs and abundant low-cost energy. Further discussion of the NWPCC and BPA adequacy assessments is in Chapter 6.

DSM Implementation

While Idaho Power has considerable experience in DSM programs and has consistently achieved IRP energy efficiency targets, an implementation risk always exists with a new program. The actual energy savings and peak reductions may vary significantly from the estimated amounts if customer participation rates are not achieved.

Technological Obsolescence

The energy industry is experiencing considerable technological innovation, a trend expected to continue well into the future. This innovation could lead to greater market penetration for emerging resources and correspondingly drive competing resources to obsolescence. The determination of competitive resources in the energy industry of the future is highly speculative. However, current trends support the critical role the electric grid is expected to continue to play well into the future, with a growing need to move intermittently produced energy from grid locations experiencing oversupply to those experiencing undersupply. Moreover, a grid resource such as B2H positions Idaho Power to participate in the Pacific Northwest wholesale electric market as the energy sources comprising that market evolve over the coming decades. Therefore, Idaho Power qualitatively views portfolios without B2H as having greater exposure to technological innovation than those with B2H.

Qualitative Benefits

Regional Resource Diversity

The Pacific Northwest wholesale electric market is a diverse mix of renewable and thermal resources. Renewable resources primarily consist of hydropower and wind generation, with lesser amounts of solar and geothermal. B2H provides expanded access to the Pacific Northwest wholesale market and its attendant diverse mix of low-cost energy resources and abundant zero-carbon energy.

Regional Transmission Initiatives

Idaho Power has a long history of collaboration in regional transmission planning. B2H is a resource providing value to project co-participants, and also to the region as a whole, with the spread of automated energy markets, such as the western EIM. B2H positions Idaho Power and the region well in furthering the interconnectivity of the regional transmission system.

Transmission Tariff Revenue

B2H is a critical interconnection to the Pacific Northwest providing Idaho Power access to low-cost energy, capacity, and balancing. B2H, uniquely among the potential IRP resources considered, provides revenue in the form of transmission tariffs when used by other entities during periods Idaho Power is not using it to transfer energy.

Local Economic Effects

The scope of the IRP does not include an analysis of macroeconomic impacts associated with considered resource portfolios. Therefore, any evaluation of macroeconomic impacts is strictly qualitative in nature and highly conjectural. Locally sited resources, such as solar PV and natural gas-fired power plants, can be reasonably linked to localized job growth associated with plant construction and operation; however, long-term job opportunities associated with plant operation are expected to be more significant with natural gas power plants than solar PV power plants. Further, solar PV modules are substantially sourced from overseas markets, whereas fuel for natural gas power plants relies heavily on domestic production and consequently can be linked more closely to domestic macroeconomic growth. B2H can be expected to lead to construction-related job growth. Moreover, B2H, as a source for reliable and low-cost energy, is consistent with Idaho Power's mission to provide reliable and fair-priced energy services, qualities recognized as instrumental in promoting economic growth in Idaho Power's service area.

Summary of Qualitative Risks and Benefits

Table 9.9 and Table 9.10 summarize the relative risks and benefits of the 12 portfolios analyzed. As noted earlier, the qualitative risk analysis is structured as an assessment of qualitative risks and benefits in relation to the lowest-cost P7, with the objective of assessing whether qualitative risk leads to the selection of a preferred portfolio different from P7. The findings of the qualitative risk analysis do not support the selection of a portfolio other than P7 as preferred.

Table 9.9 Qualitative risk analysis

Risk	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Hydro—Water Supply Risk	=	=	=	=	=	=		=	=	=	=	=
Relicensing Risk	=	=	=	=	=	=		=	=	=	=	=
Regulatory Risk	=	=	=	=	=	=		=	=	=	=	=
NOx Compliance Alternatives Risk	<	<	<	=	=	=		=	=	<	<	<
Permitting/Siting Risk	=	=	=	=	=	=		=	=	=	=	=
Regional Resource Adequacy	=	<	<	=	<	<		<	<	=	<	<
DSM Implementation	=	=	=	=	=	=		=	=	=	=	=
Technological Obsolescence	=	>	>	=	>	>		>	>	=	>	>

< Less risk
> More risk
= Equal risk

Table 9.10 Qualitative benefit analysis

Benefit	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Regional Resource Diversity	=	<	<	=	<	<		<	<	=	<	<
Regional Transmission Initiatives	=	<	<	=	<	<		<	<	=	<	<
Transmission Tariff Revenue	=	<	<	=	<	<		<	<	=	<	<
Local Economic Effects	=	=	=	=	=	=		=	=	=	=	=

< Less benefit
= Equal benefit

CAA Section 111(d)

All 12 portfolios in the 2017 IRP comply with the mass-based carbon-emission regulations as stipulated in the final rule for Section 111(d). While Idaho Power believes carbon-emission regulations in some form are likely during the next 20 years, the final regulations will likely not be as modeled in this IRP. Qualitatively, under a non-carbon-constrained future Idaho Power believes SCR investments that extend the time period of coal-fired generation at Jim Bridger units 1 and 2 would likely result in a better financial outcome for customers. Conversely, a carbon-constrained future would favor an earlier retirement of the Jim Bridger units and preclude investment in additional SCRs at Jim Bridger. While uncertainty exists regarding carbon-emission regulations, Idaho Power is not inclined to pursue a direction toward making the SCR investments. The additional SCR investments are counter to the findings of the portfolio analysis, in which portfolios without SCRs on Jim Bridger units 1 and 2 generally performed better. Finally, the company's expressed objectives related to transitioning away from coal-fired generating capacity weigh against making additional SCR investments at Jim Bridger.

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 an 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 2017 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P7, 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 or the loss of Langley Gulch. 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 Northwest Power Pool (NWPP). A 330-MW reserve margin also results in a loss of-load expectation (LOLE) of roughly 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 9.11.

Table 9.11 Capacity planning margin

	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034	July 2035	July 2036
Load and Resource Balance																				
Peak-Hour Forecast (50th%), including DSM	(3,036)	(3,078)	(3,117)	(3,148)	(3,176)	(3,209)	(3,196)	(3,280)	(3,306)	(3,331)	(3,359)	(3,387)	(3,412)	(3,433)	(3,449)	(3,462)	(3,478)	(3,497)	(3,513)	(3,528)
Existing Resources																				
Coal																				
Boardman	54	54	54	54	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Bridger	703	703	703	703	703	703	703	703	703	703	703	703	527	527	527	527	352	352	352	352
Valmy	263	263	263	132	132	132	132	132	132	–	–	–	–	–	–	–	–	–	–	–
Coal Total	1,020	1,020	1,020	889	835	835	966	835	835	703	703	703	527	527	527	527	352	352	352	352
Gas																				
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Gas Total	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric																				
Hydroelectric (50th%)—HCC	1,067	1,070	1,071	1,071	1,071	1,069	1,068	1,067	1,065	1,063	1,061	1,059	1,057	1,055	1,053	1,051	1,049	1,047	1,045	1,043
Hydroelectric (50th%)—Other	299	300	300	300	300	299	299	299	298	298	297	296	296	295	295	294	293	293	292	291
Hydroelectric Total (50th%)	1,366	1,370	1,371	1,370	1,370	1,369	1,367	1,365	1,363	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,340	1,337	1,334
CSPP (PURPA) Total	314	314	314	319	319	319	319	319	319	318	318	318	316	314	305	303	295	295	295	295
PPAs																				
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	–	–	–	–	–	–	–	–	–
Raft River Geothermal	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Neal Hot Springs Geothermal	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Clatskanie Exchange	10	10	10	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PPAs Total	35	35	35	35	25	25	23	25	25	25	25	20	20	20	20	20	20	20	20	20

	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034	July 2035	July 2036
Transmission Capacity Available for Market Purchases	313	313	302	433	492	489	488	487	486	616	615	614	613	612	611	610	608	607	607	606
Existing Resource Subtotal	**3,765**	**3,768**	**3,759**	**3,762**	**3,757**	**3,752**	**3,879**	**3,747**	**3,743**	**3,740**	**3,736**	**3,727**	**3,545**	**3,540**	**3,527**	**3,522**	**3,333**	**3,329**	**3,327**	**3,323**
Monthly Surplus/Deficit	**729**	**690**	**641**	**614**	**580**	**544**	**683**	**467**	**437**	**408**	**377**	**340**	**134**	**108**	**78**	**60**	**(146)**	**(167)**	**(187)**	**(205)**
2017 IRP New Resources																				
2026 B2H Transmission	–	–	–	–	–	–	–	–	–	500	500	500	500	500	500	500	500	500	500	500
2033 CCCT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	300	300	300	300
2030s Reciprocating Gas Engines	–	–	–	–	–	–	–	–	–	–	–	–	–	–	36	72	72	72	126	180
New Resource Subtotal	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**500**	**500**	**500**	**500**	**500**	**536**	**572**	**872**	**872**	**926**	**980**
Remaining Monthly Surplus/Deficit	**729**	**690**	**641**	**614**	**580**	**544**	**683**	**467**	**437**	**908**	**877**	**840**	**634**	**608**	**614**	**632**	**726**	**705**	**739**	**775**
Planning Margin	24%	22%	21%	20%	18%	17%	21%	14%	13%	27%	26%	25%	19%	18%	18%	18%	21%	20%	21%	22%

Flexible Resource Needs Assessment

Idaho Power analysis for the 2017 IRP indicates Idaho Power customers and independent power producers will place increasing flexibility needs on the power system. Idaho Power analyzed historical data, then compared the historical data with a forecast of conditions in 2026. Flexibility needs increase in most months based on the analysis.

Historical Analysis

Idaho Power analyzed hourly load and hourly energy production from intermittent wind generation resources during the historical time period 2012 through 2016. Idaho Power calculated hourly net load by subtracting hourly wind generation from hourly system load (there was very limited solar production on Idaho Power's system during the 2012 through 2016 time period).

$$\textit{Hourly net load} = \textit{Hourly load} - \textit{Hourly wind generation}$$

Idaho Power then calculated the change in hourly net load over four time intervals:

$$\Delta\ \textit{Net Load}_{0} = \textit{Net Load Hour}_{0} - \textit{Net Load Hour}_{-1}$$

$$\Delta\ \textit{Net Load}_{-1} = \textit{Net Load Hour}_{-1} - \textit{Net Load Hour}_{-2}$$

$$\Delta\ \textit{Net Load}_{-2} = \textit{Net Load Hour}_{-2} - \textit{Net Load Hour}_{-3}$$

$$\Delta\ \textit{Net Load}_{-3} = \textit{Net Load Hour}_{-3} - \textit{Net Load Hour}_{-4}$$

Idaho Power calculated a flexibility score by averaging the four calculated absolute (ABS) changes in net load (a four-hour moving average of the hourly change in net load):

$$\textit{Flexibility Score} = [\textit{ABS}(\Delta\ \textit{Net Load}_{0}) + \textit{ABS}(\Delta\ \textit{Net Load}_{-1})$$

$$+ \textit{ABS}(\Delta\ \textit{Net Load}_{-2}) + \textit{ABS}(\Delta\ \textit{Net Load}_{-3})] / 4$$

The absolute change was used so a significant positive change in one hour coupled with a significant negative change in an adjoining hour would not cancel the flexibility score calculation. Significant net load changes in adjoining hours are considered to represent a genuine need for system flexibility regardless of whether the net load changes are positive or negative.

The five years of historical data yielded approximately 44,000 hourly flexibility scores.

Idaho Power then specified a flexibility threshold:

$$\textit{Flexibility Score} >= 100\ \textit{MW}$$

AND

$$\textit{Flexibility Score/Hourly Net Load} >= 0.12$$

The flexibility threshold is used to identify a specific number of flexibility events. The flexibility score must be equal to or exceed 100 MW, and the flexibility score must be equal to or greater than 12 percent of the net system load to be identified as a flexibility event; both criteria must be satisfied.

The flexibility threshold and resulting number of flexibility events are not based on any specific system requirements or regulations from NERC, FERC, WECC, or any other regulatory agency. The flexibility events are solely a metric used for comparison purposes. Figure 9.6 shows the distribution of events where the flexibility score was 100 MW or greater, and Figure 9.7 shows the distribution of events where the flexibility score was 12 percent of net load or greater.

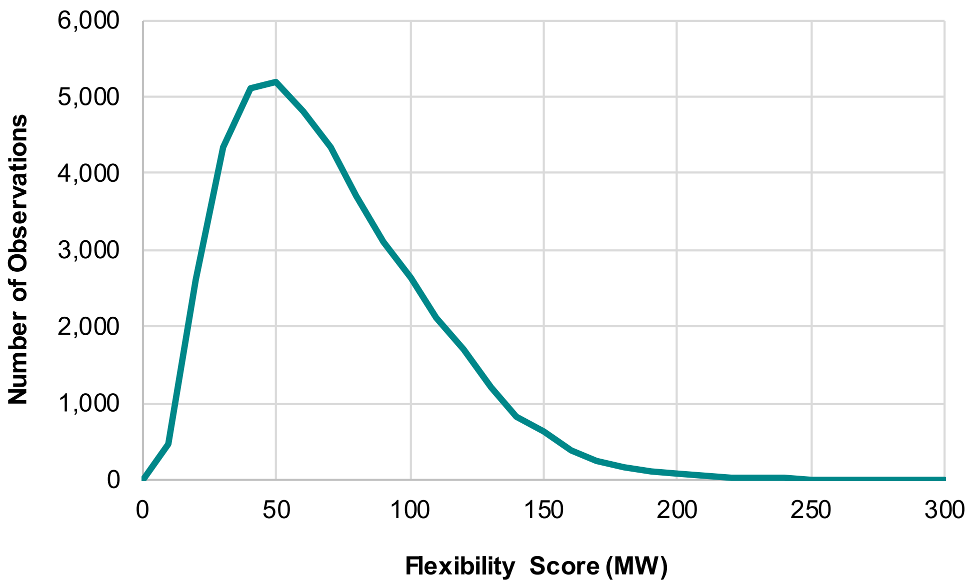


Figure 9.6 Distribution of events with flexibility score 100 MW or greater

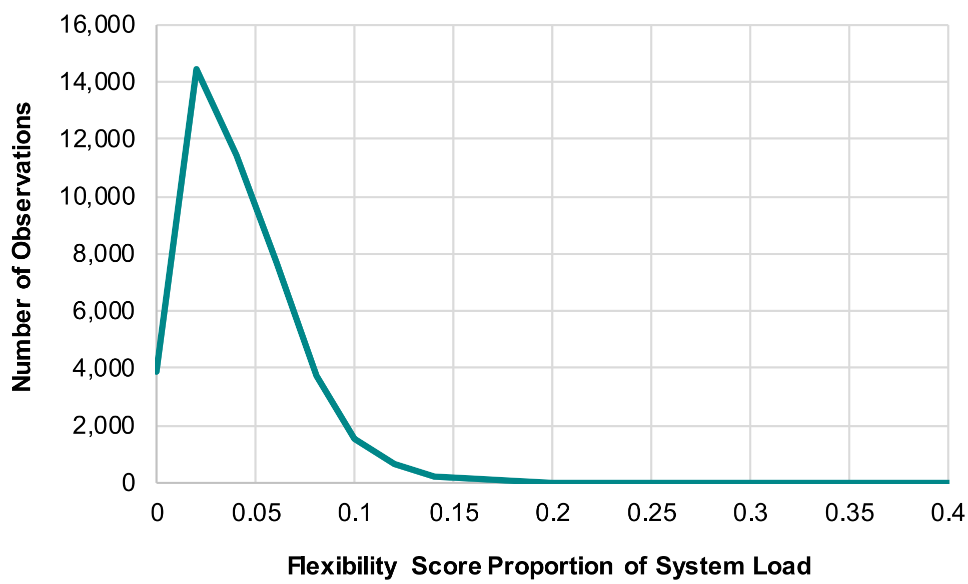


Figure 9.7 Distribution of events with flexibility score 12 percent of net load or greater

There were slightly over 600 hours during the five-year historical period that exceeded the flexibility threshold. The 600 hours represent slightly over 1.4 percent of the total hours in the historical period.

Projected Flexibility Score in 2026

Idaho Power selected 2026 as a test year in the IRP analysis. Idaho Power estimated the flexibility score for 2026 using the same arithmetic techniques that were used to analyze the 2012 through 2016 historical period. Idaho Power used forecast hourly load and forecast independent power production from intermittent renewable resources. The independent power production from intermittent resources includes both wind and solar generation facilities in 2026. As with the historical analysis, Idaho Power calculated hourly net load, the change in net load, the four-hour moving average of the change in net load, and a flexibility score based on the same flexibility threshold:

$$\text{Flexibility Score} >= 100 \text{ MW}$$

AND

$$\text{Flexibility Score/Hourly Net Load} >= 0.12$$

There are 220 hours projected in 2026 that exceed the flexibility threshold, which represent about 2.5 percent of the hours in 2026. Table 9.12 shows the hours exceeding the flexibility threshold in 2026 by month, as well as the results from analyzing the historical period.

Table 9.12 Hours exceeding flexibility threshold by month

	Yearly History, 2012–2016		2026 Forecast	
Month	**Minimum**	**Maximum**	**Flex Score**	**Flex Need***
January	1	8	9	+
February	2	15	17	+
March	7	21	33	++
April	4	17	20	+
May	6	14	27	++
June	5	11	21	++
July	3	9	13	+
August	5	14	9	
September	5	18	27	+
October	7	26	30	+
November	5	18	12	
December	3	13	2	

* Plus signs indicate a forecast change in flexibility need.

Only three months in 2026—August, November, and December—are projected to have a flexibility need approximately equivalent to the flexibility need in the historical period. Three months—March, May, and June—are projected to have a significant increase in flexibility need when compared with the historical period. The other six months—January, February, April, July, September, and October—are projected to have a moderate increase in flexibility need.

March is projected to have the largest number of flexibility events at 33 in the forecast period. Idaho Power recorded 26 flexibility events in October during the historical period. The increase in flexibility events is anticipated to be manageable by comparison with the historical period. Flexibility management will likely require curtailment of intermittent renewable generation at times to maintain system stability.

The summary conclusion is that the changes in customer load and the increase in independent power production from intermittent renewable resources will increase Idaho Power's need for system flexibility in 2026.

Solar Capacity Credit

Idaho Power updated the solar PV peak-hour capacity factors based on guidance from members of the solar work group in the 2015 IRP. The update used simulated solar generation for water years 2011 through 2013, specifically focusing the analysis on solar generation occurring during the highest 150 load hours from the three water years.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to Idaho Power's system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2015 and 2017 IRPs are reported in Table 9.13.

Table 9.13 Solar capacity credit values

PV System Description	Peak-Hour Capacity Credit
South orientation	28.4%
Southwest orientation	45.5%
Tracking	51.3%

OPUC Docket No. UM 1719 examined the determination of solar capacity credit in several recently filed IRPs. The Docket No. UM 1719 settlement agreement required Idaho Power to conduct an LOLE study, or an approximation method, to validate that Idaho Power's analysis focusing on the highest 150 load hours adequately defines Idaho Power's capacity timing need. The LOLE was to include all 8,760 hours of a test year and result in an LOLP for each hour.

Idaho Power selected 2025 for examination using an approximation method for a complete LOLE study. The evaluation used median hydro and load forecasts and the AURORA hourly preferred portfolio output as a starting point. An Excel workbook was used to simulate 500 years of random outages. The 500 years of random outages resulted in an LOLE of approximately 2.07 hours per year. The 2.07 hours per year equates to an LOLE of approximately 1 day in 10 years, a frequently used standard in determining a system as resource adequate.

The hourly LOLP of the 500 iterations for 2025 is shown in Table 9.14.

Table 9.14 Hourly LOLP of 500 iterations for 2025

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
0	0.00%	0.00%	0.00%	0.00%	0.10%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.19%**
1	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%**
2	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%**
3	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%**
4	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%**
5	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.19%**
6	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%**
7	0.68%	0.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.16%**
8	1.25%	2.60%	0.00%	0.00%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	**4.15%**
9	2.41%	3.47%	0.00%	0.19%	0.19%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**6.27%**
10	1.45%	2.51%	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	**4.15%**
11	0.87%	0.00%	0.00%	0.39%	0.19%	0.00%	0.00%	0.00%	0.10%	0.00%	0.00%	0.00%	**1.54%**
12	0.77%	0.00%	0.00%	0.39%	0.00%	0.00%	0.39%	0.00%	0.10%	0.00%	0.00%	0.10%	**1.74%**
13	0.29%	0.00%	0.00%	0.39%	0.39%	0.19%	0.68%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.93%**
14	0.10%	0.00%	0.00%	0.10%	0.19%	0.10%	1.64%	0.00%	0.10%	0.00%	0.00%	0.00%	**2.22%**
15	0.10%	0.00%	0.00%	0.19%	0.39%	0.48%	2.80%	0.19%	0.00%	0.00%	0.00%	0.00%	**4.15%**
16	0.00%	0.00%	0.00%	0.29%	0.19%	0.96%	5.30%	0.68%	0.58%	0.00%	0.00%	0.00%	**8.00%**
17	0.10%	0.00%	0.00%	0.48%	0.19%	1.06%	5.79%	1.35%	0.77%	0.00%	0.00%	0.00%	**9.74%**
18	0.58%	0.10%	0.00%	0.29%	0.48%	2.51%	8.68%	1.16%	1.35%	0.00%	0.00%	0.10%	**15.24%**
19	2.03%	2.22%	0.00%	0.48%	0.48%	1.06%	7.52%	0.96%	0.96%	0.00%	0.00%	0.10%	**15.81%**
20	1.64%	3.18%	0.00%	0.39%	0.29%	1.54%	3.28%	0.48%	0.96%	0.00%	0.00%	0.10%	**11.86%**
21	0.87%	1.25%	0.00%	0.10%	0.19%	0.87%	2.22%	0.19%	0.77%	0.00%	0.00%	0.19%	**6.65%**
22	0.39%	1.35%	0.10%	0.19%	0.29%	0.48%	0.77%	0.19%	0.19%	0.00%	0.00%	0.00%	**3.95%**
23	0.00%	0.58%	0.00%	0.19%	0.00%	0.19%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	**1.06%**
Total	**14%**	**18%**	**0%**	**4%**	**4%**	**10%**	**39%**	**5%**	**6%**	**–**	**–**	**1%**	**100.00%**

A large percentage of the LOLP hours occur in June and July and are coincident with the 150 highest load hours used in defining the capacity credit used in the 2015 and 2017 IRPs. However, a number of the LOLP hours occur outside the hourly periods containing the 150 highest load hours. The winter-hour LOLPs are especially interesting. December, January, and February contain 33 percent of the LOLP hours identified in the study compared to 0 percent of the hours evaluated in the 150 highest hours.

The distribution of the 150 highest load hours for 2013 to 2015 is given in the following monthly hour probability table (Table 9.15).

Table 9.15 Monthly probabilities

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
0	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%**
1	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%**
2	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%**
3	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%**
4	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%**
5	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%**
6	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%**
7	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%**
8	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%**
9	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%**
10	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%**
11	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%**
12	0.00%	0.00%	0.00%	0.00%	0.00%	0.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.67%**
13	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%	1.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**2.67%**
14	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	3.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**5.33%**
15	0.00%	0.00%	0.00%	0.00%	0.00%	4.00%	5.33%	0.00%	0.00%	0.00%	0.00%	0.00%	**9.33%**
16	0.00%	0.00%	0.00%	0.00%	0.00%	5.33%	7.33%	0.67%	0.00%	0.00%	0.00%	0.00%	**13.33%**
17	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	8.67%	0.67%	0.00%	0.00%	0.00%	0.00%	**15.33%**
18	0.00%	0.00%	0.00%	0.00%	0.00%	5.33%	9.33%	1.33%	0.00%	0.00%	0.00%	0.00%	**16.00%**
19	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	8.67%	0.67%	0.00%	0.00%	0.00%	0.00%	**15.33%**
20	0.00%	0.00%	0.00%	0.00%	0.00%	6.00%	6.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**12.67%**
21	0.00%	0.00%	0.00%	0.00%	0.00%	2.67%	2.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**5.33%**
22	0.00%	0.00%	0.00%	0.00%	0.00%	1.33%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**3.33%**
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.67%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.67%**
Total	**0%**	**0%**	**0%**	**0%**	**0%**	**41%**	**56%**	**3%**	**0%**	**0%**	**0%**	**0%**	**100.00%**

The LOLE study identifying LOLP outside of the 150 highest load hours methodology leads Idaho Power to re-evaluate the 150-hour methodology and update the solar capacity credit with the best available information. This analysis will be conducted in the interim between the 2017 and 2019 IRPs, and resulting updates to the solar capacity credit will be included in the 2019 IRP.

LOLE

The solar capacity credit LOLE study Excel workbook described in the preceding section was also used to evaluate the LOLE sufficiency of Idaho Power's future system plan. The 500 random outages resulted in an LOLE of approximately 2.07 hours per year. The 2.07 hours per year equates to an approximately 1-day-in-10-years LOLE, a standard used in determining a system as resource adequate.

10. Preferred Portfolio and Action Plan

Preferred Portfolio

The cost analysis performed for the IRP included an analysis of resource portfolio costs under planning-case conditions for natural gas price, hydroelectric production, and system load. The cost analysis also included an analysis of resource portfolio costs under a range of sensitivities for natural gas price, a key cost driver. A third element of the cost analysis was the stochastic risk analysis, in which resource portfolio costs were computed for 100 different iterations (or futures) for the studied stochastic risk variables: natural gas price, hydroelectric production, and system load. The B2H-based P7 consistently outperformed the other portfolios in the cost analysis. In addition to the B2H transmission line in 2026, P7 includes 180 MW of reciprocating engines and a 300-MW CCCT in the 2030s. P7 also assumes Jim Bridger units 1 and 2 are retired early at year-end 2032 and year-end 2028, respectively, without installing SCRs.

A qualitative risk analysis found that P7 does not carry greater exposure to qualitative risk factors relative to other resource portfolios. In fact, P7 has unique qualitative benefits in a future where the electric grid is a critical element to the successful development of automated energy markets (i.e., western EIM) and the integration of expanded intermittent renewable resources. Further, P7 is consistent with Idaho Power's expressed goals related to the measured and responsible transition away from coal-fired generating capacity. Following the retirement of Jim Bridger units 1 and 2, Idaho Power's coal-fired generating capacity will have dropped to approximately one-third of the capacity on-line in 2017. Based on the analysis for the 2017 IRP, P7 is selected as the preferred portfolio. A listing of the resource additions included in P7 is provided in Table 10.1.

Table 10.1 P7 Resources

Date	Resource	Installed Capacity
2026	B2H	500 MW transfer capacity, Apr–Sep 200 MW transfer capacity, Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	CCCT (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

Action Plan (2017–2021)

The expressed objective of the portfolio design for the 2017 IRP was to inform the action plan regarding SCR investments at Jim Bridger units 1 and 2 and the B2H transmission line. Idaho Power characterized these two key resource actions as pivotal to this IRP, recognizing that an essential function of the 2017 IRP is to inform the direction of these resource decisions. With respect to B2H, the action plan includes not only actions to continue permitting and planning, but also necessary preliminary construction and construction activities extending beyond 2021. These activities are described in Chapter 6.

The IRP portfolio analysis indicates a pivot away from making the SCR investments on Jim Bridger units 1 and 2. Therefore, the action plan includes actions consistent with the planning and negotiations necessary to facilitate the units' continued operation without SCRs and their ultimate 2028 and 2032 retirement. A baseline assumption common to all portfolios is the retirement of North Valmy units 1 and 2 at year-end 2019 and year-end 2025, respectively. Actions necessary to achieve these North Valmy retirement dates and assess the import dependability from northern Nevada are included in the action plan.

The Gateway West transmission line continues to be identified as a beneficial future upgrade to Idaho Power and the region, creating additional capacity and promoting continued grid reliability in a time of expanding variable energy resources. Therefore, in support of Idaho Power's agreement with our project partner, PacifiCorp, the action plan includes actions related to the continued permitting and planning associated with the Gateway West project.

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups, such as the Northwest Energy Efficiency Alliance (NEEA)
- Continued preparation for participation in the western EIM beginning in April 2018
- Continued involvement as a stakeholder in CAA Section 111(d) proceedings or alternative regulations constraining carbon emissions
- Investigation of solar PV contribution to peak and LOLP for use in the 2019 IRP

Table 10.2 provides actions with dates for the action plan period.

Table 10.2 Action plan (2017–2021)[19]

Year	Resource	Action	Action Number
2017–2018	EIM	Continue planning for western EIM participation beginning in April 2018.	1
2017–2018	Loss-of-load and solar contribution to peak	Investigate solar PV contribution to peak and loss-of-load probability analysis.	2
2017–2019	North Valmy Unit 1	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.	3
2017–2021	Jim Bridger units 1 and 2	Plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.	4
2017–2020	B2H	Conduct ongoing permitting, planning studies, and regulatory filings.	5
2018–2026[20]	B2H	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	6
2017–2021	Boardman	Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.	7
2017–2021	Gateway West	Conduct ongoing permitting, planning studies, and regulatory filings.	8
2017–2021	Energy efficiency	Continue the pursuit of cost-effective energy efficiency.	9
2017–2021	Carbon emission regulations	Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.	10
2017–2021	North Valmy Unit 2	Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.	11

Idaho Power and the Utility of the Future

A new energy world, driven by technological innovation and changing customer preferences, is emerging, one that is efficient, green, resilient, and interconnected. In the new energy world, conventional generation and increasingly complex grid connectivity will continue to exist and remain indispensable for ensuring a reliable, round-the-clock supply of power. Idaho Power is focused on transforming unidirectional powerlines into smart energy networks that incorporate renewables, providing customers with options while increasing system reliability and resiliency.

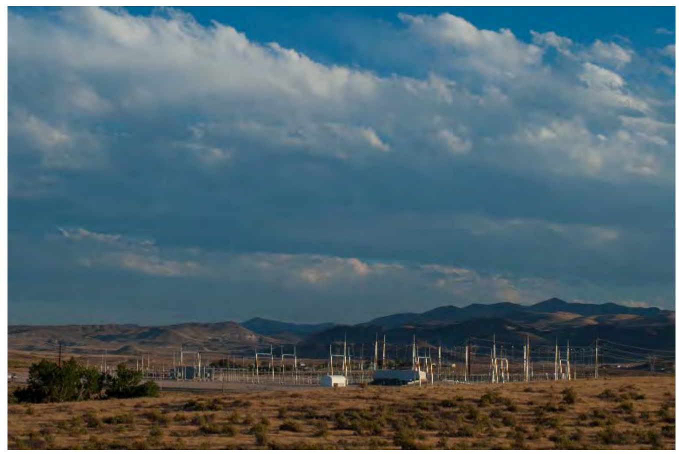
The company is investing in next-generation communication and monitoring capabilities that will facilitate the more complex web of power flow that the future will bring. Idaho Power is

[19] The B2H short-term action plan is 2017 to 2026. All other action plan items are for 2017 to 2021.

[20] B2H in-service date of 2024 or later, subject to coordination of activities with project co-participants.

laying the groundwork for future tools that will allow more automated power routing, self-healing capabilities, and enhanced power quality. The company is incorporating big-data tools and predictive analytics to anticipate issues, power flow, and usage patterns, etc., to facilitate proactive management of issues before they occur. Technological developments and capabilities will continue to occur at a rapid pace, and Idaho Power is actively, but judicially, evaluating the costs and benefits of these opportunities to take advantage of them when appropriate.

Conclusion


Hemingway Substation

The 2017 IRP indicates favorable economics associated with the B2H transmission line, the early retirement of Valmy units 1 and 2, and the early retirement (and corresponding avoided SCR investments) for Jim Bridger units 1 and 2. B2H has been treated as an uncommitted resource in every IRP beginning with the 2006 IRP. The 2017 IRP continues to show B2H as a top-performing resource alternative, capable of providing low-cost energy and capacity, as well as increasingly critical flexibility. Moreover, B2H positions Idaho Power and the region well in a future in which automated energy markets and enabling grid resources are likely to become increasingly important.

Idaho Power has expressed the objective to transition away from reliance on coal-fired generating capacity, provided this transition can be conducted in a responsible, economically beneficial, and measured manner. The findings of the 2017 IRP are consistent with this objective. The Boardman coal plant is scheduled for a 2020 retirement. A baseline assumption for the IRP is the retirement of North Valmy units 1 and 2 in 2019 and 2025, respectively. The preferred portfolio assumes the retirement of Jim Bridger Unit 2 in 2028 and Jim Bridger Unit 1 in 2032. While the North Valmy and Jim Bridger retirement dates are planning targets and subject to planning considerations with plant co-owners and/or negotiations with regulatory agencies, it can generally be asserted that over the next 15 years Idaho Power will retire more than 730 MW of coal-fired generating capacity.

Idaho Power focused the portfolio analysis for the 2017 IRP on the pivotal decisions related to SCR investments in Jim Bridger units 1 and 2 and the B2H transmission line and proffered a portfolio analysis designed to isolate these factors. However, the company recognizes resources achieving only modest market penetration to date, including notably electrochemical energy storage, are likely to achieve greater market penetration in the coming years and may outcompete the low-cost natural gas-fired resources of today. Idaho Power recognizes the importance of understanding the cost and value characteristics of all emerging resources to effective long-term resource planning.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2017 IRP. The IRPAC discussed many technical aspects of the 2017 resource plan, along with a significant number of political and societal topics at the meetings. Idaho Power's resource plan is better because of the contributions from IRPAC members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2019. The electric energy industry is experiencing what many consider a transformational era, and undoubtedly new challenges and questions necessarily addressed in integrated resource planning will be encountered in the 2019 IRP. Idaho Power will monitor the trends in the electric energy industry and adjust as necessary in the 2019 IRP.

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INTEGRATED RESOURCE PLAN

2017 IRP

APPENDIX A: SALES AND LOAD FORECAST

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2017 IRP

APPENDIX A: SALES AND LOAD FORECAST

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) 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 2017 IRP. 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 IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP 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 idahopower.com.

JUNE • 2017

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2017 Integrated Resource Plan* (IRP). Appendix A includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The above-mentioned forecast covers a 20-year period from 2017 through 2036.

The expected-case monthly average load forecast is Idaho Power's estimate of the most probable outcome for load growth during the planning. To account for inherent uncertainty and variability, four additional load forecasts were prepared in addition to the expected-case—a low case, a 70th-percentile case, a 90th-percentile case, and a high case, all of which are described in more detail in this report. The high and low economic growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. Additional cases are developed around the 70th-percentile and 90th-percentile load forecast scenarios to assist Idaho Power in reviewing the resource requirements that would result from variable loads due to variable weather conditions for temperatures and rainfall. It is important to note that in the IRP resource planning process, Idaho Power uses the 70th-percentile load forecast to account for the risk associated with weather impacts on load.

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,142 average megawatts (aMW) by 2036 from 1,810 aMW in 2017, representing an average yearly growth rate of 0.9 percent over the 20-year planning period (2017–2036). In the more critical 70th-percentile load forecast used for resource planning, the system load is forecast to reach 2,193 aMW by 2036 (0.9% average annual growth)[1]. Additionally, the number of Idaho Power active retail customers is expected to increase from the December 2016 level of 533,400 customers to nearly 755,000 customers by year-end 2036 (see footnote 1).

For capacity planning purposes, it is forecasted that Idaho Power's system will grow to 4,641 megawatts (MW) in 2036 from the all-time system peak of 3,407 MW that occurred on Tuesday, July 2, 2013, at 4:00 p.m. Idaho Power's system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2017–2036).

The numerous external factors influencing the forecast are primarily economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, metropolitan service area (MSA), and county economic and demographic 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.

[1] Recent company disclosures forecast load growth during the 2016 to 2035 planning period at 1.0 percent for average energy demand and 1.4 percent for peak-hour demand.

Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual 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 is projected to grow faster than the remainder of the state over the planning period. The number of households in the Boise –Nampa MSA is projected to grow even faster than the state of Idaho, at an annual rate of 1.6 percent during the forecast period. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. In addition, the number of households, incomes, employment, 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 assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussions of these assumptions are presented below.

Conservation influences on the load forecast, including Idaho Power energy efficiency demand-side management (DSM) programs, statutory programs, and non-programmatic trends in conservation, are included in the load forecasts of each sector. Idaho Power DSM programs are described in detail in Idaho Power's *Demand-Side Management 2016 Annual Report*, which is incorporated into this IRP document as Appendix B.

During the 20-year forecast horizon, major shifts in the electric utility industry (e.g., state and federal regulations and varying electricity prices) could influence the load forecast. 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 described previously. The alternative sales and load scenarios in *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

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

2017 IRP Sales and Load Forecast

Average Load

The economic and demographic variables driving the 2017 forecast have the impact of increasing current annual sales levels throughout the planning period. The delay in the expected "robust lift-off" of the business cycle recovery process after the Great Recession in 2008 for the national and, to a lesser extent, service-area economy halted load growth post-recession through 2011. However, in 2012, the extended recovery process was evident, and on-balance stronger growth was exhibited in most economic drivers relative to recent history at that time. It is expected that economic conditions return to long-term fundamentals during the 2017 forecast period. Significant factors and considerations that influenced the outcome of the 2017 IRP load forecast include the following:

- The load forecast used for the 2017 IRP reflects a continuance of the recovery in the service-area economy following a severe recession in 2008 and 2009. As customer growth was at a near standstill until 2012, acceleration of in-migration and business investment resulted in renewed growth in the residential and commercial connections along with increased industrial activity. As of 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

- The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflects the impact of additional plant investment and associated variable costs of integrating new resources identified in the 2015 IRP preferred portfolio Compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yields lower future prices. The retail prices are most evident after the first two years of the planning period and can impact the sales forecast positively, 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. Nonetheless, the expected load forecast reflects only those industrial customers that have made a sufficient and significant binding investment, indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area 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, and other naturally occurring efficiencies 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 (i.e., are treated as a supply-side peaking resource). 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 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs.

Peak-Hour Demands

As average demands as discussed in the preceding section are an integral component to the load forecast, so are the impact of the peak-hour demands on the system. The peak-hour forecasting regressions are expressed as a function of the sales forecast as well as the impact of peak-day temperatures. The peak forecast results and comparisons with previous forecasts differ for many reasons that include the following:

- The all-time system summer peak demand was 3,407 MW (recorded on Tuesday, July 2, 2013, at 4:00 p.m.). The system peak-hour load record was nearly matched on June 30, 2015, at 4:00 p.m., when the system peak reached 3,402 MW. Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m. and matched the previous record peak dated December 10, 2009, at 8:00 a.m.

- 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. The 95^{th} percentile forecast of peak-hour demand is utilized for peak capacity planning purposes. These normal average peak-day temperature drivers are calculated over the 1986 to 2015 time period (the most recent 30 years).

- The 2017 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

Overview of the Forecast

The sales and load forecast is constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and special contracts. In conjunction with this energy (or sales) forecast, an hour peak-load forecast was prepared. In addition, several probability cases were developed for the energy and peak forecasts. Assumptions for each of the individual categories, the peak hour impacts, and probabilistic case methodologies are described in greater detail in the following sections.

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 average 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 and the resulting derived economic forecast for Idaho Power's service area.

The expected-case average load forecast assumes median temperatures and median precipitation (i.e., there is a 50% 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, alternative scenarios were developed that address load variability due to varying weather conditions.

For example, Idaho Power's maximum annual average 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 annual average load occurs when the opposite of what is described above takes place. In the 70^{th}-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70^{th} percentile of HDD in wintertime and at the 70^{th} percentile of CDD in summertime. In the 70^{th}-percentile irrigation load forecast, GDD were assumed to be at the 70^{th} percentile and precipitation at the 30^{th} percentile, reflecting drier-than-median weather. The 90^{th}-percentile load forecast was similarly constructed.

For example, the median HDD in December from 1986 to 2015 (the most recent 30 years) was 1,029, at the Boise Weather Service office. The 70^{th}-percentile HDD is 1,060 and would be exceeded in 3 out of 10 years. The 90^{th}-percentile HDD is 1,170 and would be exceeded in 1 out of 10 years. As an example, for a single month, the 100^{th}-percentile HDD (the coldest December over the 30 years) is 1,449, which occurred in December 1990. This same concept was applied in each month throughout the year for the weather-sensitive customer classes: residential, commercial, and irrigation.

Since Idaho Power loads are highly dependent on weather, and the development of the above mentioned two scenarios allows 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 each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. For Idaho Power to properly plan for future resource requirements, a similar methodology is needed for the hour of maximum demand for the year (referred to as peak demand). Table 1 summarizes the load scenarios prepared for the 2017 IRP.

Table 1. Average load and peak-demand forecast scenarios

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

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-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 (50th percentile) average-load forecast and the 90th-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.

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared based on the expected case forecast. The forecasts provide a range of possible load growth rates for the 2017 to 2036 planning period due to high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1992–2016).

Of the three scenarios 1) the expected forecast is the median growth path, 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1992–2016).

From the above methodology, two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported in Table 2. The probability of exceeding the likelihood 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; additionally, it can be inferred that for the stated periods there is an 80 percent probability the actual growth rate will fall between the low and high scenarios.

The second probability estimate, the probability of occurrence, indicates the likelihood 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 other forecast scenario for the entire 20-year planning horizon.

Table 2. 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%

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris, Inc.) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Results of Idaho Power's system load projections are reported in Table 3 and shown in Figure 1. The expected-case system load-forecast growth rate averages 0.9 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.4 percent per year throughout the forecast period. The high scenario projects a load growth of 1.3 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These 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 3. System load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Low	1,748	1,765	1,810	1,891	0.4%
Expected	1,810	1,894	1,990	2,142	0.9%
High	1,835	1,968	2,111	2,351	1.3%

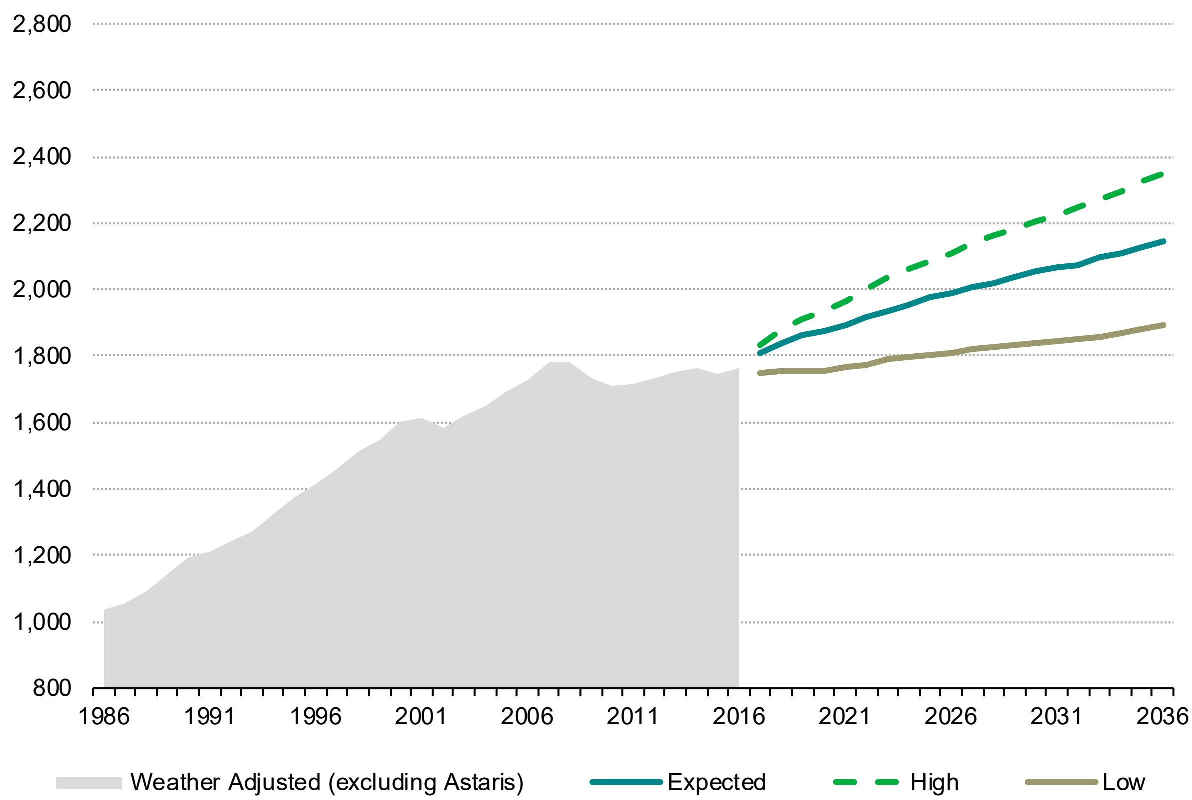

Figure 1. Forecast system load (aMW)

RESIDENTIAL

The expected-case residential load is forecast to increase from 594 aMW in 2017 to 747 aMW in 2036, an average annual compound growth rate of 1.2 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 612 aMW in 2017 to 772 aMW in 2036, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 4 and shown in Figure 2.

Table 4. Residential load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	643	681	730	810	1.2%
70th Percentile	612	648	695	772	1.2%
Expected Case	594	628	673	747	1.2%

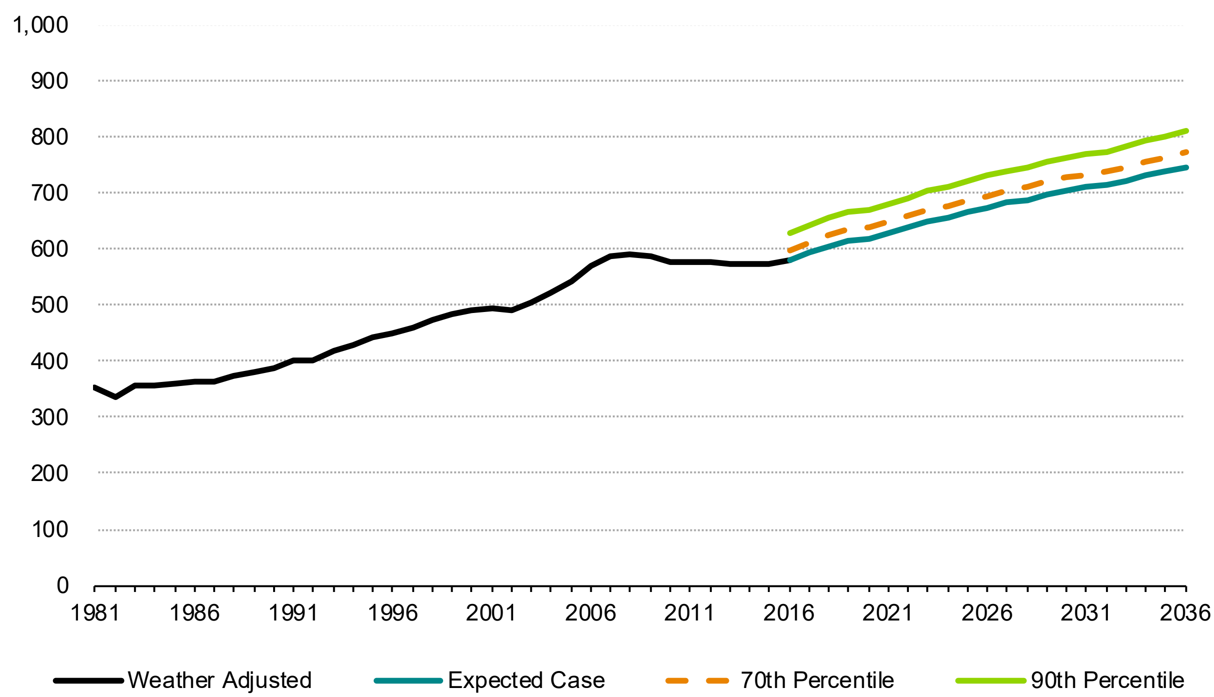

Figure 2. Forecast residential load (aMW)

Sales to residential customers made up 32 percent of Idaho Power's system sales in 1986 and 36 percent of system sales in 2016. The residential customer proportion of system sales is forecast to be approximately 38 percent in 2036. The number of residential customers is projected to increase to approximately 632,000 by December 2036.

The average sales per residential customer increased to over 14,700 kilowatt-hours (kWh) in 1980 before declining to 13,100 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—nearly 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices in those years 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 through 2007. However, the recession in 2008 and 2009 and conservation efforts further reduced residential use per customer. This trend is expected to continue, as the average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2036. Average annual sales per residential customer are shown in Figure 3.

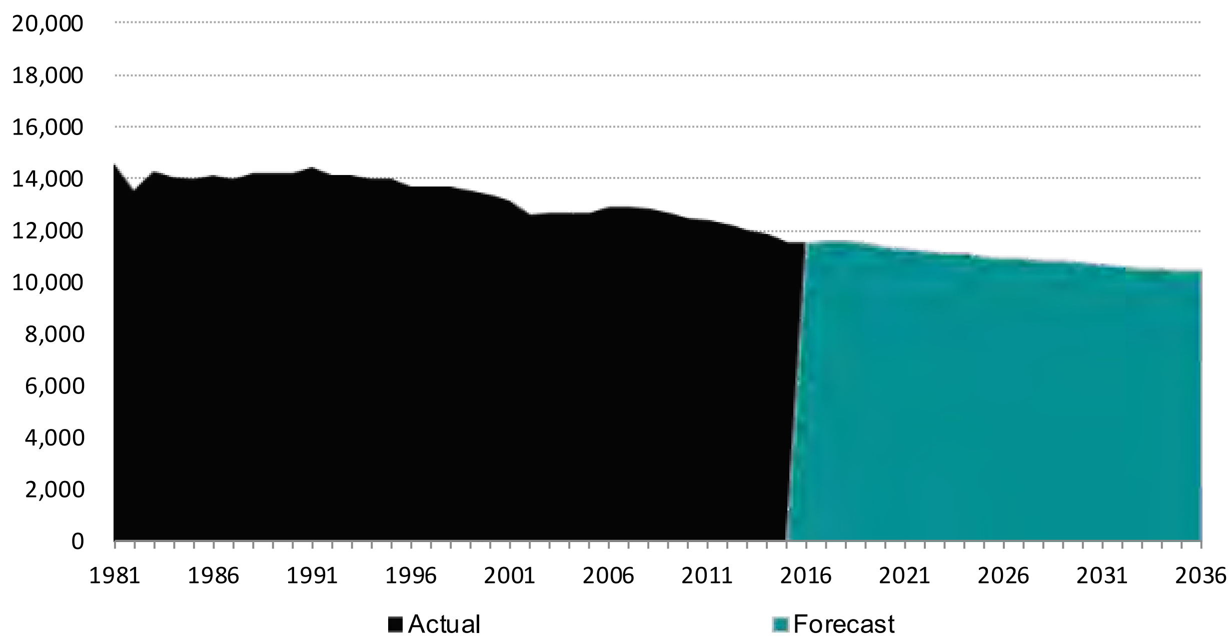

Figure 3. Forecast residential use per customer (weather-adjusted kWh)

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' May 2016 forecast of county housing stock and demographic data. The residential-customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

Sales to residential retail customers is an equation that 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; the real price of electricity; and the real price of natural gas.

COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other customers associated with this category include unmetered general service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

Within the expected-case scenario, the commercial load is projected to increase from 466 aMW in 2017 to 535 aMW in 2036 (Table 5). The average annual compound-growth rate of the commercial load is 0.7 percent during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 471 aMW in 2017 to 543 aMW in 2036. The commercial load forecasts are illustrated in Figure 4.

Table 5. Commercial load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	480	498	517	556	0.8%
70th Percentile	471	489	507	543	0.7%
Expected Case	466	482	500	535	0.7%

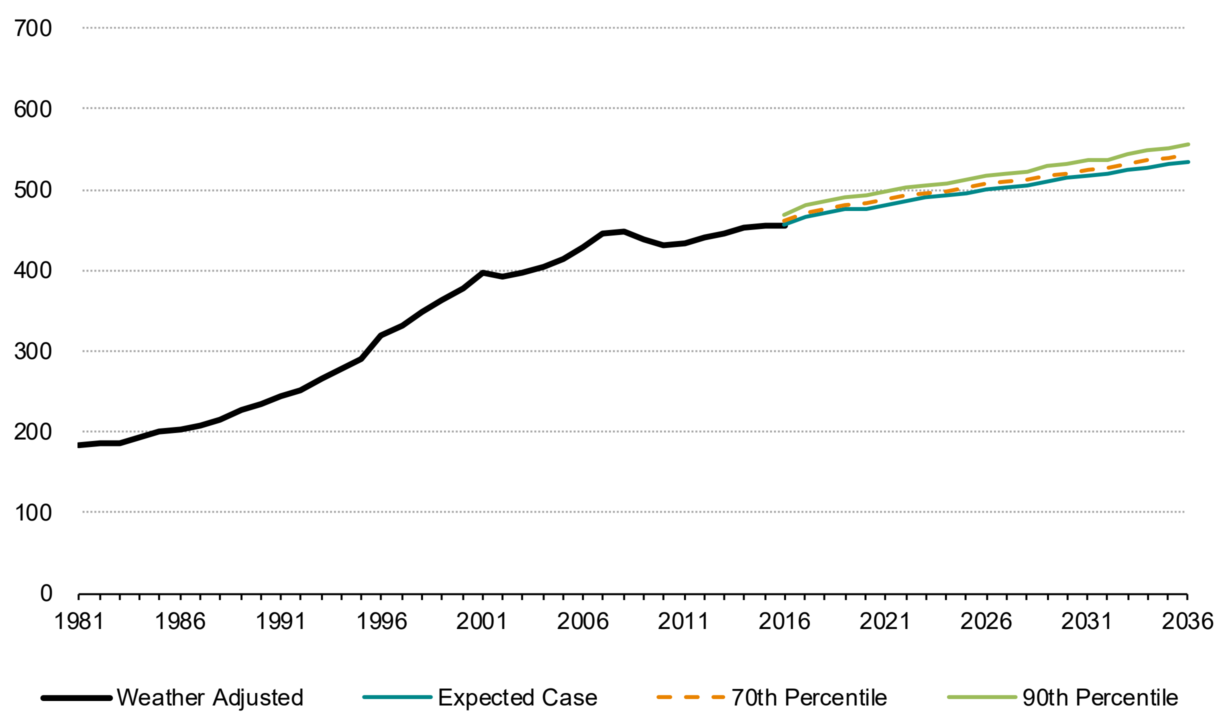

Figure 4. Forecast commercial load (aMW)

With a customer base of nearly 69,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to manufacturing. Due to this diversity, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 5 shows the breakdown of the categories and their relative sizes based on 2016 billed energy sales.

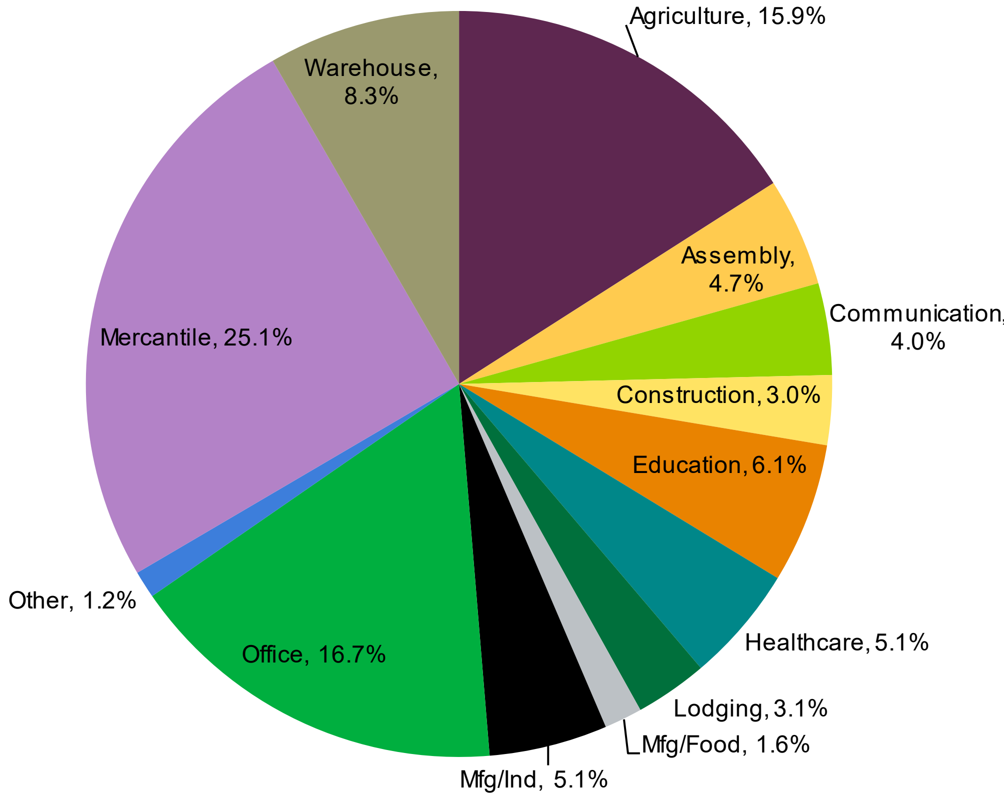

Figure 5. Commercial building share—energy bills

As indicated in Figure 5, the retail goods and service providers of the Mercantile category represent the largest commercial category of energy use, with 25.1% percent of total 2016 use. Total usage in this category has moderated, even considering the growth in total number of customers. This moderation is primarily due to customer consolidation, growth in internet-based sales, and energy efficient retrofit and new-construction technology implementation (particularly in the area of lighting) has grown. Categories showing significant post-recession (2011 to 2016) energy growth include Industrial/Manufacturing (+19.0%), Health Care (+19.2%), and Wholesale Trade (+17.6%).

The number of commercial customers is expected to increase at an average annual rate of 1.8 percent, reaching 97,500 customers by December 2036. The commercial customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

In 1986, customers in the commercial category consumed approximately 18 percent of Idaho Power system sales, growing to 28 percent by 2016. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 6 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 6 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, but it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,400 kWh and has declined at approximately 1.00 percent compounded annually to 2016. The UPC is forecast to decrease at an annual rate of 1.0 percent over the planning period. For this category, common elements that drive use down include increases in electricity prices, business-cycle recessions, and the adoption of energy efficiency technology. Within the commercial class UPC varies widely, reflecting the diversity of customer mix and range of operational size.

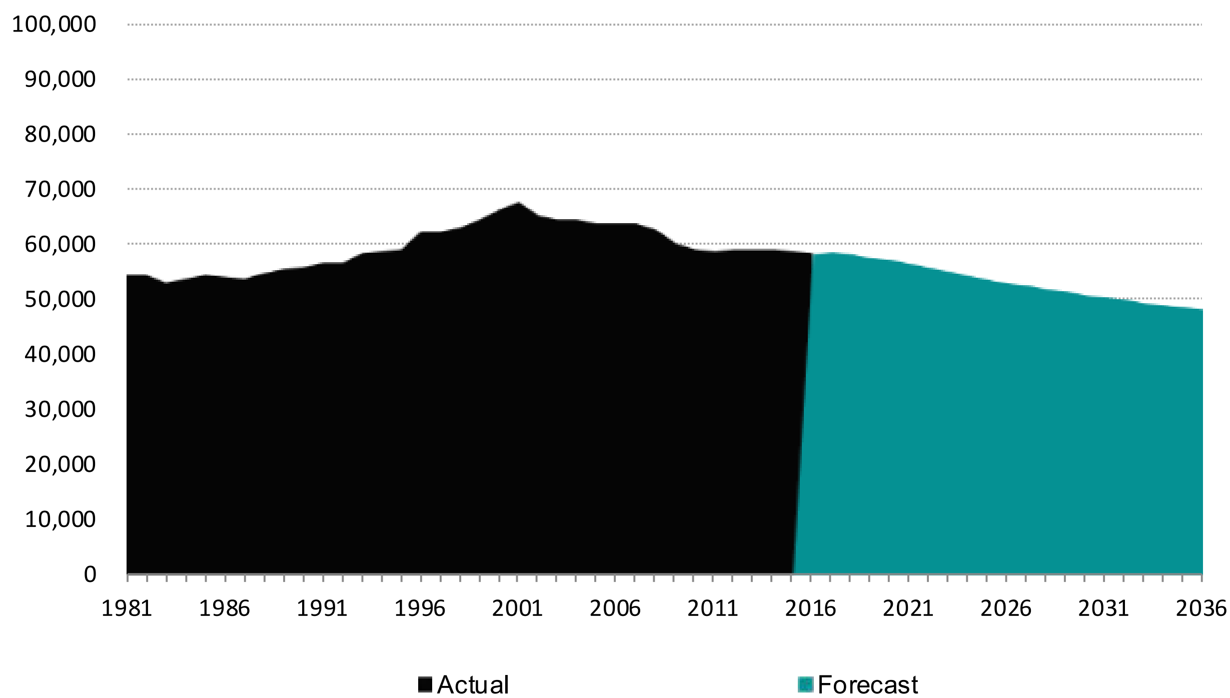

Figure 6. Forecast commercial use per customer (weather-adjusted kWh)

Figure 7 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2016 UPC for each segment relative to the 2011 UPC. A value greater than 1.0 indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 6 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

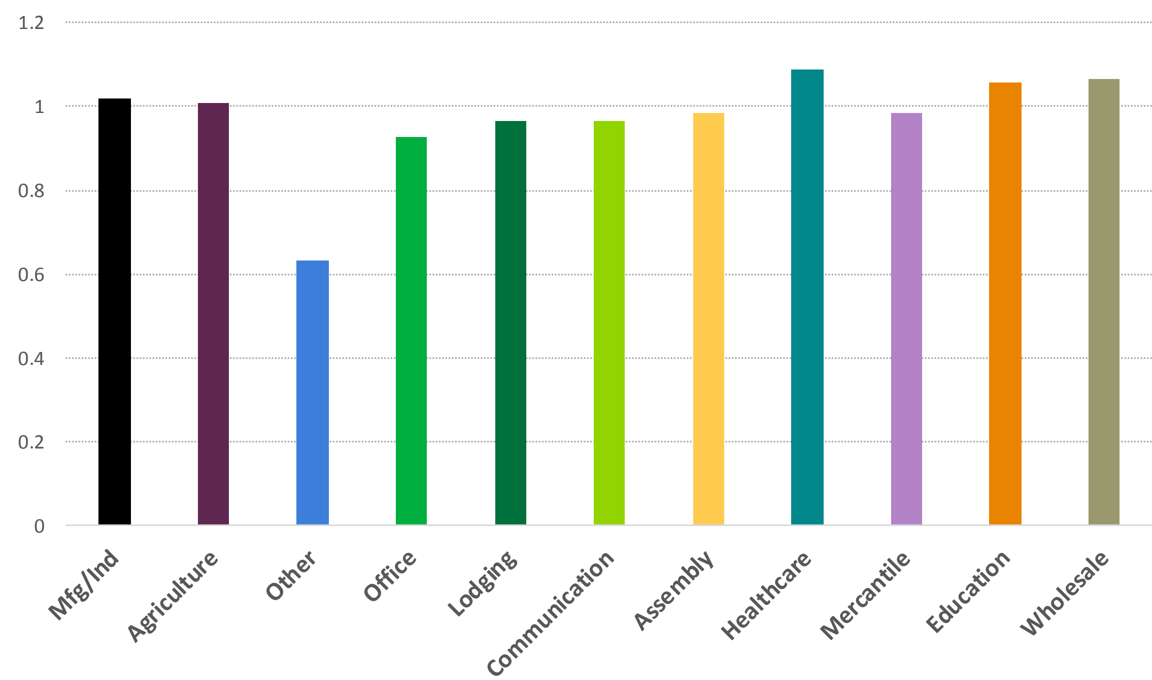

Figure 7. Commercial categories UPC, 2016 relative to 2011

Energy efficiency implementation is a large determinant in UPC decline over time. In the commercial sector, the primary DSM technology impact has come from lighting. The categories of Mercantile and Office are particularly dominant in this implementation as indicated by the UPC trend. Faster growing categories, such as Wholesale and Healthcare tend to show positive UPC trends. Other influences on UPC include differences in price sensitivity, sensitivity to business cycles and weather, and degree and trends in automation. In addition, category UPC can vary when a customer's total use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category. Due to tariff migration, which occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial), the forecast models aggregate the energy use of these two schedules to ensure continuity in the dependent variable.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the sub-category. Typical variables include weather: HDD (wintertime); CDD (summertime); specific industry growth characteristics and outlook; service-area demographics and their derivatives, such as households, employment, and small business conditions; the real price of electricity; and energy efficiency adoption.

Irrigation

The irrigation category is comprised 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.

The expected-case irrigation load is forecast to increase slowly from 221 aMW in 2017 to 246 aMW in 2036, an average annual compound growth rate of 0.6 percent. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast slow growth in irrigation load from 2017 to 2036. In the 70th-percentile scenario, irrigation load is projected to be 235 aMW in 2017 and 260 aMW in 2036. The individual irrigation load forecasts are summarized in Table 6 and illustrated in Figure 8.

Table 6. Irrigation load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	254	259	266	279	0.5%
70th Percentile	235	240	247	260	0.5%
Expected Case	221	226	233	246	0.6%

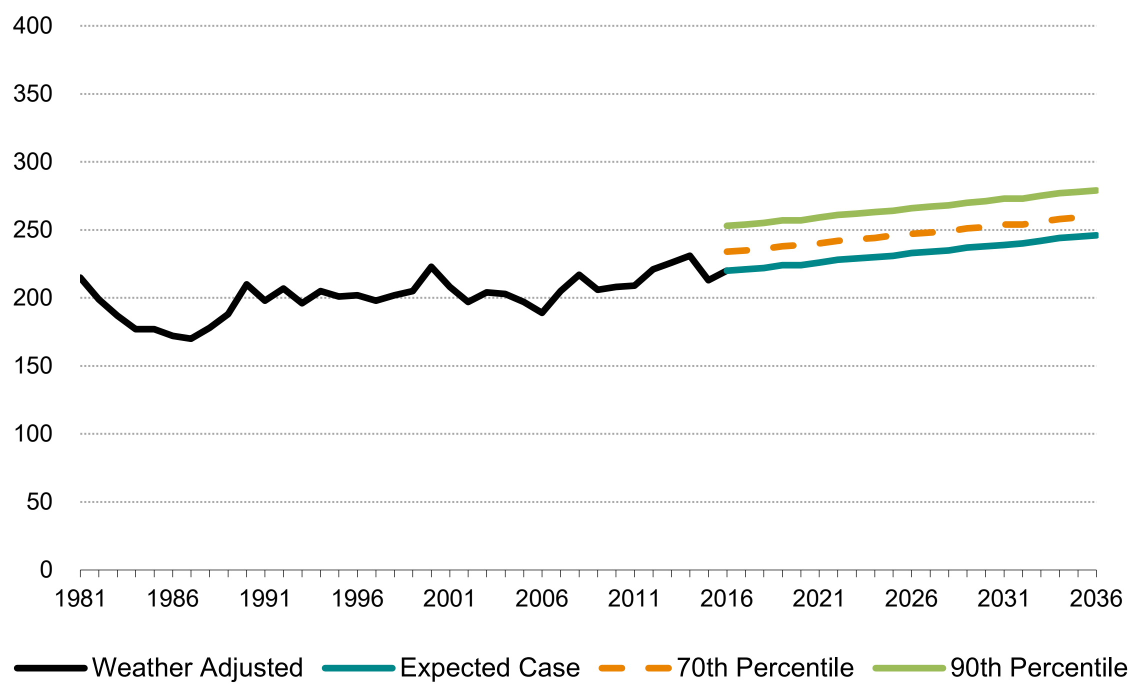

Figure 8. Forecast irrigation load (aMW)

The annual average loads in Table 6 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 reach nearly 900 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 nearly 30 percent of the energy consumed during July for general business sales. The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the forecast period due to the trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, the increased customer count from 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 2017 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; Palmer Z Index (calculated by the National Ocean and Atmospheric Administration [NOAA] from a combination of precipitation, temperature, and soil moisture data); 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 a voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt-hours (MWh) to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 2016, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2036, irrigation customers are projected to consume about 12 to 13 percent of Idaho Power system sales.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2016, the number of active irrigation accounts had increased to 20,042 and is projected to be nearly 26,000 at the end of the planning period in 2036.

As with other sectors, average use per customer is an important consideration. Since 1988, Idaho Power has experienced growth in the number of irrigation customers but slow 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. The conversion rate is slow and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells. In future forecasts, 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.

INDUSTRIAL

The industrial category is comprised of Idaho Power's large power service (Schedule 19) customers requiring monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. The category name "Industrial" is reflective of load requirements and not necessarily indicative of the industrial nature of the customers' business.

In 1980, Idaho Power had about 112 industrial customers, which represented about 12 percent of Idaho Power's system sales. By December 2016, the number of industrial customers had risen to 118, representing approximately 17 percent of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration from and to the commercial class as dictated by the tariff rules. However, generally speaking, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 281 aMW in 2017 to 320 aMW in 2036, an average annual growth rate of 0.7 percent (Table 7). To a large degree, industrial load variability is not associated with weather conditions as is the case with residential, commercial, and irrigation; therefore, the forecasts in the 70th- and 90th-percentile weather scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 9.

Table 7. Industrial load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Expected Case	281	297	305	320	0.7%

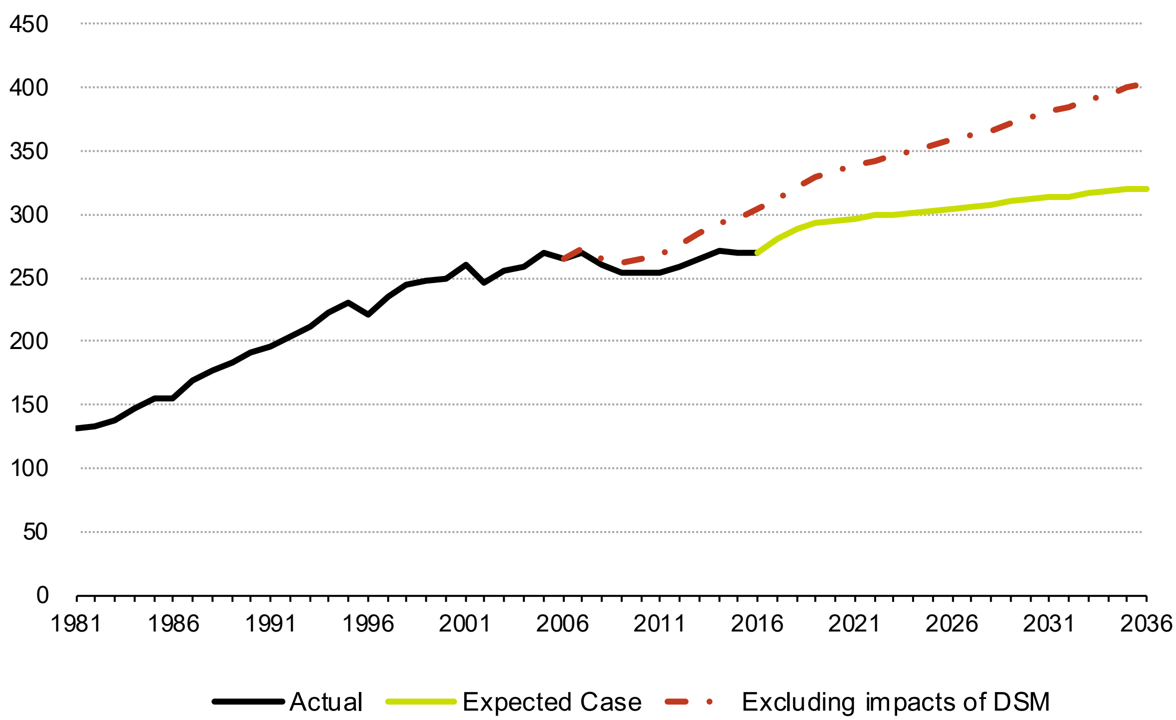

Figure 9. Forecast industrial load (aMW)

As indicated in the figure, the load growth variability is impacted by both economic and other non-weather factors, most particularly the impacts of DSM. The figure highlights the magnitude of DSM on actual and forecast sales. In developing the forecast, customer-specific DSM implementation is isolated, and the actual energy use is adjusted to remove the impacts of DSM to optimize the causal influence of non-DSM causal variables. The history and forecast of DSM is provided by the DSM specialists within Idaho Power. The economic and other independent variables for the regression models are provided by third-party data providers and internally derived time-series for Idaho Power's service area.

Figure 10 illustrates the 2016 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (36%), followed by dairy (18.7%) and electronics/technology (Electech) (7%). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

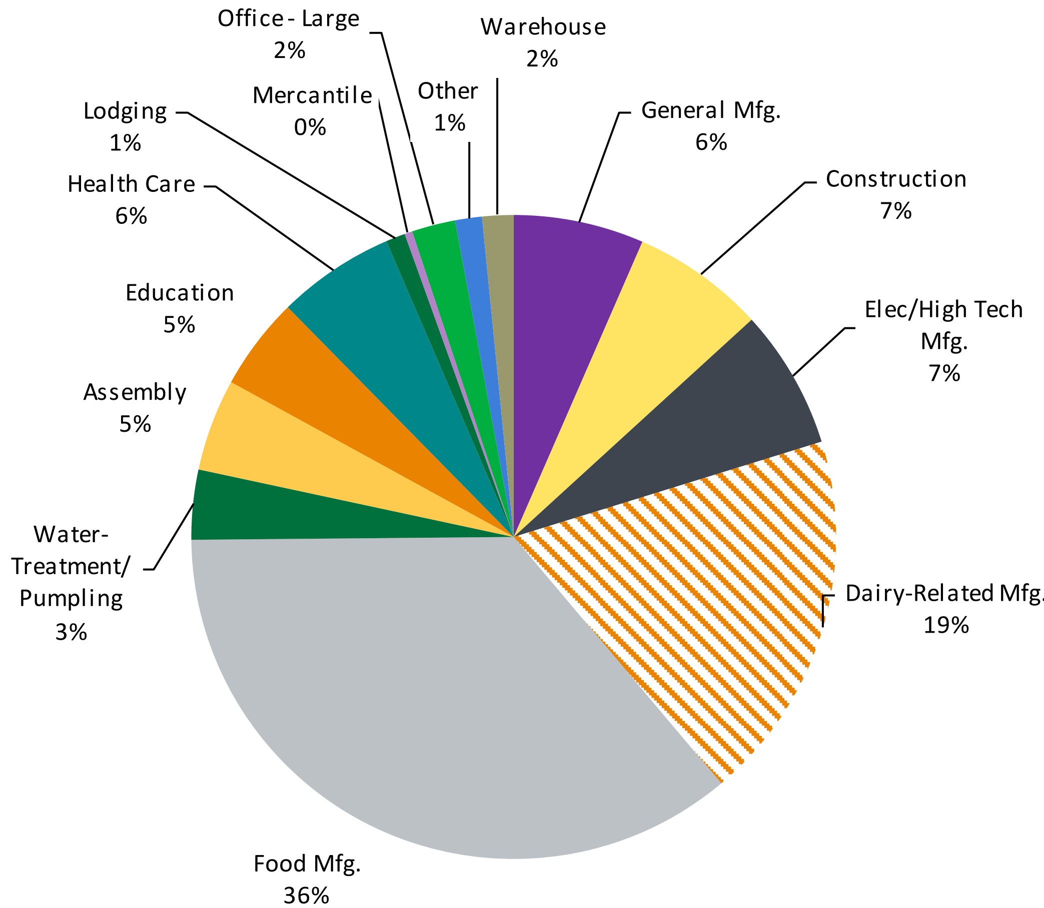

Figure 10. Industrial electricity consumption by industry group (based on 2016 sales)

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and historical independent economic, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models applied to the appropriate forecasts of independent time series of energy use. From this output, the history and forecast of DSM is subtracted.

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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 regulatory body. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

Individual energy and peak-demand forecasts are developed with for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers comprise the forecast category labeled additional firm load.

In the expected-case forecast, additional firm load is expected to increase from 108 aMW in 2017 to 124 aMW in 2036, an average growth rate of 0.7 percent per year over the planning period (Table 8). 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 8. Additional firm load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
Expected Case	108	112	124	124	0.7%

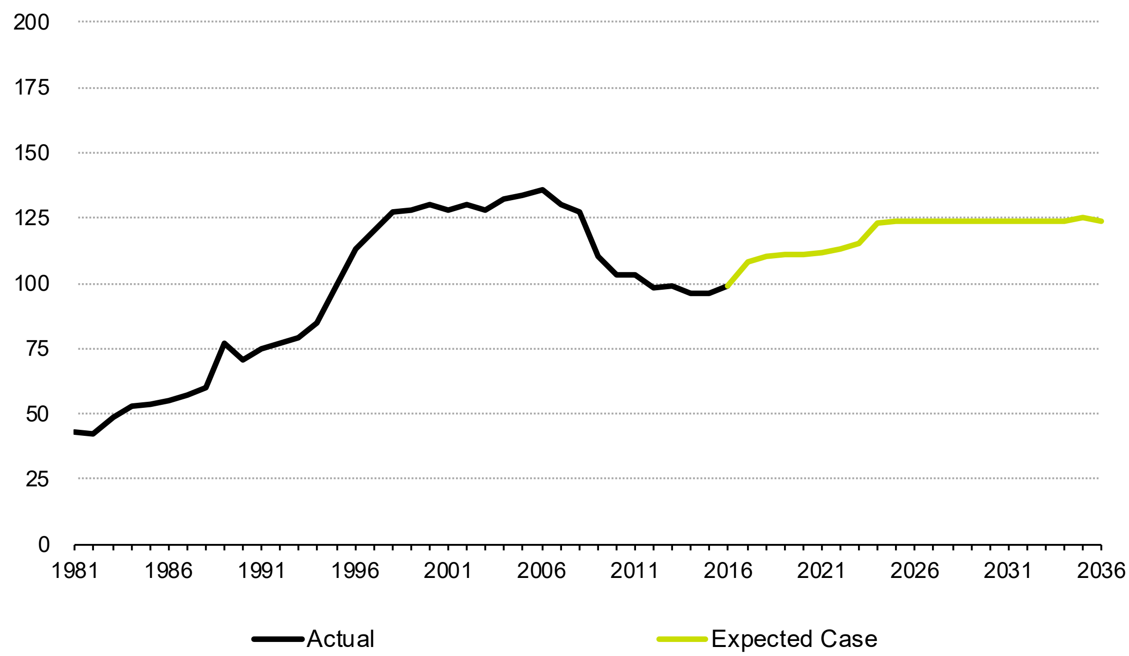

Figure 11. Forecast additional firm load (aMW)

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 services, and general services. Micron Technology's electricity use is a function of the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States (US). The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

Idaho National Laboratory

INL is part of the US Department of Energy's (DOE) complex of national laboratories. INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2036 for the INL. The forecast calls for loads to increase through 2024 and levelize throughout the forecast period.

ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions in energy use) 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 (EE) 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. For residential models, the physical unit flow of energy-efficient products is captured through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE National Energy Model [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.

Energy Efficiency data for irrigation customers and some commercial and industrial customers is not directly surveyed and collected by the DOE; therefore, models for efficiency impacts have been developed derived from methodologies established in Itron's white paper, *Incorporating DSM into the Load Forecast*.[2] These approaches include; isolating historical efficiency data and removing the impacts from historical sales (as previously discussed in application to the industrial customers); applying historical and forecast EE as an independent variable in the regression model (this method was utilized for the commercial customers); and marginal comparison of DSM growth rates for historical versus forecast trend. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output. These alternate models utilize energy efficiency data provided by Idaho Power's internal DSM group. The DSM group develops an independent energy efficiency/DSM forecast in collaboration with AEG consultants. This data served as direct input into the commercial, industrial, and irrigation models. The forecast developed by Idaho Power coincides

[2] 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).

with models that AEG developed. Output for all category forecasts are compared to the AEG output as well as data from DOE Form 861 of utility-reported data. Data from regional utility acquisition is compared to Idaho Power data to ensure the regional assumptions are consistent with Idaho Power assumptions in capturing all energy savings.

Energy savings from utility 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.

Demand Response

Beginning with the 2009 IRP, the reduction in load associated with demand response programs has been effectively treated as a supply-side resource and 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*.

As supply-side resources, demand response program impacts 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. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak-hour load reduction is integrated into the sales and load forecast models. 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 2016 Annual Report*.

Company System Peak

System peak load includes the sum of the 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 3,407 MW, recorded on Tuesday, July 2, 2013, at 4:00 p.m. That record was approached when the peak demand reached 3,402 MW on Tuesday, June 30, 2015, at 4:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

Idaho Power has two peak periods: 1) a winter peak, resulting primarily 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, which coincides with cooling load and irrigation pumping demand.

For resource planning purposes in the 95th-percentile forecast, the system summer peak load is expected to increase from 3,586 MW in 2017 to 4,641 MW in 2036. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,566 MW in 2017 to 4,613 MW in 2036, an average growth rate of 1.4 percent per year over the planning period (Table 9).

Table 9. System summer peak load growth (MW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
95th Percentile	3,586	3,819	4,102	4,641	1.4%
90th Percentile	3,566	3,797	4,078	4,613	1.4%
50th Percentile	3,446	3,668	3,937	4,449	1.4%

The three scenarios of projected system summer peak loads are illustrated in Figure 12. Much of the variation in peak load is due to weather conditions. Although not entirely, unique economic events as occurred in the summer of 2001, when the summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

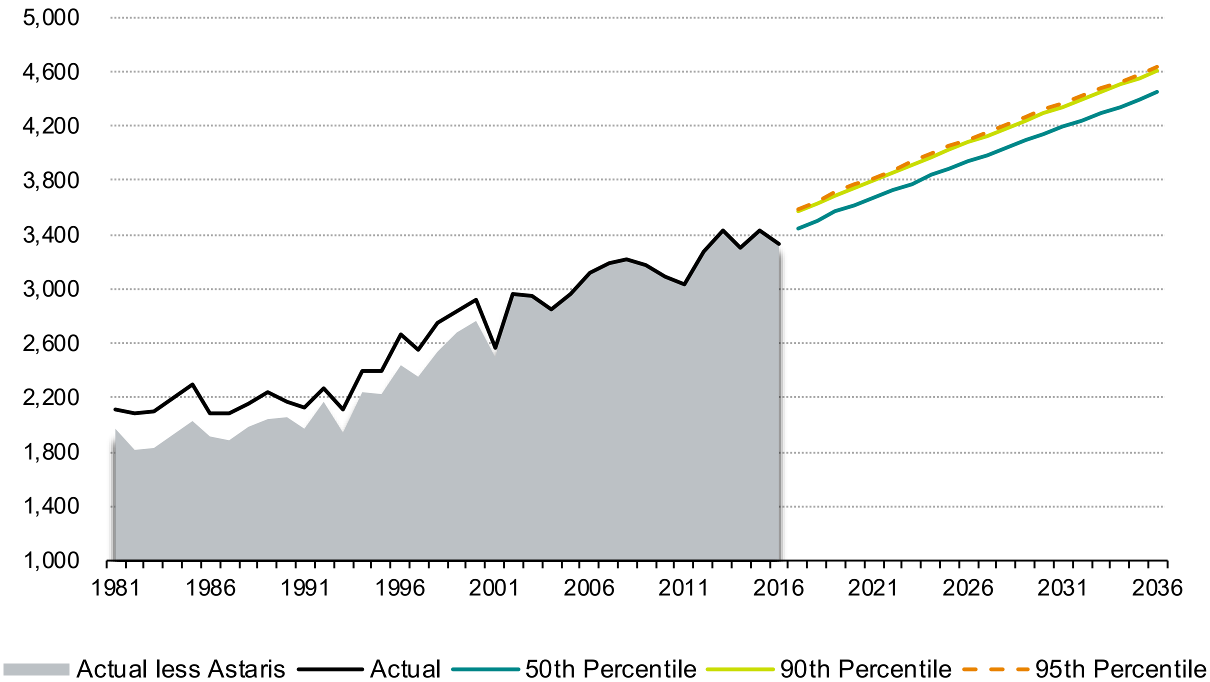

Figure 12. Forecast system summer peak (MW)

As of December 31, 2016, the all-time system winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. and January 06, 2017, at 9:00am. 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 more significant 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.

For resource planning purposes, 95th-percentile forecast, the system winter peak load is expected to increase from 2,611 MW in 2017 to 2,896 MW in 2036, an average growth rate of 0.5 percent per year over the planning period (Table 10). In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,517 MW in 2017 to 2,846 MW in 2036, an average growth rate of 0.9 percent per year over the planning period (Table 10). The three scenarios of projected system winter peak load are illustrated in Figure 13.[3]

[3] Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. 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; 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 1986 to 2015 time period (the most recent 30 years).

Table 10. System winter peak load growth (MW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
95th Percentile	2,611	2,691	2,769	2,896	0.5%
90th Percentile	2,517	2,596	2,675	2,846	0.7%
50th Percentile	2,294	2,415	2,534	2,732	0.9%

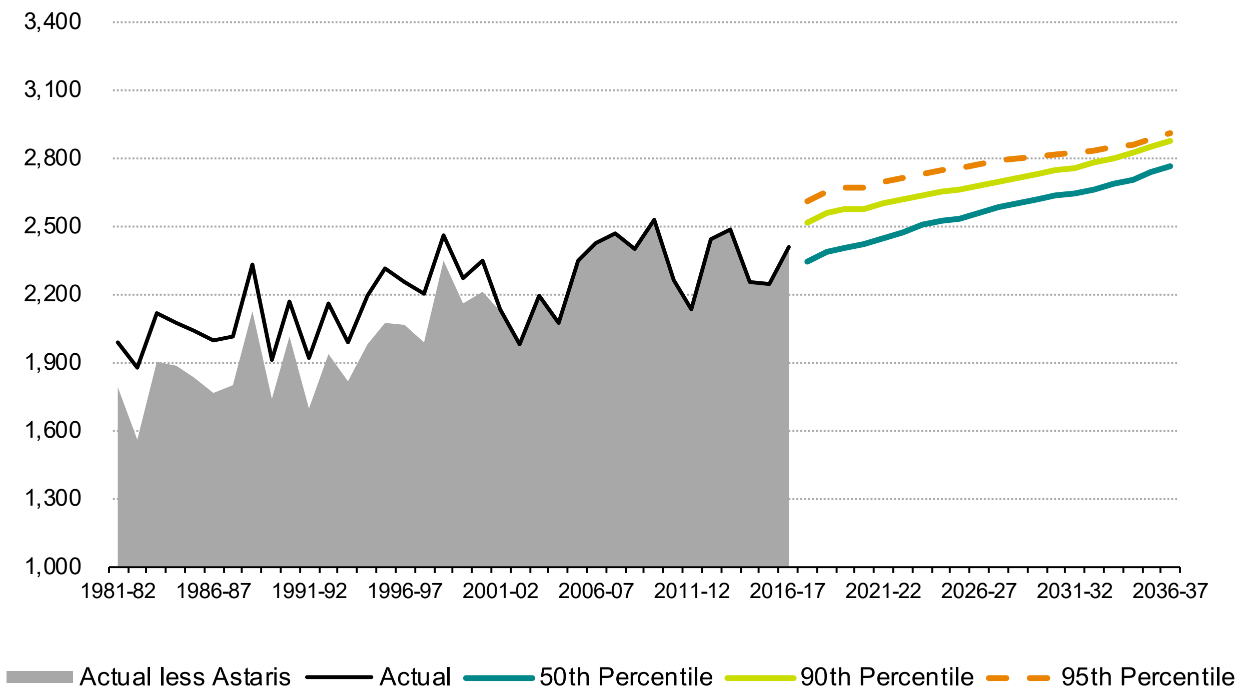

Figure 13. Forecast system winter peak (MW)

Additionally, note the 2017 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

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COMPANY SYSTEM LOAD

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 output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 0.9 percent per year from 2017 to 2036. Company system load projections are reported in Table 11 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,810 aMW in 2017 to 2,142 aMW in 2036. In the 70th-percentile forecast, the company system load is expected to increase from 1,853 aMW in 2017 to 2,193 aMW by 2036, an average growth rate of 0.9 percent per year over the planning period (Table 11).

Table 11. System load growth (aMW)

Growth	2017	2021	2026	2036	Annual Growth Rate 2017–2036
90th Percentile	1,917	2,006	2,108	2,269	0.9%
70th Percentile	1,853	1,939	2,037	2,193	0.9%
Expected Case	1,810	1,894	1,990	2,142	0.9%

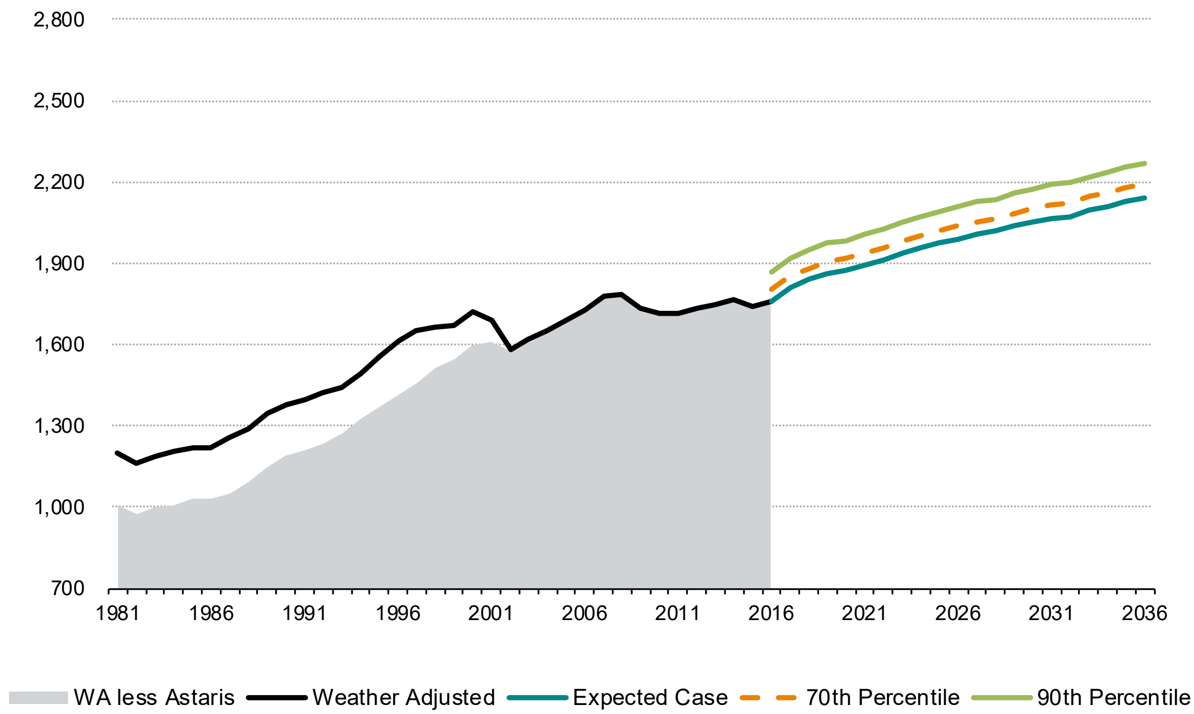

Figure 14. Forecast system load (aMW)

The system load, excluding Astaris[4], portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new large-load customer on system load. As noted previously, the forecast excludes any such prospective large-load customers.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. 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 26 percent higher in 2036, gaining 1.4 million MWh over 2017. Commercial sales are also expected to be 15 percent higher, or 0.6 million MWh, than in 2017, followed by industrial (15 percent higher, or 0.4 million additional MWh) and irrigation (12 percent higher in 2036 than 2017).

[4] 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 had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

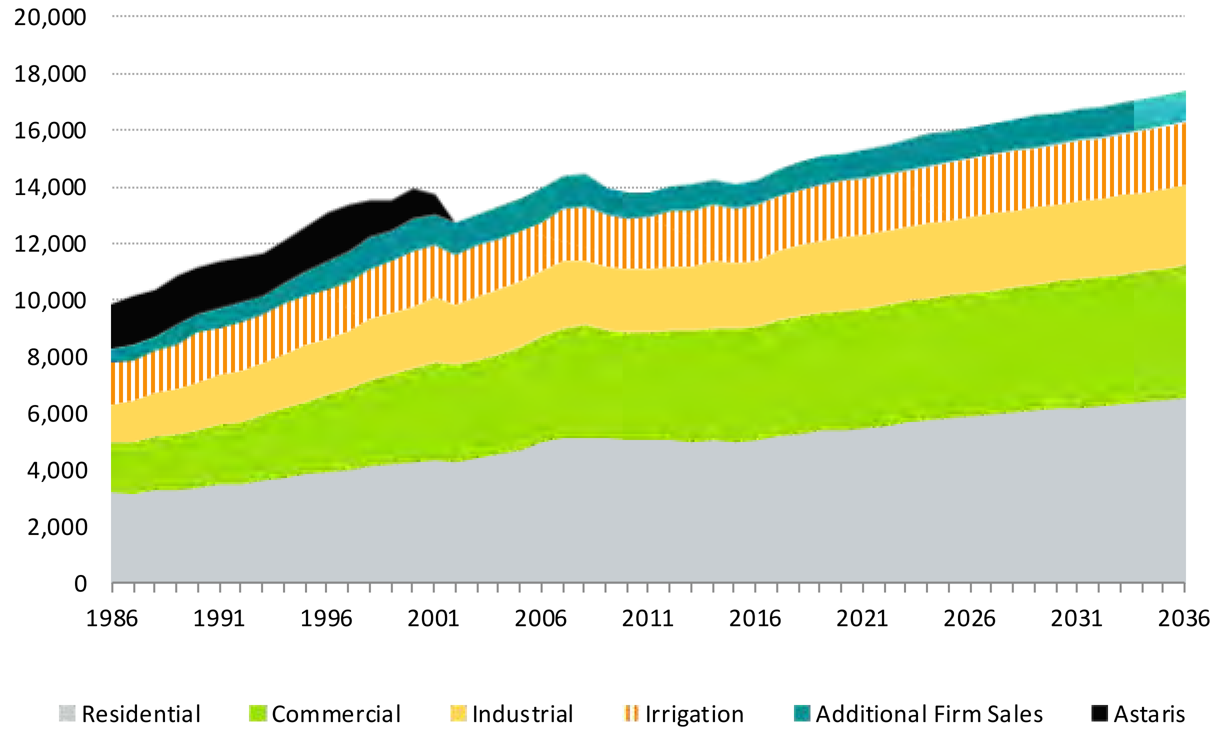

Figure 15. Composition of system company electricity sales (thousands of MWh)

Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also impact the future demand for electricity. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on 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 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 12. 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 12. Residential fuel-price escalation (2017–2036) (average annual percent change)

	Nominal	Real*
Electricity—2017 IRP	1.2%	-0.7%
Electricity—2015 IRP	2.0%	0.0%
Natural Gas	3.7%	1.7%

* Adjusted for inflation

Figure 16 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1980 to 2016 and over the forecast period 2017 to 2036. Both nominal and real prices are shown. In the 2017 IRP, nominal electricity prices are expected to climb to about 13 cents per kWh by the end of the forecast period in 2036. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 0.7 percent annually. In the 2015 IRP, nominal electricity prices were assumed to climb to about 15 cents per kWh by 2036, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of 0.0 percent annually.

The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2015 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yielded lower future prices. The retail prices are more evidently lower in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

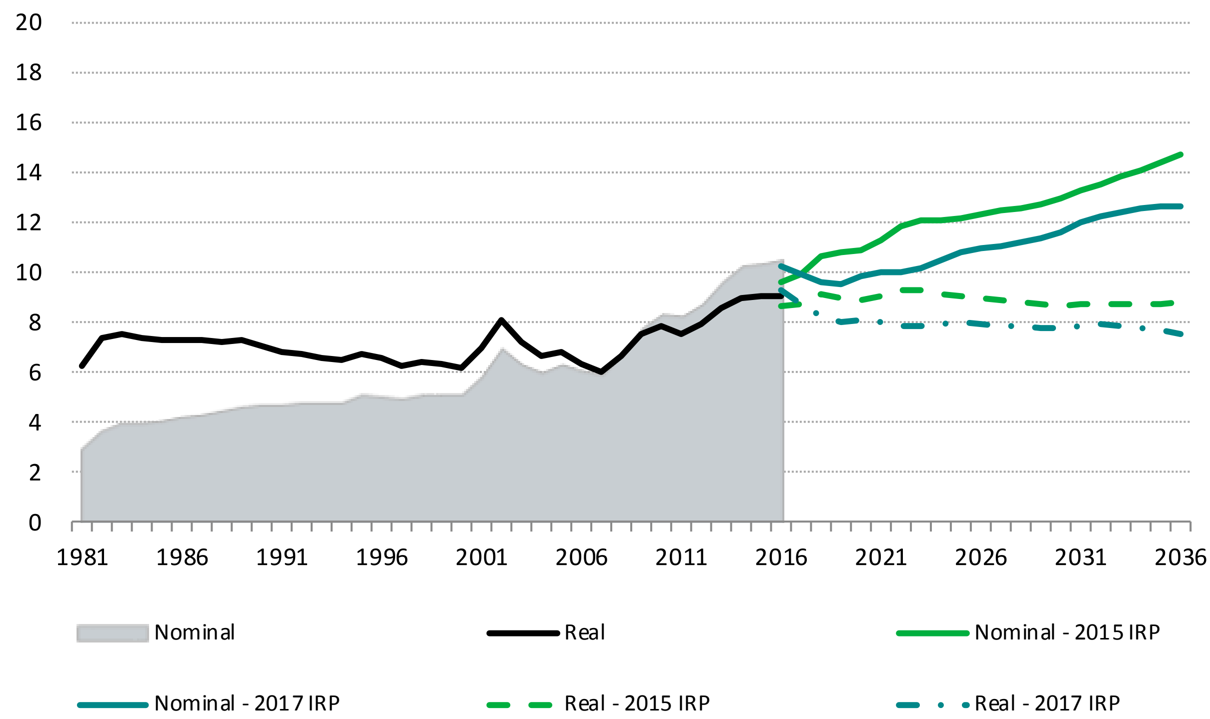

Figure 16. Forecast residential electricity prices (cents per kWh)

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, nominal electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually. More recently, over the period 2006 to 2016, nominal electricity prices rose 72 percent overall, an annual average compound growth rate of 5.6 percent annually.

Figure 17 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1981 to 2015 and forecast prices from 2016 to 2036. 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. Since 2006, natural gas prices have declined about 30 percent, compared to 2015. Nominal natural gas prices are initially expected to drop by 8 percent in 2016, then rise at a steady pace throughout the remainder of the forecast period until more than doubling by 2036, growing at an average rate of 3.7 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.7 percent annually.

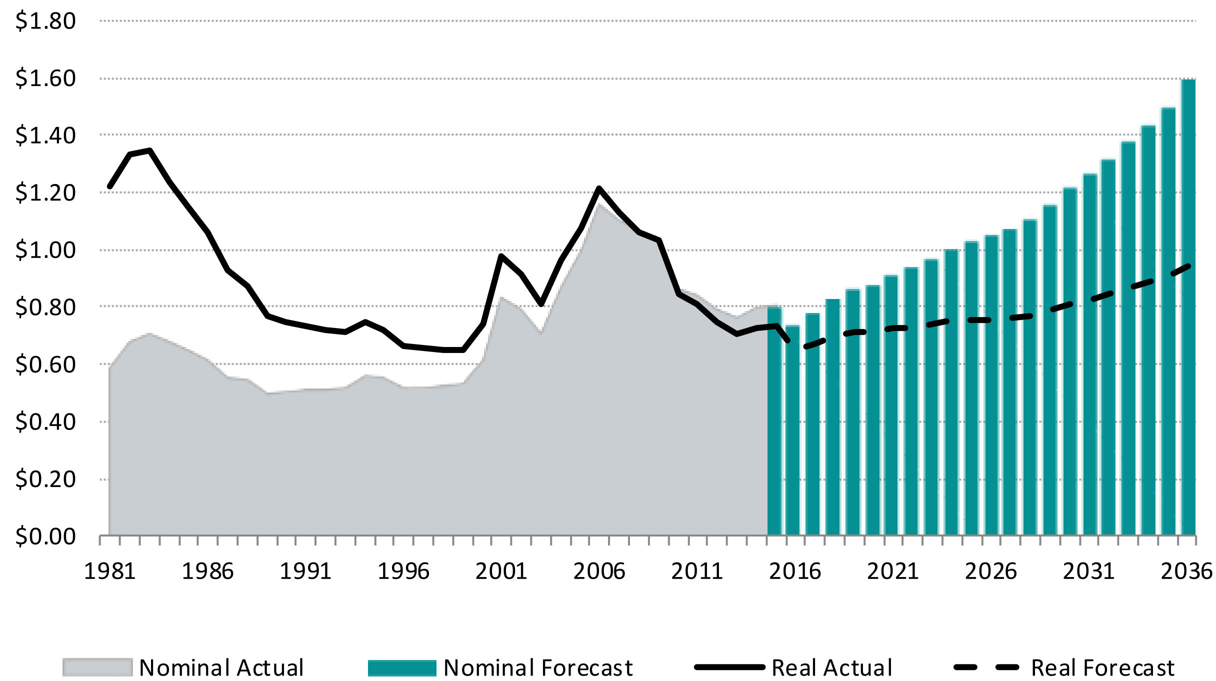

Figure 17. Forecast residential natural gas prices (dollars per therm)

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 2017 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 (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While PEV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, limiting attributes of vehicle range and re-fueling time continue to improve the competitiveness of these vehicles to non-electric models.

Since the first introduction of the Chevy Volt and Nissan Leaf, the number of PEVs offered in the marketplace has proliferated to over 50 models since 2007. Early in this period, PEVs were sold with unique model names (e.g., VOLT); however, as the market grows, the plug-in technology is increasingly offered as an option to existing models (e.g., Ford Focus).

Initially, the Idaho Power forecast for PEV impact relied on third-party forecasts from the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory due to a lack of service-area vehicle registration data; however, beginning with the 2011 IRP, sufficient service-area data became available via vehicle registration data provided by the Idaho Transportation Department (ITD). This data provides a basis from which to develop service-area adoption rates and support the collection of charging behavior. The methodology continues to integrate the fuel and technology share forecasts of the DOE's NEM. The Idaho Power vehicle share forecast uses these models as well as a Bass consumer adoption model as informed by registration data. Load impacts from the share model output are derived from assumptions of battery-only and hybrid plug-in shares evident from Idaho Power observations and informed by the DOE.

Currently, the registration data collection methodology is being revised to capture vehicles sold with PEV technology as an option (e.g., Ford Focus). The methodology will require the unique string of characters within the vehicle identification number (VIN) to be identified and serve as a key value in the ITD data extraction.

The PEV forecast in the IRP did include registration data for the Toyota Prius PEV but did not capture all models for which PEV technology is sold as an option; however, to capture the impact of these models on future adoption, the forecast used the forecast national share assumptions from the DOE. The net effect was to rely less on the registration data than the 2015 IRP model and more on third-party assumptions, as was the case in earlier forecasts.

Net Metering

In recent years, the number of customers signing up for net-metering service (Schedule 84) has raised dramatically, especially for residential customers. Currently, there are approximately 900 residential and 100 commercial net-metering customers. While the recent adoption of solar is relatively strong for our service area, the current population of net-metering customers comprises around one-fifth of 1 percent of the population of retail customers.

The installation of generating and storage equipment at customer sites will cause the demand for electricity delivered by Idaho Power to be reshaped throughout the year. It is important to measure the overall and future impact on the sales forecast. Therefore, this year's long term sales forecast was adjusted downward to reflect the impact of the increase in the number of net-metering customers, specifically solar, connecting to our system.

Schedule 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact-per-customer (in kWh) was then multiplied by a forecast of the Schedule 84 residential and commercial customer count to estimate the future energy impact on the sales forecast. The forecast of net metering customers serves as a function of historical trends and current policy considerations.

The resulting forecast of net-metering customers multiplied by the estimated use-per-customer sales impact per customer resulted in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2036, the annual residential sales reduction was about 18 aMW, and the commercial reduction was less than 1 aMW.

Other Considerations

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 converted from billed periods to calendar months to synchronize them with the time period in which load is generated. The calendar-month sales are then converted to calendar-month average load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2017 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

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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 additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1976–2016 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	175,720	–	13,280	2,334	–	267
1977	184,561	5.0%	13,240	2,444	4.7%	284
1978	194,650	5.5%	14,559	2,834	16.0%	320
1979	202,982	4.3%	13,904	2,822	-0.4%	329
1980	209,629	3.3%	14,657	3,073	8.9%	350
1981	213,579	1.9%	14,583	3,115	1.4%	353
1982	216,696	1.5%	13,544	2,935	-5.8%	337
1983	219,849	1.5%	14,287	3,141	7.0%	358
1984	222,695	1.3%	14,078	3,135	-0.2%	357
1985	225,185	1.1%	13,988	3,150	0.5%	360
1986	227,081	0.8%	14,095	3,201	1.6%	365
1987	228,868	0.8%	13,960	3,195	-0.2%	365
1988	230,771	0.8%	14,237	3,285	2.8%	375
1989	233,370	1.1%	14,237	3,323	1.1%	380
1990	238,117	2.0%	14,223	3,387	1.9%	388
1991	243,207	2.1%	14,428	3,509	3.6%	401
1992	249,767	2.7%	14,099	3,521	0.4%	402
1993	258,271	3.4%	14,124	3,648	3.6%	417
1994	267,854	3.7%	13,991	3,748	2.7%	429
1995	277,131	3.5%	13,950	3,866	3.2%	442
1996	286,227	3.3%	13,713	3,925	1.5%	448
1997	294,674	3.0%	13,640	4,019	2.4%	459
1998	303,300	2.9%	13,681	4,150	3.2%	474
1999	312,901	3.2%	13,548	4,239	2.2%	484
2000	322,402	3.0%	13,365	4,309	1.6%	492
2001	331,009	2.7%	13,128	4,346	0.9%	495
2002	339,764	2.6%	12,641	4,295	-1.2%	491
2003	349,219	2.8%	12,673	4,426	3.0%	506
2004	360,462	3.2%	12,675	4,569	3.2%	522
2005	373,602	3.6%	12,668	4,733	3.6%	543
2006	387,707	3.8%	12,884	4,995	5.5%	571
2007	397,286	2.5%	12,922	5,134	2.8%	587
2008	402,520	1.3%	12,838	5,168	0.7%	589
2009	405,144	0.7%	12,688	5,141	-0.5%	586
2010	407,551	0.6%	12,421	5,062	-1.5%	578
2011	409,786	0.5%	12,361	5,066	0.1%	577
2012	413,610	0.9%	12,251	5,067	0.0%	576
2013	418,892	1.3%	11,968	5,013	-1.1%	575
2014	425,036	1.5%	11,873	5,047	0.7%	573
2015	432,275	1.7%	11,558	4,996	-1.0%	572
2016	440,362	1.9%	11,515	5,071	1.5%	579

Projected Residential Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	448,947	1.9%	11,565	5,192	2.4%	594
2018	458,024	2.0%	11,546	5,288	1.8%	605
2019	467,730	2.1%	11,518	5,388	1.9%	615
2020	477,773	2.1%	11,372	5,433	0.8%	619
2021	487,898	2.1%	11,260	5,494	1.1%	628
2022	498,339	2.1%	11,212	5,588	1.7%	639
2023	509,058	2.2%	11,159	5,681	1.7%	649
2024	519,642	2.1%	11,092	5,764	1.5%	657
2025	529,711	1.9%	11,000	5,827	1.1%	666
2026	539,237	1.8%	10,921	5,889	1.1%	673
2027	548,388	1.7%	10,882	5,967	1.3%	682
2028	557,228	1.6%	10,843	6,042	1.3%	688
2029	565,899	1.6%	10,792	6,107	1.1%	698
2030	574,448	1.5%	10,731	6,165	0.9%	704
2031	582,924	1.5%	10,666	6,218	0.9%	710
2032	591,436	1.5%	10,588	6,262	0.7%	713
2033	600,040	1.5%	10,544	6,327	1.0%	723
2034	608,899	1.5%	10,510	6,399	1.1%	731
2035	617,979	1.5%	10,474	6,473	1.1%	740
2036	627,295	1.5%	10,452	6,557	1.3%	747

Commercial Load

Historical Commercial Sales and Load, 1976–2016 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	26,034	–	52,519	1,367	–	157
1977	27,112	4.1%	52,402	1,421	3.9%	162
1978	27,831	2.7%	52,502	1,461	2.8%	169
1979	28,087	0.9%	56,369	1,583	8.4%	180
1980	28,797	2.5%	54,161	1,560	-1.5%	178
1981	29,567	2.7%	54,302	1,606	2.9%	184
1982	30,167	2.0%	54,124	1,633	1.7%	186
1983	30,776	2.0%	52,650	1,620	-0.8%	185
1984	31,554	2.5%	53,560	1,690	4.3%	193
1985	32,418	2.7%	54,180	1,756	3.9%	201
1986	33,208	2.4%	53,937	1,791	2.0%	204
1987	33,975	2.3%	53,395	1,814	1.3%	207
1988	34,723	2.2%	54,371	1,888	4.1%	216
1989	35,638	2.6%	55,376	1,973	4.5%	226
1990	36,785	3.2%	55,746	2,051	3.9%	235
1991	37,922	3.1%	56,273	2,134	4.1%	244
1992	39,022	2.9%	56,396	2,201	3.1%	251
1993	40,047	2.6%	58,183	2,330	5.9%	266
1994	41,629	4.0%	58,274	2,426	4.1%	278
1995	43,165	3.7%	58,695	2,534	4.4%	290
1996	44,995	4.2%	62,013	2,790	10.1%	319
1997	46,819	4.1%	62,056	2,905	4.1%	332
1998	48,404	3.4%	62,718	3,036	4.5%	348
1999	49,430	2.1%	64,170	3,172	4.5%	362
2000	50,117	1.4%	65,965	3,306	4.2%	378
2001	51,501	2.8%	67,426	3,472	5.0%	396
2002	52,915	2.7%	64,794	3,429	-1.3%	392
2003	54,194	2.4%	64,254	3,482	1.6%	398
2004	55,577	2.6%	63,942	3,554	2.1%	405
2005	57,145	2.8%	63,504	3,629	2.1%	415
2006	59,050	3.3%	63,484	3,749	3.3%	429
2007	61,640	4.4%	63,352	3,905	4.2%	446
2008	63,492	3.0%	62,246	3,952	1.2%	449
2009	64,151	1.0%	59,671	3,828	-3.1%	438
2010	64,421	0.4%	58,853	3,791	-1.0%	432
2011	64,921	0.8%	58,431	3,793	0.1%	433
2012	65,599	1.0%	58,896	3,863	1.8%	440
2013	66,357	1.2%	58,599	3,888	0.6%	446
2014	67,113	1.1%	58,948	3,956	1.7%	452
2015	68,000	1.3%	58,491	3,977	0.5%	455
2016	68,883	1.3%	58,046	3,998	0.5%	456

Projected Commercial Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	69,911	1.5%	58,311	4,077	2.0%	466
2018	71,070	1.7%	58,026	4,124	1.2%	471
2019	72,344	1.8%	57,526	4,162	0.9%	475
2020	73,720	1.9%	56,864	4,192	0.7%	477
2021	75,165	2.0%	56,200	4,224	0.8%	482
2022	76,660	2.0%	55,523	4,256	0.8%	486
2023	78,208	2.0%	54,833	4,288	0.8%	490
2024	79,791	2.0%	54,094	4,316	0.6%	492
2025	81,371	2.0%	53,395	4,345	0.7%	496
2026	82,914	1.9%	52,797	4,378	0.8%	500
2027	84,419	1.8%	52,229	4,409	0.7%	503
2028	85,894	1.7%	51,648	4,436	0.6%	505
2029	87,350	1.7%	51,172	4,470	0.8%	510
2030	88,792	1.7%	50,689	4,501	0.7%	514
2031	90,227	1.6%	50,214	4,531	0.7%	517
2032	91,661	1.6%	49,753	4,560	0.7%	519
2033	93,103	1.6%	49,335	4,593	0.7%	525
2034	94,563	1.6%	48,928	4,627	0.7%	528
2035	96,046	1.6%	48,546	4,663	0.8%	533
2036	97,553	1.6%	48,191	4,701	0.8%	535

Irrigation Load

Historical Irrigation Sales and Load, 1976–2016 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	9,936	–	157,590	1,566	–	178
1977	10,238	3.0%	163,580	1,675	7.0%	191
1978	10,476	2.3%	154,417	1,618	-3.4%	185
1979	10,711	2.2%	164,233	1,759	8.7%	201
1980	10,854	1.3%	160,661	1,744	-0.9%	199
1981	11,248	3.6%	167,476	1,884	8.0%	215
1982	11,312	0.6%	154,133	1,744	-7.4%	199
1983	11,133	-1.6%	147,254	1,639	-6.0%	187
1984	11,375	2.2%	136,431	1,552	-5.3%	177
1985	11,576	1.8%	133,886	1,550	-0.1%	177
1986	11,308	-2.3%	133,605	1,511	-2.5%	172
1987	11,254	-0.5%	132,650	1,493	-1.2%	170
1988	11,378	1.1%	137,485	1,564	4.8%	178
1989	11,957	5.1%	137,849	1,648	5.4%	188
1990	12,340	3.2%	149,397	1,844	11.8%	210
1991	12,484	1.2%	138,862	1,734	-6.0%	198
1992	12,809	2.6%	141,889	1,817	4.8%	207
1993	13,078	2.1%	131,086	1,714	-5.7%	196
1994	13,559	3.7%	132,337	1,794	4.7%	205
1995	13,679	0.9%	128,923	1,764	-1.7%	201
1996	14,074	2.9%	126,199	1,776	0.7%	202
1997	14,383	2.2%	120,399	1,732	-2.5%	198
1998	14,695	2.2%	120,340	1,768	2.1%	202
1999	14,912	1.5%	120,589	1,798	1.7%	205
2000	15,253	2.3%	128,659	1,962	9.1%	223
2001	15,522	1.8%	117,561	1,825	-7.0%	208
2002	15,840	2.0%	109,186	1,730	-5.2%	197
2003	16,020	1.1%	111,786	1,791	3.5%	204
2004	16,297	1.7%	109,191	1,779	-0.6%	203
2005	16,936	3.9%	102,141	1,730	-2.8%	197
2006	17,062	0.7%	96,870	1,653	-4.5%	189
2007	17,001	-0.4%	105,466	1,793	8.5%	205
2008	17,428	2.5%	109,423	1,907	6.4%	217
2009	17,708	1.6%	101,814	1,803	-5.5%	206
2010	17,846	0.8%	101,998	1,820	1.0%	208
2011	18,292	2.5%	99,885	1,827	0.4%	209
2012	18,675	2.1%	104,064	1,943	6.4%	221
2013	19,017	1.8%	103,977	1,977	1.7%	226
2014	19,328	1.6%	104,762	2,025	2.4%	231
2015	19,756	2.2%	95,595	1,889	-6.7%	213
2016	20,042	1.4%	96,320	1,930	2.2%	220

Projected Irrigation Sales and Load, 2017–2036

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	20,322	1.4%	95,100	1,933	0.1%	221
2018	20,623	1.5%	94,261	1,944	0.6%	222
2019	20,914	1.4%	93,667	1,959	0.8%	224
2020	21,211	1.4%	92,910	1,971	0.6%	224
2021	21,508	1.4%	92,038	1,980	0.4%	226
2022	21,806	1.4%	91,417	1,993	0.7%	228
2023	22,102	1.4%	90,745	2,006	0.6%	229
2024	22,393	1.3%	90,067	2,017	0.6%	230
2025	22,691	1.3%	89,332	2,027	0.5%	231
2026	22,988	1.3%	88,614	2,037	0.5%	233
2027	23,285	1.3%	88,060	2,050	0.7%	234
2028	23,581	1.3%	87,483	2,063	0.6%	235
2029	23,877	1.3%	86,865	2,074	0.5%	237
2030	24,172	1.2%	86,305	2,086	0.6%	238
2031	24,469	1.2%	85,740	2,098	0.6%	239
2032	24,766	1.2%	85,113	2,108	0.5%	240
2033	25,062	1.2%	84,622	2,121	0.6%	242
2034	25,356	1.2%	84,178	2,134	0.6%	244
2035	25,651	1.2%	83,720	2,148	0.6%	245
2036	25,946	1.2%	83,336	2,162	0.7%	246

Industrial Load

Historical Industrial Sales and Load, 1976–2016 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	73	–	11,681,540	858	–	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%	18,597,050	2,230	-0.1%	254
2012	115	-4.2%	19,757,921	2,271	1.8%	258
2013	114	-0.7%	20,281,837	2,314	1.9%	265
2014	113	-0.7%	20,863,653	2,363	2.1%	271
2015	116	2.8%	20,271,082	2,360	-0.1%	269
2016	118	1.4%	19,997,106	2,361	0.1%	270

Projected Industrial Sales and Load, 2017–2036

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	119	0.8%	20,602,815	2,452	3.8%	281
2018	120	0.8%	21,033,767	2,524	2.9%	288
2019	121	0.8%	21,161,810	2,561	1.4%	293
2020	121	0.0%	21,372,860	2,586	1.0%	295
2021	121	0.0%	21,497,289	2,601	0.6%	297
2022	122	0.8%	21,426,910	2,614	0.5%	299
2023	123	0.8%	21,375,415	2,629	0.6%	300
2024	124	0.8%	21,318,605	2,644	0.5%	301
2025	125	0.8%	21,253,784	2,657	0.5%	303
2026	125	0.0%	21,355,032	2,669	0.5%	305
2027	127	1.6%	21,124,323	2,683	0.5%	306
2028	128	0.8%	21,082,969	2,699	0.6%	307
2029	128	0.0%	21,208,625	2,715	0.6%	310
2030	128	0.0%	21,329,641	2,730	0.6%	312
2031	129	0.8%	21,284,186	2,746	0.6%	314
2032	130	0.8%	21,226,438	2,759	0.5%	314
2033	130	0.0%	21,325,215	2,772	0.5%	317
2034	131	0.8%	21,268,565	2,786	0.5%	318
2035	133	1.5%	21,054,677	2,800	0.5%	320
2036	133	0.0%	21,155,835	2,814	0.5%	320

Additional Firm Sales and Load

Historical Additional Firm Sales and Load, 1976–2016

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	288	–	33
1977	311	7.8%	35
1978	357	14.8%	41
1979	373	4.4%	43
1980	360	-3.5%	41
1981	376	4.6%	43
1982	367	-2.4%	42
1983	425	15.7%	49
1984	466	9.7%	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	740	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	1,121	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	1,156	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%	103
2011	906	0.0%	103
2012	862	-4.8%	98
2013	867	0.5%	99
2014	841	-2.9%	96
2015	842	0.1%	96
2016	870	3.3%	99

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

Projected Additional Firm Sales and Load, 2017–2036

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	945	8.6%	108
2018	962	1.7%	110
2019	972	1.1%	111
2020	979	0.7%	111
2021	983	0.4%	112
2022	990	0.8%	113
2023	1,011	2.1%	115
2024	1,084	7.2%	123
2025	1,086	0.2%	124
2026	1,086	-0.1%	124
2027	1,087	0.1%	124
2028	1,089	0.2%	124
2029	1,088	-0.1%	124
2030	1,088	0.0%	124
2031	1,088	0.0%	124
2032	1,089	0.1%	124
2033	1,090	0.1%	124
2034	1,090	0.0%	124
2035	1,092	0.2%	125
2036	1,092	0.0%	124

*Includes Micron Technology, Simplot Fertilizer, and the INL

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1976–2016 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1976	6,413	–	799
1977	6,778	5.7%	848
1978	7,242	6.8%	899
1979	7,624	5.3%	955
1980	7,842	2.8%	971
1981	8,129	3.7%	1,009
1982	7,841	-3.5%	976
1983	8,019	2.3%	997
1984	8,125	1.3%	1,007
1985	8,285	2.0%	1,030
1986	8,341	0.7%	1,034
1987	8,478	1.6%	1,053
1988	8,814	4.0%	1,092
1989	9,209	4.5%	1,143
1990	9,568	3.9%	1,190
1991	9,756	2.0%	1,209
1992	9,990	2.4%	1,238
1993	10,235	2.5%	1,270
1994	10,657	4.1%	1,324
1995	11,062	3.8%	1,371
1996	11,414	3.2%	1,413
1997	11,746	2.9%	1,458
1998	12,211	4.0%	1,513
1999	12,491	2.3%	1,548
2000	12,911	3.4%	1,599
2001	13,050	1.1%	1,613
2002	12,748	-2.3%	1,580
2003	13,053	2.4%	1,618
2004	13,327	2.1%	1,651
2005	13,618	2.2%	1,692
2006	13,910	2.2%	1,725
2007	14,339	3.1%	1,779
2008	14,449	0.8%	1,784
2009	13,961	-3.4%	1,732
2010	13,812	-1.1%	1,712
2011	13,822	0.1%	1,713
2012	14,007	1.3%	1,732
2013	14,060	0.4%	1,750
2014	14,232	1.2%	1,763
2015	14,064	-1.2%	1,742
2016	14,231	1.2%	1,762

Company System Load

Projected Company System Sales and Load, 2017–2036

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	14,598	2.6%	1,810
2018	14,842	1.7%	1,840
2019	15,041	1.3%	1,864
2020	15,161	0.8%	1,874
2021	15,282	0.8%	1,894
2022	15,442	1.0%	1,914
2023	15,615	1.1%	1,935
2024	15,824	1.3%	1,955
2025	15,941	0.7%	1,975
2026	16,059	0.7%	1,990
2027	16,196	0.9%	2,007
2028	16,329	0.8%	2,018
2029	16,454	0.8%	2,039
2030	16,570	0.7%	2,053
2031	16,680	0.7%	2,067
2032	16,779	0.6%	2,074
2033	16,903	0.7%	2,095
2034	17,037	0.8%	2,112
2035	17,175	0.8%	2,129
2036	17,326	0.9%	2,142

INTEGRATED RESOURCE PLAN

IDAHO POWER
An IDACORP Company

2017 IRP

APPENDIX B: DSM ANNUAL REPORT

MARCH 15 • 2017

SAFE HARBOR STATEMENT

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

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IDAHO POWER
An IDACORP Company

2017 IRP

APPENDIX B: DSM ANNUAL REPORT

ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) 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 2017 IRP. 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 IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP 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 idahopower.com.

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EXECUTIVE SUMMARY

In 2016, Idaho Power celebrated providing electric service to the residents of southern Idaho for 100 years. Since starting as a small company in 1916, Idaho Power has grown to serve over 500,000 customers in over 24,000 square miles in southern Idaho and eastern Oregon. In 2002, Idaho Power revitalized its energy efficiency programs and began the Idaho and Oregon Energy Efficiency Riders (Rider) to fund the pursuit of cost-effective energy efficiency. Energy efficiency and demand response provide economic and operational benefits to the company and its customers and supports the wise use of energy by Idaho Power customers.

Idaho Power's portfolio of energy efficiency program energy savings for 2016 increased to 170,792 megawatt-hours (MWh), including the estimated savings from the Northwest Energy Efficiency Alliance (NEEA), enough energy to power more than 14,000 average homes a year in Idaho Power's service area. This is a 4-percent increase from the 2015 energy savings of 163,672 MWh. In 2016, the company's energy efficiency portfolio was cost-effective from both the total resource cost (TRC) test and the utility cost (UC) test perspectives with ratios of 2.56 and 3.58, respectively. The portfolio was also cost-effective from the participant cost test ratio was 2.93. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, increased to 146,177 MWh in 2016 from 140,633 MWh in 2015.

Idaho Power successfully operated all three of its demand response programs in 2016. The total demand reduction achieved from the company's programs was 378 megawatts (MW) from an available capacity of 392 MW. Energy efficiency and demand response is an important aspect of Idaho Power's resource planning process. Idaho Power's 2016 achievements in energy savings exceeded the annual savings target identified in Idaho Power's *2015 Integrated Resource Plan* (IRP).

Total expenditures from all funding sources on demand-side management (DSM) activities increased by nearly 10 percent, to $43 million in 2016 from $39 million in 2015. DSM program funding comes from the Idaho and Oregon Riders, Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider.

With a goal of using customers' funds wisely, Idaho Power employees and leaders strive to provide conscientious, prudent, and responsible action and activities that result in cost-effective energy efficiency. This report's content offers descriptions of the 2016 activities and savings.

In 2016, Idaho Power expanded the reach and frequency of its residential energy efficiency campaign, added a Smart-saver Pledge to engage and encourage customers to make an energy-saving behavior change, significantly increased the amount of energy efficiency-related social media posts, and began marketing the company's commercial and industrial energy efficiency offerings as a single program. Idaho Power's residential energy efficiency advertising campaign was awarded second place at the E Source Forum in the category of Best Ad Campaign for an Investor-owned Utility.

Idaho Power continued to use stakeholder input to enhance its programs. The company met regularly with its Energy Efficiency Advisory Group (EEAG) and individual customers seeking input on program improvement. To keep growth in the program portfolio, the company relied on its Program Planning Group (PPG), initiated in 2014, and NEEA's Regional Emerging Technology Advisory Committee (RETAC) to fill the pipeline with ideas for offerings to its energy efficiency programs. Additionally, Idaho Power continued program improvement to make it easier for its customers to participate in programs.

In 2016, Idaho Power distributed Energy-Saving Kits (ESK) at no additional cost to customers on request. By the end of the year, the company had distributed over 34,000 kits to customers in Idaho and Oregon. The ESK included light-emitting diodes (LED) lightbulbs, digital thermometers, shower timers, water flow-rate test bags, LED night lights, and educational materials. Additionally, by the end of the year, Idaho Power employees had personally delivered energy-efficiency messages and distributed nearly 25,000 lightbulbs directly to customers.

This *Demand-Side Management 2016 Annual Report* provides a review of the company's DSM activities and finances throughout 2016 and outlines Idaho Power's plans for future DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419. Idaho Power will provide a copy of the report to the Public Utility Commission of Oregon (OPUC) under Oregon Docket Utility Miscellaneous (UM) No. 1710.

INTRODUCTION

In 2016, Idaho Power celebrated its 100th anniversary. For the last sixteen years, the company has pursued cost-effective energy efficiency as a primary objective. Energy efficiency and demand response provide economic and operational benefits to the company and its customers. Idaho Power provides information and programs to ensure customers have opportunities to learn about their energy use, how to use energy, and participate in programs.

This report focuses on Idaho Power's demand-side management (DSM) activities and results for 2016 and previews planned activities for 2017. The appendices provide historical and detailed information on the company's DSM activities and detailed financial information from 2002 through 2016. The two supplements provide detailed cost-effectiveness data and copies of Idaho Power's evaluations, reports, and research conducted in 2016.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and to provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. Idaho Power considers cost-effective energy efficiency the company's least-cost resource and pays particular attention to ensuring the best value to Idaho Power's customers. Idaho Power strives to provide customers with programs and information to help them manage their energy use wisely.

The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. For economic and administrative efficiency and to reduce customer confusion, Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas. Idaho Power has been locally operated since 1916 and serves nearly 530,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon.

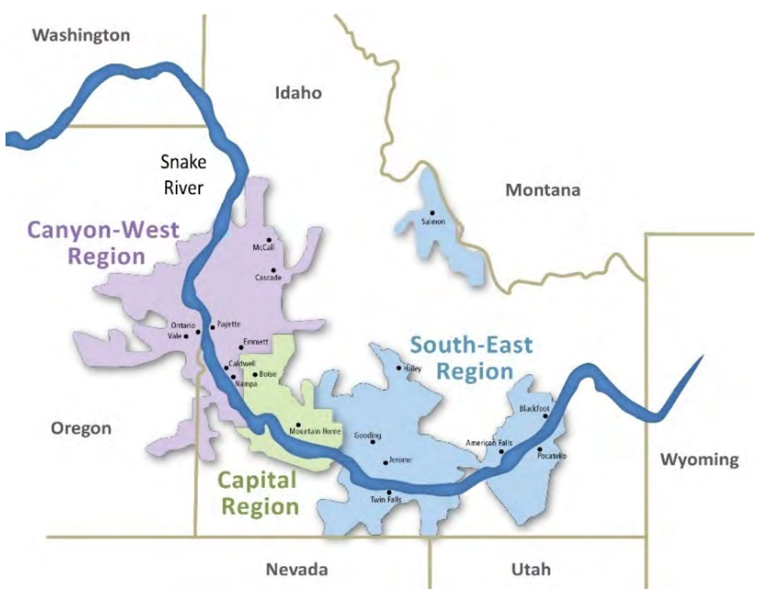

Figure 1. 2016 Idaho Power service area map

Idaho Power's energy efficiency programs focus on reducing energy use by identifying homes, buildings, equipment, or components for which an energy-efficient design, replacement, or repair can achieve energy savings. Energy efficiency programs sometimes include behavioral components, including the Residential Energy Efficiency Education Initiative and both the Smart-saver Pledge and the School Cohort, which began in 2016. Energy efficiency programs are available to all customer sectors in Idaho Power's service area.

Savings from these programs are measured in terms of kilowatt-hour (kWh) or megawatt-hour (MWh) savings. These programs usually supply energy savings throughout the year at different times depending on the energy-efficiency measure put in place. Idaho Power shapes these savings based on the end use to estimate energy reduction at specific times of the year and day. 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 system improvement or replacement. Custom programs under the irrigation and industrial sectors offer a wide range of opportunities for Idaho Power and its customers to design and execute energy-saving projects.

Energy efficiency program and demand response funding comes from the Idaho and Oregon Energy Efficiency Riders (Rider), Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider. Total expenditures from all funding sources on DSM-related activities increased by about 10 percent, from $39 million in 2015 to $43 million in 2016.

Idaho Power started its modern demand response programs in 2002, and now has over 10 percent of its all-time peak load available under demand response programs. The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side peaking resources. The company estimates future capacity needs through the IRP planning process and plans resources to mitigate any system peak deficits that exist. Demand response programs are measured by the amount of demand reduction, in megawatts (MW), available to the company during system peak periods.

DSM Programs Performance

The 2016 savings consisted of 42,269 MWh from the residential sector, 88,161 MWh from the commercial/industrial sector, and 15,747 MWh from the irrigation sector. This represents a 4-percent increase from 2015 program savings. The industrial Custom Projects (formerly Custom Efficiency) program in the Commercial and Industrial Energy Efficiency Program contributed 33 percent of Idaho Power's direct program savings, while the residential sector Energy Efficient Lighting and Educational Distributions programs contributed 86 percent of the residential savings.

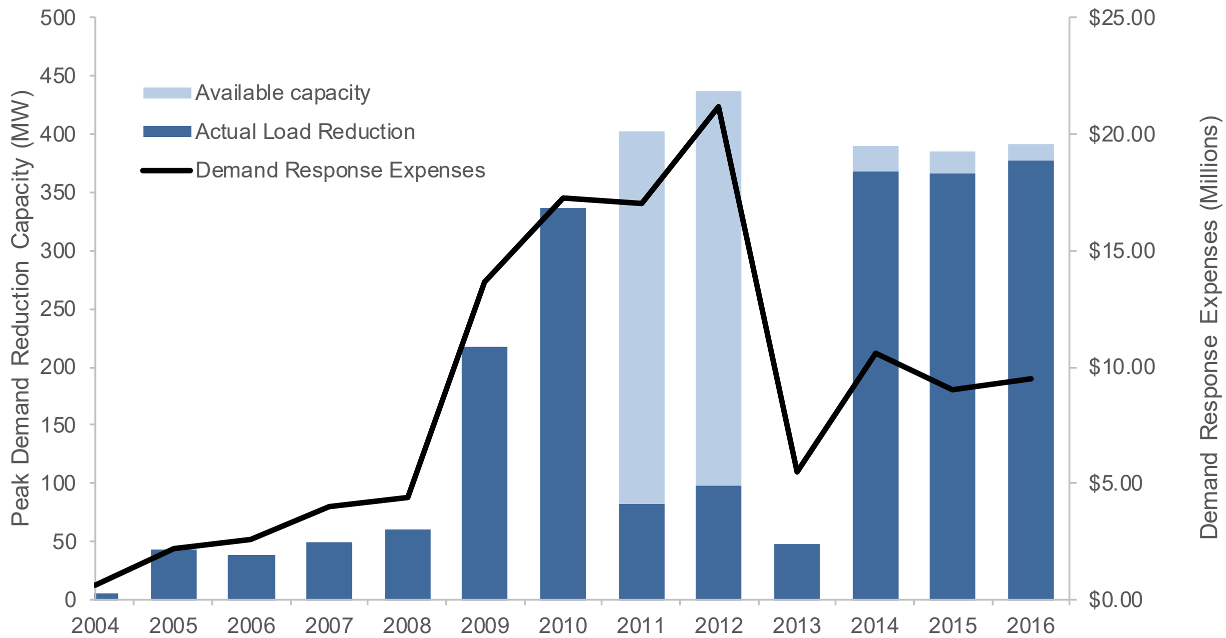

Figure 2. Peak demand-reduction capacity and demand response expenses, 2004–2016 (MW and millions [$])

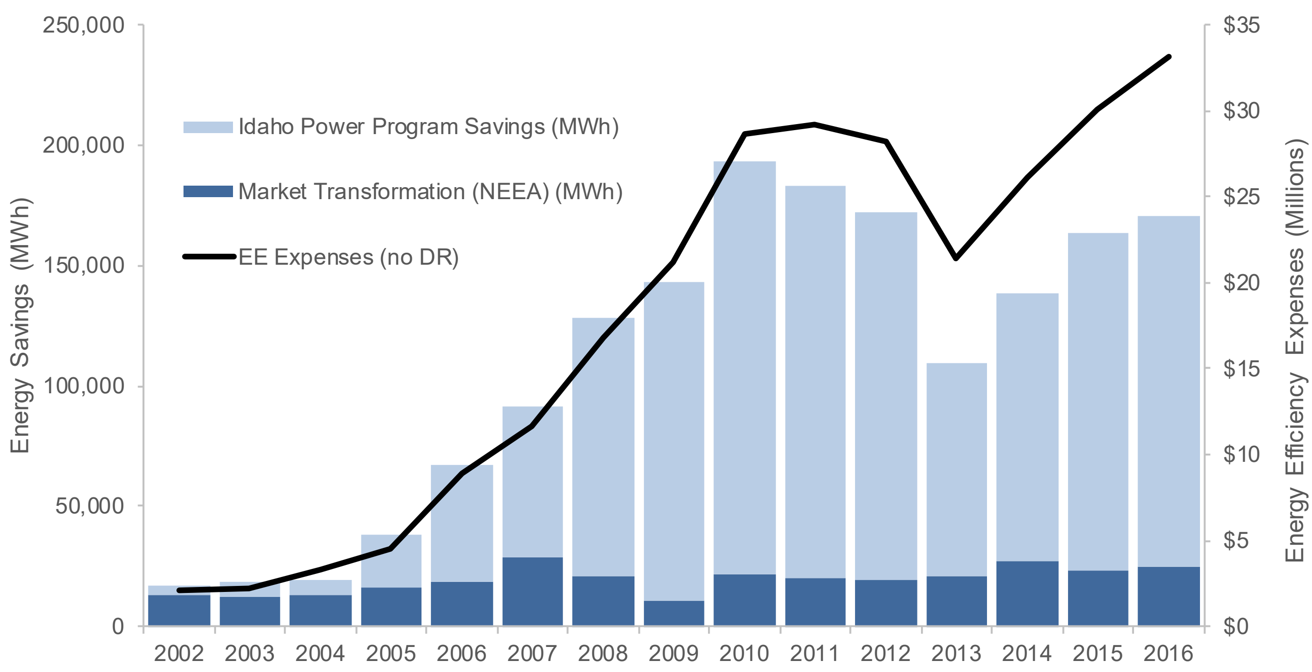

Figure 3. Annual energy savings and energy efficiency program expenses, 2002–2016 (MWh and millions [$])

Figure 3 demonstrates that as Idaho Powers energy-efficiency portfolio matures, and some savings become more difficult and costly to achieve, the expense per incremental savings increases.

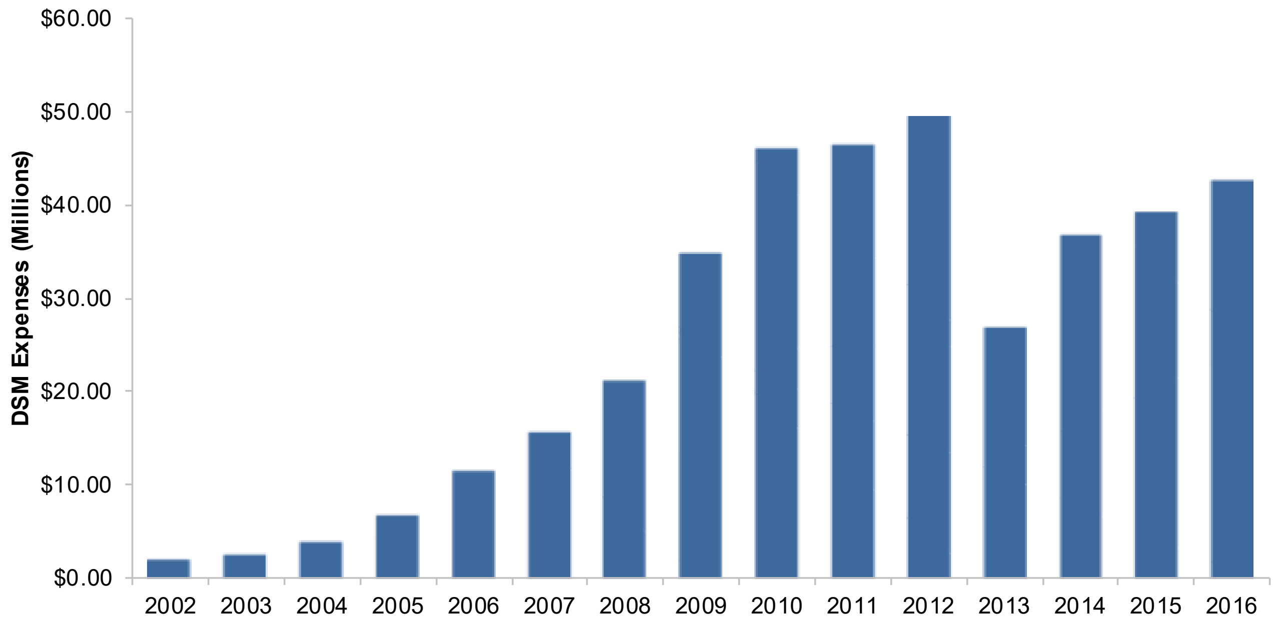

Figure 4. Total DSM expense history, including energy efficiency, demand response, and NEEA expenses, 2002–2016 (millions [$])

Energy efficiency and demand response is an important aspect of Idaho Power's resource planning process. Idaho Power's 2016 achievements in energy savings exceeded the annual savings target identified in Idaho Power's *2015 Integrated Resource Plan*. On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002.

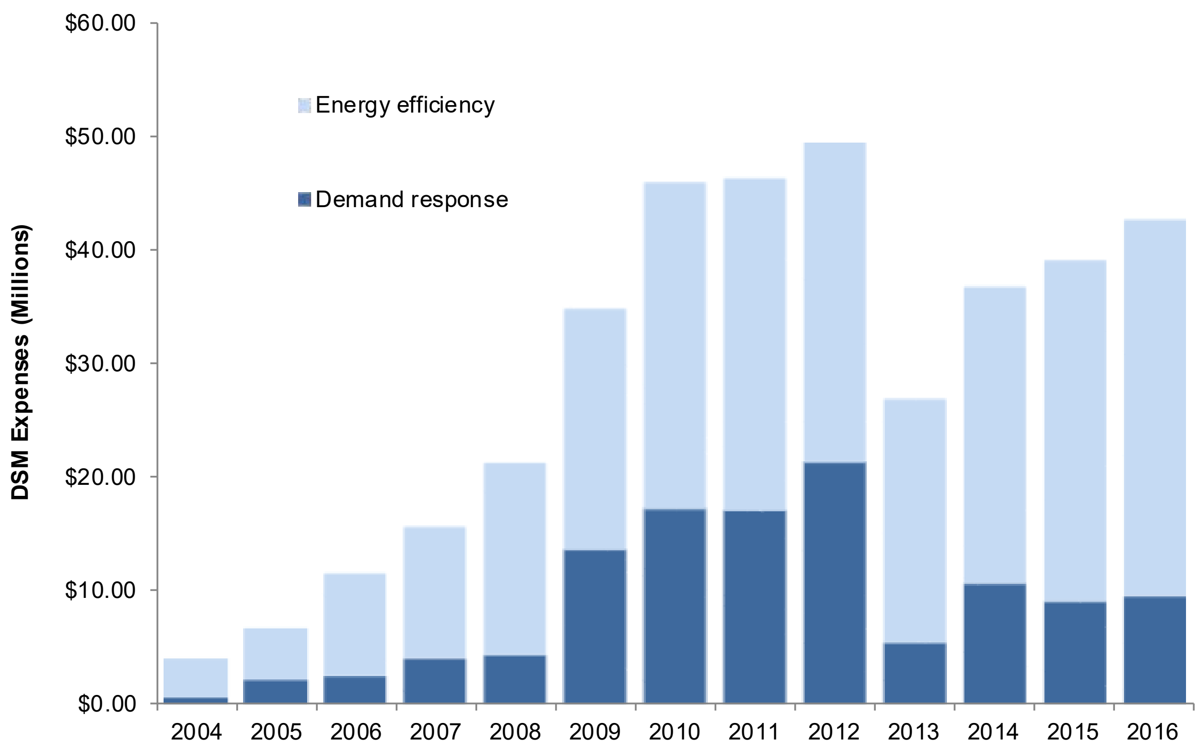

Figure 5. DSM expense history by program type, 2004–2016 (millions [$])

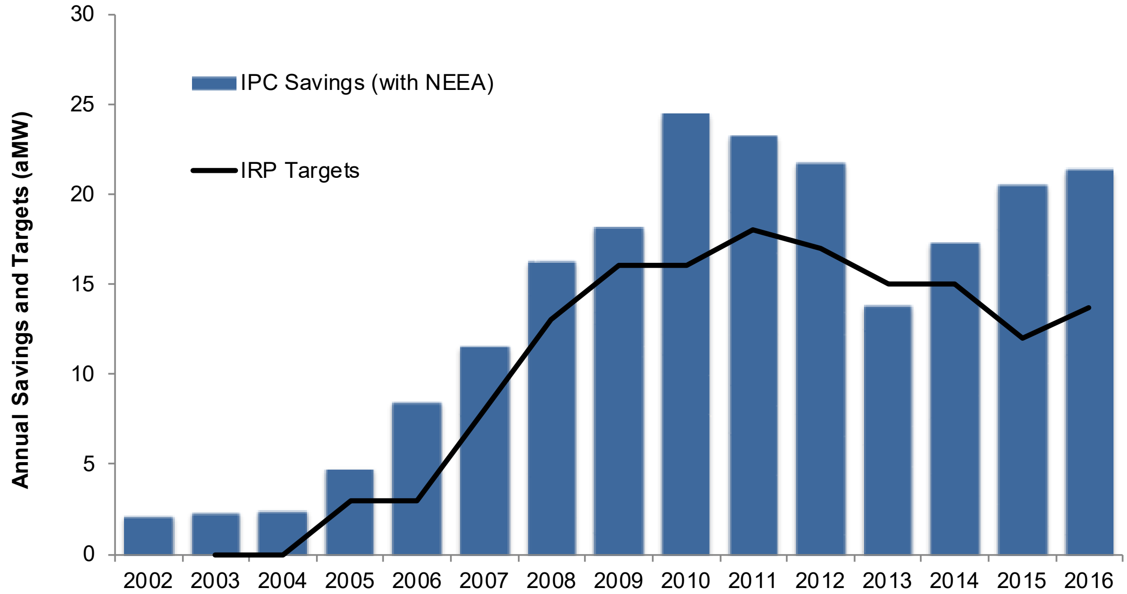

Figure 6. Annual incremental energy efficiency savings (aMW) compared with IRP targets, 2002–2016

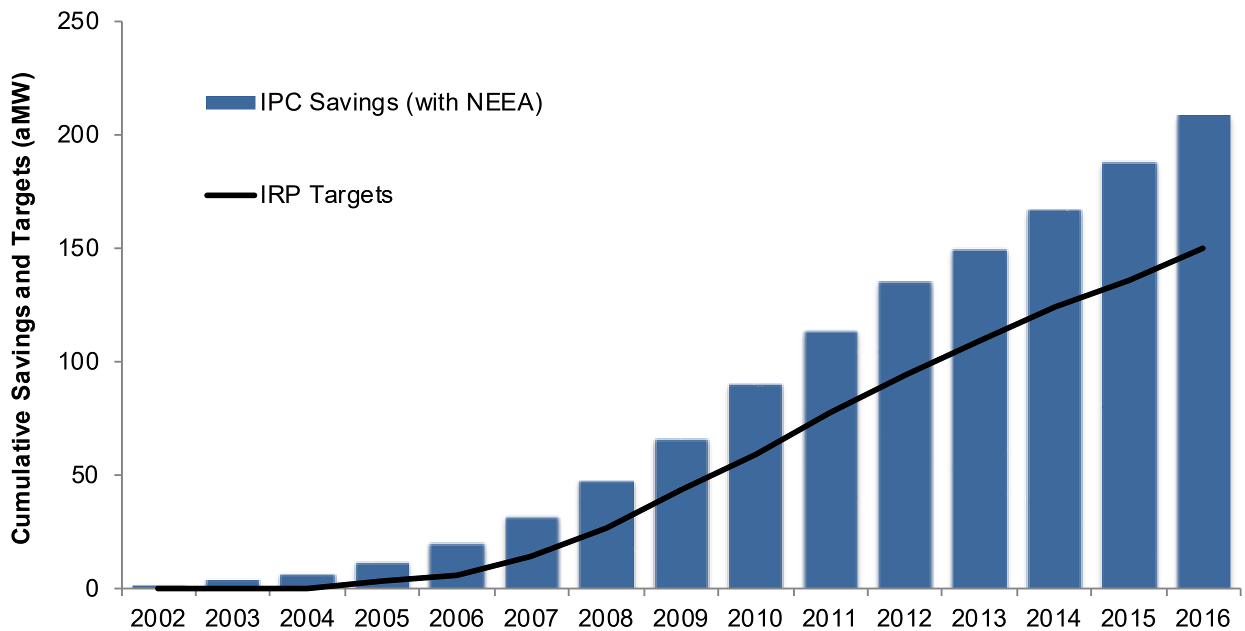

Figure 7. Annual cumulative energy efficiency savings (aMW) compared with IRP targets, 2002–2016

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 92 outreach activities, including events, presentations, trainings, and other activities. In addition, Idaho Power customer representatives delivered 189 presentations to local organizations addressing energy efficiency programs and wise energy use.

In 2016, Idaho Power's community education representatives presented *The Power to Make a Difference* 91 times to 2,350 students and gave 53 classroom presentations of *Saving a World Full of Energy* to 1,411 students. At events and presentations, company staff distributed over 24,000 light-emitting diodes (LED) lightbulbs in custom packaging that highlighted the advantages of energy-efficient lighting and encouraged participation in Idaho Power's myAccount online portal. The company also distributed over 34,000 Energy-Saving Kits (ESK) by request across its service area. On February 8, 2016, Idaho Power filed a request with the Public Utility Commission of Oregon (OPUC) to implement the Educational Distributions program in Oregon. The company received approval of Oregon Schedule 71 on March 9, 2016. This enabled Idaho Power to provide ESKs and LEDs to its Oregon customers.

Since 2008, commercial and industrial training activities have informed and educated commercial and industrial customers regarding energy efficiency, increased awareness of and participation in existing commercial and industrial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives. Raising the knowledge level of commercial and industrial customers regarding the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial and industrial energy efficiency programs.

Idaho Power continued its internal commitment to energy efficiency in 2016. Idaho Power upgraded the company's substation buildings across its service area, renovated portions of the corporate headquarters (CHQ) in downtown Boise in 2016, and redesigned the heating, ventilation, and air conditioning (HVAC) delivery system for the Maintenance and Electrical Shop. Also in 2016, the new Twin Falls Operation Center was constructed to replace the 1951-built center used to house the operations staff. The design incorporates energy-efficient lighting, heating and cooling, daylight harvesting, and a rooftop solar array.

Demand Response Programs

In summer 2016, Idaho Power had a combined maximum actual non-coincidental load reduction from all three programs of 378 MW at the generation level. The amount of capacity available for demand response varies based on weather, the time of year, and how programs are used and managed. The 2016 capacity of demand response programs was 392 MW. The demand response capacity is calculated using total enrolled MW from participants with an expected maximum realization rate for those participants. This maximum realization rate is not always achieved for every program in any given event. This realization rate is expected to be approximately 73 percent of billing demand for Irrigation Peak Rewards and 100 percent of actual non-coincidental load reduction for A/C Cool Credit and the Flex Peak Program.

On Wednesday, June 29, 2016, the company used the Irrigation Peak Rewards program and reached a system peak of 3,085 MW. Had the program not been used, the company estimates the load would have been approximately 3,327 MW. Idaho Power's 2016 summer peak occurred on June 28 with a peak of 3,299 MW while the all-time summer peak was 3,407 MW on July 2, 2013.

Energy Efficiency Programs

Idaho Power's portfolio of energy efficiency program energy savings for 2016 increased to 170,792 MWh, including the estimated Northwest Energy Efficiency Alliance (NEEA) savings. This is a 4-percent increase from the 2015 energy savings of 163,672 MWh and enough to power over

14,000 average-sized homes a year in Idaho Power's service area. In 2016, the company's energy efficiency portfolio is cost effective from both the total resource cost (TRC) test and the utility cost (UC) test perspectives with ratios of 2.56 and 3.58, respectively. The savings from Idaho Power's energy efficiency programs alone (excluding NEEA savings) increased to 146,177 MWh in 2016 from 140,633 MWh in 2015.

Table 1. 2016 DSM programs by sector, operational type, location, and energy savings/demand reduction

Program by Sector	Operational Type	State	Savings/Demand Reduction
Residential			
A/C Cool Credit	Demand Response	ID/OR	34 MW
Easy Savings	Energy Efficiency	ID	403 MWh
Educational Distributions	Energy Efficiency	ID/OR	15,150 MWh
Energy Efficient Lighting	Energy Efficiency	ID/OR	21,094 MWh
Energy House Calls	Energy Efficiency	ID/OR	510 MWh
ENERGY STAR® Homes Northwest	Energy Efficiency	ID/OR	150 MWh
Fridge and Freezer Recycling Program (See ya later, refrigerator®)	Energy Efficiency	ID/OR	632 MWh
Heating & Cooling Efficiency Program	Energy Efficiency	ID/OR	1,114 MWh
Home Energy Audit	Energy Efficiency	ID	207 MWh
Home Improvement Program	Energy Efficiency	ID	500 MWh
Multifamily Energy Savings Program	Energy Efficiency	ID/OR	150 MWh
Oregon Residential Weatherization	Energy Efficiency	OR	3 MWh
Rebate Advantage	Energy Efficiency	ID/OR	411 MWh
Shade Tree Project	Other Programs and Activities	ID	n/a
Simple Steps, Smart Savings™	Energy Efficiency	ID/OR	577 MWh
Weatherization Assistance for Qualified Customers	Energy Efficiency	ID/OR	746 MWh
Weatherization Solutions for Eligible Customers	Energy Efficiency	ID	622 MWh
Commercial/Industrial			
Commercial and Industrial Efficiency Program			
Custom Projects (Custom Efficiency)	Energy Efficiency	ID/OR	47,519 MWh
New Construction (Building Efficiency)	Energy Efficiency	ID/OR	12,393 MWh
Retrofits (Easy Upgrades)	Energy Efficiency	ID/OR	28,125 MWh
Flex Peak Program	Demand Response	ID/OR	42 MW
Green Motors—Industrial	Energy Efficiency	ID/OR	124 MWh
Oregon Commercial Audits	Energy Efficiency	OR	n/a
Irrigation			
Green Motors—Irrigation	Energy Efficiency	ID/OR	74 MWh
Irrigation Efficiency Rewards	Energy Efficiency	ID/OR	15,674 MWh
Irrigation Peak Rewards	Demand Response	ID/OR	303 MW
All Sectors			
Northwest Energy Efficiency Alliance	Market Transformation	ID/OR	24,616 MWh

Table 2. 2016 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	$10,724,671	42,268,823	4.8		4,907,730	34.92%	444,431
Commercial/Industrial	$14,961,753	88,160,599	10.1		7,198,357	51.22%	69,462
Irrigation	$2,372,352	15,747,130	1.8		1,948,079	13.86%	20,638
Market Transformation	$2,676,387	24,615,600	2.8				
Demand Response	$9,471,367	n/a	n/a	378			
Direct Overhead	$293,039	n/a	n/a				
Total Direct Program Expenses	**$40,499,570**	**170,792,152**	**19.5**	**378**	**14,054,166**	**100.0%**	**534,531**

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.

[b] Includes peak-load reduction from both demand response and energy efficiency programs. Includes 9.7% peak line loss assumptions.

Program Evaluation Strategy

Idaho Power considers program evaluation an essential component of its DSM operational activities. The company uses third-party contractors to conduct impact, process, and other evaluations on a scheduled and as required basis.

Third-party contracts are generally awarded using a competitive bid process managed by Idaho Power's Strategic Sourcing department. In some cases, research and analysis is conducted internally and managed by Idaho Power's Research and Analysis team within the Customer Relations and Energy Efficiency (CR&EE) department. Third-party evaluations are specifically managed by the company's energy efficiency evaluator.

Idaho Power uses industry standard protocols for its internal and external evaluation efforts, including the National Action Plan for Energy Efficiency—Model Energy Efficiency Program Impact Evaluation Guide, the California Evaluation Framework, the International Performance Measurement and Verification Protocol (IPMVP), the Database for Energy Efficiency Resources, and the Regional Technical Forum's (RTF) evaluation protocols.

The company also supports regional and national studies to promote the ongoing cost-effectiveness of programs, the validation of energy savings and demand reduction, and the efficient management of its programs. Idaho Power considers primary and secondary research, cost-effectiveness analyses, potential assessments, impact and process evaluations, and customer surveys to be important resources in providing accurate and transparent program-savings estimates. Recommendations and findings from evaluations research and industry best practices are used to continuously refine Idaho Power's DSM programs. Historical evaluation plans, plans for 2017, and copies of 2016 evaluations and research can be found in *Supplement 2: Evaluation.*

Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. Idaho Power's energy efficiency and demand response opportunities are preliminarily identified through the IRP process. Idaho Power uses third-party energy efficiency potential studies to identify achievable cost-effective energy efficiency potential that is added to the resources included in the IRP. Because of Idaho Power's diversified portfolio of programs, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to existing programs rather than developing new programs.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design or measure will be cost-effective from the perspective of Idaho Power and its customers. Incorporated in these models are inputs from various sources that use the most current and reliable information available.

Additionally, Idaho Power relies on the results of program impact evaluations and recommendations from consultants. In 2016, Idaho Power contracted with ADM Associates, Inc. (ADM); Applied Energy Group (AEG); CLEAResult Consulting, Inc. (CLEAResult); and Tetra Tech, MA for program evaluations and research.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the TRC test, UC test, and participant cost test (PCT) at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test provides value when evaluating program performance. If a particular measure or program is pursued even though it will not be cost-effective from each of the three tests, Idaho Power works with the Energy Efficiency Advisory Group (EEAG) to get input. The company believes this aligns with the expectations of the Idaho Public Utilities Commission (IPUC) and OPUC.

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

Future Plans

Idaho Power will continue to pursue all prudent cost-effective energy efficiency as identified by third-party potential studies, and an appropriate amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecast level of energy efficiency and the needed level of demand response are included in Idaho Power's biennial IRP planning process. Idaho Power includes all achievable cost-effective energy savings as identified in its potential studies in each IRP. Idaho Power considers this achievable potential a reasonable 20-year planning estimate. However, the company does not consider the achievable potential as a ceiling limiting energy efficiency acquisition. The IRP is developed in a public process 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 to develop a preferred portfolio of future resources to meet the specific energy needs of Idaho Power's customers.

Planning activities conducted in 2016 identified an opportunity for Idaho Power to increase its focus on small and medium business customers to build relationships and promote participation in energy efficiency programs. A new position titled customer solutions advisor has been developed as a result of this effort. Eight customer solutions advisor positions have been developed and are scheduled to be in place and performing their assigned duties by May 1, 2017. The customer solutions advisors will focus on customer outreach by phone to "on-board" new business customers and support existing business customers by familiarizing them with Idaho Power's rates, billing and payment options, and energy-usage information available through myAccount and by answering any questions they may have about services and programs offered by Idaho Power. A primary function of the customer solutions advisor role will be promoting and educating business customers on energy efficiency and demand response programs.

The company will continue to explore new energy savings potential through third-party resources, conferences, and regional organizations, and will continue to assess and develop new program offerings through its Program Planning Group (PPG). Idaho Power will work in consultation with the EEAG to expand or modify its energy efficiency portfolio. Future plans for individual programs are included under each program's *2017 Program and Marketing Strategies*.

In 2017, Idaho Power will continue to enhance its marketing and outreach efforts as described in the Marketing section of this report and within each program section. Idaho Power will continue to work with NEEA on its market transformation activities during the 2015 to 2019 funding cycle.

The company will complete its research and evaluation, measurement, and verification (EM&V) projects included in the evaluation plan in *Supplement 2: Evaluation*.

Idaho Power will incorporate energy efficiency equipment and practices into its own facilities. In 2017, the company will continue renovations at the CHQ in downtown Boise. Idaho Power plans to remodel the ninth floor of the CHQ, exchanging the old T-12 parabolic lighting fixtures with T-8 lighting, and incorporating energy efficiency measures, such as lower partitions, lighting retrofits, and automated lighting controls.

In 2016, Idaho Power redesigned the HVAC delivery system for the Maintenance and Electrical Shops; construction on these projects is planned for 2018. Idaho Power estimates that with these improvements the shops may reduce their usage by 300,000 kWh in coming years.

DSM Annual Report Structure

The *Demand-Side Management 2016 Annual Report* consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows the standard cost effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category. In 2016, the company continued its commitment to third party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2016 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. Additionally, the report and supplements will be provided under Oregon Docket UM 1710 to provide the OPUC and its staff information on the company's DSM programs and expenses.

This main *Demand-Side Management 2016 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 table containing 2016 and 2015 program metrics, followed by a general description, 2016 activities, cost-effectiveness, customer satisfaction/evaluation, and 2017 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 other programs and activities, including market transformation, and Idaho Power's regulatory initiatives. Appendices 1 through 5 follow the written sections and contain a table on 2016 expenses and savings and historic information for all energy efficiency programs and demand response activities at Idaho Power.

In 2016, Idaho Power's commercial and industrial energy efficiency programs were combined in one umbrella program, the Commercial and Industrial Energy Efficiency Program, with options named to describe their purpose: New Construction (formerly Building Efficiency), Retrofits (formerly Easy Upgrades), and Custom Projects (formerly Custom Efficiency). The specific expenses and savings data are reported in the appendices separately for comparative purposes.

Also in 2016, Idaho Power filed with the IPUC to combine the Weatherization Assistance for Qualified Customers (WAQC) report, formerly filed with the IPUC annually on April 1, with Idaho Power's *Demand-Side Management 2016 Annual Report*. This change was approved by the IPUC in January 23, 2017, Order No. 33702 IPC-E-16-30, and the information formerly included in the WAQC annual report is now included in this report.

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2016 Program Activity

DSM Expenditures

Funding for DSM programs in 2016 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. For 2016, the Idaho Rider was 4 percent of base rate revenues; the 2016 Oregon Rider was 3 percent of base rate revenues. Additionally, Idaho demand response program incentives were paid through base rates and the annual PCA mechanism. Energy efficiency and demand response related expenses not funded through the Rider are included as part of Idaho Power's ongoing operation and maintenance (O&M) costs.

Total DSM expenses funded from all sources were $43 million in 2016. At the beginning of 2016, the Idaho Rider balance was approximately $6.6 million, and by December 31, 2016, the positive balance was $10.7 million. At the beginning of the year, the Oregon Rider negative balance was approximately $4.5 million, and by year-end, the negative balance was $5.6 million.

Table 3 shows the total expenditures funded by the Idaho Rider, $31,291,579; the Oregon Rider, $2,168,868; and non-rider funding, $9,303,017, resulting in Idaho Power's total DSM expenditures of $42,763,464. The non-rider funding category includes Idaho Power demand response incentives, WAQC expenses, and O&M costs.

Table 3. 2016 funding source and energy savings

Funding Source	Expenses	kWh Savings
Idaho Rider	$ 31,291,579	162,765,429
Oregon Rider	2,168,868	7,280,560
Non-Rider Funding	9,303,017	746,162
Total	**$ 42,763,464**	**170,792,152**

Table 4 and Figure 8 indicate 2016 DSM program expenditures by category. The Materials & Equipment category includes items that directly benefit customers: ESKs and LED lightbulbs distributed at customer events ($2,105,557), and direct-install weatherization measures ($125,000). The expenses in the Other Expense category include marketing ($1,208,731), program evaluation ($198,210), program training ($455,117), and program audits ($174,861). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs.

Table 4. 2016 DSM program expenditures by category

	Total	% of Total
Incentive Expense	$23,676,667	55%
Labor/Administrative Expense	3,580,600	8%
Materials & Equipment	2,417,071	6%
Other Expense	2,111,683	5%
Purchased Services	10,977,442	26%
Total 2016 DSM Expenditures, by Category	**$42,763,464**	**100%**

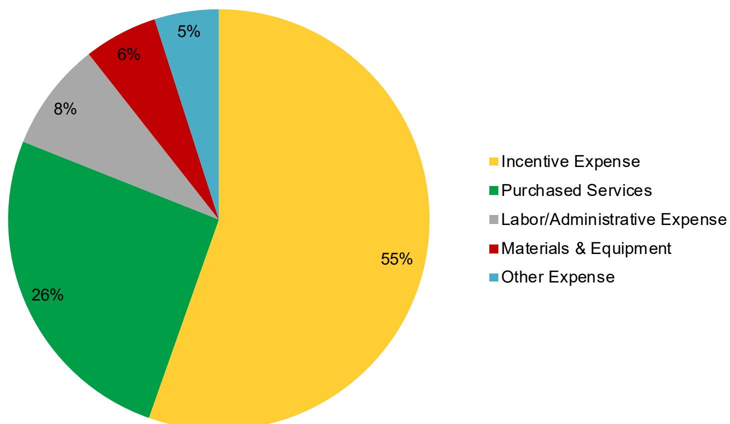

Figure 8. 2016 DSM program expenditures by category

Table 5 and Figure 9 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments (demand response and energy efficiency) and three sectors (residential, commercial/industrial, and irrigation). The incentives are funded by three mechanisms: the Idaho Rider, the Oregon Rider, and Idaho Power base rates. Market transformation related payments made to NEEA and payments made to third-party community action partners under the WAQC and Weatherization Solutions for Eligible Customers programs are not included in the incentive amounts.

Table 5. 2016 DSM program incentives totals by program type and sector

Program Type—Sector	Total	% of Total
DR[a]—Residential	$ 424,565	2%
DR—Commercial/Industrial	639,611	3%
DR—Irrigation	6,406,340	27%
EE[b]—Irrigation	2,007,311	8%
EE—Residential	2,680,473	11%
EE—Commercial/Industrial	11,518,366	49%
Total Incentive Expense	**$ 23,676,667**	**100%**

[a] DR = demand response
[b] EE = energy efficiency

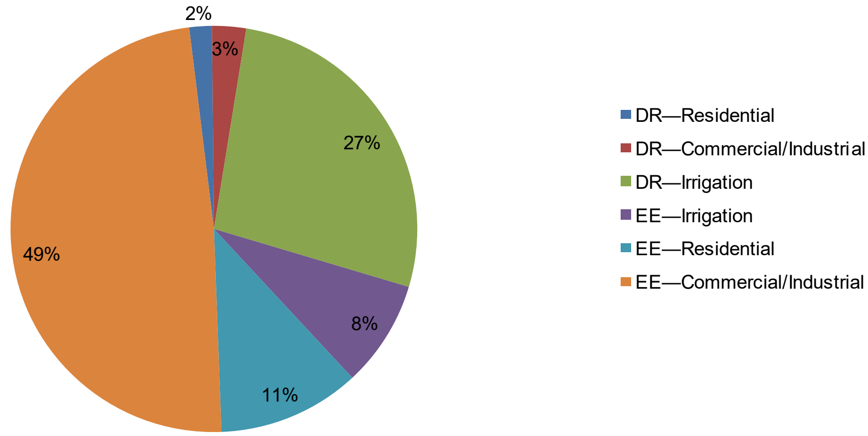

Figure 9. 2016 DSM program incentives by segment and sector

Marketing

Idaho Power used a variety of marketing, public relations, and research in 2016 to improve communication with its customers. Idaho Power takes advantage of all types of media and marketing. Owned media (social, website, newsletters) and paid media (advertising, sponsorships) allow Idaho Power to control content. Earned unpaid media (news outlets, Idaho Power's *News Briefs* sent to reporters, third-party publications, and television news appearances) gives Idaho Power access to an audience through other channels. Though Idaho Power has less control of the content with earned unpaid media, the value is established from the third-party endorsement.

The following describes a selection of the methods, approaches, and tactics used by Idaho Power to engage with customers regarding energy efficiency, along with their results.

All Sectors

Social Media

Approximately 17 percent of the company's total social media content promoted energy efficiency in 2016, a significant increase from 8 percent in 2015. Idaho Power distributed more than 200 messages about energy efficiency throughout the year via Facebook, Twitter, LinkedIn, and Instagram. Idaho Power also enjoyed the benefit from many energy efficiency-related organic posts on social media outlets. An organic post is one that originates from the customer.

In 2016, Idaho Power continued its *#TipTuesday* posts on Facebook and Twitter, a tactic launched in late 2015. *#TipTuesday* posts provide Idaho Power's Facebook and Twitter followers with a new energy efficiency tip or program information every Tuesday of the year. The posts use photos, when applicable, and include the hashtag *#TipTuesday* so the tips can be categorized together and easily searched by social media users. The company also posted information about several energy efficiency programs, sponsorships, and events on its social media pages.

Website

Idaho Power tracked the number of page views to the main energy efficiency pages—also known as landing pages—on the company's website. In 2016, the company's energy efficiency homepage received 34,938 page views; 74,984 page views on the residential landing page; 7,748 page views on the business landing page; and 1,829 page views on the irrigation landing page. The company uses Google Analytics to analyze web activity. Google's definition of page views is the total number of pages viewed, with repeated views of a single page being counted.

Bill Inserts

A January bill insert was sent to 371,600 customers with winter energy-saving tips. In February, 373,189 customers received a bill insert promoting Idaho Power's em**powered** community. Other program-specific bill inserts were also sent throughout the year. Information about those can be found in each program later in this report.

Print

Idaho Power updated the look and content of its print collateral, including a brochure and information card that provides a description of each energy efficiency program offering.

Public Relations

Public relations supported energy efficiency programs and activities through multiple channels: *Connections*, a monthly customer newsletter distributed in approximately 420,000 monthly bills and available online; *News Briefs*, a weekly email of interesting news items sent to all media in the company's service area; pitching and participating in news stories; KTVB (Boise/Twin Falls) and KPVI (Pocatello/Blackfoot) monthly energy-efficiency news segments; news releases and events (such as check presentations).

In 2016, the October and April issues of *Connections* were devoted to energy efficiency. The cover story of the March issue of *Connections* highlighted a customer who applied energy efficient measures on the job, by participating in Idaho Power's Commercial and Industrial Energy Efficiency Program, and at home. Other public relations activities are noted later in this report.

Staff

NEEA and Idaho Power staff held regular meetings throughout 2016 to coordinate, collaborate, and facilitate marketing. Monthly meetings were held via conference call, and meetings in person occurred in July and August in Portland, and September and November in Boise. All marketing activities are reviewed each month for progress, results, and collaborative opportunities.

To build marketing networks and to learn what works in other regions, Idaho Power staff attended the Chartwell Marketing and Communications Conference in March in Atlanta, the NEEA Efficiency Exchange in April in Coeur d'Alene, and the E Source Utility Marketing Executive Council and E Source Forum held in September in Denver.

Residential

Idaho Power ran a multi-faceted advertising campaign in the spring (March and April) and fall (September and October) to raise awareness of Idaho Power's energy efficiency programs for residential customers, and to demonstrate that saving energy doesn't have to be challenging. These campaigns included radio, television, newspaper advertisements (ads), digital ads, Facebook ads, *News Briefs* sent to the media, the *Connections* newsletter, and Idaho Power's website to reach a variety of demographics. In 2016, the company added a Smart-saver Pledge to the campaign to engage and encourage customers to make an energy-saving behavior change.

Figure 10 is an example of the campaign materials in 2016.

Figure 10. 2016 energy efficiency awareness campaign

The goals of the campaign are to raise awareness of the programs collectively rather than by individual program; use a variety of methods to reach various customer demographics; use all the methods in the same month to increase customer exposure to the message; and to let customers know they have options when it comes to saving energy. Messaging focused on many ways to create an energy-efficient home with Energy Savings Made Easy as a central theme, illustrating how easy energy efficiency can be with Idaho Power's help. The campaign was awarded second place in the category of Best Ad Campaign for an Investor-owned Utility at the E Source Utility Ad Awards.

Outside of the campaign, Idaho Power also deployed a number of marketing tactics to promote energy saving tips and the company's energy efficiency programs throughout the year. Results of the campaign and other marketing tactics are included below.

Television

Idaho Power used network television advertising for the spring and fall campaign. The campaign focused on primetime and news programming that reaches the highest percentage of the target market, adults age 35 to 64. Results of the spots were provided for the three major markets—Boise, Pocatello, and Twin Falls.

During the spring campaign, 95 percent of customers in Idaho Power's target audience viewing network television were exposed to the commercial. Targeted customers in Boise saw the ad an average of

13 times, while targeted customers in Pocatello and Twin Falls each saw the ad an average of 12 times. During the fall campaign, 95 percent of targeted customers saw the commercial. Targeted customers in Boise saw the ad an average of 13 times, 18 times in Pocatello, and 12 times in Twin Falls.

Radio

As part of its spring and fall campaign, Idaho Power ran 30-second radio spots on major commercial radio stations, Spanish speaking radio stations, and National Public Radio (NPR) stations in the service area. The commercial stations that ran the spots had a variety of station formats to obtain optimum reach, including classic rock, news/talk, country, adult alternative, adult contemporary, and classic hits. The message was targeted toward adults ages 35 to 64 throughout Idaho Power's service area.

Results of the spots were provided for the three major markets: Boise, Pocatello and Twin Falls. During the spring campaign, the spots reached 55 percent of the target audience in Boise and 60 percent of the target audience in Pocatello and Twin Falls. The target audience in Boise was exposed to the ad approximately nine times, 17 times in Pocatello, and 15 times in Twin Falls. During the fall campaign, the spots reached 60 percent of the target audience in all three major markets. The target audience was exposed to the message eight times in Boise and 16 times in both Pocatello and Twin Falls during the fall campaign.

In summary, Idaho Power ran 2,616 radio spots during the spring campaign and 2,590 spots during the fall campaign, totaling 5,206 radio spots in 2016.

In April and October, these 30-second spots also ran with accompanying visual banner ads on Pandora internet radio accessed by mobile and web-based devices. In April, records show 1,416,990 impressions and 2,427 banner clicks to the Idaho Power residential energy efficiency web page. October yielded 1,430,376 impressions and 2,058 banner clicks. Impressions are defined as the number of times the ad was displayed, regardless of the media type.

Print

As part of the spring and fall campaign, print advertising ran in the major daily and weekly newspapers throughout the service area. The ads conveyed individual energy efficiency programs or tips to customers, such as using insulation to keep cool air in and hot air out in summer. The ads were scheduled for 1,902,246 impressions in the spring and 2,087,983 impressions in the fall.

Social Media

Idaho Power Facebook ads reached 242,224 people and received 3,238,288 impressions and 11,399 clicks to the Idaho Power website during the spring campaign. The company also initially placed a video ad on Instagram, but discontinued the ad a few days later due to low views and click-through rates, and reallocated those funds to Facebook. During the fall campaign, the company reached 223,280 people, and the ad resulted in 1,918,264 impressions and 10,883 clicks to the Idaho Power website.

Throughout the year, Idaho Power also used Facebook boosts for various programs. A boosted post resembles a traditional Facebook post, but, for a fee, Facebook promotes the post higher in users'

News Feeds, increasing the likelihood that the targeted audience will see it. Boosting posts can help increase audience engagement and get more people interacting with the content.

Pledge

In 2016, Idaho Power launched a new offering, the Smart-saver Pledge (pledge), to encourage customers in Idaho to make an energy saving behavior change. Customers were asked to commit to making an energy-saving behavior change for 21 days, choosing from one of the following: turn thermostat down 1 to 3 degrees; wash full loads of laundry in cold water and hang dry when possible; register for myAccount, and review your energy use once a week; have a "no electronics" night once a week; and use the crockpot or barbeque once a week instead of the stove. In return, pledge participants were entered to win an ENERGY STAR® electric appliance. The pledge was primarily promoted through a bill insert that went to 367,221 customers, social media, *News Briefs*, the October issue of *Connections*, and television news segments on KTVB and KPVI.

Figure 11. The 2016 the Smart-saver Pledge bill insert

Idaho Power received 937 pledges throughout the pledge period and hundreds of additional pledges after the pledge ended. The company also received numerous positive notes from customers about the pledge and their energy habits. The company felt the participants were highly engaged and that the results were generally positive, providing good information for continuing the pledge in future years.

Customers were asked to complete a follow-up survey as part of the pledge. In return, participants were entered to win one $100 cash prize. Four hundred and eight customers responded to the follow-up survey. Highlights include the following:

- Ninety-six percent of respondents fulfilled all 21 days of their pledge.
- Of respondents who answered the question regarding whether they would continue their energy-saving changes, all but one respondent plans to continue with the energy saving changes since the pledge ended.
- Fifty-four percent of respondents indicated they were "very likely" to seek out additional ways to save energy.
- After taking the pledge, just over 97 percent of respondents are "somewhat likely" or "very likely" to participate in an Idaho Power energy efficiency program.

A copy of the full survey results can be found in *Supplement 2: Evaluation*.

Campaign Results

The response to the spring and fall Energy Savings Made Easy campaign was measured using Idaho Power's em**powered** community, an on-line panel of over 1,000 customers asked to share perceptions and feedback on a variety of topics each month. The following 2016 spring campaign survey results were obtained from 254 community members who hadn't participated in the 2015 campaign survey:

- Forty-four percent of respondents remember seeing or hearing one of the ads.
- Fifty percent of respondents recalled the television ads, the highest rate of recall.
- Eighty-six percent of respondents indicated they are "very likely" or "somewhat likely" to make energy-saving changes in their home after seeing the ads.
- Eighty-three percent are "very interested" or "somewhat interested" in more information about energy savings programs.
- Eighty-two percent of the respondents who recalled seeing or hearing the ads felt positive about them.

A copy of the results of the study is located in *Supplement 2: Evaluation*.

Energy-Saving Improvements Survey

In early 2016, Idaho Power used its em**powered** community to measure customer's planned energy-saving improvements and their motivation for making changes to their home. Key findings include the following:

- Nearly 74 percent of respondents were “somewhat” or “very likely” to make energy-saving improvements to their home in the next two to three years. The most common improvement is lighting, followed by windows, appliances, insulation, and other.
- The primary motivator for making energy-saving improvements is to save money.
- The biggest barriers to making energy-saving improvements are cost or already making improvements to the home, followed by the perception that these improvements are not needed.
- Financial incentives and free products and services are the top motivators for customers to participate in an Idaho Power energy-saving program.

A copy of the results of the study is located in *Supplement 2: Evaluation*.

Commercial and Industrial

In mid-2016, Idaho Power renamed the offerings under the overall Commercial and Industrial Energy Efficiency Program to better describe that the program offers customers financial incentives for New Construction, Custom Projects, and Retrofits. The company redesigned much of the program’s marketing materials, and began marketing these offerings, along with Flex Peak, as a single entity with something for every business customer. Marketing activities were targeted toward business customers, architects, engineers, and other design professionals.

Airport Advertising

Idaho Power expanded its use of airport signage in 2016. Each year, three million people travel through the Boise Airport. Fifty-nine percent of travelers have made purchasing decisions for their companies in the past year. To reach the business customer, Idaho Power placed two backlit display ads. One ad is located at the baggage claim and the other rotates throughout the airport display boards based on availability. Idaho Power also purchased digital network ads which played 10-second Idaho Power video clips on 15 television screens throughout the terminal as part of a three-minute advertising loop. The videos played an estimated 216,000 times per month.

Print

Several print ads ran in 2016, promoting the Commercial and Industrial Energy Efficiency Program. Ads ran in Alaska Airline’s *Horizon Air Magazine*, Building Owners and Managers Association (BOMA) membership directory and symposium program, American Institute of Architects Idaho Chapter membership directory, Business Insider, Grow Smart Awards event program. The company also placed an ad in the *Idaho Business Review* as part of the publication’s Top Projects Awards that congratulated the 10 companies that had the most energy savings throughout the year.

Revision and updating of the Commercial and Industrial Energy Efficiency Program brochure, business card, and industry specific energy efficiency tip brochures also began in 2016.

Bill Insert

In August, a bill insert promoting Idaho Power's Commercial and Industrial Energy Efficiency Program was included in 39,742 business customers' bills highlighting how Idaho Power's incentives can save customers money.

Newsletters

Idaho Power promotes energy efficiency and its programs through the company's *Energy@Work* newsletter. Written for small- and medium-sized business customers, Idaho Power published this newsletter in May and September 2016. Content included customer success stories and information on training opportunities, energy efficiency programs, electric vehicles, reduced wattage T-8 lightbulbs, the water supply optimization cohort (WSOC), and more.

Idaho Power also sends an email newsletter, *Energy Insights*, quarterly to large industrial customers. Topics included how businesses use energy, Idaho Power's environmental efforts, energy efficiency success stories, LED advantages, power quality devices, and more.

Public Relations

Idaho Power provides public relations support to commercial and industrial customers who want to publicize the work they have done to become more energy efficient. Upon request, Idaho Power creates large-format checks that are used for media events and/or board meetings. Idaho Power will continue to assist customers with public relations opportunities by creating certificates for display within the building and having an Idaho Power representative speak at press events, if requested.

Sponsorships

Idaho Power's Commercial and Industrial Energy Efficiency Program supports a number of associations and events, including sponsoring the Grow Smart awards, Top Projects Awards, BOMA symposium, American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Technical Conference, and the Idaho Energy and Green Building Conference.

Idaho Power sponsored the BOMA Commercial Real Estate Symposium February 9, in Boise. Idaho Power Vice President of Customer Operations, Vern Porter, spoke about why energy efficiency makes good business sense, how Idaho Power's programs can help businesses save energy and money, and provided an example of a recent energy efficiency project and a reminder about the importance of putting down your phone in the car to Just Drive.

Idaho Power and NEEA were also major sponsors of the Idaho Energy and Green Building Conference, and had two members on the planning committee. The conference, held November 1 and 2 at The Wyndham Garden Boise Airport Hotel, provided four training tracks on energy efficiency and green building, and attracted over 100 participants. The conference targeted policy makers, developers, architects, code officials, engineers, energy professionals, and industrial plant managers and operators.

Irrigation

See the Irrigation Efficiency Rewards section for 2016 irrigation-related marketing activities.

2017 Marketing Activities

In 2017, the Idaho Power marketing department plans on several approaches to reach and educate customers: updating the Residential Energy Efficiency Awareness Campaign, developing new Commercial and Industrial Energy Efficiency ads, and enhancing the company website.

The marketing team will refresh the Residential Energy Efficiency Awareness Campaign with new ads that promote different programs and tips. However, the campaign will continue to use the Energy Savings Made Easy theme and cartoon artwork that has resonated with customers. The team will also continue exploring a consistent look and feel for all residential program materials, and consider the potential for email marketing.

A new ad campaign will be implemented for the Commercial and Industrial Energy Efficiency Program. The campaign features former program participants and iconic local landscapes to capture the readers' attention. The ads will speak to small to large businesses, and show that saving energy and money is for everyone. Several of the customers in the ad campaign will be featured in videos about businesses that took advantage of Idaho Power's incentives and the resulting benefits. The ads will be placed in business and association publications, and event programs.

Idaho Power will also move toward a consistent look and feel for marketing materials for business customers. The company will update the remaining industry-specific energy efficiency tip brochures, and may add new industries and inserts highlighting the incentives available for each industry. Customer representatives will use these brochures on customer visits, and the company will consider mailing them to targeted customers.

The company will continue to support various organizations and programs, including the Intermountain Building Operators Association, Building Operators Certification, Center for Advanced Energy Studies Industrial Assessment Center, and more. Idaho Power will market the organizations' services during customer site visits and at technical training workshops and provide discounted registration when appropriate.

Additionally, the company will consider an ad campaign similar to the new Commercial and Industrial Energy Efficiency Program campaign for its irrigation programs.

Idaho Power will also redesign its website to an adaptive framework, including updating navigation for a better customer experience. The company's interactive approach, which began with myAccount in 2015, and saw additional user improvements in 2016, is scheduled for completion in 2017. Idaho Power's new adaptive site will enhance navigation to make energy efficiency program information easier to find. An adaptive website recognizes the device accessing the website and automatically responds or adapts to the dimensions of that device (e.g., a smart phone).

Cost-Effectiveness

In 2016, most of Idaho Power's energy-efficiency programs were cost-effective, except the Fridge and Freezer Recycling Program, Home Improvement Program and the weatherization programs for income-qualified customers.

The Fridge and Freezer Recycling Program has a UC of 0.92 and TRC of 1.31. In November 2015, the program vendor JACO Environmental, Inc. (JACO), entered receivership and ceased operations. Idaho Power then contracted with Appliance Recycling Center of America (ARCA) and re-launched the program in June 2016. Due to the mid-year launch, the company had forecasted that participation would be at 1,000 units, and the program would likely not be cost-effective from the UC perspective but would be cost-effective from the TRC perspective. This was discussed with the EEAG in February 2016. When considering individual measures within the program, both freezers and refrigerators fail the UC test with a ratio of 0.79 and 0.91 respectively. However, both freezers and refrigerators pass the TRC. However, by allowing the less cost-effective freezers into the program, it increase overall participation and increases the program cost-effectiveness by spreading the portion of the fixed administrative costs across more units.

The Home Improvement Program has a UC of 2.54, TRC of 0.60 and PCT of 0.80. The RTF reduced savings for single-family home weatherization projects in 2015. With the changes, average savings estimates per project for both 2015 and 2016 were just under 50 percent of 2014 projects. These new savings were a result of the nearly 18-month RTF process to calibrate residential savings models. Additionally, in early 2016, the RTF finished calibrating the savings models for multifamily weatherization. These lower savings as well as the DSM avoided costs from the 2015 IRP further reduces the TRC and PCT of the program. Idaho Power analyzed ways to modify the program to improve the cost-effectiveness, but the company concluded that the program would remain not cost-effective. At the November EEAG meeting, the company presented the non-cost-effective aspects of the Home Improvement Program, the result of the company's analysis, and informed EEAG of the company's plan to end the program in 2017.

WAQC had a TRC of 0.65 and a UC ratio of 0.73, and Weatherization Solutions for Eligible Customers had a TRC of 0.70 and a UC ratio of 0.59. The programs showed increased savings and increased cost-effectiveness ratios over 2015. Idaho Power performed a billing analysis of the 2013–2014 weatherization projects from both WAQC and Weatherization Solutions for Eligible Customers. The billing analysis was needed to reflect the increased replacement of forced-air electric resistance heat systems with efficient heat pump systems.

Eleven individual measures in various programs are shown to not be cost-effective from either the UC or TRC perspective. These measures will be discontinued, analyzed for additional NEBs, modified to increase potential per-unit savings, or monitored to examine their impact on the specific program's overall cost-effectiveness.

Table 6. Cost-effectiveness summary by program

Program/Sector	UC	TRC	Ratepayer Impact Measure (RIM)	PCT
Easy Savings	1.69	2.04	0.55	n/a
Educational Distributions	3.63	6.33	0.65	n/a
Energy Efficient Lighting	4.27	2.52	0.68	3.17
Energy House Calls	2.11	2.75	0.56	n/a
ENERGY STAR ® Homes Northwest	1.79	1.00	0.63	1.46
Fridge and Freezer Recycling Program	0.92	1.31	0.43	n/a
Heating & Cooling Efficiency Program	2.33	1.26	0.71	1.76
Home Improvement Program	2.54	0.60	0.64	0.80
Multifamily Energy Savings Program	1.43	2.55	0.51	n/a
Rebate Advantage	3.89	3.33	0.62	6.45
Simple Steps, Smart Savings	2.40	1.33	0.61	2.13
Weatherization Assistance for Qualified Customers	0.73	0.65	0.41	n/a
Weatherization Solutions for Eligible Customers	0.59	0.70	0.36	n/a
Residential Energy Efficiency Sector	**2.74**	**2.36**	**0.63**	**4.10**
Commercial and Industrial Energy Efficiency Program				
Custom Projects	5.26	2.86	1.44	1.92
New Construction	4.40	3.07	0.96	3.19
Retrofits	3.83	2.64	0.93	2.83
Commercial/Industrial Energy Efficiency Sector *	**4.67**	**2.81**	**1.19**	**2.31**
Irrigation Efficiency	4.95	3.21	1.34	2.78
Irrigation Energy Efficiency Sector **	**5.00**	**3.17**	**1.35**	**2.73**
Energy Efficiency Portfolio	**3.58**	**2.56**	**0.95**	**2.93**

* Commercial/Industrial Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors projects.
** Irrigation Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors projects.

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

Customer Satisfaction

Based on surveys conducted in 2015, Idaho Power ranked fifth out of seven utilities included in the west region midsize segment of the J.D. Power and Associates *2016 Electric Utility Business Customer Satisfaction Study*. Forty-one percent of the business customer respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

Based on surveys conducted in the last six months of 2015 and the first six months of 2016, Idaho Power ranked third out of 13 utilities included in the west region midsize segment of the J.D. Power and Associates *2016 Electric Utility Residential Customer Satisfaction Study*. Forty-nine percent of the residential respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

Idaho Power employs Burke, Inc., an independent, third-party research vendor, to conduct quarterly customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The Burke Customer Relationship 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, it is not the intent of this survey to measure all aspects of energy efficiency programs offered by Idaho Power.

The 2016 results of Idaho Power's customer relationship survey showed an increase in overall satisfaction from the previous year. Sixty-five percent of customers indicated their needs were met or exceeded by Idaho Power encouraging energy efficiency among its customers.

Figure 12 depicts the annual change in the percent of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power. In 2016, offering energy efficiency programs was one of the overall top five attributes with a positive change in the Burke Customer Relationship Survey.

In 2016, offering energy efficiency programs was one of the overall top five attributes with a positive change in the Burke Customer Relationship Survey. Three questions related to energy efficiency programs in the general relationship survey continued in the 2016 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 2016, 44 percent of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program, and 93 percent were "very" or "somewhat" satisfied with the program they participated in.

Idaho Power will not survey most energy efficiency program participants annually. This is due primarily to a concern of over-surveying program participants and because the measures and specifics of most program designs do not change annually. To ensure meaningful research in the future, Idaho Power will conduct program research periodically (every two to three years), unless there have been major program changes.

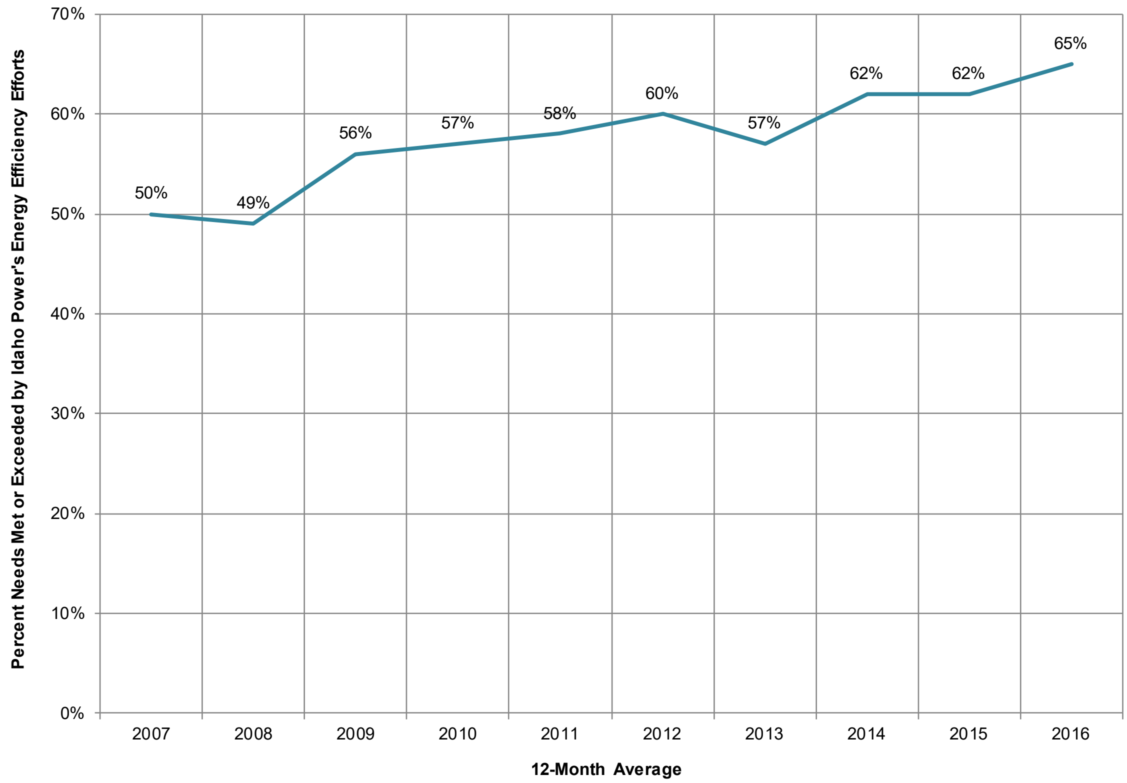

Figure 12. Customers' needs "met" or "exceeded" (percent), 2007–2016

In 2015, Idaho Power created the em**powered** community, an on-line community of residential customers, to measure customer perceptions on a variety of company-related topics, including energy efficiency. Recruiting for the community is conducted annually primarily through billing inserts and mailed postcards. The community has just over 1,000 active members. The em**powered** community includes customers from across Idaho Power's service area. Idaho Power sends out at least one survey per month to active members. Energy efficiency-related survey topics in 2016 included likelihood to install energy-saving improvements, recall of the spring 2016 energy efficiency marketing campaign, energy-efficient lighting, an engagement survey on air conditioning efficiency, thermostatic shower shut-off valves, an engagement survey on using energy-efficient cooking methods and holiday lighting. The average response rate for surveys conducted with the online community is 61.3 percent.

Results of these studies are included in *Supplement 2: Evaluation*.

Evaluations

In 2016, Idaho Power contracted with Leidos Engineering (Leidos) to conduct four program impact evaluations and two program process evaluations. Impact evaluations were performed for the Retrofit (Easy Upgrades), New Construction (Building Efficiency), Rebate Advantage, and Irrigation Efficiency Rewards programs. Process evaluations were performed for the Rebate Advantage and Irrigation Efficiency Rewards programs. CLEAResult, conducted impact evaluations of the A/C Cool Credit, and Flex Peak programs' 2016 demand response events.

Throughout 2016, Idaho Power administered several surveys regarding energy efficiency programs to measure customer satisfaction. Some surveys were administered by a third-party contractor; other surveys were administered by Idaho Power either through traditional means or through the company's em**powered** community on-line survey.

Final reports from all evaluations, research, and surveys completed in 2016 and an evaluation schedule is provided in *Supplement 2: Evaluation*.

Residential Sector Overview

Idaho Power's residential sector consists of over 444,431 customers. In 2016, the residential sector's number of customers increased by 8,329, an increase of 1.9 percent from 2015. The residential sector represents 43 percent of Idaho Power's actual total electricity usage and 35 percent of overall revenue in 2016.

Table 7 shows a summary of 2016 participants, costs, and savings from the residential energy efficiency programs.

Table 7. 2016 residential program summary

			Total Cost		Savings	
Program	**Participants**		**Utility**	**Resource**	**Annual Energy (kWh)**	**Peak Demand (MW)**
Demand Response						
A/C Cool Credit	28,315	homes	$1,103,295	$ 1,103,295	n/a	34
Total			**$1,103,295**	**$ 1,103,295**	**n/a**	**34**
Energy Efficiency						
Easy Savings	2,001	kits	$127,587	127,587	402,961	
Educational Distributions	67,065	kits/lightbulbs	2,392,884	2,392,884	15,149,605	
Energy Efficient Lighting	1,442,561	lightbulbs	3,080,708	10,770,703	21,093,813	
Energy House Calls	375	homes	206,437	206,437	509,859	
ENERGY STAR® Homes Northwest	110	homes	142,158	297,518	150,282	
Fridge and Freezer Recycling Program (See ya later, refrigerator®)	1,539	refrigerators/freezers	257,916	257,916	632,186	
Heating & Cooling Efficiency Program	486	projects	594,913	1,404,625	1,113,574	
Home Energy Audit	539	homes	289,812	289,812	207,249	
Home Improvement Program	482	homes	324,024	1,685,301	500,280	
Multifamily Energy Savings Program	3	projects	59,046	59,046	149,760	
Oregon Residential Weatherization	7	homes	3,930	5,900	2,847	
Rebate Advantage	66	homes	111,050	148,142	411,272	
Shade Tree Project	2,070	trees	76,642	76,642	n/a	
Simple Steps, Smart Savings	7,880	appliances/ showerheads	153,784	379,752	577,320	
Weatherization Assistance for Qualified Customers	246	homes/non-profits	1,289,809	1,934,415	746,162	
Weatherization Solutions for Eligible Customers	232	homes	1,323,793	1,323,793	621,653	
Total			**$10,434,493**	**$21,360,473**	**42,268,823**	**34**

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

In 2016, the company added two new residential programs and reintroduced or modified others. The Multifamily Energy Savings Program was added in March, the ESK program launched in May, and the Fridge and Freezer Recycling program was re-introduced in June. The Home Energy Audits program was extended to customers with non-electric heat sources and a smart thermostat incentive was added to the Heating and Cooling Efficiency (H&CE) Program. Additionally, the residential team supported a Drying Rack Pilot Project.

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2016, 54 percent of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-three percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Forty-eight percent of Idaho Power residential customers surveyed in 2016 indicated Idaho Power is meeting or exceeding their needs in offering energy efficiency programs, and 34 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, 86 percent are "very" or "somewhat" satisfied with the program. In 2016, offering energy efficiency programs was one of the residential top five attributes with a positive change in the Burke Customer Relationship Survey.

Forty-nine percent of the Idaho Power residential customers included in the *2016 J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study* indicated they are familiar with Idaho Power's energy efficiency programs.

In 2016, the em**powered** community was surveyed regarding customer recall of the energy efficiency marketing campaign, shut-off shower valves, air conditioning efficiency, energy-efficiency tips, cooking methods, and holiday lighting. Results of these studies are included in *Supplement 2: Evaluation*.

During 2016, presentations to community groups and businesses continued to be an important method of communicating with Idaho Power customers. The company's customer representatives and community education representatives made hundreds of presentations in communities in Idaho Power's service area.

A/C Cool Credit

		2016	2015
Participation and Savings			
	Participants (participants)	28,315	29,000
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	34	36
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$632,079	$659,471
	Oregon Energy Efficiency Rider	$41,833	$45,825
	Idaho Power Funds	$429,383	$443,639
	Total Program Costs—All Sources	$1,103,295	$1,148,935
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Originating in 2003, A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers in Idaho and Oregon. Using communication hardware and software, Idaho Power cycles participants' central air conditioning (A/C) units 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 capacity needs during times when summer peak load is high.

Customers' A/C units are controlled using switches that communicate by powerline carrier (PLC). A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C unit during a cycling event.

The cycling season is June 15 through August 15. The maximum number of cycling hours available per season is 60 hours, with a minimum of three cycling events per season. The cycling rate is the percentage of an hour that the A/C unit will be turned off by the switch. For instance, with a 55 percent cycling rate, the switch should be off for 33 minutes of each hour on average, though not 33 consecutive minutes. Instead, the switch turns the A/C unit off for a period of time and then back on for a period of time.

Idaho Power measures the communication levels to validate whether the signal reaches the switches. Interruptions may be caused by a malfunctioning or broken switch, or by an A/C unit that is not powered on. The incentive is $15 per season, paid as a $5 bill credit on the July, August, and September bills. The program is not available on weekends or holidays, and the maximum length of an event is four hours.

Program Activities

In 2016, over 28,000 customers participated in the program. Three cycling events occurred, and all were successfully deployed.

The first event was Thursday, June 30 from 4 p.m. to 7 p.m. Communication levels were between 92.10 percent and 94.78 percent. The cycling rate was 55 percent. The Boise area temperature was 97 degrees, and the Pocatello/Twin Falls area temperature was 97 degrees. The expected demand reduction for the event was 1.02 kilowatt (kW) per participant for Boise and 0.7 kW per participant for Pocatello/Twin Falls for a total reduction of 27.63 MW. Analysis results show a max reduction of 1.11 kW per participant in Boise, 0.84 kW per participant in Pocatello/Twin Falls, and a total reduction of 30.165 MW. This is 109 percent of expected demand reduction.

The second event was Tuesday, July 26 from 4 p.m. to 7 p.m. Communication levels were between 93.6 percent and 93.99 percent. The cycling rate was 55 percent. The Boise area temperature was 99 degrees, and the Pocatello/Twin Falls area temperature was 95 degrees. The expected demand reduction for the event was 1.09 kW per participant for Boise and 0.68 kW per participant for Pocatello/Twin Falls for a total reduction of 29.23 MW. Analysis results show a max reduction of 1.1 kW per participant in Boise and 0.86 kW per participant in Pocatello/Twin Falls for a total reduction of 29.77 MW. This is 102 percent of expected demand reduction.

The third event was Thursday, July 28 from 4 p.m. to 7 p.m. Communication levels were between 93.99 percent and 94.25 percent. The cycling rate was 55 percent. The Boise area temperature was 99 degrees, and the Pocatello/Twin Falls area temperature was 95 degrees. The expected demand reduction for the event was 1.09 kW per participant for Boise and 0.68 kW per participant for Pocatello/Twin Falls for a total reduction of 29.15 MW. Analysis results show a max reduction of 1.13 kW per participant in Boise, 0.93 kW per participant in Pocatello/Twin Falls, and a total reduction of 30.935 MW. This is 106 percent of expected demand reduction.

Marketing Activities

Per the settlement agreement reached in Idaho Case No. IPC-E-13-14 and Oregon Case No. UM 1653, Idaho Power did not actively market the A/C Cool Credit program in 2016; however, Idaho Power did actively communicate with participants about the program in an effort to maintain participant retention.

Before the cycling season began, Idaho Power sent current participants a postcard reminding them of the program specifics. Idaho Power also attempted to recruit customers who had moved into a home that already had a load control device installed and previous participants who changed residences to a location that may or may not have a load-control device installed. The company used postcards, phone calls, direct-mail letters, and home visits, leaving door hangers for those not home, to recruit these customers. At the end of the summer, a thank-you postcard was sent to program participants.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The A/C Cool Credit program was dispatched for 9 event hours and achieved a maximum demand reduction of 33.94 MW. The total expense for 2016 was $1,103,295 and would have remained the same if the program was fully used for 60 hours because there is no variable incentive paid for events beyond the three required events.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective.

A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-effectiveness.*

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

Idaho Power contracted with CLEAResult to complete an impact evaluation of the 2016 A/C Cool Credit program. The goal of the evaluation was to estimate demand reduction achieved during three curtailment events and update the existing predictive model to incorporate results from the 2016 curtailment events.

CLEAResult completed analyses of curtailment events held on June 30, July 26, and July 28, each with a three-hour duration. Results of the analyses showed maximum single hour demand reductions of 1.07 kW, 1.06 kW, and 1.11 kW per participant, respectively, for the three events. The results of the curtailment event analyses showed maximum generation-level demand reductions of 33.09, 32.66, and 33.94 MW, respectively, for the three events. The results of the curtailment event analyses showed maximum meter-level demand reductions of 30.2, 29.8, and 30.9 MW, respectively, for the three events.

The results of the impact evaluation demonstrated that Idaho Power's A/C Cool Credit program functions as intended, and if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid. Due to the distinct weather patterns between Boise and Pocatello/Twin Falls, each curtailment event analysis included region-specific results. A copy of the report is included in *Supplement 2: Evaluation*.

2017 Program and Marketing Strategies

Idaho Power anticipates no program changes in 2017.

Per the terms of the above-mentioned settlement agreements, Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing but will accept new participants who request to participate, regardless of whether they were previous participants in the program.

Attempts will continue to be made to recruit previous participants who have moved, as well as new customers moving into homes that already have a load control device installed.

Easy Savings

		2016	2015
Participation and Savings			
	Participants (kits)	2,001	2,068
	Energy Savings (kWh)	402,961	624,536
	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	$127,587	$127,477
	Total Program Costs—All Sources	$127,587	$127,477
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.035	$0.021
	Total Resource Levelized Cost ($/kWh)	$0.035	$0.021
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.69	2.61
	Total Resource Benefit/Cost Ratio	2.04	2.95

Description

The desired outcomes of the Easy Savings program are to educate recipients about saving energy in their homes by using energy wisely, to allow hands-on experience while installing low-cost measures, and to reduce the energy burden for energy assistance/Low Income Home Energy Assistance Program (LIHEAP) recipients.

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 low-income customers and provide $125,000 to Community Action Partnership (CAP) agencies in the Idaho Power service area on a prorated basis. These orders specified that Idaho Power provide educational information to customers who heat their homes with electricity provided by Idaho Power in Idaho. This is accomplished through the development and distribution of kits containing low cost, self-install energy efficiency items and educational materials.

Initiated in 2009, the Easy Savings program straddles two calendar years. The LIHEAP program cycle starts annually in November at CAP agencies and follows the federal fiscal calendar, while Idaho Power summarizes activities annually based on a January to December cycle. However, the following report summarizes activities from November 2015 through October 2016 and covers future plans for the 2016 to 2017 program.

Program Activities

By April 2016, 2,001 kits from the 2015 to 2016 program year were distributed by regional CAP agencies to Idaho Power customers approved to receive LIHEAP benefits on their Idaho Power bills.

Each kit contained the following low-cost and no-cost energy-saving items and a survey:

- Three LED lightbulbs—9 watts (W)
- Set of draft stopping outlet gaskets
- Digital thermometer
- 1.5 gallons per minute (gpm) kitchen faucet aerator
- One single-line indoor clothesline
- LED nightlight with photocell and a set of reminder stickers and magnets
- Easy Savings Quick Start Guide to installation
- Mail-in survey and energy-savings information

Marketing Activities

Idaho Power does not actively market this program.

Cost-Effectiveness

The RTF LED giveaway deemed savings values are used for the three LED lightbulbs included in the kit because the savings are discounted to reflect the potential that all the kit items may not be installed. For the faucet aerator, the RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimates the annual faucet aerator savings to be 106 kWh. For the single-line clothes line, Idaho Power used the assumptions for the clothes drying racks and discounted the annual savings to be 68 kWh. For further information regarding the clothes drying rack savings, see the *Cost-Effectiveness* section for the Educational Distributions program.

Customer Satisfaction and Evaluations

A mail-in survey inquiring about installation experiences and actions taken to reduce energy use was included in the 2,001 kits distributed. Returned surveys were analyzed to track the effectiveness and educational impact of the program.

There were 213 completed surveys received from customers describing their experience in installing kit items in their homes during the 2015 to 2016 program. 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.

Over 92 percent of respondents reported they have, or will lower their heat during the day, and just over 90 percent reported they have, or will lower their heat at night. Just over 85 percent of the respondents reported installing at least one of the LEDs provided in the kit. Just over 38 percent of the respondents reported installing the high indoor clothesline and another 30 percent reported they planned to install it.

Overall, survey results showed that almost 39 percent of the respondents installed all kit items. Just over 77 percent of the respondents 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*.

During the 2015 to 2016 program, three gift certificates valued at $100 each were provided by Community Action Partnership Association of Idaho, Inc. (CAPAI), to encourage survey completion. A drawing from all returned surveys was held, and three households won a $100 gift certificate.

Idaho Power conducted no program evaluations in 2016.

2016 to 2017 Program and Marketing Strategies

For the 2016 to 2017 program period, Idaho Power sent checks totaling $125,000 in October to the five Idaho regional CAP agencies. Each agency signed a Memorandum of Understanding (MOU) agreeing to use 30 percent of the agency's allotment to cover expenses for administering the program at their agency. The 30 percent includes the provision for an agency certified energy educator to inform kit recipients about installation techniques and energy efficiency information.

CAP agencies ordered 2,470 kits in October 2016, and received them from the vendor in November. These kits, which include five LED lightbulbs and an indoor clothesline, will be distributed to customers throughout the 2016 to 2017 LIHEAP season.

Upon completion of kit distribution and receipt of corresponding surveys, Idaho Power and CAPAI will consider program changes for the future.

Educational Distributions

		2016	2015
Participation and Savings			
	Participants (kits/lightbulbs)	67,065	28,197
	Energy Savings (kWh)	15,149,605	1,669,495
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$2,334,206	$432,185
	Oregon Energy Efficiency Rider	$56,164	$0
	Idaho Power Funds	$2,514	$0
	Total Program Costs—All Sources	$2,392,884	$432,185
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.016	$0.026
	Total Resource Levelized Cost ($/kWh)	$0.016	$0.026
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.63	2.05
	Total Resource Benefit/Cost Ratio	6.33	2.60

Description

Designated as a specific program in 2015, the Educational Distributions effort is administered through the Residential Energy Efficiency Education Initiative and seeks to use low-cost and no-cost channels to deliver energy efficiency items with energy savings directly to customers. As with the initiative, the goal for these distributions is to drive behavior change and create awareness of and demand for energy efficiency programs in Idaho Power's service area.

Items selected for distribution have an initial cost-effectiveness analysis that indicates the installed measure is either currently cost-effective or is expected to be cost-effective in the near future. Typically, selected items have additional benefits beyond traditional energy savings, such as educating customers about energy efficiency, expediting the opportunity for customers to experience newer technology, or allowing Idaho Power to gather data or validate potential energy savings resulting from behavior change.

Idaho Power recognizes that behavioral measures and programs require appropriate education and guidance to optimize savings and will plan education accordingly. Items may be distributed at events, presentations, through direct-mail, or home visits conducted by customer representatives.

Drying Rack Pilot Project

Idaho Power distributed drying racks to determine whether customers can comfortably shift about 25 percent of their clothes drying from an automatic dryer to a drying rack.

Energy-Saving Kits

Idaho Power knows that managing household energy use can be a challenge. To help make it easier for families, Idaho Power works with a kit vendor to provide two versions of free ESKs—one for homes with electric water heaters and one for homes with alternate-source water heaters. Customers enroll online at idahopower.com/save2day, by calling 800-465-6045, or by returning a postcard. Kits are sent directly to the customer's home.

Each ESK contains nine LED lightbulbs—six 60-watt equivalent lightbulbs, three 45-watt equivalent lightbulbs, a digital thermometer (to check refrigerator, freezer and water temperatures), a shower timer, a water flow-rate test bag, an LED night light and educational materials. In addition, the kit for homes with electric water heaters contains a high-efficiency showerhead and three faucet aerators.

Figure 13. Ad for Idaho Power residential customers to order a 2016 ESK

LED Lightbulbs as Giveaways

LED lightbulbs are a welcome and effective way to connect Idaho Power with customers, and to begin productive conversations around energy efficiency. Idaho Power field staff and energy efficiency program managers seek opportunities to educate customers about LEDs, and to offer customers a free lightbulb to use immediately in their own homes.

Student Energy Efficiency Kit Program

The Student Energy Efficiency Kit (SEEK) program provides fourth- to sixth-grade students in schools in Idaho Power's service area with quality, age-appropriate instruction regarding the wise use of electricity. Each child who participates receives an energy efficiency kit. The products in the kit are selected specifically to encourage energy savings at home and engage families in activities that support and reinforce the concepts taught at school.

Once a class enrolls in the program, teachers receive curriculum and supporting materials. Students receive classroom study materials, a workbook, and a take-home kit containing three LED lightbulbs, a high-efficiency showerhead, an LED nightlight, a furnace filter alarm, a digital thermometer for measuring water, refrigerator and freezer temperatures, a water flow-rate test bag, and a shower timer. At the conclusion of the program, students and teachers return feedback to the vendor indicating how the program was received and which measures have been installed. The vendor uses this feedback to provide a comprehensive program summary report showing program results and savings.

Unlike other residential programs offered by Idaho Power, SEEK results are reported on a school-year basis.

Program Activities

On February 8, 2016, Idaho Power filed a request with the OPUC seeking authority to implement the Educational Distributions program in Oregon. The company received approval of Oregon Schedule 71 on March 9, 2016.

Drying Rack Pilot Project

Idaho Power gave away approximately 1,300 drying racks at eight events, primarily in the Treasure Valley and Pocatello areas. In the Boise area, attendees at select 2015 fall events filled out a card expressing interest in receiving a free drying rack. Idaho Power representatives explained the enrollment and distribution process, and enrollment emails were sent early in January 2016. Most participants enrolled online, confirming their eligibility and completing a survey about their current laundry habits. Customer distribution events in Boise and Nampa occurred in late January.

The first Pocatello event was held in Fort Hall in March with a slightly different distribution model—customers were enrolled on-site when they presented a current Idaho Power bill. Idaho Power staff administered the pre-survey verbally to each Fort Hall participant.

The Salmon and Pocatello events followed—again with the on-line enrollment strategy. The remaining drying racks were given to American Falls residents in August using a third distribution model. Participants were not pre-enrolled. Instead, customers reviewed eligibility requirements and signed an agreement confirming their eligibility and committing to take the survey within 24 hours of receiving the drying rack.

Education and information regarding efficient laundry practices was conveyed via the website enrollment tool, the enrollment survey, at each event via a "Ways to Save" card addressing ways to "Lighten Your Laundry Load," and through follow-up email prompts.

Energy-Saving Kits

By the end of 2016, 34,546 kits had been shipped—19,715 kits to homes with electric water heaters and 14,831 to homes with alternate-source water heaters. Kits were distributed to all geographic regions within Idaho Power's service area, including 33,682 to Idaho residences and 864 to Oregon homes.

LED Lightbulbs as Giveaways

Field staff distributed over 8,000 lightbulbs at Spring Home and Garden Shows in Pocatello, Twin Falls, and Boise. Participants in Earth Day Events and employee sustainability fairs in Caldwell, Nampa, and Pocatello received lightbulbs. In Boise at Wells Fargo and Hewlett Packard (HP) World Environment Day events attendees received lightbulbs. Oregon customers received lightbulbs at a St. Alphonsus's Safety Fair, Platt Electric Days and a Home Depot children's safety fair. LEDs were also distributed at the Smart Women, Smart Money Conference, West Valley Medical Center employee meetings, Paint the Town™, the Mountain Home Air Force Base, FitOne™ Expo, and through presentations at chambers of commerce and senior centers.

By the end of the year, Idaho Power employees had personally delivered a brief energy efficiency message and distributed 24,913 lightbulbs directly to customers.

SEEK Program

During the 2015 to 2016 school year, Idaho Power community education representatives actively recruited fourth- to sixth-grade teachers to participate in SEEK. As a result, Resource Action Programs (RAP) delivered 6,305 kits to 219 classrooms in 70 schools within Idaho Power's service area. This resulted in 1,542 MWh of savings.

Marketing Activities

Drying Rack Pilot Project

In the Boise area, attendees at select 2015 fall events filled out a card expressing interest in receiving a free drying rack. In other areas, flyers, posters, print ads, online calendars and social media marketing boosted participation to the desired levels. The cover story of the October *Connections* featured customers who had participated in the project, and KPVI in Pocatello ran a news story on the distribution of the drying racks.

Energy-Saving Kits

Marketing efforts included a direct-mail campaign from the kit vendor to about 15,000 customers in May, publicity via television news segments in May and June on KPVI and KTVB, and social media posts. The program was greatly bolstered by unsolicited social media—in one case, a single Facebook post garnered over 10,000 kit requests.

LED Lightbulbs as Giveaways

In 2016, Idaho Power field staff and energy efficiency program managers continued to seek opportunities to educate customers about LEDs, and offer customers a free LED lightbulb to use immediately in their own homes.

Student Energy Efficiency Kit Program

During the 2015 to 2016 school year, Idaho Power community education representatives actively recruited fourth- to sixth-grade teachers to participate in SEEK. In addition, community education representatives appeared on both KPVI (September) and KTVB (October) news segments sharing information about the kits.

Cost-Effectiveness

In situations where Idaho Power manages the education and distribution through existing distribution channels, the cost-effectiveness calculations will be based on the actual cost of the items. Conversely, if outside vendors are used to assist with distribution, the cost-effectiveness calculations will include all vendor-related charges.

Drying Rack Pilot Project

Idaho Power is currently assessing if this is an energy-saving and cost-effective measure to continue in the future. To determine an estimate of the potential savings for the drying rack, Idaho Power used estimates from NEEA's *2011 Residential Building Stock Assessment: Single-Family Characteristics and*

Energy Use (RBSA). Based on the Residential Building Stock Assessment (RBSA), study participants in Idaho wash 5.71 loads of laundry per week. Approximately 87.4 percent of those washer loads are dried in a clothes dryer. According to a RTF clothes washer workbook, the baseline dryer uses between 1.36 to 1.27 kWh per load. Using a simple average of these two values, Idaho Power estimates that clothes dryers use approximately 342 kWh per year. However, it must be noted that the NEEA 2014 RBSA Laundry Study estimates that dryers use 805 to 915 kWh per year. For a conservative estimate, Idaho Power kept the 342 kWh per year estimate and assumed that if customers shifted 25 percent of their drying load to a drying rack, they could save at least 85.5 kWh per year.

Energy-Saving Kits

The RTF provides mail-by-request deemed savings for LED lightbulbs and 1.75 gpm low-flow showerheads. The RTF mail-by-request deemed savings values are discounted to reflect the potential that all of the kit items may not be installed. The LED lightbulbs have a deemed savings value of 10 to 11 kWh per year depending on the lumens of the lightbulb. The 1.75 gpm low-flow showerhead is estimated to save 187 kWh per year. For the faucet aerator, the RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimates the annual faucet aerator savings to be 106 kWh. The annual savings for an ESK for a home with an electric water heater is 601 kWh. The annual savings for a kit for a home with a non-electric water heater is 96 kWh.

LED Lightbulbs as Giveaways

In 2016, Idaho Power used the same savings and assumptions as were used in 2014. For the LED giveaways, Idaho Power used the giveaway deemed savings provided by the RTF. The RTF-deemed annual savings of 9 kWh includes assumptions regarding the installation rate, efficiency levels of the existing equipment, and the location of the installation.

SEEK Program

The cost-effectiveness analysis for the SEEK offering is based on the savings reported by RAP during the 2015 to 2016 school year. RAP calculated the annual savings based on information collected from the participants' home surveys and the installation rate of the kit items. Questions on the survey included the number of individuals in each home, water-heater fuel type, flow rate of old showerheads, and the wattage of any replaced lightbulbs. The response rate for the survey was nearly 71 percent. The survey gathers information on the efficiency level of the existing measure within the home and which efficient measure is installed. The energy savings will vary for each household based on the measures offered within the kit, the number of items installed, and the existing measure that is replaced. Based on the feedback received from the 2015 to 2016 school year, each kit saved approximately 245 kWh annually per household on average. A copy of the report is included in *Supplement 2: Evaluation*.

Customer Satisfaction and Evaluations

Drying Rack Pilot Project

When customers enrolled in this pilot, they completed a survey about their current laundry habits. Combined with the post-survey conducted in 2017, the company will analyze the results and determine the potential energy savings of a drying rack. While approximately 1,300 drying racks were distributed in 2016, 2,120 customers completed the pre-survey. Several hundred customers completed the survey, but did not pick up a drying rack

Of customers who own a clothes washer, nearly 35 percent of respondents indicated they have a washer that is less than 5 years old while just over 42 percent of respondents indicated they have a washer that is 5 to 10 years old. Approximately 50 percent of respondents said they own a top-loading clothes washer with a center agitator. Just over 51 percent of respondents wash 3 to 5 loads of laundry each week, while nearly 31 percent of respondents wash 6 to 10 loads of laundry each week.

Of customers who own a clothes dryer, nearly 30 percent of respondents reported that their dryer is less than 5 years old, while nearly 43 percent of respondents indicate their dryer is 5 to10 years old. Just over 29 percent of respondents said they dry 100 percent of their laundry in the dryer, while nearly 53 percent indicated they dry 75 to 99 percent of their laundry in the dryer. Of customers who indicated they dry some of their clothes outside of a clothes dryer, 72 percent of respondents indicated they hang their clothes to dry indoors. When asked how likely they would shift an additional 25 percent or more of their drying to the drying rack, nearly 72 percent of respondents said "very likely," while just over 26 percent of respondents said "somewhat likely." A copy of this report is included in *Supplement 2: Evaluation*.

At pickup events, customers were engaged and grateful, tweeting and sharing Facebook posts to let their friends and family know what they were doing.

Figure 14. Customer picking up his drying rack, 2016

Other customers sent emails: "Thank you for the clothes drying rack. I have already used it after picking it up on Saturday at 5 Mile and Franklin. The people were very kind and cheerful and all was organized well. Just wanted to say thank you"

The following Facebook post was indicative of those posted by a number of customers.

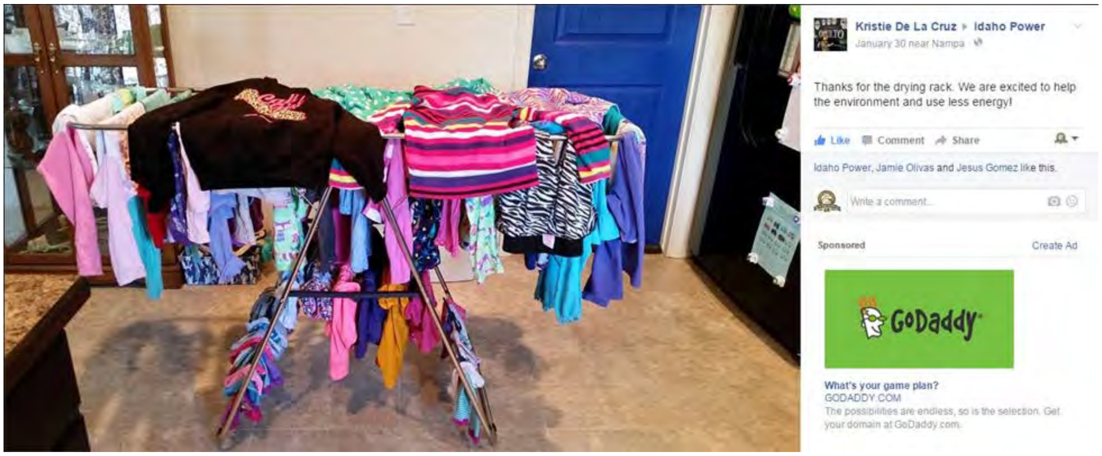

Figure 15. Screenshot showing customer appreciation for the drying rack, 2016

But the best part was when participants began to share their stories.

- One customer emailed saying "My drying rack has been so wonderful. About 99% of my laundry is on it. I bought a second one so I can hang the entire weekly batch. Thank you."
- Another emailed, "I am using the drying rack right at the moment! I have loved it. I really appreciate receiving it; I know we have saved energy because of it this summer.
- Another stopped by Idaho Power's booth at the FitOne Expo and raved about her drying rack, stating that she was saving $20 each month.

Other customers' stories were featured in the October edition of *Connections*.

Energy-Saving Kits

When customers ordered a kit, they completed a short enrollment survey. Upon receipt of the kit, they were encouraged to return a more in-depth survey to indicate which measures had been installed and how satisfied they were with the ordering process. Results from both surveys are included in Supplement 2: *Evaluation*.

Of the 19,715 electric kits distributed, RAP received 2,790 returned surveys for a response rate of just over 14 percent. Of the 14,831 non-electric kits distributed, RAP received 2,588 returned surveys for a response rate of over 17 percent. The overall response rate was over 15 percent.

Approximately 95 percent of respondents indicated they were "very satisfied" with the kit ordering process with 4 percent indicating they "somewhat satisfied." Nearly 94 percent of respondents said they were "very likely" to tell a friend or family member to order a kit. While just over 54 percent of respondents said they were not aware of that Idaho Power had energy efficiency programs and incentives prior to receiving their kit, 99 percent said they were either "very likely" or "somewhat likely" to participate in another energy efficiency program.

Customers organically promoted the ESKs through numerous social media posts similar to the one below. This single post generated tremendous buzz, receiving over 3000 shares and generating over 10,000 enrollments.

Figure 16. Screenshot showing customer excitement on Facebook about the Energy-Saving Kits, 2016

Another customer from Midvale reached out to Idaho Power via the website with this message, “After receiving the free package of LED light bulbs you offered, we have since retrofitted our home and shop with all LED light bulbs, and we love the increased brightness. Thank you for prompting us to make these changes. We definitely want to conserve energy and reduce our power bill to boot!”

LED Lightbulbs as Giveaways

Idaho Power conducted no customer satisfaction surveys for this offering in 2016.

Customers at events and presentations continued to readily express appreciation for receiving free LED lightbulbs.

SEEK Program

The SEEK program is evaluated annually regarding participant satisfaction. For more details on the SEEK program, view the most recent annual report, *Energy Wise® Program Summary Report* located in *Supplement 2: Evaluation*.

Teachers continued to be pleased with the program. One hundred percent of teachers who completed surveys would recommend the program to other colleagues, and 97 percent would conduct the program again. Student engagement remained high as well—71 percent of student surveys were returned, and 69 percent indicated their families changed the way they used energy as a result of the program. Parents also responded favorably, indicating the program was easy to use, they would like to see it continued in local schools, and they would continue to use the kit items at home after completion of the program.

Some participants posted YouTube videos reviewing their kits and the home activities: youtube.com/watch?v=0UrhdTP4ZKc and youtube.com/watch?v=-lyHxacMqvo.

2017 Program and Marketing Strategies

Drying Rack Pilot Project

The Drying Rack Project will be fully evaluated and analyzed to determine how effective the drying racks were in producing the desired behavior change, i.e., reducing automatic dryer use by at least 25 percent. If the project results are favorable, the project may be offered again.

Energy-Saving Kits

Idaho Power will augment its ESK program with an opportunity to use the basic non-electric water-heating kit as a giveaway, in limited quantities, to garner additional interest and participation at presentations and small events. Promotional materials will be readily available for staff-use at larger events. Social media posts and advertising in the semi-annual *Energy Efficiency Guide*s, *Connections,* and Idaho Power's website will all be used to promote ESKs. Direct and targeted digital marketing campaigns will be considered, as needed, to boost participation with more challenging geographic or demographic populations.

LED Lightbulbs as Giveaways

Idaho Power plans to continue to offer LED lightbulbs to customers at community events, presentations, and customer visits.

Other Educational Distributions

Idaho Power will continue to look for opportunities to engage customers with new technologies that stress the importance of energy-efficient behaviors at home. Idaho Power is currently evaluating thermostatic shower valves.

SEEK Program

Plans for the 2016 to 2017 school year include updating the marketing flyer and developing an electronic marketing piece for distribution to more remote schools and districts. The company will continue to leverage the positive relationships Idaho Power's community education representatives have within the schools to maintain program participation levels and will heighten visibility to enrollments to add an element of competition amongst the geographic regions. Curriculum will be reviewed for continued relevance to state standards.

Energy Efficient Lighting

		2016	2015
Participation and Savings			
	Participants (lightbulbs)	1,442,561	1,343,255
	Energy Savings (kWh)	21,093,813	15,876,117
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$3,009,970	$1,997,292
	Oregon Energy Efficiency Rider	$63,200	$60,800
	Idaho Power Funds	$7,538	$5,291
	Total Program Costs—All Sources	$3,080,708	$2,063,383
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.014	$0.013
	Total Resource Levelized Cost ($/kWh)	$0.049	$0.028
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.27	4.53
	Total Resource Benefit/Cost Ratio	2.52	4.23

Description

Idaho Power and other regional utilities participate in the Simple Steps, Smart Savings™ program, managed by CLEAResult. Idaho Power promotes Simple Steps, Smart Savings offerings to customers in two areas: this lighting program and the appliance promotion program (see the Simple Steps, Smart Savings section of this report).

Initiated in 2002, the Energy Efficient Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers, with savings passed on to the customer at the point of purchase. The benefits of this model are low administration costs, better availability of products to the customer, and the ability to provide an incentive for specific products. The program goal is to help Idaho Power's Idaho and Oregon residential customers afford to adopt more efficient lighting technology.

ENERGY STAR® lightbulbs, including compact fluorescent lightbulbs (CFL) and LEDs, are a more efficient alternative to standard incandescent and halogen incandescent lightbulbs. Lightbulbs come in a variety of wattages, colors, and styles, including lightbulbs for three-way lights and dimmable fixtures. ENERGY STAR lightbulbs use 70 to 90 percent less energy and last 10 to 25 times longer than traditional incandescent lightbulbs.

Idaho Power pays a flat fee for each kWh savings achieved. The minimum base amount goes directly to buy down the price the product was reduced; the amount applied to administration and marketing varies and can be used for things like retailer promotions. Promotions may include special product placement, additional discounts, and other retail merchandising tactics designed to increase sales.

In addition to managing the program's promotions, CLEAResult is responsible for contracting with retailers and manufacturers, providing marketing materials at the point of purchase, and supporting and training to retailers.

Program Activities

In 2016, LED lightbulbs comprised 59 percent of lightbulb sales each month, an increase from the 32 percent of lightbulb sales in 2015. LED fixtures comprised approximately 5 percent of lighting sales, up from 3 percent of lighting sales in 2015.

Idaho Power continued to participate in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings program focusing on ENERGY STAR CFLs and LEDs and light fixtures.

In 2016, Idaho Power worked with 16 participating retailers, representing 89 individual store locations throughout its service area. Of those participating retailers, 55 percent were smaller grocery, drug, and hardware stores, and the remaining 45 percent are big box retailers.

Marketing Activities

In 2016, CLEAResult and participating Simple Steps, Smart Savings utility partners decided the current logo was outdated and needed a new look. CLEAResult developed several new designs, and the utility partners decided the new logo would have a simple message: Simple + Smart. The logo colors were selected so they would standout on shelves to help customers identify qualifying products. Throughout the year, the old point-of-purchase pieces were replaced with the new Simple + Smart pieces.

Figure 17. The new 2016 Simple + Smart logo

Several Simple Steps, Smart Savings promotions were conducted through CLEAResult at retail stores in 2016. These promotions generally involved special product placement and signs. CLEAResult staff continued to conduct monthly store visits in 2016 to check on stock, point-of-purchase signs, and displays.

Additional activities in 2016 involved education and marketing. During events where Idaho Power staffed a booth and distributed LED lightbulbs, customers were informed about the importance of using energy-efficient lighting, the quality of LED lightbulbs, and the special pricing available for the Simple Steps, Smart Savings products.

The company continued to host an Energy Efficient Lighting program website; to make available a *Change a Light* program brochure, designed to help customers select the right lightbulb for their needs; and to discuss energy-efficient lighting with customers at community events. Also, ads for the Fridge and Freezer Recycling Program promoted the free LED lightbulb offer. Several *#TipTuesday* posts on social media throughout the year also focused on energy-efficient lighting.

The Idaho Power winter *Energy Efficiency Guide* included two lighting-related articles, and the summer *Energy Efficiency Guide* included a mini-home assessment where customers could gauge how efficient their behaviors are in areas including, lighting, heating and cooling, and more. During energy efficiency segments in November on the KPVI morning news (broadcast in Pocatello) and on KTVB news (broadcast in Boise and Twin Falls), the discussion focused on energy-efficient holiday lighting, timers, inflatables, and laser lights.

Cost-Effectiveness

In 2016, the Energy Efficient Lighting program provided 50 percent of all energy savings derived from residential energy efficiency customer programs.

In 2016, Idaho Power used the same RTF-deemed savings for both CFLs and LEDs as were used in 2015. For other non-RTF lightbulb types, Idaho Power used the site savings approved by the BPA for the Simple Steps, Smart Savings promotion.

In August 2015, RTF updated and revisited the assumptions for both CFLs and LEDs to account for market changes due to the federal standards compliance. The number of lightbulb types was further reduced to combine three-ways with the general purpose and dimmables. Additionally, the lumen categories were shifted to reflect current consumer trends. Due to the timing of the RTF's update, BPA and CLEAResult did not implement the new savings in the Simple Steps, Smart Savings promotion in 2016.

For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

2017 Program and Marketing Strategies

Idaho Power will continue to participate in the Simple Steps, Smart Savings lighting program in 2017 by contracting with CLEAResult, who was awarded the annual BPA implementation contract. New savings will be calculated using the new RTF workbook, version 4.2.

Idaho Power will continue to monitor the number of participating retailers and geographic spread of these retailers, and to develop on-line promotions that allow customers to access promotional pricing regardless of location.

CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, special product placement, and displays. The program specialist and customer representatives will continue to staff educational events to promote the importance of using energy-efficient lighting.

Energy House Calls

		2016	2015
Participation and Savings			
	Participants (homes)	375	362
	Energy Savings (kWh)	509,859	754,646
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$188,253	$194,939
	Oregon Energy Efficiency Rider	$15,815	$15,057
	Idaho Power Funds	$2,368	$4,108
	Total Program Costs—All Sources	$206,437	$214,103
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.029	$0.020
	Total Resource Levelized Cost ($/kWh)	$0.029	$0.020
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.11	2.81
	Total Resource Benefit/Cost Ratio	2.75	2.96

Description

Initiated in 2002, the Energy House Calls program gives homeowners of electrically heated manufactured homes an opportunity to reduce electricity use by improving the home's efficiency. Specifically, this program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon who use an electric furnace or heat pump. Participation is limited to one service call per residence.

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 up to eight LED lightbulbs; testing the temperature set on the water heater; installing water heater pipe covers when applicable; up to two low-flow showerheads and bathroom faucet aerators; a kitchen faucet aerator; two replacement furnace filters with installation instructions; and energy efficiency educational materials appropriate for manufactured-home occupants.

Idaho Power provides contractor contact information on its website and marketing materials. The customer schedules an appointment directly with one of the certified contractors in their region. The contractor verifies the customer's initial eligibility by testing the home to determine if it qualifies for duct-sealing. Additionally, contractors have been instructed to install LED lightbulbs only in high-use areas of the home and install bathroom aerators and showerheads only if the upgrade can be performed without damage to a customer's existing fixtures.

The actual energy savings and benefits realized by each customer depend on the measures installed and the repairs and/or adjustments made. Although participation in the program is free, a typical cost for a similar service call would be $400 to $600, depending on the complexity of the repair and the specific measures installed.

Program Activities

Since the addition of the direct-install measures in March 2015, there has been a slight increase in participation. In 2016, 375 homes received products and/or services through this program, resulting in 509,859 kWh savings (Figure 18).

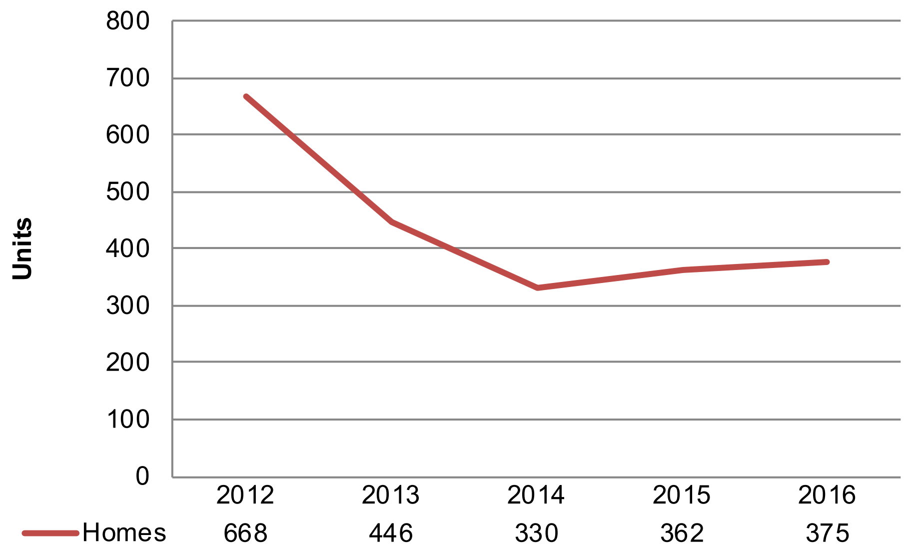

Figure 18. 2012–2016 participation in the Energy House Calls program

Of the total participating homes, 48 percent were located in the Canyon–West Region, 26 percent were located in the Capital Region, and 26 percent were located in the South–East Region.

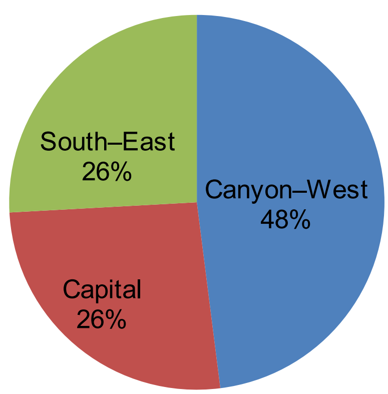

Figure 19. 2016 Energy House Calls participation by region

Duct-Sealing

Each year, a number of customers who apply for the Energy House Calls program cannot be served because the ducts do not require duct-sealing or cannot be sealed, for various reasons. These jobs are billed as a test-only job. Some reasons may be the home is too difficult to seal, or the initial duct blaster test identifies the depressurization with respect to the outdoors is less than 150 cubic feet per minute (CFM) and sealing is not needed. Additionally, if, after sealing the duct work, the contractor is unable to reduce leakage by 50 percent, the contractor will bill the job as a test-only job. Prior to 2015, these test-only jobs were not reported in the overall number of jobs completed for that year, because there was no kWh savings to report. Because Idaho Power now offers direct-install measures in addition to the duct-sealing component, all homes are reported. While some homes may not have been duct sealed, they all would have had some of the direct-install measures included, which would allow us to report kWh savings for each home. Of the 375 homes that participated in 2016, 52 homes were serviced as test-only.

If a home had a blower door and duct blaster test completed, and it is determined that only duct-sealing is necessary, it will be billed as test and seal. For a home with a crossover duct system that needs replaced in addition to the duct-sealing, it will be charged as an x-over. When a home requires the existing belly return system to be decommissioned and have a new return installed along with the duct-sealing, it will be billed as a complex system. A complex system that also requires the installation of a new crossover and duct-sealing will be billed as a complex system and x-over job.

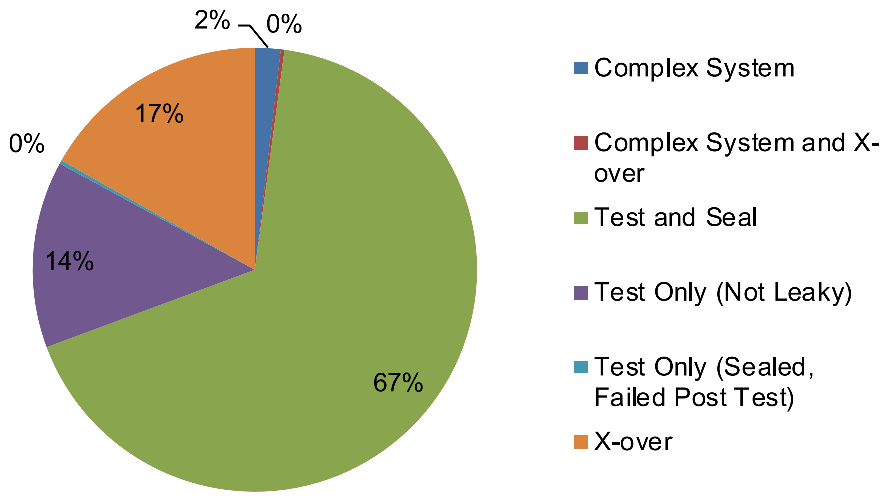

Figure 20. 2016 Energy House Calls participation by job type

Direct-Install Measures

In 2016, contractors installed 3,079 LED lightbulbs, 206 showerheads, 351 bathroom aerators and 233 kitchen faucet aerators.

Marketing Activities

Idaho Power updated all marketing materials in late 2015 and began using them in 2016 to better highlight the program as a free service for manufactured homes and to capture the attention of the target audience. Idaho Power sent two bill inserts to all residential customers in Idaho and Oregon. The March bill insert was shared with the Rebate Advantage program and sent to 374,301 customers, and the October bill insert promoted only the Energy House Calls program and was sent to 378,955 customers. The company sent postcards in February and September to residents of electrically heated manufactured homes who had not yet participated in the program. Written in English and Spanish, 9,042 postcards were delivered in February and 8,650 in September.

Idaho Power also used Facebook ads in February and July. The February ad reached 40,044 people and resulted in 707 website clicks and an increase in enrollments. The July ad reached 60,288 people and resulted in 1,303 website clicks and an increase in enrollment. In addition, Idaho Power customer representatives and customer service representatives knowledgeable about the program continued to promote the program to qualified customers.

Cost-Effectiveness

In late 2015, RTF updated savings for performance-based duct-sealing in manufactured homes based on both the Simplified Energy Enthalpy Model (SEEM) calibration and the move toward prescriptive savings only. RTF approved the removal of PTCS requirements for duct-sealing. As a result of these changes, the 2016 deemed savings for duct-sealing are 19 to 60 percent lower than the deemed savings used in 2015.

Savings and a cost-effectiveness analysis for the direct-install measures, including low-flow showerheads, faucet aerators, and LED lightbulbs, were completed using deemed savings from the RTF.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Again this year, Idaho Power contractors reported that customers appreciated receiving the program services and direct-install measures, with most positive comments regarding the free LED lightbulbs. Customers continue to be pleased with the program.

To monitor quality assurance (QA) in 2016, third-party verifications were conducted by Momentum, LLC on approximately 5 percent of the 375 participant homes, resulting in 19 home audits. Homes were selected at random. The QA reports indicate customers were pleased with the work sub-contractors completed in their homes. Each home inspection included an on-site visual confirmation that the reported work had been completed. Weather permitting, blower door and duct blaster tests were also conducted to verify the results submitted by the sub-contractor.

2017 Program and Marketing Strategies

Idaho Power will continue to provide free duct-sealing and selected direct-install efficiency measures for all-electric manufactured/mobile homes in its service area.

Idaho Power will continue to include program promotional materials in its bill, to send direct-mail postcards, and to use social media and other proven marketing tactics. Contractors and customer representatives will also distribute door hangers in mobile-home parks and program literature at appropriate events and presentations. Idaho Power will continue to provide Energy House Calls program postcards to CAP agencies for distribution to customers who need assistance but do not qualify to receive weatherization assistance through these agencies.

ENERGY STAR® Homes Northwest

		2016	2015
Participation and Savings			
	Participants (homes)	110	598
	Energy Savings (kWh)	150,282	820,684
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$138,203	$646,991
	Oregon Energy Efficiency Rider	$1,510	$2,692
	Idaho Power Funds	$2,445	$3,990
	Total Program Costs—All Sources	$142,158	$653,674
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.051	$0.046
	Total Resource Levelized Cost ($/kWh)	$0.107	$0.099
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.79	2.10
	Total Resource Benefit/Cost Ratio	1.00	1.04

Description

Initiated at Idaho Power in 2003, this program targets the lost-opportunity energy savings and summer-demand reduction that is achieved 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 Residential Services Network (RESNET)-certified rater working under a RESNET certified provider. The rater is hired by the builder to ensure the stringent ENERGY STAR requirements have been met. In addition to verifying the installation of building components and equipment during on-site inspections, the rater ensures the home passes a blower door test, an air-duct leakage test, and combustion back-draft tests. The ENERGY STAR Homes Northwest residential construction program promotes homes that use electric heat pump technology and are at least 15 percent more energy-efficient than those built to standard Idaho and Oregon code.

ENERGY STAR homes are more efficient, comfortable, and durable than homes constructed to standard building codes. Homes that earn the ENERGY STAR certification must meet six specifications: 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.

Prior to January 1, 2016, this ENERGY STAR Homes Northwest program was supported by a partnership between Idaho Power and NEEA's Northwest ENERGY STAR Homes to improve and promote the construction of energy-efficient homes using regional program guidelines approved by the United States (US) Environmental Protection Agency (EPA). NEEA has ended their oversight of the regional, single-family Northwest ENERGY STAR Homes program as of January 1, 2016.

All homes throughout the Northwest that were permitted on or after January 1, 2016, are now required to meet national EPA's ENERGY STAR program certification requirements. To receive the Idaho Power program incentive, certified homes in the company's service area must meet the national EPA Version 3, ENERGY STAR Homes requirements and be electrically heated. Additionally, an ENERGY STAR Homes RESNET-certified rater must enter home-related data into the regional AXIS database, which is maintained by NEEA. The AXIS database allows for utility tracking and review. The rater must also generate a Northwest Compliance Report that is consistent with Northwest REM/Rate™ modeling guidelines.

All single-family homes permitted prior to January 1, 2016 and certified by September 30, 2016, were allowed to be certified under the pre-existing NEEA Northwest ENERGY STAR Homes specifications. The regional Northwest ENERGY STAR Homes program retains oversight of multi-family ENERGY STAR Home certifications. To qualify for an Idaho Power Multifamily ENERGY STAR Homes incentive, the rater must certify the homes according to the Northwest Multifamily Builder Option Package (BOP) 1. The rater must enter the multi-family units into the AXIS database for utility tracking and review.

Program Activities

To encourage the construction of ENERGY STAR homes, the program offered qualified builders a $1,000 incentive per home built to the Northwest ENERGY STAR Single and Multifamily Homes requirements with heat pump technology. Builders who entered their homes in a Parade of Homes were eligible to receive the standard $1,000 incentive plus an additional $500 marketing incentive to cover their expenses for ENERGY STAR signage and brochures. Builders benefit by earning the right to use the ENERGY STAR Homes logo and the ENERGY STAR name to promote themselves as an ENERGY STAR qualified builder.

A large part of the program's role in 2016 was to provide support for the building contractors associations (BCA) throughout Idaho Power's service area.

The regional trend toward increased ENERGY STAR certifications for multi-family homes continued in 2016. Out of 110 total incentives paid through Idaho Power's program, 108 were for multi-family dwellings. The other two were for single-family homes located in McCall as part of NEEA's Next Step Home (NSH) pilot program.

Marketing Activities

Idaho Power maintained a strong presence in the building industry by supporting the Idaho Building Contractors Association (IBCA) and several of its local affiliates throughout Idaho Power's service area in 2016. The company presented the Energy Efficient Design and Construction Awards to builders who integrated energy efficiency features in their parade homes at the Building Contractors Association of Southwest Idaho (BCASWI) Parade of Homes awards banquet. In addition, the company participated in the BCASWI builder's expo and the Snake River Valley Building Contractors Association (SRVBCA) builder's expo.

Idaho Power supported Parade of Homes events with full-page ENERGY STAR ads in the Parade of Homes magazines of the following BCAs: The Magic Valley Builders Association (MVBA), the BCASWI, SRVBCA, and the Building Contractors Association of Southeast Idaho (BCASEI). Idaho Power also ran ads in the April 20 *Business Insider* and June 10 *Idaho Business Review* targeting residential contractors. Inserts were added to residential customers' billing statements in April and May informing them of Parade of Homes events in their area. Due to a change in tactics, one bill insert was not used in 2016 as originally planned. Instead, social media and a weekly *News Briefs* article to media were used to promote ENERGY STAR Homes and local Parade of Homes events. These tactics allowed Idaho Power to better target potential participants. In addition, the company sponsored the IBCA annual winter and summer meetings.

The program, in collaboration with NEEA, sponsored a Lunch & Learn course on September 27, 2016. This was a two-hour course presented by energy professionals from Advanced Energy. The purpose of this course was to facilitate a summit of residential real estate professionals to explore solutions leading to the increased market value of energy-efficient and green homes. The 35 professionals in attendance included sales agents, brokers, lenders, home inspectors, and home energy experts.

Cost-Effectiveness

Savings and cost-effectiveness assumptions for the primary multi-family-style home for 2016 were the same compared with 2015. The townhome/multi-family homes in the Boise–Nampa–Caldwell climate zone were cost-effective from a UC and a TRC perspective with the inclusion of the non-energy benefits (NEB). No single-family homes were certified in 2016. Two homes in NEEA's NSH pilot program were completed and incentives were paid in 2016.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

Independent, RESNET-certified program providers verified the rater's input for accuracy and confirmed that program requirements had been met. The provider then certified each home within the AXIS database. Providers performed file and on-site field QA, and offered technical assistance to the raters who had contracted with them. Per RESNET guidelines, the provider performed QA on minimum of 10 percent of files or desk checks and 1 percent QA on-site field QA of all projects. In 2016, the raters reported no issues resulting from the QAs.

2017 Program and Marketing Strategies

Idaho Power will continue to support NEEA's NSH, high-performance specification pilot program. This specification is designed to build homes that are 30 percent more efficient than homes built to standard building codes. Though NEEA is no longer recruiting homes for the pilot, it plans to analyze the data collected through in-home monitoring from all three phases of the pilot. Results are expected by the second quarter of 2017. Homes built during Phase III incorporated NSH minimum requirements, guidelines, and best practices learned from Phase I and II. When completed, the final version of the NSH specification will be made available to utilities interested in offering NSH incentives. At this time, NEEA does not plan to offer a branded, customer-facing program, based on this specification, to the region.

Idaho Power plans to continue marketing efforts to promote this program to builders and new homebuyers. These marketing efforts include Parade of Homes ads in parade magazines for the BCASWI, SRVBCA, MVBA, and the BCASEI. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Bill inserts, social media, and other advertising will be considered based on past effectiveness.

Fridge and Freezer Recycling Program (See ya later, refrigerator®)

		2016	2015
Participation and Savings			
	Participants (refrigerators/freezers)	1,539	1,630
	Energy Savings (kWh)	632,186	720,208
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$250,535	$212,674
	Oregon Energy Efficiency Rider	$4,555	$11,497
	Idaho Power Funds	$2,826	$3,007
	Total Program Costs—All Sources	$257,916	$227,179
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.062	$0.048
	Total Resource Levelized Cost ($/kWh)	$0.062	$0.048
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.92	1.21
	Total Resource Benefit/Cost Ratio	1.31	1.53

Description

Since 2009, the Fridge and Freezer Recycling program (formerly See ya later, refrigerator®) achieves energy savings by removing and recycling qualified refrigerators and stand-alone freezers from residential homes throughout Idaho Power's service area.

Idaho Power uses a third-party contractor to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, and reporting. Applicants enroll online or by phone, and the contractor screens each to confirm the refrigerator or freezer unit under consideration meets these initial program eligibility requirements: residential grade; at least 10 cubic feet (ft^3) as measured using inside dimensions, but no larger than 30 ft^3; and in working condition. Idaho Power then screens each applicant to confirm participation eligibility; the program targets older, extra refrigerator and freezer units for maximum savings.

Program Activities

In late November 2015, Idaho Power learned the program vendor, JACO had entered into receivership and ceased operations. After multiple internal conversations and consulting with EEAG, Idaho Power reintroduced the program using a new vendor, Appliance Recycling Center of America (ARCA), and a new name, Fridge and Freezer Recycling Program. Idaho Power re-launched the program on June 1, 2016.

Despite temporarily suspending the program and reintroducing the program mid-year, Idaho Power received almost as many participants in 2016 as it did in 2015. Idaho Power was invoiced by JACO for 292 units that it picked up in October and November 2015. The invoices were received after JACO entered into receivership. To allow time to ensure all appliances were disposed of according to the terms of the contract, Idaho Power paid the invoices in 2016. Because no savings from these units were claimed in 2015, the unit count and savings will be claimed in 2016.

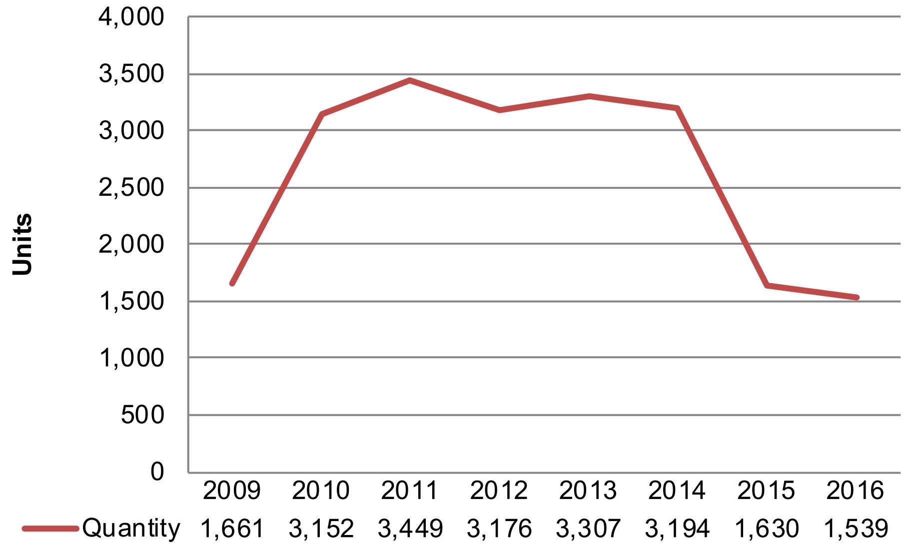

Figure 21. 2009–2016 Fridge and Freezer Recycling Program (See ya later, refrigerator®) participation by year

Marketing Activities

Idaho Power re-launched the program in June with a new name, new look, and updated web page. The marketing materials used the theme "Retire Your Old Fridge (or Freezer)" with images of a refrigerator retiring on the beach, lake, and Europe among other locations (Figure 22). The new messaging and imagery was chosen to resonate with the program's primary target audience, customers age 35 to 64, but skewing 55 and older. Idaho Power used bill inserts, direct-mail, Facebook, and earned media to promote the program.

Figure 22. 2016 Fridge and Freezer Recycling Program customer postcard

A *News Briefs* email was sent to reporters in June to alert the media and customers of the re-launch of the program. Bill inserts were sent to 228,961 residential customers in June; 377,345 customers in July; 378,671 customers in August; and 378,243 customers in September. In September, a postcard was mailed to 15,000 customers thought to have a higher propensity to own a second fridge or freezer. The September issue of *Connections* included an ad for the Fridge and Freezer Recycling Program, and the re-launch of the program was mentioned in further detail in the October issue of *Connections*.

Idaho Power placed a Facebook ad in July targeted to customers ages 35 to 65 or older who have an interest in energy efficiency, home improvement, and do-it-yourself efforts. The ad reached nearly 35,000 customers and resulted in 615 clicks to the Fridge and Freezer Recycling Program web page.

In June, Idaho Power promoted the program and the savings that can occur as a result of recycling an older or second fridge or freezer on Pocatello's KPVI live morning news.

Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because the goal of the program is to promote the removal of secondary units rather than replacing existing units.

Cost-Effectiveness

In 2016, Idaho Power used the same savings and assumptions used in 2015. When Idaho Power re-introduced the program in mid-2016, the company forecasted that participation would be at 1,000 units, and the program would likely not be cost-effective from the UC perspective but would be cost-effective from the TRC perspective. Idaho Power discussed this with EEAG in February 2016. When the company filed for program reinstatement in Oregon, the company requested a cost-effectiveness exception as outlined in OPUC Order No. 94-590. The exception was approved by the OPUC in Advice No. 16-07.

Despite the temporary suspension of the program, 1,539 units were recycled in 2016. As a result, the program had a TRC of 1.31 and a UC of 0.92. Had the program been operational for the full 12 months, it is likely that the program would have passed the UC test. In late 2016, RTF revisited and approved new, lower savings for freezer and refrigerator decommissioning, as well as LED bulbs. Idaho Power believes the Fridge and Freezer Recycling Program could be cost-effective in 2017 at the TRC level because of the non-energy benefits associated with decommissioning a refrigerator and freezer. However, the program may not pass the UC test. The company will re-evaluate the program in 2017.

For cost-effectiveness details and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

ARCA 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 2016 unit data showed 19 percent of units the program picked up were stand-alone freezers, and 81 percent of the units were refrigerators. Sixty-nine percent of the units were secondary, 27 percent were primary, and 4 percent were unknown. In 2016, 21 percent of the units collected were manufactured between 1965 and 1990, which generally represents the least efficient years of refrigerator manufacturing. By comparison, in 2015, 34 percent of the units collected through this program were of this vintage.

ARCA and Idaho Power also tracked data related to the marketing effectiveness of the program. Results of customer tracking information indicate 42 percent of customers learned of the program through bill inserts, and 11 percent from a friend or neighbor.

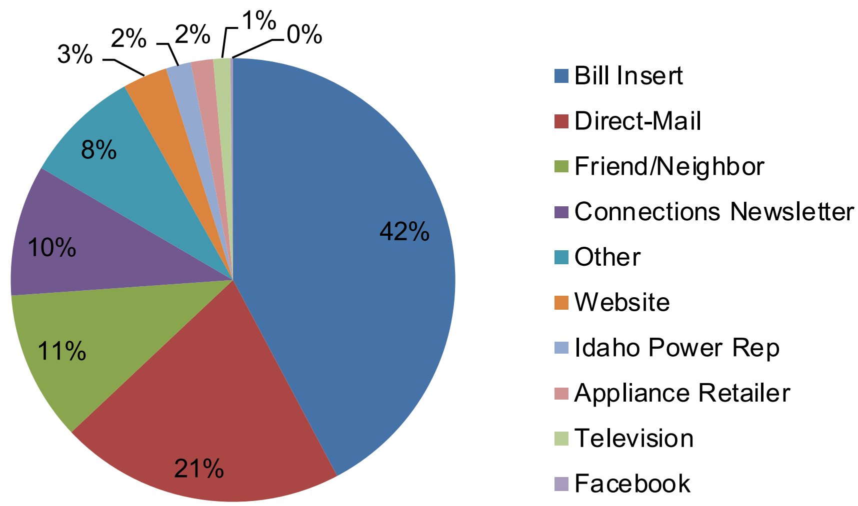

Figure 23. How customers heard about Fridge and Freezer Recycling Program in 2016

Figure 23 indicates ways customers heard about the program. The "Other" category includes sources, such as community events, repeat customers, the truck wrap ad, and unknown sources.

Sixty-seven percent of customers who enrolled used the toll-free telephone number, and 33 percent used the on-line enrollment form.

2017 Program and Marketing Strategies

Idaho Power plans to continue the Fridge and Freezer Recycling Program using the current program strategy in 2017, and to monitor its cost-effectiveness for long-term viability.

Idaho Power will continue to use customer information ARCA collected and the surveys from in-house evaluations to target future marketing efforts and increase the effectiveness of marketing. The company plans to use bill inserts, direct-mail, and paid and organic social media posts, and to reach out to customers at community events.

Heating & Cooling Efficiency Program

		2016	2015
Participation and Savings			
	Participants (projects)	486	427
	Energy Savings (kWh)	1,113,574	1,502,172
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$545,454	$583,663
	Oregon Energy Efficiency Rider	$27,184	$25,186
	Idaho Power Funds	$22,275	$17,520
	Total Program Costs—All Sources	$594,913	$626,369
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.036	$0.028
	Total Resource Levelized Cost ($/kWh)	$0.085	$0.092
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.33	3.11
	Total Resource Benefit/Cost Ratio	1.26	1.05

Description

The Heating & Cooling Efficiency (H&CE) Program provides incentives to residential customers in Idaho Power's Idaho and Oregon service area for the purchase and proper installation of qualified heating and cooling equipment and services.

Initiated in 2007, the objective of the program is to acquire energy savings by providing customers with energy-efficient options for electric space heating and cooling. Incentive payments are provided to the residential customers for all measures. Three of the measures also include a payment to the installing contractor. The available measures in 2016 include ducted air-source heat pumps, ducted open-loop water-source heat pumps, ductless air-source heat pumps, duct-sealing, whole-house fans (WHF), electronically commutated motors (ECM), evaporative coolers, and smart thermostats.

Idaho Power requires licensed contractors to perform the installation services related to these measures, with the exception of evaporative coolers that can be self-installed. A licensed contractor must also be an Idaho Power participating contractor for the ducted air-source heat pump, ducted open-loop water-source heat pump, ductless air-source heat pump, and duct-sealing measures.

The H&CE Program's list of measures and incentives includes the following:

- Customer incentive for replacing an existing ducted air-source heat pump with a new ducted air-source heat pump is $250 for a minimum efficiency 8.5 Heating Seasonal Performance Factor (HSPF).

- Customer incentive for replacing an existing oil or propane heating system with a new ducted air-source heat pump is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- Customer incentive for replacing an existing electric forced-air or zonal electric heating system with a new ducted air-source heat pump is $800 for a minimum efficiency 8.5 HSPF.
- Incentive for customers or builders of new construction installing a ducted air-source heat pump in a new home is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- Customer incentive for replacing an existing ducted air-source heat pump with a new ducted open-loop water-source heat pump is $500 for a minimum efficiency 3.5 coefficient of performance (COP).
- The customer incentive for replacing an existing electric forced-air or zonal electric, oil, or propane heating system with a new ducted open-loop water-source heat pump is $1,000 for a minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.
- The incentive for customers or builders of new construction installing a ducted open-loop water-source heat pump in a new home is $1,000 for a minimum efficiency 3.5 COP. Participating homes must be located in areas where natural gas is unavailable.
- The customer incentive for displacing a zonal electric heating system with a new ductless air-source heat pump is $750.
- The customer incentive for duct-sealing services performed in an existing home with an electric forced-air heating system or a heat pump is $350.
- The customer incentive for a WHF installed in an existing home with central A/C, zonal cooling, or a heat pump is $200.
- The customer incentive for replacing a Permanent Split Capacitor (PSC) air handler motor with an ECM in an existing home with oil or propane or natural gas forced-air heat, electric forced-air heat, or a heat pump is $50.
- The customer incentive for installing an evaporative-cooler is $150.
- The customer incentive for a smart thermostat installed in an existing home with an electric forced-air furnace or a heat pump is $75.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review and enter incentive applications into the Idaho Power system. Honeywell reviews and submits incentive applications for Idaho Power payment using a program database portal developed by Idaho Power. This allows Idaho Power to maintain the database within the company’s system, which is secure yet accessible to the third-party contractor. They also perform on-site verifications (OSV) and provide technical support to the customer representatives and contractors. Honeywell offers local program and technical assistance to contractors through on-site visits at their businesses.

Program Activities

Idaho Power began offering one new measure through the program on March 31, 2016. The measure provided a cash incentive to customers who installed a smart thermostat. During the development stage of this measure, the company provided updates and requested input from EEAG at quarterly meetings. EEAG's feedback regarding the measure was generally positive. With EEAG's recommendation, Idaho Power piloted the measure in 2016, and additional recommendations will be considered when the pilot expands.

The expansion of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal is to support contractors currently in the program while adding new contractors. The company held meetings with several prospective contractors to support this strategy, and added 15 new companies to the program as authorized participating contractors in 2016.

To qualify to participate in this program, a contractor must first complete the required training regarding program guidelines and technical information on HVAC equipment. Idaho Power held 13 of these training sessions for contractors in 2016.

The 2016 Heating and Cooling Efficiency Program paid incentives are listed in Table 8.

Table 8. H&CE Program incentives paid in 2016 Program incentives paid in 2016

Incentive Measure	2016 Project Quantity
Ducted Air-Source Heat Pump	169
Ducted Open-Loop Water-Source Heat Pump	17
Ductless Heat Pump	150
Evaporative Cooler	22
Whole-House Fan	19
Electronically Commutated Motor	50
Duct-Sealing	3
Smart Thermostat	56

The customer representatives, Idaho Power's program contractor, and the program specialist continually engaged with over half of the participating contractors to help them increase participation in the program. Some of the barriers to participation were uncovered anecdotally. One barrier stems from, in many cases, a need for improved technical skills in the HVAC technicians. Employee turnover and a lack of having a repeatable sales process are other barriers addressed. These barriers were addressed by the program specialist through one-on-one discussions with the participating contractors, usually in person. The program has 109 participating contractors therefore much more work will be done in this area.

Marketing Activities

Idaho Power used multiple marketing methods for its H&CE Program. The company mailed a bill insert to 374,173 residential customers in April and 378,239 residential customers in September. The H&CE Program was also mentioned in the April issue of *Connections*, mailed to all residential customers with their bill. Several *#TipTuesday* social media posts throughout 2016 focused on heating- and cooling-related tips. Two versions of a direct-mail postcard were sent to a total of 39,457 residential customers in November. The two versions were used as an A/B test (or a comparative test) to determine which new look resonated best with customers.

On several occasions, Idaho Power marketed the new smart thermostat incentive separate from the overall H&CE Program: on May 23, Idaho Power sent a *News Briefs* article to local media that was picked up by 1310 KLIX in Twin Falls; a May *#TipTuesday* social media post; the summer *Energy Efficiency Guide*; and the October issue of *Connections*.

In 2016, emphasis on Idaho Power's contractor portal was reduced since it was not being used by contractors and was found to be of lesser value compared to other support tactics, such as ongoing training on the program process and HVAC technical skills for new and existing contractor employees.

Cost-Effectiveness

Idaho Power implemented numerous changes to the H&CE Program measures for 2016 savings. Most changes were related to the measure definitions of heat pumps that were adopted by RTF in 2015.

Savings values for retrofit air source heat pumps were changed in 2015 by RTF to reflect different savings values that result from differing weatherization levels of the homes. The updated measure standard requires that a home's savings be assigned by whether the level of insulation is considered, "good," "fair," or "poor." Because of the quality installation component of the program, the overall condition of the home could be determined through contractor worksheets. Most homes had an insulation level of "fair" or "good" resulting in a slight decrease in savings than would have been seen from the previous measure definition not requiring judgment on the home's overall level of insulation.

For the measure level cost-effectiveness, cost data from RTF was used in lieu of actual project costs reported by customers. RTF costs contain updated baseline information for electric forced-air furnaces and air conditioning systems that was not available through local contractor surveys for 2016.

Air-source heat pumps installed in new construction or installed to replace existing less efficient heat pumps saw their claimed savings for 2016 drop significantly from approximately 2,500 kWh per unit to between 55 to 90 kWh depending on the climate zone. The drop was caused by the increased federal manufacturing standard for split system air source heat pumps in January 2015. This change was the biggest reason savings in the program dropped from 2015 levels while overall program participation increased. The air-source heat pump replacing an existing air-source heat pump measure, as with all heat pump measures in the program, mandates proper equipment commissioning, control setting, and sizing (CCS). CCS allows for an additional claimed savings of between 630 and 1,014 kWh per installed heat pump as deemed by RTF.

RTF geothermal heat pump savings, while specifically designed around closed loop systems, were deemed appropriate by RTF to be applied to open loop heat installations. Idaho Power replaced its previous engineering estimate of savings with the savings from the RTF workbook resulting in an increase in average retrofit savings of 900 kWh and a decline of 300 kWh in annual savings for new construction situations.

Ductless heat pumps (DHP) continue to be not cost-effective using RTF regional costs rather than prices reported on customer applications. RTF costs were used for 2016 cost-effectiveness analysis because the DHP measure definition was changed to reflect differing heating system performance factors. The company does not have sufficient cost data from its projects to split out costs by different levels of efficiency.

For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Honeywell performed random OSV on 47 (10 percent) of the completed installations in Idaho Power's service area. These OSVs confirmed that the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with respect to the contractors' quality of work. The program specialist continues to work with contractors to help them understand the importance of accurate documentation and quality installations.

Idaho Power accessed additional information from other sources. In 2016, NEEA provided two reports with identical content that updated the DHP Initiative. A copy of each is included on the CD accompanying *Supplement 2: Evaluation*. The following are highlights from the reports.

NEEA Reports E16-334 and E16-337, released July 2016

NEEA published this fifth Market Progress Evaluation Report (MPER) for the NW Ductless Heat Pump Project (Initiative). The report discusses findings obtained through extensive surveys, interviews, and focus groups comprised of homeowners, utilities, installers, and supply chain actors. The initiative was launched as a pilot in 2008 to demonstrate that DHPs were a viable technology to displace electric resistance heat in existing homes. The report describes the Initiative as well-designed and continuing to have a positive influence on the market. Some of the findings include the indication that interest continues to grow although lack of awareness remains a barrier. Word of mouth continues to be an initial source of information. DHP owners relied on their own research when making their purchasing decision. Financial considerations can be an opportunity or barrier because while DHPs can provide energy savings they can also be seen as expensive. The report provides detailed recommendations for NEEA to consider in the future.

2017 Program and Marketing Strategies

Idaho Power will provide program training to existing and prospective contractors to assist them in meeting program requirements and further their product knowledge. Sessions will be held on-site at contractor businesses and at Idaho Power facilities. Training sessions remain an important part of the program because they create opportunities to invite additional contractors into the program. The sessions also provide refresher training for existing participating contractors, and help them increase their customers' participation while improving the contractors' work quality. An additional dozen other interested companies will be taken through the authorization process by the program specialist.

Developing the existing network of participating contractors remains a key strategy for the program. The performance of the program is substantially dependent on the contractors' abilities to promote and leverage the measures offered. Idaho Power's primary goal in 2017 is to develop contractors currently in the program while adding new contractors. To meet this objective, the program specialist, along with Idaho Power customer representatives, will arrange frequent individual meetings to discuss the program with contractors in 2017.

The 2017 marketing strategy will include several tactics previously used, such as bill inserts, direct-mail, and social media, and will explore using additional tactics to market individual measures and the program as a whole.

Home Energy Audit

		2016	2015
Participation and Savings			
	Participants (homes)	539	351
	Energy Savings (kWh)	207,249	136,002
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$278,959	$192,873
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$10,853	$9,084
	Total Program Costs—All Sources	$289,812	$201,957
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

The current Home Energy Audit program is based on the insights gained from the Boise City Home Audit project conducted in 2011 and 2012, as described in the *Demand-Side Management 2012 Annual Report*. In 2014, the audit project became the Home Energy Audit program under Idaho Power's management.

The Home Energy Audit program is an in-home energy evaluation by a certified, third-party home performance specialist (HPS). It is used to identify areas of concern, and to provide specific recommendations to improve the efficiency, comfort, and health of the home. An audit includes a visual inspection of the crawl space and attic, a health and safety inspection, and a blower door test to identify and locate air leaks. In addition to the evaluation, some energy-saving improvements are installed at no additional cost to the customer if appropriate. After the audit is complete, the customer is supplied with a hardcopy or password-protected electronic copy of the HPS's findings and recommendations. Improvements available from Idaho Power include installation of the following:

- Up to 20 efficient lightbulbs (CFLs and LEDs)
- One high-efficiency showerhead
- Pipe insulation from the water heater to the home wall (approximately 3 feet)

To qualify for the Home Energy Audit program, a participant must live in Idaho and be the Idaho Power customer of record for a home. The home must be an existing site built home, and up until 2016, homes had to be all electric. Renters may participate with prior written permission from the landlord. Single-family homes, duplexes, triplexes, and fourplexes qualify, though multi-family homes must have discrete heating units and meters for each unit. Manufactured homes, new construction, or buildings with more than four units do not qualify.

Participating customers pay $99 (all-electric homes) or $149 (other homes: gas, propane or other fuel sources) for the audit and installation of measures, with the remaining cost covered by the Home Energy Audit program. The difference in cost covers the additional testing that is necessary for homes that are not all-electric. These types of energy audits normally cost $300 or more, not including the select energy saving measures, materials, and labor. The retail cost of the materials installed in each home averages $145.

Program Activities

In 2016, this became a fuel-neutral program. This change allows more customers to participate and learn ways to be energy efficient. Even if the space or water heating source in a home is not electric, often there can be many opportunities to use electricity wisely.

Seven HPS companies served the program in 2016. Homes were randomly assigned to the HPSs serving each service area, grouping locations for each HPS to save on travel time and expense. When the program became fuel-neutral, Idaho Power required HPSs who hadn't had previous training in Combustion Appliance Zone (CAZ) testing within the last six months to participate in Idaho Power's CAZ refresher class, or to attend a refresher class offered through another source. Although all HPSs had previous CAZ training, Idaho Power provided a refresher course in February 2016, and all HPSs participated.

In 2016, the program completed 539 energy audits. The average age of participating homes was 34 years old. The homes were built between 1898 and 2015. Home sizes ranged from 288 square feet (ft^2) to 8,500 ft^2, with 2,403 ft^2average home size. Figure 24 depicts the program's reach across Idaho Power's service area, and Figure 25 depicts the space and water heating fuel types.

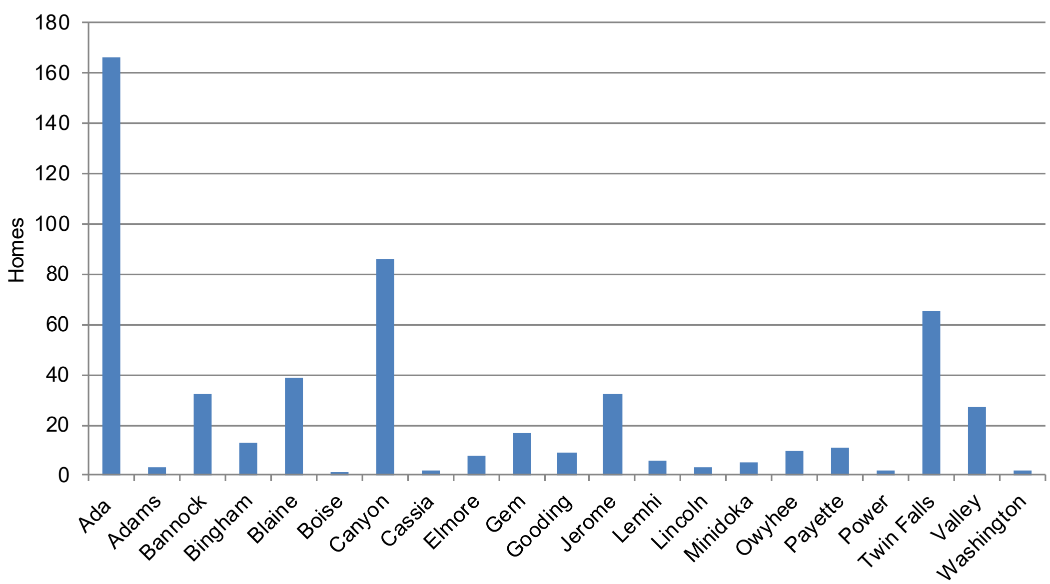

Figure 24. Home Energy Audit summary of participating homes in 2016, by county

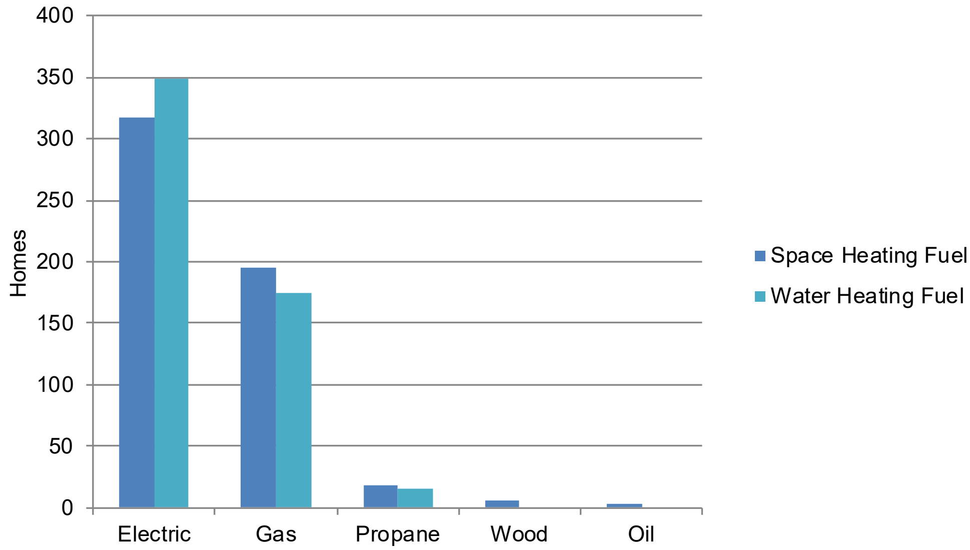

Figure 25. Home Energy Audit summary of space and water heating fuel types, 2016

The HPSs collected information on types and quantities of appliances and lighting in each home. The average number of incandescent lights per home was 21, and the average number of fluorescent or LED lights was 13. When performing an audit, the HPS determined which available measures were appropriate for the home, and, with homeowner approval, those measures were installed. Figure 26 indicates the total quantity of items installed by measure.

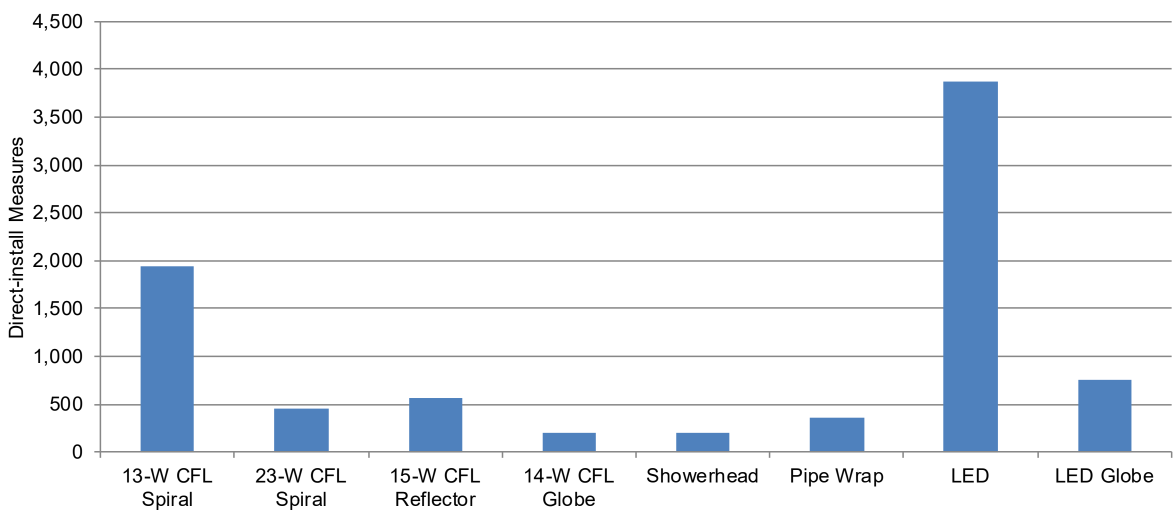

Figure 26. Home Energy Audit measures installed in participating homes in 2016

As Idaho Power's existing stock of CFLs has been used and the cost of LEDs has come down, all new lightbulb orders are for LEDs. With the exception of the CFL 15-watt reflectors, all lightbulbs being installed by the end of 2016 were LEDs.

The QA goal for the program was inspection of 10 percent of all audits, translating into approximately 53 audits in 2016. Ultimately, 34 QAs were completed in 2016, with all audits passing inspection. The 10 percent goal was unmet in 2016 because it was challenging to find participants willing to allow the auditor into their home for a 1- to 2-hour period, especially if the participant worked outside the home.

Marketing Activities

In January 2016, all program materials including the website were updated to promote eligibility changes to include all Idaho residential customers, regardless of fuel type. Additionally, an infographic was designed and used online and in social media to provide a visual representation and additional detail on what occurs during the audit.

Idaho Power recruited participants for the program through small batches of 1,000 to 2,000 direct-mail letters. Customers interested in participating were directed to a website for additional information and the on-line application. Those who did not have internet access or were uncomfortable using the on-line application were encouraged to call Idaho Power to apply. A program brochure was added to some mailings, but did not result in an increase in enrollment compared to mailings without the brochure.

In October 2016, Idaho Power partnered with the University of Idaho's Valley County Extension Office to host an energy efficiency workshop in McCall, Idaho. Direct-mail letters were sent to residents, and posters were hung at local businesses inviting the community to attend the evening workshop. Attendees learned how to check their homes for efficiency, how to make improvements, and how to use myAccount. The Home Energy Audit program was emphasized as were various other Idaho Power efficiency programs. For attending, each person was given an LED lightbulb.

Bill inserts were sent to 369,000 residential customers in June and 355,000 residential customers in December. Articles highlighting the Home Energy Audit program were also included in the April and October issues of *Connections*, which is mailed along with the customer's bill.

The Home Energy Audit program was mentioned in the Idaho Power *Winter Energy Efficiency Guide* as a way to improve your home's performance. In addition, the program was the focus of the Idaho Power energy-efficiency segment on the KTVB afternoon news program in March.

Idaho Power used social media, including boosted Facebook posts, throughout 2016 to highlight the Home Energy Audit program. In May, a boosted post targeted to Idaho homeowners ages 35 and older with an interest in home improvement or energy efficiency reached 45,495 people, resulting in 1,745 post engagements (likes, comments and shares). In November and December, Idaho Power used boosted posts targeted to South–East Region customers. These boosted posts reached 44,662 people with 1,229 engagements, 97 shares, and 694 post clicks.

For several months throughout 2016, a short article about the program was also placed in the Pocatello-Chubbuck Chamber of Commerce e-newsletter.

Digital re-targeting advertising was also used to target the South-East Region customers. Customers who visited the Idaho Power website and then moved onto a different website were "followed" by a Home Energy Audits digital ad. Overall, 787,293 impressions were served resulting in 1,993 clicks with a total click-through rate of 0.25 percent. The total click-through rate was 3.6 times higher than the national average.

Cost-Effectiveness

One of the goals of the Home Energy Audit program is to increase participants' understanding of how their home uses energy and to encourage their participation in Idaho Power's energy efficiency programs. Since the Home Energy Audit program is primarily an educational and marketing program, the company does not apply the traditional cost-effectiveness tests to the program.

For the items installed directly in the homes, Idaho Power used the same assumptions during 2016 as were used in 2015. Idaho Power used RTF savings for direct-install bulbs, which range from 17 to 30 kWh per year. RTF savings for 2.0 gpm showerheads directly installed in a home are 139 to 166 kWh per year. In Idaho Power's *Energy Efficiency Potential Study*, AEG estimates that pipe wraps save 150 kWh per year. Savings for both showerheads and pipe wrap were only counted for homes with electric water heaters.

In 2015 and 2016, the RTF reviewed and updated the savings assumptions for CFLs, LEDs, and showerheads. These new savings will be applied in 2017.

Customer Satisfaction and Evaluations

Throughout 2016, a survey was sent to 482 customers who had participated in the program between October 2015 and September 2016. The purpose of the survey was to assess customers' satisfaction with program enrollment, scheduling, the auditor, the personalized report, and information learned. Participants who supplied an email address on the initial program enrollment form were sent an electronic survey (320 participants); those without an email address were sent a hardcopy of the survey with a postage-paid envelope (162 participants). The response rate was just over 43 percent, with 208 participants responding. Program strengths and areas for improvement were also assessed. Results were reviewed for the program as a whole and for responses related to individual HPSs.

When asked a series of questions about their experience with the program, 96 percent of respondents "strongly agree" or "somewhat agree" they would recommend the program to a friend or relative, and just over 94 percent of respondents "strongly agree" or "somewhat agree" they were satisfied with their overall experience with the program. And, over 97 percent of the respondents indicated it was "very easy" or "somewhat easy" to apply for the program.

Over 34 percent of respondents reported accessing their report online through an email address supplied to Idaho Power on the enrollment application, while over 37 percent reported receiving a paper copy, and 28 percent reported receiving their report both ways. Of those who accessed their report online, nearly 64 percent indicated that accessing the report online was "very easy" or "somewhat easy."

HPSs were rated on a number of attributes including courteousness, professionalism, explanation of work/measurement to be performed, explanation of audit recommendations, and overall experience with the HPS. Respondents rated their HPSs as "good" or "excellent" 93 to 100 percent of the time.

When asked how strongly they agree or disagree with statements about what they learned during the audit process, just over 95 percent of respondents "strongly agree" or "somewhat agree" they were more informed about the energy use in their home. Over 81 percent reported they "strongly agree" or "somewhat agree" they were more informed about energy efficiency programs available through Idaho Power. Just over 89 percent indicated they "strongly agree" or "somewhat agree" they learned what additional no- to low-cost actions they could take.

According to the survey, nearly 48 percent of respondents indicated they visited the Idaho Power website after the audit, just over 50 percent unplugged appliances when not in use, over 33 percent signed up for myAccount, and just over 72 percent shared their experience with relatives and/or friends. Just over 78 percent of the respondents reported they replaced additional incandescent lightbulbs with CFLs or LEDs. Just over 37 percent indicated they serviced their heating equipment, and almost 35 percent serviced cooling equipment. Additional information on the actions respondents indicated they already completed or planned to do within the next year are shown in the survey results included in *Supplement 2: Evaluation*.

Survey participants were asked to identify all of the benefits they experienced from participating in the program. Over 73 percent of respondents indicated the biggest benefit they found in the audit was personal satisfaction, with over 75 percent citing raised awareness of energy use, almost 61 percent citing cost savings, nearly 49 percent citing home improvement, approximately 44 percent citing comfort, and almost 37 percent citing benefit to the environment. When survey participants were asked to identify all of the barriers they encounter when making energy-saving changes in their home, over 77 percent of respondents indicated the biggest barrier was cost. Figure 27 shows participant benefits experienced by category and percent.

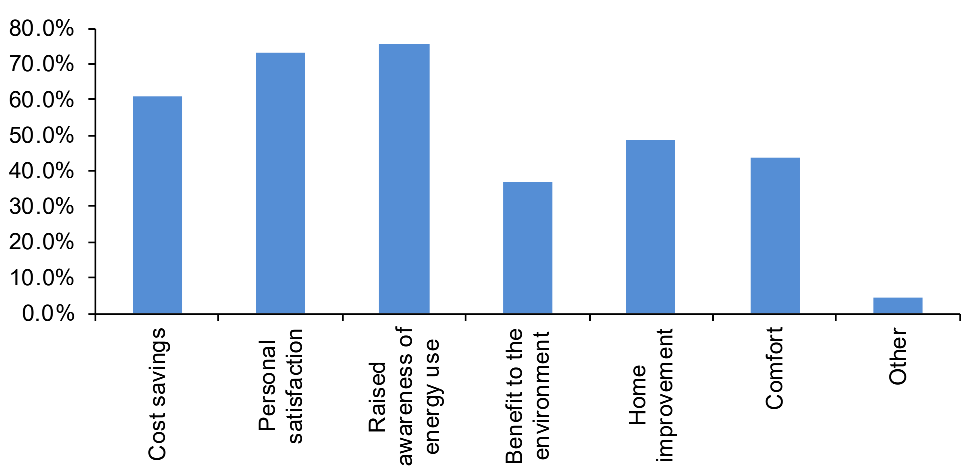

Figure 27. Home Energy Audit program participants' benefits experienced in 2016

Idaho Power conducted no program evaluations in 2016.

2017 Program and Marketing Strategies

The 2017 program goal is 500 participants, with approximately half being for all-electric homes and half for homes with other fuel sources for space and water heating. When the Home Energy Audit program began, the company's goal was to perform QA on 10 percent of the homes audited. The cost of this level of QA was justified to make sure the auditors were complying with the program's specifications. The program is now more established and the QA is verifying that the auditors are meeting and exceeding the requirements. The company believes it is more reasonable to reduce the QA to 5 percent in addition to the online QA and survey results review. Additionally, the company has found it logistically difficult to find 10 percent of the participants who will take the additional time to allow a second visit by a QA auditor.

In 2017, Idaho Power will continue recruiting participants through small batches of direct-mail, social media, advertising, bill inserts and through the use of the trade show booth backdrop at select events. Additional digital advertising may be considered if the program needs to be strategically promoted in specific regions.

Home Improvement Program

		2016	2015
Participation and Savings			
	Participants (homes)	482	408
	Energy Savings (kWh)	500,280	303,580
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$309,799	$259,898
	Oregon Energy Efficiency Rider	$0	$0
	Idaho Power Funds	$14,225	$12,611
	Total Program Costs—All Sources	$324,024	$272,509
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.034	$0.046
	Total Resource Levelized Cost ($/kWh)	$0.174	$0.152
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.54	1.91
	Total Resource Benefit/Cost Ratio	0.60	0.67

Description

Since 2008, the Home Improvement Program has offered incentives for upgrading insulation and windows in electrically heated homes/units. To qualify for an incentive under this program, the home must be a single-family home, a multi-family structure with individually metered residential units, or a manufactured home in Idaho Power's service area in Idaho. The home/units 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

Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor.

- Customer incentives are 15 cents per ft^2 for attic insulation and 50 cents per ft^2 for wall and under-floor insulation for additional insulation professionally installed by Idaho residential customers, multi-family building owners, and property managers in Idaho Power's Idaho service area.
- 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 includes 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 or fill the cavity.
- The existing insulation level under floors must be R-5 or less, and the final R-value must be R-30 or fill the cavity.

Windows

Windows must be professionally installed.

- Customer incentives are $2.50 per ft^2 of window area to Idaho residential customers for installing energy-efficient windows and/or sliding glass doors with a U-factor of 0.30 or lower.
- Pre-existing windows/sliding glass doors must be single- or double-pane aluminum or single-pane wood.
- Customers must use a participating contractor to qualify for the Idaho Power incentive, which is processed by Idaho Power.

Program Activities

During 2016, the Home Improvement Program paid incentives on 482 window and insulation upgrades. Attic insulation accounted for 20 percent, under-floor insulation accounted for 9 percent, wall insulation accounted for 2 percent and windows accounted for 69 percent of completed jobs. Both multi-family and single-family homes took advantage of these program incentives.

Marketing Activities

In early 2016, Idaho Power developed a new look for all Home Improvement Program marketing materials to better capture the attention of customers, including multi-family building owners, and highlight available incentives. Based on customer feedback, the application form became a part of the updated brochure. The brochure also included a checklist of required documentation to enhance clarification for the customer.

To promote the program, the company ran a series of newspaper ads multiple times during February, March, and September 2016. Idaho Power placed ads in newspapers in rural areas with a higher concentration of electrically heated homes (a program eligibility requirement). The company also sent bill inserts to 361,455 customers in February; 362,473 customers in April; and 364,100 customers in May and a targeted direct-mail letter to 40,000 customers in April and November 2016.

Idaho Power ran Facebook ads in September and reached 86,631 customers, resulting in 10,586 link clicks, 83 likes, 12 shares and had a total cost-per-click of $0.19. Anything at or under that level is good; the $0.19 cost-per-click is considered above expectations for a utility company niche product.

In the April energy efficiency issue of *Connections*, the cover story focused on a customer who had participated in the Home Improvement Program and saw a large reduction in her bill since replacing 13 windows in her home. The *Connections* issue and the customer story was promoted through a *News Briefs* item in April.

Cost-Effectiveness

In 2015 and 2016, the Home Improvement Program was not cost-effective from the TRC perspective. RTF reduced savings for single-family home weatherization projects between 2013 and 2014, and the reduced savings were updated prior to the 2015 program year. With the changes, average savings estimates per project were just under 50 percent of 2014 savings levels. These savings estimates were a result of an 18-month RTF process to calibrate residential savings models to billing and housing-characteristic data collected in the northwest, including Idaho, during 2011 as part of the RBSA. As a consequence, the majority of measure combinations in the Home Improvement Program are no longer cost-effective from the TRC perspective--neither is the overall program.

There are several factors that are impacting cost-effectiveness beyond the reduced regional average savings estimates. The few measure combinations that are cost-effective (insulations levels with R-values near zero or existing single-pane windows) are not common in single-family homes. Very little savings from weatherization measures occurs during the summer peak which limits the peak capacity cost-effectiveness benefits in the program.

Home Improvement Program was the only program in Idaho Power's energy efficiency portfolio requiring customer investment where the PCT B/C ratio was less than one at 0.80, which means the customer investment in weatherization on average exceeds the lifetime energy savings benefits, or that for every $1.00 invested by the customer to participate in the program, the customer only sees a $0.80 return through bill savings over 45 years.

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 performed random reviews of at least 5 percent of all installations completed in the Home Improvement Program. QA contractors verified the correct installation of measures. In addition, the QA contractors assisted and educated the contractors on program requirements. Of the 30 QA inspections completed in 2016, no major issues were reported.

The program incentive application form included an optional question asking customers how they heard about the program. The 482 projects came in on 459 applications. Customers answered the marketing question on 437 applications. The results are as follows:

- 248 respondents (56.8%) heard about the program from a program contractor.
- 114 respondents (26.1%) heard about the program from an Idaho Power bill insert.
- 45 respondents (10.3%) heard about the program from the Idaho Power website.
- 18 respondents (4.1%) received a referral from a friend or acquaintance.
- 4 respondents (.9%) heard about the program from a direct-mail piece.
- 8 respondents (1.8%) heard about the program from a newspaper, online, or television/radio ad.
- 0 respondents (0%) heard about the program from a home improvement show or fair.

2017 Program and Marketing Strategies

As reported in the *Demand-Side Management 2015 Annual Report*, the recalibrated savings from the RTF resulted in four of the six measures not being cost-effective from the TRC perspective. This program was not cost-effective from a TRC perspective in 2015. In 2016, the program was not cost-effective from a TRC or PCT perspective but was cost-effective from the UC perspective.

In 2016, the company evaluated the non-cost-effective measures and the potential impact of those measures on the program's overall cost-effectiveness. Idaho Power first discussed the concerns it had regarding the continued deterioration in cost-effectiveness of the Home Improvement Program with EEAG during the August 30, 2016 EEAG meeting, and Idaho Power committed to presenting its preliminary 2016 cost-effectiveness findings at the November 3, 2016 EEAG meeting.

At the November meeting, the company informed EEAG that the program was not cost-effective in 2016 based on preliminary savings information. The company advised EEAG that under the scenarios it evaluated, the cost-effectiveness of the Home Improvement Program would not improve. The company assured EEAG it would continue to encourage customers through education to continue to upgrade these measures even though an incentive may no longer be offered and asked for suggestions from EEAG members as to how Idaho Power could best sunset the program.

At this meeting, EEAG suggested the company wait until 2017 to end the program to ensure customers had adequate time to benefit from program incentives and look at a more targeted approach for the program.

Idaho Power analyzed different scenarios to modify the program to improve its cost-effectiveness. One scenario was to consider only offering the highest savings measure combinations in only the coldest climate zone (heating zone 3). These areas produce on average less than 5 percent of the projects annually. Under this scenario, the modified program would fail all the cost-effectiveness tests except the PCT.

In another scenario, Idaho Power analyzed offering only those measure combinations closest to being cost-effective; this modified program would only include window replacements in situations where there are existing single pane window, and insulation incentives where the existing home's R-value is essentially zero. Under this scenario, the program would remain not cost-effective under all tests except the UC test which would decrease from 2.54 as the program exists today to 1.42.

Due to the continued lack of cost-effectiveness, Idaho Power ceased marketing the program in the fourth quarter of 2016. The company plans to sunset the Home Improvement Program beginning on June 30, 2017. Customers will have 90 days from the day the job is started to submit their incentive applications, and those customers whose jobs were started on or before June 30, 2017, will qualify for an incentive.

Multifamily Energy Savings Program

		2016	2015
Participation and Savings			
	Participants (projects)	3	n/a
	Energy Savings (kWh)	149,760	n/a
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$55,758	n/a
	Oregon Energy Efficiency Rider	$0	n/a
	Idaho Power Funds	$3,288	n/a
	Total Program Costs—All Sources	$59,046	n/a
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.040	n/a
	Total Resource Levelized Cost ($/kWh)	$0.040	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	1.43	n/a
	Total Resource Benefit/Cost Ratio	2.55	n/a

Description

The Multifamily Energy Savings Program provides for the direct installation of energy-saving products in electrically heated, multi-family dwellings in Idaho and Oregon. The definition of multi-family dwelling is a building consisting of five or more rental units. The products are: ENERGY STAR® LED lightbulbs, high-efficiency showerheads, kitchen and bathroom faucet aerators, and water heater pipe insulation, and are installed at no cost to the property owner/property manager or the tenant. To ensure energy savings and applicability, each building is pre-approved by the contracted energy efficiency measure installation contractor.

Program Activities

The program began in March 2016 with a successful pilot project in Pocatello. This was followed by direct install projects in Boise and Twin Falls in September and December respectively. Between all three projects, a total of 196 apartment units received some if not all of the following; ENERGY STAR LED lightbulbs, high-efficiency showerheads, kitchen and bathroom faucet aerators, and water heater pipe insulation.

- Fairway Apartments, Pocatello: 73 units
- Greenbriar Apartments, Boise: 43 units
- Washington Park Apartments, Twin Falls: 80 units

Marketing Activities

Tenants in participating apartment complexes received a door hanger before the service date informing them that contractors would be entering their home to install energy-saving products. Once installation was complete, Idaho Power left materials to explain the new energy efficiency measures and to provide contact information should the tenant have any questions.

Cost-Effectiveness

The RTF provides deemed savings for LED lightbulbs and 2.0 gpm low-flow showerheads. The LED lightbulbs have a deemed savings value of 11 to 32 kWh per year depending on the type and lumens of the lightbulb. The 2.0 gpm low-flow showerhead is estimated to save 139 kWh per year. For the faucet aerator and pipe wrap, RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimated the annual faucet aerator savings to be 106 kWh and the annual pipe wrap savings to be 150 kWh.

Customer Satisfaction and Evaluations

Idaho Power included a satisfaction survey on the leave behind materials for the Pocatello pilot project. Both an online and mail-in option were offered. The response rate was very low with only six of the 73 residents responding by mailing in the stamped survey cards, no on-line surveys were submitted. These results will be considered with the expansion of this program.

2017 Program and Marketing Strategies

In 2017, Idaho Power plans to expand the program to include a minimum of two, energy-efficient measure direct-installation projects in multi-family dwellings in each of our three regions.
The satisfaction survey will be revised and included in 2017 leave behind materials for all projects. Property managers/owners will also be surveyed.

Idaho Power will continue to use informative pre-installation door hangers and post-installation informational marketing pieces. Use of direct-mail will be explored to encourage engagement and participation from property owners/managers, and to increase program visibility.

Oregon Residential Weatherization

		2016	2015
Participation and Savings			
	Participants (audits/projects)	7	19
	Energy Savings (kWh)	2,847	11,910
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$0	$0
	Oregon Energy Efficiency Rider	$3,906	$5,341
	Idaho Power Funds	$24	$467
	Total Program Costs—All Sources	$3,930	$5,808
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.079	$0.028
	Total Resource Levelized Cost ($/kWh)	$0.118	$0.050
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a program required by Oregon Revised Statute (ORS) 469.633 offered under Oregon Tariff Schedule 78 since 1980. Upon a customer's request, an Idaho Power customer representative 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.

Program Activities

Seven customers returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Seven customers requested audits, three audits met the program requirements and were completed, and three customers did not have electric heat and were advised to contact their heating source supplier for program information. One customer did not move forward with the recommended energy efficiency upgrades. Two incentives were paid.

Idaho Power issued two incentives totaling $426.44 for 2,847 kWh savings. Both incentives and related savings were for ceiling insulation measures. There were no loans made through this program during 2016.

Marketing Activities

During May, as required, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing.

Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program described in Oregon Schedule 78, and includes a cost-effectiveness definition of this program. Pages three and four of the schedule identify the measures determined to be cost-effective and the specified measure life cycles for each. This schedule also includes the cost-effective limit (CEL) for measure lives of seven, 15, 25, and 30 years.

Two savings projects were completed under this program in 2016; both consisted of increasing attic insulation. Combined, the projects' annual energy savings is 2,847 kWh at a levelized TRC of $0.12 per kWh over the 30-year attic insulation measure life compared to a CEL of $0.85 per kWh as defined by Oregon Schedule 78.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

2017 Program and Marketing Strategies

Idaho Power will complete requested audits and fulfill all incentives deemed cost-effective and loan applications as required by under Tariff Schedule 78. The company will continue to market the program to customers with a bill insert/brochure in their May bill.

Rebate Advantage

		2016	2015
Participation and Savings			
	Participants (participants)	66	58
	Energy Savings (kWh)	411,272	358,683
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$103,056	$80,243
	Oregon Energy Efficiency Rider	$6,392	$4,351
	Idaho Power Funds	$1,602	$843
	Total Program Costs—All Sources	$111,050	$85,438
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.016	$0.014
	Total Resource Levelized Cost ($/kWh)	$0.022	$0.020
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	3.89	4.54
	Total Resource Benefit/Cost Ratio	3.33	3.45

Description

Initiated in 2003, the Rebate Advantage program helps Idaho Power customers in Idaho and Oregon 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. The program also provides an incentive to the sales consultants to encourage more sales of ENERGY STAR qualified homes and more discussion of energy efficiency with their customers during the sales process.

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.

Program Activities

Idaho Power residential customers who purchased a new, all-electric, ENERGY STAR qualified manufactured home in 2016, and sited it in Idaho Power's service area were eligible for a $1,000 incentive through the Rebate Advantage program. Salespersons received $200 for each qualified home they sold.

During 2016, Idaho Power paid 66 incentives on new manufactured homes, which accounted for 411,272 annual kWh savings.

Marketing Activities

One bill insert, shared with the Energy House Calls program, was sent to 374,301 customers in Idaho and Oregon in March. A second bill insert and Facebook ads were not used because the program had exceeded its goal, and both techniques identified had limited options to target potential participants and proved less successful than direct dealer support.

Idaho Power continued to support dealerships in 2016 by providing them with Rebate Advantage program brochures, banners, and applications as needed. The program specialist and the customer representatives visited some of these dealerships to distribute materials, promote the program, and answer salespersons' questions.

Cost-Effectiveness

In 2016, Idaho Power used the same savings and assumptions as were used in 2015. The measures remained cost-effective for 2016.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

In 2016, Idaho Power contracted with Leidos to perform an impact and process evaluation for this program. The impact evaluation found that submitted applications were accurately assigned ex-ante unit energy savings values according to assigned equipment type, cooling zone, and heating zone codes in the tracking database.

Equipment type was determined to vary between ENERGY STAR with electric resistance heating, Eco-Rated with electric resistance heating, and ENERGY STAR with electric heat pump heating. This equipment appeared to be accurately coded in the tracking database (with the exception of two Eco-Rated projects which were assigned "regular" ENERGY STAR savings values). Accuracy of cooling zone and heating zone coding for each project could not be verified due to lack of information about how these codes were assigned. Overall, this impact evaluation found an ex-post savings realization rate that exceeds 100 percent.

The process evaluation found that the program processes in place are effective, efficient, and result in a high degree of accuracy in program tracking.

A copy of the evaluation can be found in *Supplement 2: Evaluation.*

2017 Program and Marketing Strategies

Idaho Power plans to distribute a bill insert to Idaho and Oregon customers and will look for additional opportunities to engage potential manufactured home buyers. Idaho Power will also continue to support dealers by providing them with program materials.

Shade Tree Project

		2016	2015
Participation and Savings			
	Participants (trees)	2,070	1,925
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$70,669	$99,672
	Oregon Energy Efficiency Rider	$0	–$66*
	Idaho Power Funds	$5,973	$5,786
	Total Program Costs—All Sources	$76,642	$105,392
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

*Reversal of a 2014 charge to the Oregon Rider.

Description

The Shade Tree Project began as a pilot in 2013. According to the US Department of Energy (DOE), a well-placed shade tree can reduce energy used for summer cooling by 15 percent or more. Utility programs throughout the country report high customer satisfaction with shade tree programs and an enhanced public image for the utility related to sustainability and environmental stewardship. Other utilities report energy savings between 40 kWh per year (coastal climate San Diego) and over 200 kWh per year (Phoenix) per tree planted.

To be successful, trees should be planted to maximize energy savings and ensure survivability. Two technological developments in urban forestry—the state-sponsored Treasure Valley Urban Tree Canopy Assessment and the Arbor Day Foundation's Energy-Saving Trees tool—provided Idaho Power with the information to facilitate a shade tree project.

The Shade Tree Project operates in Ada and Canyon counties (Idaho), offering free shade trees to residential customers. Participants enroll using the on-line Energy-Saving Trees tool and pick up their tree at specific events. Unclaimed trees are donated to city partners and schools.

Using the on-line enrollment tool, participants locate their home on a map, select from a list of available trees, and evaluate the potential energy savings associated with planting in different locations. During enrollment, participants learn how trees planted to the west and east save more energy over time than trees planted to the south and north.

Ensuring the tree is planted properly helps it grow to provide maximum energy savings. At the tree pickup events, participants receive additional education on where to plant trees for maximum energy savings and other tree care guidance from experts. Local specialists include city arborists from Boise, Kuna, Nampa, and Meridian; Idaho Power utility arborists; Canyon County master gardeners; and College of Western Idaho horticulture students.

In August each year, Idaho Power sends participants from the previous two offerings a newsletter filled with reminders on proper tree care and links to resources, such as tree care classes and educational opportunities in the region. This newsletter was developed after the 2015 field audits identified common customer tree care questions and concerns.

Program Activities

In 2016, Idaho Power distributed 2,070 shade trees to residential customers through the Shade Tree Project. Because the best time to plant shade trees is in the spring and fall, Idaho Power held offerings in April and October, with 701 trees and 1,369 trees distributed, respectively. Idaho Power purchased the trees from a local wholesale nursery in advance of each event. The species offered for each event depended on the trees available at the time of purchase. Idaho Power worked with city and state arborists to select a variety of large-growing, deciduous trees that traditionally grow well in the climate and soils of the two participating counties.

Participants picked up the trees at events throughout the Treasure Valley—four in the spring and four in the fall. By offering several pickup days, locations, and times, 88 percent of spring trees and 90 percent of fall trees were distributed to homeowners.

Idaho Power continues to track the program data in the DSM database. The database is also used to screen applicants during enrollment to determine whether participants meet the eligibility requirements for the project, such as residential status within the eligible counties (customer type and location).

In 2016, this project was partially funded by a US Forest Service Western Competitive States Grant, which was used to purchase all of the trees for both offerings. The grant also funded the development of an instructional tree planting video posted to Idaho Power's website.

Marketing Activities

For both offerings, Idaho Power developed a direct-mailing list using the state-sponsored Treasure Valley Urban Tree Canopy Assessment tool (tvcanopy.net/). The tool is the result of a geographic information system (GIS)-based study that mapped land use throughout the Treasure Valley, including existing trees and vegetation, buildings, roads, waterways, and parking lots. The study identified areas where a large-growing shade tree could be planted. Idaho Power used the tool to identify residential properties with potential planting sites to the west of the homes.

For both offerings, Idaho Power also sent emails to customers who had requested information about the project through Idaho Power's website. Project partners, such as the cities of Nampa, Kuna, Meridian and Boise, shared information through their networks. Idaho Power announced its Shade Tree Project to allied groups, such as the Idaho Conservation League, Idaho Chapter of the US Green Building Council (USGBC), and Treasure Valley Canopy Network. Information was sent to Green

Team leads at large employers, such as HP, Wells Fargo, Ch2MHill, and Citi Bank. The company also distributed program flyers at local events, where appropriate.

An Idaho Power Facebook post in the spring reached 1,478 people and resulted in 20 shares, 3 comments, 30 likes and 68 link clicks. A boosted Facebook post was used in the fall and reached 16,668 people and resulted in 909 post engagements (which includes likes, shares and comments). The boosted post cost-per-engagement was $0.07. The company also promoted the program in specific neighborhoods on Nextdoor.com in the spring and fall. This combination of marketing tactics was successful. The spring offering filled in 20 days; the fall offering filled in 16 days.

Cost-Effectiveness

Idaho Power does not calculate the cost-effectiveness tests for this program since no savings are currently being attributed to this program. The company plans to begin counting energy saving for the Shade Tree Program when the originally planted trees are five years old.

Customer Satisfaction and Evaluations

After each offering, a survey was emailed to participants. The survey asked questions related to program marketing, tree-planting education, and participant experience with the enrollment and tree pickup processes. Results are compared, offering to offering, to look for trends to ensure the program processes are still working, and to identify opportunities for improvement. Data are also collected about where and when the participant planted the tree. This data will be used by Idaho Power to refine energy-savings estimates.

In total, the survey was sent to 1,112 Shade Tree Project participants. The company received 531 responses for a response rate of 48 percent. Participants were asked how much they would agree or disagree that they would recommend the project to a friend; nearly 96 percent of respondents said they "strongly agree," and just over 3 percent said they "somewhat agree." Participants were asked how much they would agree or disagree that they were satisfied with the overall experience with the Shade Tree Project; nearly 93 percent of respondents indicated they "strongly agree," and just over 6 percent "somewhat agree" they were satisfied. View survey information in *Supplement 2: Evaluation*.

Idaho Power conducted no program evaluations in 2016.

2017 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2017 using the Arbor Day enrollment tool; trees will be distributed at multiple events. This will be the last year of US Forest Service grant funding to help support the program. Idaho Power will use these funds to purchase some trees, and to send a representative to visit a subset of planting sites to collect data on tree placement and health.

Idaho Power will also explore expanding the program to new areas in western Idaho, such as Elmore County (Mountain Home) and the Payette area.

Idaho Power will continue to market the program through direct-mail, focusing on customers identified using the Urban Tree-Canopy Assessment. In addition, Idaho Power maintains a waiting list of customers who were unable to enroll before previous offerings filled. Idaho Power will reach out to these customers through direct-mail or email for the 2017 offerings. Idaho Power will continue to leverage allied interest groups, and will use social media and boosted Facebook posts if enrollment response rates decline.

Simple Steps, Smart Savings™

		2016	2015
Participation and Savings			
	Participants (products)	7,880	9,343
	Energy Savings (kWh)	577,320	770,822
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$147,055	$130,575
	Oregon Energy Efficiency Rider	$3,535	$6,676
	Idaho Power Funds	$3,194	$1,845
	Total Program Costs—All Sources	$153,784	$139,096
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.025	$0.018
	Total Resource Levelized Cost ($/kWh)	$0.063	$0.054
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	2.40	3.37
	Total Resource Benefit/Cost Ratio	1.33	4.83

Description

Initiated in 2015, the Simple Steps, Smart Savings™ program is a promotion-based appliance program that aims to increase sales of qualified energy-efficient appliances. The payments provided by Idaho Power through this program are applied during special promotions, which align with holidays or events throughout the year at retail stores. Incentives are shared between the retailer, manufacturer, and the customer, though they may differ between promotions and between retailers and manufacturers.

Retailer and manufacturer incentives may be provided as co-marketing dollars to the retailer or manufacturer to fund activities such as promotional events, special product placement, point-of-purchase signage, retailer activities, event kits, sales associate training, training material, and other marketing activities during the promotional periods.

Customer rewards may include, but are not limited to, retailer gift cards, retailer credit to the customer or free laundry products for the purchase of qualified products. These promotions are available in Idaho and Oregon.

The 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. For example, since 2010 Idaho Power has offered retailer markdowns for low-flow showerheads. Program payments reduce the cost of the showerheads for customers at the retail level, as well as to retailers and manufacturers to drive the manufacture, distribution, and promotion of these products.

Idaho Power also participates in the BPA-sponsored, Simple Steps, Smart Savings energy-efficient lighting program, which is discussed further in the Energy Efficient Lighting program section of this report.

All Simple Steps, Smart Savings promotions are administered by the BPA and coordinated by CLEAResult.

Program Activities

On May 18, 2016, Idaho Power received approval to begin offering the appliance promotion to our customers in Oregon.

Appliances

In 2016, Idaho Power participated in five major Simple Steps, Smart Savings appliance promotions with these retailers: Sears, Sears Hometown, Dell's Home Appliance, Home Depot, and RC Willey. At each event, CLEAResult personnel staffed a table and answered customer questions about the appliance promotion. To further educate customers about the promotions, CLEAResult created an Idaho Power-branded promotional landing page that highlights promotion details and participating retailers.

The five promotions took place on the following dates: 1) the 2015 Black Friday took place in November through the first week of December—because these sales data were delayed, the sales from this promotion will be included with the remaining four 2016 promotions; 2) the President's Day promotion ran for two weeks in February; 3) the Memorial Day promotion ran for the last week in May and first week in June; 4) the Independence Day promotion ran for the last week in June and first two weeks in July; and 5) the Labor Day promotion ran for the last week in August and first week in September. In-store events were held at all participating retailers in Idaho Power's service area during the promotion.

Incentives for the purchase of an ENERGY STAR® clothes washer included a $10 gift card at Sears and Home Depot; a 180-load supply of free laundry detergent at Sears Hometown; a gift of free laundry products at Dell's Home Appliances; and a $25 gift card at RC Willey. RC Willey added their own $15 to the $10 provided to allow them to offer a $25 gift card to customers.

Showerheads

In early 2016, The Home Depot's contract to offer buy downs on qualified showerheads ended. Due to the length of time to prepare monthly reports for these sales, they declined to continue participating in the showerhead buy down. To make up for the decrease in showerhead sales after The Home Depot's departure, CLEAResult engaged Costco and Lowe's to begin offering qualified showerheads to their list of available buy down products.

Marketing Activities

In 2016, CLEAResult and participating Simple Steps, Smart Savings utility partners, decided the marketing was outdated and needed a new, fresh look. Several new designs were presented, and it was decided that the new logo would be Simple + Smart. See Figure 17 to see the updated logo. All table tents and clings used for the 2016 Simple Steps, Smart Savings appliance promotions used the new Simple + Smart logo.

To help support the promotions, table tents and static clings were displayed on all qualifying appliances. These pieces informed customers about the promotion and the incentive they would receive. In-store gift cards were placed in gift card holders that displayed the Idaho Power logo. For purchases from Sears Hometown, where the customer received an instant markdown, customers also received a thank-you card with the Idaho Power logo.

During the promotions, Idaho Power placed Facebook and Twitter posts to notify customers of the details.

Cost-Effectiveness

Idaho Power used the same savings and cost assumptions for showerheads in 2016 as were used in 2015. In 2015 and 2016, RTF reviewed and updated the savings assumptions for showerheads, and Idaho Power will adopt those in 2017. The parameters that impacted the savings for showerheads the most were changes to the baseline showerhead, the showers per person per year, and the annual usage of each showerhead. Due to the timing of RTF's update, BPA and CLEAResult did not implement the new savings in the Simple Steps, Smart Savings promotion in 2016. The new RTF workbook, version 2.4, will be used in 2017.

In 2016, Idaho Power participated in five clothes washer promotions. Idaho Power applied the per-unit savings from the approved BPA's unit energy savings (UES) Measure List. While BPA applies the annual generator busbar savings of 73 kWh per unit, Idaho Power applies the annual site savings of 67 kWh per unit. This difference is due to the different line losses applied by Idaho Power and BPA. For the NEBs, Idaho Power used RTF's clothes washer workbook to determine the water and wastewater savings for the ENERGY STAR clothes washers.

For detailed information for all measures within the Simple Steps, Smart Savings program, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

2017 Program and Marketing Strategies

Idaho Power has committed to participate in the 2017 Simple Steps, Smart Savings appliance promotions. Five promotions are scheduled: 1) February for President's Day, 2) May to June for Memorial Day, 3) July for Independence Day, 4) August to September for Labor Day, and 5) November to December for Black Friday. Current participating retailers are Sears, Sears Hometown, RC Willey, and Dell's Home Appliance.

CLEAResult is in the process of working with local independent retailers to encourage their participation in the program. For each promotion, Idaho Power will provide incentives only for products that meet Idaho Power's cost-effectiveness requirements.

Idaho Power will also continue participation in the Simple Steps, Smart Savings energy-efficient showerheads buy-down program in 2017.

CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, Idaho Power-branded gift card holders, and thank-you cards. When provided, Idaho Power will continue to use Idaho Power-branded promotion landing pages and Facebook posts to notify customers of the promotions.

Weatherization Assistance for Qualified Customers

		2016	2015
Participation and Savings			
	Participants (homes/non-profits)	246	243
	Energy Savings (kWh)	746,162	550,021
	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	$1,289,809	$1,315,032
	Total Program Costs—All Sources	$1,289,809	$1,315,032
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.105	$0.145
	Total Resource Levelized Cost ($/kWh)	$0.158	$0.235
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.73	0.54
	Total Resource Benefit/Cost Ratio	0.65	0.43

Description

The Weatherization Assistance for Qualified Customers (WAQC) program provides financial assistance to regional CAP agencies in Idaho Power's service area. This assistance helps fund weatherization costs of electrically heated homes occupied by qualified customers who have limited incomes. The WAQC program also provides a limited pool of funds for the weatherization of buildings occupied by non-profit organizations serving primarily special-needs populations, regardless of heating source, with priority given to buildings with electric heat. Weatherization improvements enable residents to maintain a more comfortable, safe and energy-efficient home while reducing their monthly electricity consumption. Improvements are available at no cost to qualified customers who own or rent their homes.
These customers also receive educational materials and ideas on using energy wisely in their homes. Local CAP agencies determine participant eligibility according to federal and state guidelines.

In 1989, Idaho Power began offering weatherization assistance in conjunction with the State of Idaho Weatherization Assistance Program (WAP). In Oregon, Idaho Power offers weatherization assistance in conjunction with the State of Oregon WAP. Through the WAQC program, Idaho Power provides supplementary funding to state-designated CAP agencies for additional weatherization of electrically heated homes occupied by qualified customers and buildings occupied by non-profit organizations that serve special-needs populations. This allows CAP agencies to combine Idaho Power funds with federal LIHEAP weatherization funds to serve more customers in electrically heated homes with special needs.

Idaho Power has an agreement with each CAP agency for the WAQC program that specifies the funding allotment, billing requirements, and program guidelines. Currently, Idaho Power oversees the program in Idaho through five regional CAP agencies: Eastern Idaho Community Action Partnership (EICAP), El Ada Community Action Partnership (EL ADA), Aging, Weatherization and Human Services (CCOA, now Metro Community Services), South Central Community Action Partnership (SCCAP), and Southeastern Idaho Community Action Agency (SEICAA). In Oregon, Community Connection of Northeast Oregon, Inc. (CCNO), and Community in Action (CINA) provide weatherization services for qualified customers in Idaho Power's service area.

The Idaho Department of Health and Welfare (IDHW) uses the energy audit program (EA5) for the Idaho WAP and therefore, the Idaho CAP agencies use the EA5. The EA5 is a software program approved for use by the DOE.

Annually, Idaho Power physically verifies approximately 10 percent of the homes that were weatherized under the WAQC program. This is done through two methods. The first method includes the Idaho Power program specialist participating in Idaho's and Oregon's state monitoring process that reviews weatherized homes. The process involves utility representatives; weatherization personnel from the CAP agencies; CAPAI; and a Building Performance Institute (BPI)-certified quality control inspector hired by the state reviewing homes weatherized by each of the CAP agencies.

The second method involves Idaho Power contracting with two companies—The Energy Auditor, Inc. (The Energy Auditor), and Momentum, LLC (Momentum)—that employ certified building performance specialists to verify installed measures in customer homes. The Energy Auditor verifies homes weatherized for the WAQC program in Idaho Power's eastern and southern Idaho regions. The owner of The Energy Auditor is certified by PTCS and is an ENERGY STAR® HPS. Momentum verifies weatherization services provided through the WAQC program in the Capital and Canyon–West regions of Idaho and in the company's Oregon service area. The owner of Momentum is a RESNET® certified home energy rater. After these companies verify installed measures, any required follow-up is done by the CAP agency personnel.

Regulatory Compliance

Idaho Power reports the activities related to the WAQC program in compliance with the IPUC Order No. 29505, as updated in Case No. IPC-E-16-30, Order No. 33702. This order approved Idaho Power's request to modify Order No. 29505 to consolidate the WAQC Annual Report with the DSM Annual Report.

Program Activities

All information previously available in the WAQC Annual Report is available in this section of the DSM Annual Report. In the future, WAQC activities will be reported solely in this manner. This report includes the following topics:

- Review of weatherized homes and non-profit buildings by county
- Review of measures installed
- Overall cost-effectiveness
- Customer education and satisfaction
- Plans for 2017

Weatherized Homes and Non-Profit Buildings by County

In 2016, Idaho Power made $1,250,693 available to Idaho CAP agencies. Of the funds provided, $1,186,192 were paid to Idaho CAP agencies in 2016, while $64,501 were accrued for future funding. Of the funds paid in 2016, $1,055,649 directly funded audits, energy efficiency measures, and health and safety measures for qualified customers' homes (production costs) in Idaho, and $105,565 funded administration costs to Idaho CAP agencies for those homes weatherized.

These funds provided for the weatherization of 231 Idaho homes and 3 Idaho non-profit buildings. The production cost of the non-profit building weatherization measures was $22,707, while $2,271 in administrative costs were paid for the Idaho non-profit building weatherization jobs. In Oregon, Idaho Power paid $29,742 in production costs for 12 qualified homes and $2,974 in CAP agency administrative costs for homes in Malheur and Baker Counties. Table 9 shows each CAP agency, the number of homes weatherized, production costs, the average cost per home, administration payments, and total payments per county made by Idaho Power.

Table 9. 2016 WAQC activities and Idaho Power expenditures by agency and county

Agency	County	Number of Homes	Production Cost	Average Cost[1]	Administration Payment to Agency	Total Payment
Idaho Homes						
CCOA	Adams	1	$ 6,313	$ 6,313	$ 631	$ 6,944
	Boise	1	5,588	5,588	559	6,146
	Canyon	35	170,066	4,859	17,007	187,073
	Gem	4	23,389	5,847	2,339	25,728
	Payette	4	38,345	9,586	3,834	42,179
	Valley	3	24,643	8,214	2,464	27,107
	Washington	1	6,201	6,201	620	6,821
	Agency Total	**49**	**$ 274,545**	**$ 5,603**	**$ 27,454**	**$ 301,999**
EICAP	Lemhi	4	11,625	2,906	1,163	12,788
	Agency Total	**4**	**$ 11,625**	**$ 2,906**	**$ 1,163**	**$ 12,788**
EL ADA	Ada	69	342,706	4,967	34,271	376,977
	Elmore	19	88,319	4,648	8,832	97,151
	Owyhee	17	85,773	5,045	8,577	94,351
	Agency Total	**105**	**$ 516,799**	**$ 4,922**	**$ 51,680**	**$ 568,479**
SCCAP	Blaine	3	6,737	2,246	674	7,411
	Gooding	2	9,302	4,651	930	10,232
	Jerome	8	34,366	4,296	3,437	37,803
	Lincoln	1	7,262	7,262	726	7,988
	Twin Falls	23	90,594	3,939	9,059	99,653
	Agency Total	**37**	**$ 148,261**	**$ 4,007**	**$ 14,826**	**$ 163,087**

Table 9. 2016 WAQC activities and Idaho Power expenditures by agency and county (continued)

Agency	County	Number of Homes	Production Cost	Average Cost[1]	Administration Payment to Agency	Total Payment
Idaho Homes						
SEICAA	Bannock	14	$ 41,254	$ 2,947	$ 4,125	$ 45,380
	Bingham	10	29,394	2,939	2,939	32,333
	Power	12	33,771	2,814	3,377	37,148
	Agency Total	**36**	**$ 104,419**	**$ 2,901**	**$ 10,442**	**$ 114,861**
Total Idaho Homes		**231**	**$ 1,055,649**	**$ 4,570**	**$ 105,565**	**$ 1,161,214**
Non-profit	Ada	1	10,387		1,039	11,426
Buildings	Lemhi	1	9,518		952	10,470
	Twin Falls	1	2,802		280	3,082
Total Non-Profit Buildings		**3**	**$ 22,707**	**$ 7,569**	**$ 2,271**	**$ 24,978**
Total Idaho		**234**	**$ 1,078,356**		**$ 107,836**	**$ 1,186,192**
Oregon Homes						
CCNO	Baker	1	3,831	3,831	383	4,214
	Agency Total	**1**	$ **3,831**	$ **3,831**	$ **383**	$ **4,214**
CINA	Malheur	11	25,911	2,356	2,591	28,503
	Agency Total	**11**	$ **25,911**	$ **2,356**	$ **2,591**	$ **28,503**
Total Oregon Homes		**12**	**$ 29,742**	**$ 2,479**	$ **2,974**	**$ 32,717**
Total Program		**246**	$ **1,108,098**		$ **110,810**	**$ 1,218,908**

Note: Dollars are rounded.

The base funding for Idaho CAP agencies is $1,212,534 annually, which does not include carryover from the previous year. Idaho Power's agreements with CAP agencies include a provision that identifies a maximum annual average cost per home up to a dollar amount specified in the agreement between the CAP agency and Idaho Power. The intent of the maximum annual average cost is to allow CAP agency flexibility to service some homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes. The average cost per home weatherized is calculated by dividing the total annual Idaho Power production cost of homes weatherized by the total number of homes weatherized that the CAP agencies billed to Idaho Power during the year.
The maximum annual average cost per home the CAP agencies were allowed under the 2016 agreement was $6,000. In 2016, Idaho CAP agencies had a combined average cost per home weatherized of $4,570. In Oregon, the average was $2,479 per home weatherized.

There is no maximum annual average cost for the weatherization of buildings occupied by non-profit agencies.

CAP agency administration fees are equal to 10 percent of Idaho Power's per-job production costs. The average administration cost paid to agencies per Idaho home weatherized in 2016 was $457, and the average administration cost paid to Oregon agencies per Oregon home weatherized during the same period was $248. Not included in this report's tables are additional Idaho Power staff labor, marketing, home verification, and support costs for the WAQC program totaling $55,087 for 2016. These expenses were in addition to the WAQC program funding requirements in Idaho specified in IPUC Order No. 29505.

In compliance with IPUC Order No. 29505, WAQC program funds are tracked separately, with unspent funds carried over and made available to Idaho CAP agencies in the following year. In 2016, $38,159 in unspent funds from 2015 were made available for expenditures in Idaho. Table 10 details the funding base and available funds from 2015 and the total amount of 2016 spending. In 2015, the Idaho non-profit-pooled fund overspent by $10,529 which was deducted from the carryover amount to 2016.

Table 10. 2016 WAQC base funding and unspent funds made available

Agency	2016 Base	Available Funds from 2015	Total 2016 Allotment	2016 Spending
Idaho				
CCOA	$ 302,259	$ –	$ 302,259	$ 301,999
EICAP	12,788	–	12,788	12,788
EL ADA	568,479	–	568,479	568,479
SCCAP	167,405	45,430	212,835	163,087
SEICAA	111,603	3,258	114,861	114,861
Non-profit buildings	50,000	(10,529)	39,471	24,978
Idaho Total	**$ 1,212,534**	**$ 38,159**	**$ 1,250,693**	**$ 1,186,192**
Oregon				
CCNO	6,750	12,322	19,072	28,503
CINA	38,250	4,277	42,527	4,214
Oregon Total	**$ 45,000**	**$ 16,599**	**$ 61,599**	**$ 32,717**

Note: Dollars are rounded. Overspending of non-profit pooled fund in 2015 was deducted from 2016 non-profit available fund.

Weatherization Measures Installed

Table 11 details home and non-profit building counts for which Idaho Power paid all or a portion of each measure cost during 2016. The home counts column shows the number of times any percentage of that measure was billed to Idaho Power during the year. If totaled, measure counts would be higher than total homes weatherized because the number of measures installed in each home varies. For example, Table 11 shows 68 homes in Idaho received a lightbulb replacements measure. Each home received more than one lightbulb. Consistent with the Idaho WAP, the WAQC program offers several measures that have costs but do not necessarily save energy, or for which the savings cannot be measured. Included in this category are health and safety measures, vents, furnace repairs, other, 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 home’s existing indoor air quality. Examples of health and safety items are smoke and carbon monoxide detectors, bathroom fans, and dryer vents.

Other non-energy-saving measures are allowed under this program because they interact with the energy-saving measures. Examples of items included in the other measure category include vapor barriers, dryer vent hoods, and necessary electrical upgrades.

Table 11. 2016 WAQC review of measures installed

	Home Counts	Production Costs
Idaho Homes		
Audit	142	$ 14,139
Ceiling Insulation	111	86,188
Doors	93	63,495
Ducts	62	34,794
Floor Insulation	95	100,979
Furnace Repair	16	11,604
Furnace Replace	132	480,421
Health and Safety	45	14,423
Infiltration	143	36,850
Lighting Replacement	68	1,602
Other	37	9,807
Pipes	46	4,625
Refrigerator	8	6,373
Vents	14	912
Wall Insulation	12	5,909
Water Heater	24	23,204
Windows	110	160,324
Total Idaho Homes		**$ 1,055,650**
Oregon Homes		
Ceiling Insulation	7	8,582
Ducts	4	2,437
Floor Insulation	2	5,084
Health and Safety	7	3,251
Infiltration	5	1,605
Pipes	2	105
Vents	1	660
Wall Insulation	2	2,141
Windows	3	5,878
Total Oregon Homes		**$ 29,742**
Idaho Non-Profits		
Audit	3	$513
Ceiling Insulation	1	1,003
Doors	1	575
Ducts	1	988
Floor Insulation	1	3,546
Furnace Repair	1	509
Health and Safety	2	623
Infiltration	2	1,462
Lighting Replacement	2	35

Table 11. 2016 WAQC review of measures installed (continued)

	Home Counts	Production Costs
Idaho Non-Profits		
Other	1	$ 120
Pipes	2	211
Refrigerator	1	10,357
Vents	1	67
Wall Insulation	1	667
Water Heater	1	20
Windows	1	2,013
Total Idaho Non-Profit Measures		**$ 22,707**

Note: Dollars are rounded.

Marketing Activities

Idaho Power provided educational materials to each CAP agency to help qualified customers who receive weatherization assistance learn how to use energy efficiently. Included in the materials were copies of the Idaho Power publications: *Energy Efficiency Guide, Maintenance of Your High-Efficiency Water Fixtures,* and *Energy Saving Tips*, which describe energy conservation tips for the heating and cooling seasons, saving water, and a pamphlet that describes the energy-saving benefits of using CFLs, LEDs, and other tips for choosing the right lightbulb. Idaho Power developed and distributed a brochure that provided information about both the WAQC program and Weatherization Solutions for Eligible Customers program. This was meant to help customers realize there is more than one way to qualify for weatherization services. Idaho Power actively informed customers about WAQC through energy and resource fairs and other customer contacts including communication from its Customer Service Center.

Cost-Effectiveness

The WAQC program, while showing increases in savings and cost-effectiveness ratios, remains not cost-effective. The program had a total UC B/C ratio of 0.73, and a TRC B/C ratio of 0.65.

New savings values were introduced in 2016 that reflect an updated billing analysis completed in 2015. This analysis considered pre- and post-weather normalized consumption in homes weatherized during the 2013-2014 program years from both WAQC and Weatherization Solutions for Eligible Customers programs. The billing analysis was needed to reflect the increased replacement of forced-air electric resistance heat systems with efficient heat pump systems, and to ensure that the proper level of savings was captured for the average home. Variable-based degree-day analysis methods were used, consistent with other regional billing data studies and with whole-house consumption analysis methods published as part of the DOE's Uniform Methods project.

Table 12 shows the updated results that identify the difference between homes that only received weatherization versus homes that were weatherized and upgraded with an efficient heat pump.

Table 12. 2016 savings values for WAQC program

	Weatherization only		Weatherization and heating system change	
Home Type	kWh/project	kWh/project/ft^2	kWh/project	kWh/project/ft^2
Single-family Homes	1,797	1.16	4,154	2.48
Manufactured Homes	1,734	1.36	4,418	4.30
Multi-family Homes	n/a	1.16	n/a	2.48
Non-profit Buildings	n/a	1.16	n/a	2.48

Table 12 also shows, as expected, weatherization combined with the installation of an efficient heat pump results in savings nearly twice that from just installing weatherization measures. Manufactured homes demonstrate a higher savings per square foot of weatherized space than single-family homes in both projects where only weatherization measures were installed and cases where heating system upgrades occurred.

Idaho Power used savings of 1.16 kWh/ft^2 of weatherized heated space for multi-family projects where only weatherization measures were installed and 2.48 kWh/ft^2 where heating system were changed. In 2016 and previous program years, there has been insufficient data from multi-family projects in both the WAQC and Weatherization Solutions for Eligible Customers programs to conduct a billing analysis so savings are assumed to be similar on a savings per square foot basis as single-family homes where like measures were installed.

Idaho Power used savings of 1.16 kWh/ft^2 of weatherized heated space for non-profit projects where only weatherization measures were installed, which is the average per square foot savings values for weatherized single-family homes from the updated billing analysis. It is not feasible at this time to conduct a post-weatherization billing analysis or to create a commercial whole building simulation model prior to weatherization for non-profit projects.

The initial phase for assessing cost-effectiveness occurs during the initial contacts between CAP agency weatherization staff and the customer. In customer homes, the agency weatherization auditor uses the EA5 to conduct the initial audit of potential energy savings for a home. The EA5 compares the efficiency of the home prior to weatherization to the efficiency after the proposed improvements and calculates the value of the efficiency change into a savings-to-investment ratio (SIR). The output of the SIR is similar to the PCT ratio. If the EA5 computes an SIR of 1.0 or higher, the CAP agency is authorized to complete the proposed measures. The weatherization manager can split individual measure costs between Idaho Power and other funding sources with a maximum charge of 85 percent of total production costs to Idaho Power. Using the audit form to pre-screen projects ensures that each weatherization project will result in energy savings. The use of the audit tool is one of the primary reasons that consistent results have been seen from recent billing analysis of weatherization projects.

The following recommendations from the IPUC Order No. 32788 were used for the 2016 cost-effectiveness analysis:

- Applying a 100-percent net-to-gross (NTG) value to reflect the likelihood that WAQC weatherization projects would not be initiated without the presence of a program
- Claiming 100 percent of project savings
- Including an allocated portion of the indirect overhead costs
- Applying the 10-percent conservation preference adder
- Claiming $1 of benefits for each dollar invested in health, safety, and repair measures
- Amortizing evaluation expenses over a three-year period

Customer Satisfaction and Evaluations

Idaho Power used independent, third-party verification companies to ensure the stated measures were installed in the homes, and to discuss the program with these customers. In 2016, home verifiers visited 36 homes, requesting feedback about the program. When asked how much customers learned about saving electricity, 30 customers answered they learned “a lot” or “some.” When asked how many ways they tried to save electricity, 31 customers responded “a lot” or “some.”

A customer survey was used to assess major indicators of customer satisfaction throughout the service area. The *2016 Weatherization Programs Customer Survey* was provided to all program participants in all regions upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely.

Idaho Power received survey results from 238 of 243 households weatherized by the program in 2016. Of the 238 completed surveys, 227 were from Idaho customers and 11 were from Oregon customers. Some highlights include the following:

- Over 37 percent of respondents learned of the program from a friend or relative, and another almost 23 percent learned of the program from an agency flyer. Nearly 8 percent learned about the weatherization program from direct-mail.
- Over 84 percent of the respondents reported that their primary reason for participating in the weatherization program was to reduce utility bills, and over 39 percent wanted to improve the comfort of their home.
- Over 73 percent reported they learned how air leaks affect energy usage, and just over 67 percent indicated they learned how insulation affects energy usage during the weatherization process.
- Over 56 percent of respondents said they learned how to use energy wisely. Seventy-five percent reported they were very likely to change habits to save energy, and almost 66 percent reported they have shared all of the information about energy use with members of their household.

- Over 87 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost 94 percent said they were very satisfied with the program.
- Almost 86 percent of the respondents reported the habit they were most likely to change was turning off lights when not in use, and 61 percent said that washing full loads of clothes was a habit they were likely to adopt to save energy. Turning the thermostat up in the summer was reported by over 53 percent of the respondents, and turning the thermostat down in the winter was reported by 65 percent as a habit they and members of the household were most likely to adopt to save energy.

A summary of the report is included in the *Supplement 2: Evaluation*.

2017 Program and Marketing Strategies

As in previous years, unless directed otherwise, Idaho Power will continue to provide financial assistance to CAP agencies while exploring changes to improve program delivery. The company will continue to provide the most benefit possible to special-needs customers while working with Idaho and Oregon WAP personnel.

Idaho Power will continue to participate in the Idaho and Oregon state monitoring process of weatherized homes and will continue to verify approximately 10 percent of the homes weatherized under the WAQC program via certified home-verification companies.

In 2017, Idaho Power will support the whole-house philosophy of the WAQC program and Idaho and Oregon WAP by continuing to allow a $6,000 annual maximum average per-home cost. Based on the required funding, Idaho Power estimates approximately 182 homes and four non-profit buildings in Idaho will be weatherized, and approximately 11 homes in Oregon will be weatherized in 2017.

In Idaho during 2017, Idaho Power expects to contribute the base amount plus available funds from 2016 to total approximately $1,350,000 in weatherization measures and agency administration fees. Of this amount, approximately $64,490 will be provided to the non-profit pooled fund to weatherize buildings housing non-profit agencies that primarily serve qualified customers in Idaho.

Weatherization Solutions for Eligible Customers

		2016	2015
Participation and Savings			
	Participants (homes)	232	171
	Energy Savings (kWh)	621,653	432,958
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,226,540	$1,204,147
	Oregon Energy Efficiency Rider	$56,571*	$0
	Idaho Power Funds	$40,681	$39,122
	Total Program Costs—All Sources	$1,323,793	$1,243,269
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.130	$0.175
	Total Resource Levelized Cost ($/kWh)	$0.130	$0.175
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	0.59	0.45
	Total Resource Benefit/Cost Ratio	0.70	0.50

* Oregon Rider charges were reversed and charged to the Idaho Rider in February 2017.

Description

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers in Idaho whose income falls between 175 percent and 250 percent of the most current federal poverty level. Initiated in 2008, the program is designed to mirror the WAQC program. These customers often do not have disposable income to participate in other residential energy efficiency programs, and they typically live in similar housing as WAQC customers.

Potential participants are interviewed by a contractor to determine household occupant income eligibility, as well as to confirm the home is electrically heated. If the home is a rental, the landlord must agree to maintain the unit's current rent for a minimum of one year, and to help fund a portion of the cost of weatherization. If the customer is eligible, an auditor inspects the home to determine which upgrades will save energy, improve indoor air quality, and/or provide health and safety for the residents. To be approved, energy efficiency measures and repairs must have a SIR of 1.0 or higher, interact with an energy-saving measure, or be necessary for the health and safety of the occupants.

The Weatherization Solutions for Eligible Customers program uses a home audit tool called the HAT14.1 which is similar to the EA5 audit tool used in WAQC. The home is audited for energy efficiency measures and the auditor proposes upgrades based on the SIR ratio calculated by HAT14.1. As in WAQC, if the SIR is 1.0 or greater, the contractor is authorized to upgrade that measure. Measures considered for improvement are window and door replacement, ceiling, floor and wall insulation, HVAC repair and replacement, water heater repair and replacement and pipe wrap. Also included is the potential to replace lightbulbs and refrigerators. Contractors invoice Idaho Power for the project costs and if the home is a rental, a minimum landlord payment of 10 percent of the cost is required.

Idaho Power's agreement with contractors includes a provision that identifies a maximum annual average cost per home for the program. The intent of the maximum annual average cost is to allow Contractors the flexibility to service homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes.

Program Activities

In 2016, a new contractor provided weatherization services to customers residing in Lemhi County, Idaho. Energy Solutions weatherized two homes in 2016 for the program with an average of approximately $4,125 each. With the addition of this new contractor, Idaho Power offers the Weatherization Solutions for Eligible Customers in all of its Idaho service area.

In 2016, the five contractors weatherized 232 Idaho homes for the program. In eastern Idaho, contractors Savings Around Power and Energy Solutions weatherized 26 homes. In Idaho Power's Canyon–West Region, Metro Contractors weatherized 56 homes. HEM-LLC weatherized 36 homes in south central Idaho, and Power Savers weatherized 114 homes in the Capital Region. Of those 232 homes weatherized, 148 were single-family and manufactured homes and 84 were low income multi-family apartments where LEDs, showerheads, kitchen and bath sink aerators, indoor clotheslines, and smoke detectors were installed.

Marketing Activities

Marketing was adjusted in 2016 to reach more customers who live in electrically heated homes and income-eligible households to increase participation in the program. Inserts were included in 263,625 residential bills in February and 367,222 bills in October. The program was promoted throughout the year at seasonal, resource, and conservation fairs, as well as at other events targeting people with limited incomes, including seniors. Ads and articles promoted the program in the *Seniors BlueBook*, *Healthy Idaho Magazine*, *Idaho Senior News*, and the *Idaho State Journal* boomers' edition. The program was also mentioned in Idaho Power's winter *Energy Efficiency Guide*.

Idaho Power's community relations representatives and customer representatives promoted the program at meetings in their communities, with specific emphasis on smaller Idaho communities. The program specialist and customer representatives promoted the program to home healthcare provider groups, religious groups, and members of the Idaho Nonprofit Center. Customer representatives used updated brochures (in English and Spanish) that included current income qualifications and location-specific contractor information. New contractor door hangers and flyers were also created so the program could be promoted by canvassing specific neighborhoods. Weatherization tips were also mentioned in various social media postings.

Cost-Effectiveness

While showing increases in savings and cost-effectiveness ratios from updated billing analysis and the addition of cost-effective direct-install options, the WAQC program remains not cost-effective. The 2016 program total UC B/C ratio is 0.59, and a TRC B/C ratio is 0.70. New savings values were introduced for 2016 that reflect an updated billing analysis completed in 2015 that analyzed pre- and post-weather normalized consumption in homes weatherized during the 2013-2014 program years from both WAQC and Weatherization Solutions for Eligible Customers. The WAQC program section in this report offers a discussion of the billing analysis changes from previous versions.

Table 13 shows the updated savings results that identify the difference between homes that only received weatherization versus homes that were weatherized and upgraded with an efficient heat pump.

Table 13. 2016 savings values for Weatherization Solutions for Eligible Customers program

	Weatherization		Weatherization and heating system change	
Home Type	**kWh/project**	**kWh/project/ft²**	**kWh/project**	**kWh/project/ft²**
Single-family Homes	1,453	0.83	6,321	3.47
Manufactured Homes	897	0.39	5,355	4.50
Multi-family Homes	n/a	0.83	n/a	3.47

Similar to billing analysis results for WAQC, weatherization combined with the installation of an efficient heat pump results in savings nearly twice that from just installing weatherization measures. Manufactured homes demonstrate a higher savings per square foot of weatherized space than single family homes in cases where both weatherization and heating system upgrades occurred.

Idaho Power used savings of .83 kWh/ft^2 of weatherized heated space for multi-family projects where only weatherization measures were installed and 3.47 kwh/ft^2 where heating system where changed. Prior to 2015, insufficient data from multi-family projects existed to conduct a billing analysis so savings are assumed to be similar on a savings per square foot basis as single-family homes where like measures were installed.

Weatherization Solutions for Eligible Customers projects, similar to WAQC program guidelines, benefit from a pre-screening of measures through a home audit process. The home audit process ensures that there is an adequate number of kWh savings to justify the project and provides more consistent savings for billing analysis. See WAQC cost-effectiveness for a discussion of the audit and prescreening process which are similar for both programs.

For further details on the overall program cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

A 2016 customer survey was provided to all program participants upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, the amount of information customers learned about saving energy in their homes, and the likelihood that household members would change their behavior to use energy wisely. Additionally, demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 130 of the 232 households weatherized by the program in 2016. Some key highlights include the following:

- Almost 27 percent of respondents learned of the program through a letter in the mail and another 22 percent learned of the program from a friend or relative.
- Over 86 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills.
- Almost 80 percent indicated they learned how insulation affects energy usage during the weatherization process, and over 85 percent reported they learned how air leaks affect energy usage. Another almost 60 percent of respondents said they learned how to use energy wisely.
- Over 79 percent reported they were very likely to change habits to save energy, and over 71 percent reported they have shared all of the information about energy use with members of their household.
- Almost 91 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 92 percent said they were very satisfied with the program.

A summary of the report is included in *Supplement 2: Evaluation*.

Two independent companies performed random verifications of weatherized homes and visited with customers about the program. In 2016, 35 homes were verified, and 23 (66 percent), of those customers reported they learned "a lot" or "some" about saving electricity in their home. Another 33 customers (95 percent) reported they had tried "a lot" or "some" ways to save energy in their home.

2017 Program and Marketing Strategies

Idaho Power will update brochures to help spread the word about the program in all communities. Additional marketing for the program will include bill inserts and advertisements in *Healthy Idaho Magazine*, *Seniors BlueBook*, *Idaho Senior News*, and *Idaho State Journal* boomers, edition.
Idaho Power will send a direct-mail letter to targeted residential customers mid-year, and use social media in an effort to reach a more customers. Customer testimonials will be posted online, and the door hangers produced late in 2016 will continue to be used when canvassing neighborhoods.

Commercial/Industrial Sector Overview

Idaho Power's commercial sector consists of over 69,341 customers. In 2016, the commercial sector's number of customers increased by 830, an increase of a little over 1 percent from 2015. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 28 percent of Idaho Power's actual total electricity sales.

The industrial and special contracts customers are Idaho Power's largest individual energy consumers. There are 121 Rate 19 and special contract industrial customers. These customers account for approximately 23 percent of Idaho Power's total electricity sales.

In June 2016, the three Commercial and Industrial Energy Efficiency programs were combined into a single program. Previously, the programs were: Building Efficiency, Custom Efficiency, and Easy Upgrades. The measure offerings to the customers remained relatively unchanged with prescriptive measures for new construction and major renovations, custom incentives for complex projects, and prescriptive measures for simple retrofits. The programs were combined with the intention to clarify program offerings and to improve marketing to customers. The combined program continues to be successful, with a reported overall savings of 88,161 MWh on 1,903 projects.

The 2016 season was the second year of the internally managed Flex Peak Program. The results were greatly improved from 2015 as was participation, including 65 participants enrolled with 137 sites in the program. Of those 137 sites, 67 were new—a 90 percent increase over 2015. Idaho Power also offers the statutory-required Oregon Commercial Audits program to medium and small commercial customers. The program identifies opportunities for commercial building owners to achieve energy savings.

Table 14. 2016 commercial/industrial program summary

		Total Cost		Savings	
Program	**Participants**	**Utility**	**Resource**	**Energy (kWh)**	**Demand (MW)**
Demand Response					
Flex Peak Program	137 sites	$ 767,997	$ 767,997	n/a	42
Total		**$ 767,997**	**$ 767,997**		**42**
Energy Efficiency					
Custom Projects (Custom Efficiency)	196 projects	$ 7,982,624	$ 16,123,619	47,518,871	
Green Motors—Industrial	14 projects			123,700	
New Construction (Building Efficiency)	116 projects	1,931,222	4,560,826	12,393,249	
Oregon Commercial Audits	7 audits	7,717	7,717	n/a	
Retrofits (Easy Upgrades)	1,577 projects	5,040,190	8,038,791	28,124,779	
Total		**$ 14,961,753**	**$ 28,730,952**	**88,160,599**	**42**

Note: See Appendix 3 for notes on methodology and column definitions.

Customer Satisfaction and Evaluations

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. Sixty-five percent of Idaho Power's large commercial and industrial customers surveyed in 2016 for the Burke Customer Relationship Survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Sixty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Seventy-four percent of respondents indicated Idaho Power was meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 78 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 customers surveyed and who had participated in at least one Idaho Power energy efficiency program, 98 percent are "very" or "somewhat" satisfied with the program. In 2016, offering energy efficiency programs was one of the large commercial and industrial top five attributes with a positive change in the Burke Customer Relationship Survey.

The results from surveying Idaho Power's small business customers indicated 51 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-four percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty-three percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 39 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, 92 percent are "very" or "somewhat" satisfied with the program.

Forty-one percent of the Idaho Power business customers included in the *2016 J. D. Power and Associates Electric Utility Business Customer Satisfaction Study* indicated they are familiar with Idaho Power's energy efficiency programs.

Training and Education

Technical training and education continue to be important in helping Idaho Power commercial and industrial customers identify where they may have energy efficiency opportunities within their facilities. These activities increase awareness and participation in existing commercial and industrial energy efficiency and demand response programs, and enhance customer satisfaction regarding the company's energy efficiency activities.

Educating commercial and industrial customers requires working with and supporting multiple stakeholders and organizations. Examples of key stakeholders include the Integrated Design Lab (IDL), BOMA, USGBC, ASHRAE, and International Building Operators Association (IBOA). Through funding provided by Idaho Power, the IDL performed several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities included sponsoring a Building Simulation Users Group (BSUG), conducting Lunch & Learn sessions held at various design and engineering firms, and offering a Tool Loan Library (TLL).

Idaho Power also used two newsletters to educate and inform our customers about energy efficiency. *Energy at Work*, which is new in 2016, was mailed to commercial and industrial customers twice in

2016; the major customer representatives emailed *Energy Insights* to 400 of Idaho Power's largest industrial customers each quarter.

Idaho Power delivered eight technical classroom-based training sessions in 2016. Of the eight sessions, one was a two-day class, and the others were one-day classes. Topics included industrial refrigeration, energy auditing, an introduction to unitary A/C, advanced unitary A/C, pump systems, motors, variable speed drives, and commercial refrigeration. A schedule of training events is posted on Idaho Power's website and marketed through *Energy at Work* and *Energy Insights*. Commercial and Industrial Energy Efficiency personnel or the major customer representatives also give an overview of the commercial and industrial programs during each technical training session offered to commercial and industrial customers.

The level of participation in 2016 remained high, with 217 attendees. Customer feedback indicated the average satisfaction level was 94 percent.

Idaho Power's average cost to deliver trainings in 2016 was approximately $5,300 per class. For NEEA's 2015 to 2019 funding period, Idaho Power chose not to participate in NEEAs industrial trainings. Prior to the current funding period from 2010 to 2014, NEEA offered an average of nine trainings per year at an approximate cost of $22,000 per class. By Idaho Power providing these trainings directly to Idaho Power customers, the company has realized significant cost reduction for its customers.

Idaho Power posted prior years' webinar recordings and related PDFs on the commercial and industrial training page on the Idaho Power website. Also, on Idaho Power's industrial training page is a listing of all IBOA events. Idaho Power covered at least 50 percent of cost for Idaho Power customers to take part in their educational classes including the Building Operator Certification Level 1, consisting of eight day-long classes, and Level 2, consisting of seven day-long classes. In 2016, 42 customers attended the Level 1 classes, and eight attended the Level 2 classes.

Field Staff Activities

Idaho Power field staff are on-site with customers each day. The field staff uses a variety of Idaho Power-developed programs, tools, and services to help customers with their energy-related questions and challenges. The customer representatives and major customer representatives have specific goals related to proactive activities, such as a specific number of visits or projects, designed to engage commercial and industrial customers in the energy efficiency. Additionally, program specialists and engineers work closely with customer representatives and major customer representatives to use their established relationships with customers. Customer representatives and major customer representatives distribute informational materials to trade allies and other market participants who, in turn, support and promote Idaho Power's energy efficiency programs.

Customers regularly ask how to get the most out of their energy dollar. Idaho Power staff has been trained to properly advise customers in the wise use of energy-specific energy efficiency measures and, when needed, can recommend where to find answers. Idaho Power is equipped with experienced engineers, technically proficient personnel, and an extensive network of nationally recognized organizations and energy efficiency clearing houses to handle energy-related questions.

Commercial and Industrial Energy Efficiency Program

		2016*	2015*
Participation and Savings			
	Participants (projects)	1,903	1,463
	Energy Savings (kWh)**	88,160,599	102,073,910
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$14,319,999	$14,629,149
	Oregon Energy Efficiency Rider	$508,538	$798,424
	Idaho Power Funds	$125,500	$97,921
	Total Program Costs—All Sources	$14,954,036	$15,525,494
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$0.014	$0.014
	Total Resource Levelized Cost ($/kWh)	$0.026	$0.031
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.67	4.48
	Total Resource Benefit/Cost Ratio	2.81	2.13

*Metrics for each option (New Construction, Custom Projects, and Retrofits) are reported separately in appendices and in *Supplement 1: Cost-Effectiveness.*

***2016 total includes 123,700 kWh of energy savings from 14 Green Motors projects.*

Description

Three major program options targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas.

Custom Projects (Custom Efficiency)

The Custom Projects option incentivizes energy efficiency modifications for new and existing facilities. The goal is to encourage commercial and industrial energy savings in Idaho and Oregon service areas by helping customers implement energy efficiency upgrades. Incentives reduce customers' payback periods for customize modifications that might not be completed otherwise. The Custom Projects option offers an incentive level 70 percent of the project cost or 18 cents per kWh for first year estimated savings, whichever is less. The Custom Projects option also offers energy auditing services to help identify and evaluate potential energy saving modifications or projects.

Interested customers submit applications to Idaho Power for potential modifications that have been identified by the customers, Idaho Power, or by a third-party consultant. Idaho Power reviews each application and works with the customer and vendors to gather sufficient information to support the energy-savings calculations.

Once completed, customers submit a payment application; in some cases, large, complex projects may take as long as two years to complete. Every payment application is verified by Idaho Power staff or an Idaho Power contractor. All lighting modifications utilize the Idaho Power lighting tool to determine incentive.

Each project is reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant verifies the energy savings methods and calculations. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, especially the 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 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.

New Construction (Building Efficiency)

The New Construction option enables customers in Idaho Power's Idaho and Oregon service areas to apply energy-efficient design features and technologies in new commercial or industrial construction, expansion, or major remodeling projects. New construction and major renovation project design and construction life is much longer than small retrofits and often encompasses multiple calendar years. Originated in 2004, the program currently offers a menu of measures and incentives for efficient lighting, cooling, building shell, controls, appliances, and refrigeration options. These measures may otherwise be lost opportunities for savings on customers' projects.

Twenty-four prescriptive measures are offered: interior lighting, exterior lighting, daylight photo controls, occupancy sensors, high-efficiency exit signs, efficient A/C and heat pump units, efficient variable refrigerant flow units, efficient chillers, air-side economizers, direct evaporative coolers, evaporative pre-coolers on air-cooled condensers, reflective roof treatment, energy-management control systems, guest room energy-management systems, HVAC variable-speed drives, kitchen hood variable-speed drives, onion/potato shed ventilation variable-speed drives, efficient laundry machines, ENERGY STAR® under-counter dishwashers, ENERGY STAR commercial dishwashers, refrigeration head-pressure controls, refrigeration floating-suction controls, efficient condensers, and smart power strips.

Retrofits (Easy Upgrades)

The Retrofits option is Idaho Power's prescriptive measure option for existing commercial and industrial facilities. This part of the program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency upgrades by offering incentives on a defined list of measures. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, variable-frequency drives (VFD), food-service equipment, and other commercial measures. Customers can also apply non-standard lighting incentives. A complete list of the measures offered through Retrofits (Easy Upgrades) is included in *Supplement 1: Cost-Effectiveness*.

Program Activities

Custom Projects

Incentive levels for the non-lighting projects remained the same in 2016 at 18 cents per kWh of first year savings with a 70-percent project cost cap on the incentive.

The Custom Projects option had another very successful year with a total of 196 projects, including 11 in Oregon, completed by 103 customers. However, related energy savings decreased in 2016 by 14 percent over 2015, from 55,186 MWh to 47,519 MWh. Idaho Power also received 248 new applications representing a potential of 61,240 MWh of savings on future projects.

Idaho Power made the following tariff changes in 2016: The required 100,000 kWh minimum savings was removed to allow for projects that may not meet that threshold to receive a Custom Projects incentive, such as Streamlined Custom Efficiency (SCE). The three-year term requirement was removed for the self-direct projects, which eliminates the need to file for tariff changes for every new three-year term.

Custom Projects may reach some level of saturation through program maturity, over 95 percent of the large-power service customers have participated in the program. With the high percentage of industrial customers who have taken advantage of the program, deeper energy savings may be challenging to achieve. The company is addressing this ongoing challenge in several ways by continuing to use multiple channels to reach customers and to encourage new energy-saving modifications. The company has expanded the cohort offerings, SCE, and expanded its ability to conduct energy audits through an expanded list of engineering firms.

Table 15 indicates the program's 2016 annual energy savings by primary project measures.

Table 15. 2016 Custom Projects annual energy savings by primary project measure

Program Summary by Measure	Number of Projects	kWh Saved
Lighting	117	9,386,277
Refrigeration	11	23,681,463
HVAC	6	4,839,312
Compressed Air	18	2,726,482
Commissioning	7	2,739,491
Controls	1	224,756
Pump	3	708,555
VFD	32	3,158,906
Other	1	53,629
Total [a]	196	47,518,871

[a] Does not include Green Motor Initiative project counts and savings.

Facility energy auditing, customer technical training, and education services are key components used to encourage customers to consider energy efficiency modifications. The Municipal Water Supply Optimization Cohort (MWSOC) and Wastewater Energy Efficiency Cohort (WWEEC) program offerings are also driving a significant number of new projects in addition to increasing vendor engagement from the SCE offering. The 2016 activities in the key components are described below.

Facility Energy Auditing

Idaho Power funds the cost of engineering services, up to $3,500, for conducting energy scoping audits to encourage its larger customers to adopt energy efficiency improvements. Currently, there are 11 different firms on contract to provide scoping audits and general energy efficiency engineering support services.

In 2016, Idaho Power consultants completed 25 scoping audits and two detailed audits on behalf of Idaho Power customers. These audits identified over 20,000 MWh of savings potential. Most of the customers engaged in these audits used the information to move forward with projects or expressed interest in moving forward in the near future.

Program Education and Offerings

Custom Projects engineers and the major customer representatives set up numerous visits with the large commercial and industrial customers in 2016. The visits ranged from commercial/industrial efficiency program training to a comprehensive targeted technical training sessions for a larger audience on potential energy-saving opportunities for different measure types, such as refrigeration, pumps and fans, compressed air, HVAC, lighting, etc. In addition to the eight comprehensive targeted technical training sessions that were held by Idaho Power, Custom Projects engineers also gave presentations on Idaho Power programs and offerings at a multi-industrial customer program training sessions, such as the Northwest Chapter of American Association of Airport Executives Airfield and Facilities Management Conference, the International Society of Healthcare Engineers (ISHE) Conference, the Energy Community Partnership Workshop facilitated by Mountain Home Air Force Base, and the Idaho Green Building and Energy Conference. In 2016, Custom Projects continued three offerings to increase the total program savings—WWEEC, MWSOC, and SCE. A new, fourth offering launched in November 2016—Continuous Energy Improvement (CEI) Cohort for Schools.

Wastewater Energy Efficiency Cohort

In January 2014, Custom Projects launched WWEEC, its third program offering since 2013, to increase the total program savings. WWEEC is a cohort training approach to low-cost or no-cost energy improvements. WWEEC is a two-year engagement with 11 Idaho Power service area municipalities and ended in 2016. WWEEC provided a series of five technical training workshops with a cohort training approach. In addition, WWEEC provided energy audits in conjunction with a qualified wastewater system expert and an energy management assessment conducted by a strategic energy management professional for each participating facility. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as turning off equipment or adjusting control points for systems. They also implemented many energy management principles, including forming an energy team, setting energy goals, and establishing energy policies in their organization for persistence of savings. Energy savings were tracked via Idaho Power-provided, third-party software using an energy model for each facility. WWEEC participants also completed several capital projects that received separate incentives from our Commercial and Industrial Energy Efficiency Program. Additionally, multiple pre-planning meetings were held with consultants and municipalities for upcoming new wastewater construction projects.

Due to involvement with our WWEEC, Custom Projects engineers also set up multiple program informational meetings with the area civil engineering firms specializing in water and wastewater designs to educate them on the Commercial and Industrial Energy Efficiency Program, audit process, energy efficiency opportunities, and available tools and resources. Presentations on Idaho Power offerings were given at a multi-industrial customer program training session in Boise, the annual Southwest Idaho Operators Section (SWIOS) Conference, the national annual Water Environment Federation Technical Exhibition and Conference (WEFTEC) in New Orleans, and Idaho Power had a booth at the Pacific Northwest Section American Water Works Association (PNWS-AWWA) regional conference.

Year-one incentives and savings totaled $57,559 and 2,561,177 kWh/year. In all cases, the incentive was capped at 70 percent of the eligible costs. Year-one incentives and savings were processed in 2016. Additionally, some WWEEC participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These capital projects' savings are captured separately and not included in the above number. Year-two of the offering consisted of phone call check-ins with the participants and model data updates. Year-two incentives and savings will be processed in 2017.

Municipal Water Supply Optimization Cohort

In September 2015, Idaho Power held a recruiting/training session for municipal water supply operators and public works personnel garnering interest in a third Strategic Energy Management cohort—the MWSOC, similar to WWEEC but for clean water operators. The program officially launched in January 2016. The goal of the cohort is to equip water professionals with the skills necessary to identify and implement energy efficiency opportunities on their own, and to ensure that these energy and cost savings are maintained long term.

A series of three workshops were held in the Twin Falls area with representatives from the 15 participating organizations. Sessions included technical training, hands-on learning exercises to demonstrate simple low-cost and no-cost actions to diagnose problems and save energy, and peer-to-peer sharing of lessons learned as the classes progressed. MWSOC provided energy audits of the participants' facilities. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as changing pressure regulating valve (PRV) settings or well level adjustments. Participants had engineering support between each workshop, facilitated by an expert team of energy engineers with specific experience in optimizing water supply systems. Participants all received tools, such as a baseline hydraulic model (updated and modernized with the energy modules loaded), a mass balance for water, and an energy map showing locations of stored and lost energy, as well as the energy footprint of the various pumps within each system. A top down baseline energy model was constructed for each participant that uses electric data normalized for system operating data and weather. The baseline energy model will be used in conjunction with on-going actual energy, production and weather data to determine the energy savings for the offering.

Continuous Energy Improvement Cohort for Schools

In November 2016, Idaho Power held a recruiting/training session for school district personnel garnering interest in this cohort. Representatives from 19 school districts attended. The session introduced the upcoming cohort whose goal is to equip district personnel with hands-on training and guidance to help get the most out of their systems while reducing energy consumption. Idaho Power and the company's consultants gave an overview what Continuous Energy Improvement is and how numerous low-cost or no-cost measures can be uncovered in schools. By 2016 year-end, 9 school districts have signed up for the cohort. The Cohort for Schools Kickoff Workshop is scheduled for late January 2017, in Boise with a final Report-out Workshop to be scheduled in December 2017. Energy savings for this offering are tracked with multi-variant regression models that are custom-built for each participating facility and based on historical utility data and current operations.

Streamlined Custom Efficiency

The SCE offering was initially started in 2013 and continues to keep vendor engagement high and provides custom incentives for small compressed air system improvements, fast-acting doors in cold-storage spaces, refrigeration controllers for walk-in coolers, and process-related VFDs. This offering targets projects that may have typically been too small to participate in the Custom Projects due to the resources required to adequately determine measure savings. Idaho Power contracted with a third party to manage SCE data collection and analysis for each project. In 2016, the SCE offering processed 42 projects, totaling 2,837,200 kWh per year of savings and $399,523 in incentives paid.

New Construction

The New Construction option completed 116 projects, the largest total number of projects completed in a calendar year, resulting in 12,393,249 kWh in annual energy savings in Idaho and Oregon. The total number of projects increased by over 43 percent from 81 projects in 2015.

Maintaining a consistent offering is important for large projects with long construction periods, though changes are made to enhance customers' options or to meet new code changes. Idaho Power ideally tries to keep the New Construction option consistent by making less frequent changes, approximately every other year. The option was modified in mid-2016 to include the addition of four new measures; evaporative pre-coolers on air-cooled condensers, kitchen hood variable-speed drives, onion/potato shed ventilation variable-speed drives, and smart-strip power strips.

Idaho Power contracted with ADM in 2015 to update the Technical Reference Manual (TRM) to address code changes that occurred January 1, 2015 in Idaho. The revised TRM provided updated savings for existing measures and savings for new measures that were added to the program. Minor modifications were also made to several existing measures to update requirements based on the code changes.

Thirty projects received the Professional Assistance Incentive, an incentive given to architects and/or engineers for supporting technical aspects and documentation of the project, in 2016 (equal to 10 percent of the participant's total incentive, up to a maximum amount of $2,500) compared to nine projects in 2015.

In 2016, Idaho Power continued its contract with GreenSteps to target the commercial real estate industry by continuing to support the Kilowatt Crackdown™ competition past participants. The original competition, which included benchmarking each building in ENERGY STAR® Portfolio Manager, encouraged builders to implement low-cost and no-cost efficiency measures. Idaho Power also expanded engagement with participants through Strategic Energy Management (SEM). GreenSteps worked with 26 buildings in Boise and Ketchum, and six property management firms. A summary of the report is located in *Supplement 2: Evaluations.*

Idaho Power customer representatives visited 20 architectural and engineering firms in Boise, Meridian, Nampa, Hailey, Ketchum, Twin Falls, and Pocatello in 2016. Customer representatives visited with 100 professionals total to build relationships with the local design community, and to discuss Idaho Power's commercial and industrial energy efficiency programs.

Retrofits

The Retrofits option experienced increases in participation and energy savings in 2016. Some of the increase was attributed to the mid-June program change to adjust the screw-in LED incentive. The option received a noticeable number of projects with screw-in LED product before that change became effective. This also resulted in increased energy savings. Overall, Retrofits received more LED-only projects, which had a significant contribution to energy savings.

Several measure changes were implemented mid-year. The most notable changes were to adjust the screw-in LED incentive, to add the tube LEDs (TLED), and to add seven non-lighting measures to the incentive menu.

For the Retrofits option, Idaho Power facilitated eight workshops across the Idaho Power service area targeting contractors and large customers. The purpose of the workshops was to review option updates with market participants.

Idaho Power staff and contractors contacted over 195 trade allies to respond to inquiries, strengthen relationships, encourage participation, increase knowledge of the incentives, and receive feedback about the market, and individual experiences. This targeted outreach was to electrical contractors, electrical distributors, HVAC contractors, and food service equipment suppliers.

Idaho Power continued its contracts with Evergreen Consulting Group, LLC, Honeywell, Inc., and RM Energy Consulting to provide ongoing program support for lighting and non-lighting reviews and inspections as well as trade ally outreach.

Marketing Activities

Most marketing activities engaged in for the Commercial and Industrial Energy Efficiency Program can be found in the Marketing section of this report. Below are the 2016 activities specific to the option within the overall program.

Custom Projects

Idaho Power's Custom Projects option is unique from the company's other energy efficiency options by providing individualized energy efficiency solutions to a somewhat limited number of customers. Idaho Power's major customer representatives often act as the company's sales force. Marketing supports the major customer representatives by providing written program materials to help them inform customers of the measures and benefits available to them. Idaho Power presented the Simplot Don Plant in Pocatello an incentive check for $197,335 toward energy efficiency upgrades to a pumping project.

New Construction

Idaho Power placed ads in the Idaho Association of General Contractors membership directory specific to the New Construction option. The New Construction brochure was also updated to include a list of current measures and provided to customers planning new construction and major renovation projects. Idaho Power alerted the media to its presentation of a cash incentive to Vallivue School District 139. During a board meeting, the School District accepted a check for more than $193,000 it had earned for adopting energy-efficient construction measures at two schools in Caldwell, Idaho.

Retrofits

Ads thanking contractors for their participation ran in numerous papers in December 2015, and continued in the *Business Insider*, *Southeast Idaho Business Journal*, *Idaho Business Review,* and *Business News* within the *Blackfoot Morning-News* in January 2016. Idaho Power also ran an ad promoting energy-efficient Retrofit incentives in the January Boise Chamber of Commerce newsletter.

Cost-Effectiveness

Custom Projects

All projects submitted through the Custom Projects option 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 a 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 Projects option. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

New Construction

To calculate energy savings for the New Construction option, Idaho Power 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, including the efficiency of the installed measure compared to code-related efficiency. Another method for calculating savings is based on industry standard assumptions, when precise measurements are unavailable. Since the New Construction option is prescriptive and the measures are installed in new buildings, there are no baselines of previous measurable kWh usage in the building. Therefore, Idaho Power uses industry standard assumptions from the International Energy Conservation Code (IECC) to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

New Construction 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.

To prepare for 2016 program changes, ADM, under contract with Idaho Power, updated the TRM for New Construction. The TRM, which provides savings and costs related to existing and new measures for the New Construction option, was updated to include the IECC 2012 baseline. These new savings were applied in 2016 when other program changes were implemented.

Based on the deemed savings value from the TRM, nearly all measures were cost-effective, with the exception of some air conditioning units and daylight photo controls. Idaho Power determined these measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power had received a cost-effectiveness exception on these measures when it filed changes to the program in 2014 under Advice No. 14-10. When Idaho Power filed Advice No. 16-08 for the combined commercial and industrial program, the company requested and received another cost-effectiveness exception for variant refrigerant flow (VRF) heat pumps.

Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Retrofits

In 2016, Idaho Power used most of the same savings and assumptions as were used in 2015 for the Retrofits option. For all lighting measures, Idaho Power uses a lighting tool calculator developed by Evergreen Consulting, Group LLC. An initial analysis was conducted to see if the lighting measures shown in the tool were cost-effective based on the average input of watts and hours of operation, while the actual savings for each project are calculated based on specific information regarding the existing and replacement fixture. For most non-lighting measures, deemed savings from the TRM or RTF are used to calculate the cost-effectiveness. To prepare for 2016 program changes, ADM, under contract with Idaho Power, updated the TRM for the Retrofit option. The TRM which provides savings and costs related to existing and new measures for the Retrofit option. The TRM was updated to include the IECC 2012 baseline for several heating and cooling measures.

Several measures that are not cost-effective remain in the program. These measures include high-efficiency A/C units and heat pump units. After reviewing these measures, Idaho Power determined the measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These cost-effectiveness exceptions were approved by the OPUC in Advice No 14-06 in 2014. When Idaho Power filed Advice No. 16-08 for the combined commercial and industrial program, the company requested and received another cost-effectiveness exception for VRF heat pumps.

Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Customer satisfaction with regards to the Commercial and Industrial Energy Efficiency Program is mentioned in the Commercial and Industrial sector overview. Activities that are specific to each component of the program are mentioned below.

Custom Projects

No specific activities were conducted in 2016.

New Construction

The New Construction option continued random installation verification on 10 percent of projects in 2016. The purpose of the verifications is to confirm program guidelines and requirements are adequate and ensure participants are able to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 12 of the 116 projects, which encompass approximately 10 percent of the total completed projects in the program. Out of the 12 projects verified, only minor discrepancies were discovered. The minor discrepancies consist of the addition or subtraction of lighting fixtures compared to what was claimed on the application. Random project installation verification will continue in 2017.

In 2016, Idaho Power contracted with Leidos to conduct an impact evaluation of this option. The evaluation determined a high level of ex-post realization for option demand and energy savings at .99 and .98 respectively, as well as high realization at the measure level. The kWh confidence and precision ratios were 90 percent confidence at +/- 0.2 percent precision and 90 percent confidence at +/-4.8 percent for kW. In general, project documentation was adequate for verifying most measure impacts, and project data are recorded and tracked with high accuracy. Final reports are provided in *Supplement 2: Evaluation*.

Retrofits

In 2016, Idaho Power contracted with Leidos Engineering to perform an impact evaluation for the incentives paid in 2015 under the Retrofits option. The final report indicated that the option is well designed, well managed, and well implemented. The project documentation was adequate for verifying most measure impacts, and project data are recorded and tracked with high accuracy. The evaluation also determined a high level of ex-post realization for energy savings, as well as high realizations at the measure level. The 2015 kWh savings realization rate was 0.99 with 90 percent confidence at +/- 0.2 percent precision. Final reports are provided in *Supplement 2: Evaluation*.

2017 Program and Marketing Strategies

Future marketing for the overall Commercial and Industrial Energy Efficiency Program is described in the Marketing section of this report. Below are specific strategies that apply to the individual components of the program.

Custom Projects

Over the years, the Custom Projects option has achieved a high service-area penetration rate. As stated previously, over 95 percent of the large-power service customers have submitted applications for a project. Company staff is actively working to support these customers in new ways and find additional opportunities for cost-effective energy saving projects. Additional program offerings are currently under consideration for implementation in 2017.

Idaho Power will report the second year of energy savings and incentives for WWEEC in the *Demand-Side Management 2017 Annual Report*. Idaho Power will report the first year of energy savings, and incentives in 2017 or early 2018 for the MWSOC offering. Activities and coaching will continue for the MWSOC participants and the report-out workshop will be held in 2017. The first year of the CEI Cohort for Schools will commence in January 2017. Three half-day workshops and a final report-out workshop will be held in 2017 along with monthly activities and frequent coaching. The SCE offering will continue in 2017, and new measures, processes, and other improvements will be evaluated to continuously improve the effectiveness of this offering.

Idaho Power will continue to provide site visits by Custom Projects engineers and energy scoping audits for project identification and energy-savings opportunities; measurement and verification of larger, complex projects; technical training for customers; and funding for detailed energy audits for larger, complex projects.

Custom Projects will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

New Construction

The following strategies are planned for 2017:

- Continue to perform random post-project verifications on a minimum of 10 percent of completed projects.
- Continue to sponsor technical training through the IDL to address the energy efficiency education needs of design professionals throughout the Idaho Power service area.
- Support organizations focused on promoting energy efficiency in commercial construction.
- Actively support the 2017 Idaho Energy and Green Building Conference as a member of the conference planning committee. Participate in planning the conference agenda and energy efficiency sessions.
- Continue to sponsor the BOMA symposium and offer energy efficiency training and support to the real estate market.
- Continue customer representative relationship building with local design professionals by targeting Idaho Power's Boise and Pocatello areas.

The New Construction option will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

Retrofits

Idaho Power will review and address the recommendations from the Leidos impact evaluation, and offer technical lighting classes to trade allies.

Retrofits will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

Flex Peak Program

		2016	2015
Participation and Savings			
	Participants (sites)	137	72
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	42	26
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$105,116	$86,445
	Oregon Energy Efficiency Rider	$247,897	$219,654
	Idaho Power Funds	$414,984	$286,773
	Total Program Costs—All Sources	$767,997	$592,872
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

The Flex Peak Program is a voluntary program available in Idaho and Oregon service areas. It's designed for Idaho Power's large commercial and industrial customers, with the objective to reduce the demand on Idaho Power's system during periods of extreme peak electricity use. By reducing demand on extreme system load days during summer months, the program reduces the amount of generation and transmission resources required to serve customers. Program participants earn a financial incentive for reducing load during peak electricity use: non-holiday weekdays, June 15 to August 15, between the hours 2:00 p.m. and 8:00 p.m. Reduction events may be called a maximum of 60 hours per season.

Customers with the ability to offer load reduction of at least 20 kW are eligible to enroll in the program. The 20-kW threshold allows a broad range of customers the ability to participate in the program. Participants receive notification of a load reduction event two hours prior to the start of the event, and events last between two to four hours.

The program originated in 2009 as the FlexPeak Management program managed by a third-party contractor. In 2015, Idaho Power took over full administration, and changed the name to Flex Peak Program. The IPUC issued Order No. 33292 on May 7, 2015, while the OPUC approved Advice No. 15-03 on May 1, 2015, authorizing Idaho Power to implement an internally managed Flex Peak Program (Schedule No. 82 in Idaho and Schedule No. 76 in Oregon), and to continue recovery of its demand response program costs in the previous manner.

Program Activities

In 2016, 65 participants enrolled 137 sites in the program. Of those 137 sites, 67 were new—a 90-percent increase over 2015. Participants had a nominated load reduction of 34.2 MW in the first week of the program, which was the highest committed load reduction for the season. This weekly commitment, or nomination, was comprised of all 137 sites, 70 of which had participated in the 2015 season. The maximum realization rate during the season was 120 percent and the average for all three events combined was 98.8 percent. The realization rate is the percentage of load reduction achieved versus the amount of load reduction committed for an event. The highest hourly load reduction achieved was 41.5 MW during the July 26 event.

The first event was called on Thursday, June 30. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. to 8:00 p.m. The total nomination for this event was 34.2 MW for each hour. The average load reduction was 32.8 MW, with the highest hourly load reduction of 34.8 MW from 6:00 p.m. to 7:00 p.m. The realization rate for this event was 96 percent.

A second event was called on Tuesday, July 26. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. and 8:00 p.m. The total nomination for this event was 33.5 MW for each hour. The average load reduction was 40.3 MW, with the highest hourly load reduction of 41.5 MW from 4:00 p.m. to 5:00 p.m. The realization rate for this event was 120 percent.

The third event was called on Thursday, July 28. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. to 8:00 p.m. The total nomination for this event was 33.9 MW. The average load reduction was 27 MW, with the highest hourly load reduction of 27.7 MW from 4:00 p.m. to 5:00 p.m. The realization rate for this event was 80 percent. Some larger sites underperformed or reduced participation because this was the second event in one week, therefore the realization rate was lower.

The Idaho Power CHQ building participated in the program again in 2016, and committed to reduce up to 200 kW of electrical demand during events—an increase from the 150 kWs nominated during the 2015 season. Unlike other program participants, Idaho Power does not receive any financial incentives for its participation. Idaho Power's CHQ participated in all three demand response events in 2016. The average reduction achieved by the facility across the three events was 348 kW, which exceeded the nominated amount. The maximum hourly reduction was 685 kW, achieved on July 28. Reductions were mostly obtained by turning off lights, adjusting chiller set points, decreasing fan speeds, and curtailing elevator use. Besides the benefit of experiencing firsthand what participants experience with the program, Idaho Power now has a quantifiable energy-reduction plan in place that can be executed when needed. Idaho Power will continue to look for opportunities to enroll more of its facilities in the program for future seasons.

Marketing Activities

Idaho Power developed new program literature including a new program brochure. These were sent by direct-mail to encourage both past participants and new customers to enroll in 2016. Idaho Power launched an additional marketing campaign early in 2016 using customer representatives to recruit new participants. Customer representatives conducted field visits in early winter and followed up with additional communication in early spring. This marketing campaign focused on identifying customer characteristics that make successful program participants based on load size, load shape, and type of operation. Customer representatives also communicated available incentive amounts based on customer load size.

The program's marketing campaign goals were expanded to increase the number and size diversity (in terms of nominated load reduction) of customers enrolled. By having a larger diversity of customer sizes enrolled, it was expected that the program would be less prone to volatility in its realization rate. The company also included an advertisement in the spring *Energy at Work* newsletter and published an article promoting the program in its commercial and industrial electronic newsletter, *Energy Insights*.

Idaho Power implemented an educational campaign with currently enrolled participants and potential participants to promote a variety of demand-reduction strategies. The goal was to refine the amount of nominated load reduction from each site to more realistically align with load reduction potential.

The Flex Peak Program was also marketed along with the Commercial and Industrial Energy Efficiency Program. Additional details can be found in the Marketing section of this report.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The Flex Peak Program was dispatched for 12 event hours and achieved a maximum reduction of 41.5 MW. The total cost of the program in 2016 was $767,997, had the Flex Peak Program been used for the full 60 hours, the cost would have been approximately $1,004,000.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective. A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-effectiveness.*

Customer Satisfaction and Evaluations

Idaho Power conducted a post-season survey that was sent via email to all participants enrolled in the program. The survey was sent to 97 individuals representing 64 participating customer sites.
Idaho Power received feedback from 34 individuals for a response rate of 35 percent. When customers were asked how satisfied they were with the Flex Peak Program, nearly 97 percent of respondents indicated they were "very satisfied" or "somewhat satisfied." When asked how likely they would be to re-enroll in the Flex Peak Program, 100 percent of respondents indicated they were likely to re-enroll next year with just over 91 percent indicating they were "very likely" to re-enroll. The complete details of the survey results are in *Supplement 2: Evaluation*, as is the *Flex Peak Program 2016 Report*.

Idaho Power contracted CLEAResult to conduct an impact evaluation of the 2016 Flex Peak Program. The goals of the impact evaluation were to determine the demand reduction (in MW) and realization rate for the three curtailment events during the program's June 15 through August 15, 2016 season.

The results of the analyses showed maximum demand reductions of 34.8, 41.5, and 27.7 MW, respectively, for the three events, and an average of 34.7 MW. The events achieved realization rates of 96.0 percent, 120 percent, and 80 percent, respectively, averaging 98.8 percent. These results are different than those listed in the CLEAResult report; these have been converted to generation-level reductions, while the CLEAResult report lists meter-level reductions.

The results of the impact evaluation show that Idaho Power's 2016 Flex Peak Program functioned as intended, and provided up to 42 MW to the electricity grid. A summary of the results is in *Supplement 2: Evaluation*.

2017 Program and Marketing Strategies

The company is exploring opportunities to improve the re-enrollment process for participants, and has filed a tariff advice with both the IPCU and OPUC to request that existing participants would be automatically enrolled each year without having to complete a new application and program agreement. Customers would still have the ability to change their nomination amounts and decline participation.

Recruitment efforts for the 2017 season will begin in the first quarter to encourage participation. Idaho Power will meet with existing participants during the winter/spring months to discuss past-season performance and upcoming season details.

For the upcoming season, Idaho Power plans to focus on retaining currently enrolled customers and to recruit new customers that show interest and are a good fit for the program. However, the company does not plan to actively market the program like it did in 2016 because the capacity from this past season remained around 35 MW, which comports with the desired program capacity set forth in the settlement agreement.

The company will continue to use its customer representatives to retain the currently enrolled sites and encourage new sites to participate. Flex Peak will also be marketed along with Idaho Power's Commercial and Industrial Energy Efficiency Program. See the Marketing section of this report for 2017 marketing strategies.

Oregon Commercial Audits

		2016	2015
Participation and Savings			
	Participants (a)	7	17
	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	$7,717	$4,251
	Idaho Power Funds	$0	$0
	Total Program Costs—All Sources	$7,717	$4,251
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

The Oregon Commercial Audits identifies opportunities for commercial building owners to achieve energy savings. Initiated in 1983, this statutory required program (ORS 469.865) is offered under Oregon Tariff Schedule No. 82.

Through this program, Idaho Power provides free energy audits, evaluations, and educational products to customers. Energy audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Business owners can make the decisions to change operating practices, or make capital improvements designed to use energy wisely.

Program Activities

Seven customers requested audits. Of those audits, EnerTech Services, a third-party contractor, completed four, Idaho Power personnel completed two, and one customer received only the program-related booklet. No customers cancelled their audits. The costs were down in 2016 from 2015 because the third-party contractor performed only four audits.

Auditors inspected the building shell, HVAC equipment, lighting systems, and operating schedules, if available, and reviewed the customer's past billing data. Additionally, these visits provided a venue for auditors to discuss incorporating specific business operating practices for energy savings, and to distribute energy efficiency program information.

Marketing Activities

Idaho Power sent out its annual mailing to 1,413 Oregon commercial customers in mid-September 2016 regarding the no-cost or low-cost energy audits, and the availability of Idaho Power's *Saving Energy Dollars* booklet.

Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82, the Commercial Energy Conservation Services Program. Because the required parameters of the Oregon Commercial 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

Idaho Power conducted no customer satisfaction surveys or evaluations in 2016.

Historically, customers have been pleased with the audit process because the audits help identify energy-saving opportunities that may not be obvious to the business owner.

2017 Program and Marketing Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities.

Idaho Power will continue to market the program through the annual customer notification.

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Irrigation Sector Overview

The irrigation sector is comprised of agricultural customers operating water-pumping or water-delivery systems to irrigate agricultural crops or pasturage. End-use electrical equipment primarily consists of agricultural irrigation pumps and center pivots. The irrigation sector 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 2016, the active and inactive irrigation service locations totaled 20,638 system-wide. This was an increase of 1.7 percent compared to 2015, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow irrigated to sprinkler irrigation. Irrigation customers accounted for 1,948,079 MWh of energy usage in 2016, which was a decrease from 2015 of approximately 4.8 percent primarily due to variations in weather. This sector represented nearly 14 percent of Idaho Power's total electricity sales, and approximately 33 percent of July sales. 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 Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components

2. Irrigation Peak Rewards, a demand response program designed to provide a system peak resource

The Irrigation Efficiency Rewards program, including Green Motor Initiative, experienced increased annual savings, from 14,027 MWh in 2015 to 15,747 MWh in 2016. Annual savings were up in 2016 likely because several large projects were completed this year.

In 2016, the Irrigation Peak Rewards program was in its third full season of full operation after temporarily being suspended for the 2013 season. Idaho Power successfully recruited the majority of prior participants to continue their participation in 2016, with a small increase of 1.2 percent in eligible service points participating over 2015.

Table 16 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

Table 16. 2016 irrigation program summary

			Total Cost		Savings	
Program	Participants		Utility	Resource	Annual Energy (kWh)	Peak Demand (MW)
Demand Response						
Irrigation Peak Rewards	2,286	service points	$ 7,600,076	$ 7,600,076	n/a	303
Total			**$ 7,600,076**	**$ 7,600,076**	**n/a**	**303**
Energy Efficiency						
Green Motors—Irrigation	23	motor rewinds			73,617	
Irrigation Efficiency Rewards	851	projects	$ 2,372,352	$ 8,162,206	15,673,513	
Total			**$ 2,372,352**	**$ 8,162,206**	**15,747,130**	**303**

Note: See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 56 percent of Idaho Power irrigation customers surveyed in 2016 for the Burke Customer Relationship Survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-three percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty-seven percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 41 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, 93 percent are "very" or "somewhat" satisfied with the program.

Training and Education

Idaho Power continued to market its irrigation programs by varying the location of workshops and offering new presentations to irrigation customers. In 2016, Idaho Power provided eight workshops promoting the Irrigation Efficiency Rewards program. Approximately 200 customers attended workshops in Twin Falls, Emmett, McCall, Homedale, Mini-Cassia, Shoshone, American Falls, and Oxbow. The company displayed exhibits at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show and the Treasure Valley Irrigation Conference.

Idaho Power sends out *Irrigation News* to all irrigation customers in Idaho and Oregon. The newsletter focuses on the Idaho Power Irrigation topics. This newsletter provides an opportunity to increase awareness, and to promote our Irrigation programs.

Field Staff Activities

Idaho Power's agricultural representatives offer customer education, training, and irrigation-system assessments and audits across the service area. Agricultural representatives also engage agricultural irrigation equipment dealers in training sessions, with the goal to share expertise about energy-efficient system designs, and to bring awareness about the program. Agricultural representatives and the irrigation segment coordinator, a licensed agricultural engineer, participate in annual training to maintain or obtain their Certified Irrigation Designer and Certified Agricultural Irrigation Specialist accreditation. 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.

Irrigation Efficiency Rewards

		2016	2015
Participation and Savings			
	Participants (projects)	851	902
	Energy Savings (kWh)*	15,747,130	14,027,411
	Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,672,328	$1,714,399
	Oregon Energy Efficiency Rider	$634,101	$61,295
	Idaho Power Funds	$65,923	$60,018
	Total Program Costs—All Sources	$2,372,352	$1,835,711
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	$.018	$0.016
	Total Resource Levelized Cost ($/kWh)	$.063	$0.085
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	4.95	6.00
	Total Resource Benefit/Cost Ratio	3.21	3.84

*2016 total includes 73,617 kWh of energy savings from 23 Green Motors projects.

Description

Initiated in 2003, 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 areas can receive financial incentives and reduce their electricity usage through participation in the program. Two options help meet the needs for major or minor changes to new or existing systems: Custom Incentive and Menu Incentive.

Custom Incentive Option

The Custom Incentive Option addresses extensive retrofits or installation of an efficient new system.

New Systems: For a new system, the incentive is based on installation of a system Idaho Power determines to be more energy efficient than standard. Water source changes to an existing system are treated as a new system. The incentive is 25 cents per annual kWh saved, not to exceed 10 percent of the project cost.

Existing Systems: For existing system upgrades, the incentive is 25 cents per annual kWh saved or $450 per kW demand reduction, whichever is greater. The incentive is limited to 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 use of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each project. All project information is reviewed for each completed project before final payment. Prior usage history, actual invoices, and, in most situations, post-usage demand data are used to verify savings and incentives.

Menu Incentive Option

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 where small maintenance upgrades provide energy savings from 11 separate measures. These measures are as follows:

- New flow-control type nozzles
- New nozzles for impact, rotating, or fixed-head sprinklers
- New or rebuilt impact or rotating type sprinklers
- New or rebuilt wheel-line levelers
- New complete low-pressure pivot package
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand-lines, wheel-lines, and portable mainlines
- 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.

Program Activities

Of the 851 irrigation efficiency projects completed in 2016, 728 were associated with the Menu Incentive Option, providing an estimated 10,357 MWh of energy savings and 2.02 MW of demand reduction. The Custom Incentive Option had 123 projects, of which 65 were new irrigation systems and 58 were on existing systems. This option provided 5,316 MWh of energy savings and 2.03 MW of demand reduction for the year.

Marketing Activities

In addition to training and education mentioned in the overview section, Idaho Power agricultural representatives targeted visits with a selected number of customers who had not participated in the program to increase customer education. Idaho Power maintained a database of irrigation dealers and vendors for direct-mail communication. Irrigation dealers and vendors are a key component to the successful marketing of the program. Therefore, Idaho Power's face-to-face interactions and direct-mailings containing the most up-to-date program information, brochures, and dealer-specific meetings ensured correct program promotion.

In 2016, the company sent a copy of *Irrigation News* to all irrigation customers in Idaho and Oregon. The August 2016 newsletter focused on the Irrigation Efficiency Rewards program: why read dates are important and summary bill options. This newsletter provides an opportunity to increase transparency, and to promote the Irrigation Efficiency Rewards program.

Idaho Power also placed numerous ads in print agricultural publications including the *Argus Observer*, *Gem State Producer*, *Capital Press*, *Power County Press,* and *Potato Grower Magazine;* updated and distributed the program brochure; and used radio advertising during Agri-Action and FFA week.

Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements under the Custom Incentive Option and the Menu Incentive Option of Irrigation Efficiency Rewards.

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. On existing system upgrades, Idaho Power calculates the savings of a project by determining what changes are being made and comparing it to the service point's previous five years of electricity usage history on a case-by-case basis. On new system installations, the company uses standard practices as the baseline and determines the efficiency of the applicant's proposed project. Based on the specific equipment to be installed, the company calculates the estimated post-installation energy consumption of the system. The company verifies the completion of the system design through aerial photographs, maps, and field visits to ensure the irrigation system is installed and used in the manner the applicant's documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure deemed savings are appropriate and reasonable. Payments are calculated on a prescribed basis by measure. In some cases, the energy-savings estimates in the Menu Incentive Option are adjusted downward from deemed RTF savings to better reflect known information on how the components are actually being used. For example, a half-circle rotation center pivot will only save half as much energy per sprinkler head as a full-circle rotation center pivot. All deemed savings are based on seasonal operating hour assumptions by region. If a system's usage history indicates it has lower operating hours than the assumptions, like the example above, the deemed savings are adjusted.

Based on the deemed savings from the RTF, all the measures offered under the Menu Incentive Option are cost-effective. Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program.

In 2016, Idaho Power contracted with Leidos to conduct an impact and process evaluation of this program. The evaluation team conducted 46 desk reviews; 30 for a stratified sample of Menu Option projects and 16 for a stratified sample of Custom Option projects. The team also completed site visits for 11 custom incentive projects.

The findings of the impact evaluation indicate a realization rate of 98 percent, with a relative precision of +/- 2.4 percent overall at 90 percent confidence, on the ex-post kWh savings for both the Menu Option and the Custom Option savings combined. The realization rate on the ex-post kW impacts was 97 percent for the Menu Option and 75 percent for the Custom Option, respectively. The overall combined realization rate for the program demand savings was 90 percent with a relative precision of +/-3.3 percent at 90 percent confidence. The realization rate is the percent comparison of the expected savings or load reduction to the realized savings or load reduction.

The process evaluation indicated that the program is well designed, well managed and well implemented. A summary of the results is in *Supplement 2: Evaluation*.

2017 Program and Marketing Strategies

Marketing plans for 2017 include conducting six to eight customer-based irrigation workshops. Additionally, Idaho Power will continue to participate in four regional agricultural trade shows. Idaho Power will work closely with customers who have participated in the Irrigation Efficiency Rewards program, and continue to take photos for program promotion highlighting efficient irrigation system designs.

Idaho Power will continue to promote the program in agriculturally focused editions of newspapers and magazines, and to provide valuable information in its *Irrigation News* newsletter.

Irrigation Peak Rewards

		2016	2015
Participation and Savings			
	Participants (participants)	2,286	2,259
	Energy Savings (kWh)	n/a	n/a
	Demand Reduction (MW)	303	305
Program Costs by Funding Source			
	Idaho Energy Efficiency Rider	$1,082,113	$1,018,139
	Oregon Energy Efficiency Rider	$218,906	$222,614
	Idaho Power Funds	$6,299,056	$6,018,079
	Total Program Costs—All Sources	$7,600,076	$7,258,831
Program Levelized Costs			
	Utility Levelized Cost ($/kWh)	n/a	n/a
	Total Resource Levelized Cost ($/kWh)	n/a	n/a
Benefit/Cost Ratios			
	Utility Benefit/Cost Ratio	n/a	n/a
	Total Resource Benefit/Cost Ratio	n/a	n/a

Description

Idaho Power's Irrigation Peak Rewards program is a voluntary program available only to Idaho and Oregon agricultural irrigation customers with metered service locations that have participated in the past. Initiated in 2004, the purpose of the program is to minimize or delay the need to build new supply-side resources. By reducing demand on the most extreme load days in the most extreme summer conditions, the Irrigation Peak Rewards program can reduce the amount of generation and transmission resources Idaho Power needs to build.

The program pays irrigation customers a financial incentive to interrupt the operation of specified irrigation pumps with the use of one or more load control devices. Historically, the Irrigation Peak Rewards program provides approximately 300 MW of load reduction during the program season of June 15 through August 15, which is nearly 9 percent of Idaho Power's all-time system peak.

The program offers two interruption options: an Automatic Dispatch Option and a Manual Dispatch Option. To participate in the Automatic Dispatch Option, either an advanced metering infrastructure (AMI) or a cellular control device is attached to the customer's electrical panel that allows Idaho Power to remotely control the pumps. To participate in the Manual Dispatch Option, Idaho Power must determine that the service location cannot take advantage of the current installation and communication technology, or the service point offers at least 1,000 cumulative horse power (hp). These customers must nominate a particular amount of kW reduction by June 1 of the program year.

For either interruption option, 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. Customers will experience at least three events per season between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday.

The incentive structure consists of fixed and variable payments. The fixed incentive is paid to those who participate during each of the first three events. A variable incentive is paid to those who participate in subsequent events. Customers who participate from 5:00 p.m. until 9:00 p.m. can receive a higher variable incentive.

Program rules allow customers the ability to opt out of dispatch events up to five times per service point. The first three opt outs each incur a penalty of $5 per kW, while the remaining two each incur a penalty of $1 per kW based on the current month's billing kW. The opt-out penalty may be prorated to correspond with the dates of program operation, and are accomplished through manual bill adjustments. The penalties will never exceed the amount of the incentive that would have been paid with full participation.

Program Activities

Idaho Power filed a request in December 2015 to modify the existing Irrigation Peak Rewards program to allow the company to use more of its AMI technology for load control as well as to allow greater flexibility for some customers to participate in the Manual Dispatch Option. After approval in Idaho and Oregon in February 2016, Idaho Power decided not to renew the contract with program provider, EnerNOC/M2M Communications.

Idaho Power enrolled 2,286 service points in the program in 2016, an increase of 1 percent over 2015. The enrolled service points accounted for approximately 82 percent of the eligible service points (where there is a load control device installed). The incentive rate remained the same in 2016. The customer's incentive is a demand credit of $5.00/kW and an energy credit of $0.0076/kWh applied to the monthly bills for the period of June 15 through August 15. The demand credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount. The energy credit is calculated by multiplying the monthly billing kWh usage by the energy-related incentive amount. Credits were prorated for periods when reading/billing cycles did not align with the program season dates from June 15 to August 15. The incentive structure also includes a "variable" payment for more than three events of $0.148/event kWh, with an increased variable credit of $0.198/event kWh for service points that voluntarily participate in the "extended" 9 p.m. interruption period.

The three load control events occurred June 29, July 27, and July 29, 2016 with the highest load reduction occurring on June 29, providing an estimated 316.9 MW at the generation level.

Marketing Activities

Idaho Power used workshops, trade shows, and direct-mailings to encourage past participants to re-enroll in the program. See the Irrigation Sector Overview section. The company updated an informational flyer to increase appeal and readability by using a brochure format. Idaho Power mailed the new brochure, program enrollment application, and program agreement, to all eligible participants in February 2016.

Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 302.7 MW. The total expense for 2016 was $7,600,075 and would have been approximately $10.8 million if the program was fully used for 60 hours.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective. A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

On the June 29 event, the program experienced two unexpected problems. The AMI signal to the load control device was not able to process all of the necessary commands because the communication settings were incorrect. The issue was discovered near the beginning of the event, and was corrected within two hours of the event starting time. Additionally, the EnerNOC/M2M device notification process did not work as intended, consequently not all of the participants were notified. EnerNOC/M2M corrected the issue, and it did not happen in subsequent events.

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load-reduction analysis, cost-effectiveness information, and program changes. A copy is included in *Supplement 2: Evaluation*.

In 2016, Idaho Power conducted a potential realization rate analysis and, as in past years, that potential event date has a large influence on the expected realization rate. Table 18 shows the season in two-week blocks and the potential realization rate associated with each. The rate drops off significantly in August due to a higher percentage of pumps turned off during the baseline period. The 2016 counterfactual realization rate peaked the last two weeks of June. The analysis determined that the highest realization rate of 76.9 percent occurred June 29. A further breakdown of the load reduction for each event by is shown in Table 17.

Table 17. Irrigation Peak Rewards program load reduction for each 2016 event by program option

Event	Automatic Dispatch Option (MW)	Manual Dispatch Option (MW)	Total Load (MW)
June 29	233,589	69,171	302,760
July 27	177,685	66,911	244,569
July 29	185,180	64,096	249,275

Table 18. Irrigation Peak Rewards 2016 potential realization rate

2016 Season Timeframe	Average Potential Realization Rate
June 15–June 30	68.82%
July 1–July 15	62.42%
July 16–July 31	58.89%
August 1– August 15	55.66%

2017 Program and Marketing Strategies

The company is in the process of exchanging all of the EnerNOC/M2M communication devices with load control units that work with its AMI meters or company designed cell phone-controlled devices. Once the exchanges are complete, the program will no longer use EnerNOC/M2M to provide services for the program. This change out of devices is expected to reduce overall program costs and potentially reduce the complexity of coordinating communications and load control commands.

Idaho Power will continue to recruit past participants in this program for the 2017 irrigation season. The company will conduct six to eight workshops throughout its service area to familiarize customers with the program details and eligibility requirements. Each eligible customer will be sent a comprehensive packet containing an informational brochure, sign-up worksheet, and contract agreement encouraging their participation. Idaho Power agricultural representatives will continue one-on-one customer contact to inform and encourage program participation.

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Other Programs and Activities

Idaho Power recognizes the value of energy efficiency awareness and education to create behavioral change to help customers use energy wisely. The goal of other programs and activities is to promote energy efficiency programs, projects, and behavior in customers. These awareness efforts increase customer demand for, and satisfaction with, Idaho Power's programs and activities. These activities include customer outreach, marketing, research, project development, and education programs. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Education, and Educational Distributions.

Building-Code Improvement

Since 2005, the State of Idaho has been adopting a state-specific version of the IECC. The Idaho Building Code Board convened another Energy Code Collaborative in late 2015 in an effort to address implementation of the new series of building-related codes.

The Idaho Building Code Board requested the collaborative review of the 2015 codes and suggested recommendations to the board regarding adoption of codes. The first meeting occurred on December 2, 2015 and three subsequent meetings occurred in 2016.

Idaho Power participated and offered support in those collaborative meetings, which was attended by members of the building industry, local building officials, code development officials, and other interested stakeholders. The Energy Code Collaborative is an ongoing effort in which Idaho Power will continue to participate. Additional meetings will be scheduled in 2017.

Energy Efficiency Advisory Group

Formed in 2002, EEAG provides input on enhancing existing DSM programs and on implementing energy efficiency programs. Currently, EEAG consists of 13 members from Idaho Power's service area and the Northwest. Members represent a cross-section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives from low-income households, environmental organizations, state agencies, public utility commissions, and Idaho Power. EEAG meetings are generally open to the public and attract a diverse audience. Idaho Power appreciates the input from the group, and acknowledges the commitment of time and resources the individual members give to participate in EEAG meetings and activities.

EEAG met four times in 2016: February 18, May 5, August 30, and November 3. Additionally, EEAG held two conference calls on February 16 and November 28. During these meetings, Idaho Power discussed and requested feedback on new program ideas and new measure proposals, marketing methods, and specific measure details; provided a status of the Idaho and Oregon Rider funding and expenses; gave an update of ongoing programs and projects; and supplied general information on DSM issues and other important issues occurring in the region. Idaho Power relies on input from EEAG to provide a customer and public-interest view of energy efficiency and demand response programs and expenses. A summary of each meeting and phone call is below; the complete notes from the 2016 EEAG meetings are included in *Supplement 2: Evaluation*.

February 16, 2016: EEAG members participated in a confidential conference call to discuss the *2015 Flex Peak Program One-Time Report*. This report was submitted to the IPUC by May 7, 2016, and compares the current Flex Peak Program to the prior program managed by EnerNOC.

February 18, 2016: Darrel Anderson, President and CEO of Idaho Power, addressed the group and thanked members of EEAG for their time and guidance throughout the years. He commented that Idaho Power has benefited by having the EEAG as a resource that brings new thoughts and ideas about energy efficiency. CLEAResult presented results of the demand response program evaluations. Idaho Power sought feedback from the group on two programs: See ya later, refrigerator® and the Multifamily Direct Install project (Multifamily Energy Savings Program). The group supported continuing See ya later, refrigerator® in 2016, and provided good ideas for other measures that could be included in the Multifamily Direct Install project. Idaho Power also discussed its website redesign; spring 2016 residential energy efficiency ad campaign tactics, including a new customer pledge; and results from an em**powered** community survey to gauge customers' interest in making energy-saving improvements to their homes.

May 5, 2016: Idaho Power demonstrated its myAccount web tool, and handed out an abridged home assessment form for the group to fill out. The Energy Savings Pledge (later named the Smart-saver Pledge) was discussed and EEAG was asked for feedback on behavioral change options that could be included in the pledge. The group provided several options that pledge participants could choose from. Idaho Power presented its Program Planning Update, and asked EEAG for feedback on a couple of new residential ideas it is researching. The group suggested Idaho Power continues the Multifamily Direct Install project and continues to look for ways to encourage the installation of DHPs into new multi-family housing units if they appear to be cost-effective. The history of the Idaho and Oregon Rider was presented to the group and included the financial history for both Idaho and Oregon balances since their inception. Idaho Power provided EEAG with results from the spring residential energy efficiency ad campaign, further discussed plans for the Smart-saver Pledge, and reviewed Idaho Power's social media channels and specific energy efficiency posts and ads on each channel.

August 30, 2016: EEAG member and CSHQA president, Kent Hanway, hosted this meeting at the CSHQA office on Broad Street in Boise. Along with a presentation of the building's energy efficiency measures, EEAG members and guest were given a tour of the building. A presentation covering 2017 preliminary cost-effectiveness provided a summary of all programs and how anticipated changes may impact programs for 2017. Idaho Power updated the group on activities related to customer alerts and home energy reports, and presented the results of an analysis conducted by the company to quantify the estimated value of deferral of transmission and distribution investments that could occur as a result of energy-efficiency efforts. Idaho Power discussed results from an em**powered** community survey about the spring residential energy efficiency ad campaign, plans for the fall ad campaign, and 2017 marketing efforts.

November 3, 2016: EEAG members were given an update on the development of a home energy report pilot to be deployed in 2017. EEAG was asked for feedback on target audience type for these reports. The Commercial Program Performance presentation highlighted energy savings and participation and feedback was requested from EEAG regarding some possible changes to the Flex Peak Program for 2017. Idaho Power provided an update about its various surveys and how they impact marketing, shared results from the fall residential energy efficiency ad campaign and Smart-saver Pledge, discussed plans for new Commercial and Industrial Energy Efficiency Program ads, and shared some new initiatives and successes from 2016. The company presented the non-cost-effective aspects of the Home Improvement Program and advised EEAG of the company's plan no longer offer the program.

November 28, 2016: A conference call was held to discuss Idaho Power's recommendations to decrease the collection percentage of the Rider.

Green Motors Initiative

Idaho Power participates in the Green Motors Practices Group's (GMPG) Green Motors Initiative (GMI). Under the GMI, service center personnel are trained and certified to repair and rewind motors in an effort to improve reliability and efficiency. If a rewind returns a motor to its original efficiency, the process is called a "Green Rewind." By rewinding a motor under this initiative, customers may save up to 40 percent when compared to buying a new motor. The GMI is available to Idaho Power's agricultural, commercial, and industrial customers.

Twenty-one service centers in Idaho Power's service area have the training and equipment to participate in the GMI, and perform an estimated 1,200 Green Rewinds annually. Of the 21 service centers, currently nine have signed on as GMPG members. The GMPG will work to expand the number of service centers participating in the GMI, leading to market transformation and an expected kWh savings in southern Idaho and eastern Oregon.

Under the initiative, Idaho Power pays service centers $2 per hp for each National Electrical Manufacturers Association (NEMA)-rated motor up to 5,000 hp that received a verified Green Rewind. Half of that incentive is passed on to customers as a credit on their rewind invoice. The GMPG requires all member service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG is responsible for verifying quality assurance.

In 2016, a total of 37 motors were rewound under the GMI. Table 19 provides a breakdown of energy savings and the number of motors by customer segment.

Table 19. 2016 Green Motor Initiative savings, by sector and state

Sector	State	Number of Motors	Sum of kWh Savings
Irrigation	ID	22	72,871
	OR	1	746
Irrigation Total		**23**	**73,617**
Commercial and Industrial	ID	12	50,955
	OR	2	72,745
Commercial and Industrial Total		**14**	**123,700**
Grand Total		**37**	**197,317**

Idaho Power's Internal Energy-Efficiency Commitment

Idaho Power continues to upgrade the company's substation buildings across its service area. Focus for 2017 will be to provide energy-efficient heating and cooling, and to develop a plan to replace all T-12 lighting with LED fixtures in substation buildings.

Renovation projects continued at CHQ in downtown Boise in 2016. The company remodeled the eighth floor, and exchanged the old T-12 parabolic lighting fixtures with T-8 lighting. Remodels continue to incorporate energy efficiency measures, such as lower partitions, lighting retrofits, and automated lighting controls. In 2017, Idaho Power plans to remodel the ninth floor of the CHQ.

Also in 2106, the new Twin Falls Operation Center was constructed to replace the 1951-built center used to house the South-East Region operations staff. The design incorporates LED lighting, energy-efficient heating and cooling by way of a VRF design, and lighting control that includes daylight harvesting to reduce power consumption. The building also features a rooftop solar array to offset the amount of energy the building uses from the grid.

In 2016, Idaho Power redesigned the HVAC delivery system for the Maintenance and Electrical Shops; construction on these projects is planned for 2018. Idaho Power estimates that with these improvements the shops may reduce their usage by 300,000 kWh in coming years.

Idaho Power continued its major sustainability initiative by installing more electric vehicle (EV) charging stations at the company's EV Workplace Charging Center at CHQ and at several operations centers. The company continues to provide a variety of models of EV charging stations to promote awareness, use, and information dissemination about EVs. More employees now have the opportunity to charge their EV while at work. In addition to adding more EVs to the Idaho Power fleet, employees' personal use of EVs will further promote the financial and environmental benefits of EVs.

Idaho Power's internal energy efficiency projects and initiatives are funded by non-rider funds.

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 still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

Idaho Power received two applications for LEEF in 2016. Both applications were reviewed and found to be standard practice, and not appropriate for LEEF. A residential program specialist followed up with these applicants, and directed them to the residential energy efficiency resources found on Idaho Power's website. One project involved replacing all lighting in the applicant's house with LED lighting. The other project involved replacing single-pane windows with new, more energy-efficient windows.

Market Transformation

Market transformation is an effort to change the existing market for energy efficiency goods and services by engaging and influencing large national companies to manufacture or supply more energy-efficient equipment. Market transformation can also attempt to identify barriers and opportunities to increase the market adoption of efficiency. Idaho Power achieves market transformation savings primarily through its participation in the NEEA.

Northwest Energy Efficiency Alliance

Idaho Power has been a funding member of NEEA since its inception in 1997. NEEA's role in this process is to look to the future to find emerging opportunities and to create a path forward to make those opportunities a reality in the region.

NEEA's current, five-year funding cycle began 2015. In this cycle the 2015 to 2019 NEEA business plan is forecast to obtain 145 average megawatt (aMW) of regional energy savings at a cost savings of about $3 million over the next five years to Idaho Power customers as compared to the previous five-year business plan. The NEEA plan also offered some optional programs and activities to prevent overlap of activities when local utilities have the capability to provide the same services at a lower cost or more effectively.

Idaho Power participates in all of NEEA's committees and workgroups including representation on the Regional Portfolio Advisory Committee and the Board of Directors. In 2016, Idaho Power continued to help with the implementation of the Commercial and Industrial Lighting Regional Market Plan.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports, through third-party contractors, for energy efficiency initiatives throughout the Pacific Northwest. Copies of these reports are included on the CD accompanying *Supplement 2: Evaluation* and on NEEA's website under Market Effects Evaluation.

NEEA Marketing

As stated in Idaho Power's agreement with NEEA for the 2015 to 2019 funding cycle: "Idaho Power will fund, create, and deliver specific market transformation activities for all initiatives that are relevant for the Idaho Power service area." In 2016, these activities included educating residential customers on heat pump technology and heat pump water heaters, and promoting reduced wattage T-8 lightbulbs to business customers.

Idaho Power placed an article about heat pump technology and included heat pump water heaters as an example in its summer *Energy Efficiency Guide*. The company also issued a *News Briefs* article titled *New, More-Efficient Heat Pump Water Heater!* on heat pump water heaters to media April 25, and promoted the products on social media and in the October issue of *Connections.*

To promote reduced wattage lightbulb replacement, Idaho Power published an article in its fall *Energy @Work* newsletter, placed a promo pod linking to a newly developed flyer (PDF) on the company's Retrofits web page, and wrote an article that was included in BOMA's member email in November.

Residential NEEA Activities

Idaho Power participates in the Residential Advisory Committee, Efficient Homes Workgroup, the Manufactured Homes Interest Group, the Retail Products Platform (RPP) Initiative, the DHP research project, the Smart Water Heat Initiative (previously known as the HPWH Initiative), Efficient Homes Workgroup, the Super Efficient Dryers Workgroup, the Northwest Regional Strategic Market Plan for Consumer Products group, and Northwest Regional Retail Collaborative. During 2016, NEEA combined the Efficient Homes Workgroup and the Manufactured Homes Interest Group and renamed it the Better Built NW Workgroup.

NEEA provides Better Built NW builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates energy-efficient new construction activities with utilities in Idaho, Montana, Oregon, and Washington.

In 2016, NEEA completed the sun setting of their ENERGY STAR® Homes Northwest program. All single-family and multi-family builders seeking ENERGY STAR certification must now go through the national EPA ENERGY STAR Homes program. NEEA will continue oversight of a regional database for utilities to access ENERY STAR Home certifications for incentive payments and will continue working towards the creation of a single-family Residential Performance Path program to offer utilities flexibility in program design and the opportunity to capture all above building code savings on residential new construction projects.

In 2016, NEEA formed the Super Efficient Dryers Initiative to support the acceleration of heat pump dryers into the market and Idaho Power participated in the workgroup. The initiative focuses on influencing manufacturer product development and executing strategies to overcome the barriers of this new technology. Barriers include a high incremental cost, limited consumer awareness, and product availability. The initiative offers incentives to reduce the retail price. A second goal of the initiative is lab and field-testing to better understand how heat pump dryers perform in real-world conditions, evaluate consumer preferences, and gather data to support RTF provisional energy savings.

Idaho Power participated in RETAC which met quarterly to review the emerging technology pipeline for BPA, NEEA, and the Northwest Power and Conservation Council (NWPCC) Seventh Power Plan. RETAC is developing a regional database to increase coordination among the utilities to identify and track emerging technologies; plan and conduct research; and develop, implement, and assess pilots and field demonstrations.

Idaho Power continued participation in the RBSA. The purpose of the RBSA is to determine common attributes of residential homes, and develop a profile of the existing residential buildings in the Northwest.

Commercial and Industrial NEEA Activities

NEEA continued to provide support for commercial and industrial energy efficiency activities in Idaho in 2016, which included partial funding of the IDL for trainings and additional tasks.

The Idaho Building Code Board requested the Idaho Code Collaborative review the 2015 codes and make a recommendation to the board on adoption. NEEA facilitated the Code Collaborative meetings and Idaho Power participated.

NEEA facilitated regional webinars for the Commercial Code Enhancement (CCE) initiative for new construction to discuss how utilities can effectively align code changes and utility programs. NEEA is using the code collaborative in Idaho and Montana as examples of success for other regions.

NEEA facilitated the conference planning committee and, along with Idaho Power, supported the 2016 Idaho Energy and Green Building Conference held in Boise on November 1 and 2, 2016. Idaho Power had two active members on the conference planning committee.

NEEA's work on SEM in the commercial and industrial sectors continued in 2016. The primary focus in 2016 was to consolidate all of the SEM templates, guidelines, and documents into the new SEM Hub website.

NEEA's work with the Refrigerating Engineers & Technicians Association (RETA) on the RETA certified refrigeration energy specialist (CRES) certification process continued in 2016. A new CRES contractor was hired in 2016 to work with RETA marketing of the RETA CRES certification, improving the RETA CRES training materials, and improving the RETA CRES practice exams.

Idaho Power kept abreast on NEEA's initiatives in the commercial lighting arena via periodic conference calls and in-person meetings. Idaho Power continued participation as a member of the NEEA Commercial Lighting Program Manager Work Group.

The Reduced Wattage Lamp Replacement (RWLR) initiative achieved some success in 2016, especially in Idaho. NEEA worked with 20 branches across five electrical distributor organizations in Idaho Power's service area, with new distributors added to the initiative in 2016. Preliminary data shows the 2016 market penetration of reduced wattage T-8 lightbulb in the company's service area is between 30 to33 percent, which is higher than the average 22 percent penetration across all four Pacific Northwest states. Overall, linear fluorescent lightbulb sales continue to decline at roughly 10 percent per year. Market sales of linear LEDs are increasing, which is having an impact on the RWLR initiative; however, NEEA estimates 2017 will continue to see good participation from distributors in reduced wattage T-8 sales.

In 2016, the NEEA Top-Tier Trade Ally (TTTA) training was renamed NXT Level. Ultimately, the plan is to offer lighting trade allies throughout the region the opportunity for multi-tiered training, each level building on the one before, over the next few years. NEEA rolled out Level 1 on-line training to the Idaho Power service area June 2016. Level 1 is geared toward more seasoned trade allies. In October, the company's first trade ally completed the course and received the Level 1 designation. Several other trade allies in the Idaho Power service area are in process of taking the course.

Idaho Power continued participation in the Regional Strategic Market Planning Collaborative for commercial and industrial lighting. The collaborative formed in 2015 to create regional strategic market plans in four market segments. Commercial and industrial lighting was the first segment of focus because it was identified as the collaborative's top priority. Idaho Power is represented on a steering committee formed to monitor and oversee the progress of the regional commercial and industrial lighting plan.

The NEEA Existing Building Renewal (EBR) pilot project in Boise, which began in 2013 and phased through 2016, saw no significant results in 2016. The project has not resulted in any Idaho Power incentive applications.

NEEA completed several assessment studies related to irrigated agriculture to support their scanning activities. Idaho Power has kept apprised of these activities, and has reviewed each of these assessments. Copies of the reports are included on the CD accompanying *Supplement 2: Evaluation* and on NEEA's website under NEEA Market Effects Evaluations.

NEEA Funding

In 2016, Idaho Power began the second year of the 2015 to 2019 *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 2016, 100 percent was funded through the Idaho and Oregon Riders.

In 2016, Idaho Power paid $2,676,387 to NEEA. The Idaho jurisdictional allocation of the payments was $2,542,567, while $133,820 was paid for the Oregon jurisdiction. Other expenses associated with Idaho Power's participation in NEEA activities, such as administration and travel, were paid from Idaho and Oregon Riders.

Final NEEA savings for 2016 will be released in June 2017. Preliminary estimates reported by NEEA for 2016 indicate Idaho Power's share of regional market transformation MWh savings for 2016 is

24,616 MWh. These savings are reported in two categories; codes- and standards-related savings of 20,060 MWh and non-codes and standards related savings of 4,556 MWh.

In the *Demand-Side Management 2015 Annual Report*, preliminary funding share estimated savings reported were 21,900 MWh. The revised estimate included in this report for 2015 final funding share NEEA savings is 23,039 MWh. These saving include savings from code-related initiatives as well as non-code-related initiatives. 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 neea.org.

Program Planning Group

In 2014, Idaho Power convened an internal PPG to explore new opportunities to expand current DSM programs and offerings. The group consisted of residential program specialists, commercial and industrial engineers, energy efficiency analysts, marketing specialists, energy efficiency program leaders, and the research and analysis leader. The PPG does not perform program execution. Instead, the group's role is to determine if a measure has energy-saving potential, has market adoption potential, and is potentially cost-effective.

Throughout 2016, the group met regularly to explore new ideas to promote energy efficiency including evaluating new potential programs and measures. Idaho Power incorporated five new ideas from the PPG into the overall portfolio of residential program offerings: 1) mailing energy efficiency kits, 2) initiating a multi-family direct-install project, 3) installing smart thermostats, and 4) distributing clothes drying racks for educational purposes. The first three offerings will continue to be available in 2017. Idaho Power will evaluate the drying rack offering for its long-term viability.

In the commercial sector, the company began the school cohort. In November 2016, Idaho Power recruited school districts to establish a structured energy program where each district will have an individualized initiative and develop a program to implement energy efficiency measures and behaviors at their schools.

Three other PPG ideas were presented to EEAG and are being considered for implementation in 2017: 1) Home Energy Reports, mailed to customers to inform them of their energy use and how it compares to others; 2) an on-line marketplace for customers to review and purchase energy-efficient appliances; and 3) installation of a thermostatic shower valve to reduce hot water use. Each of these measures has an element of behavior change.

Idaho Power will continue to use the PPG to review, evaluate, and deliver new energy efficiency offerings in 2017 and beyond.

Regional Technical Forum

The RTF is a technical advisory committee to the NWPCC, established in 1999 to develop standards to verify and evaluate energy efficiency savings. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, participating in sub-committees, and sharing research and data beneficial to the forum's efforts.

The forum is made up of both voting members and corresponding members from investor-owned and public utilities, consultant firms, advocacy groups, Energy Trust of Oregon, and BPA, all with varied expertise in engineering, evaluation, statistics, and program administration. The RTF advises the NWPCC during the development and implementation of the regional power plan in regards to the following listed in the RTF charter:

- Developing and maintaining a readily accessible list of eligible conservation resources, including the estimated lifetime costs and savings associated with those resources and the estimated regional power system value associated with those savings.
- Establishing a process for updating the list of eligible conservation resources as technology and standard practices change, and an appeals process through which utilities, trade allies, and customers can demonstrate that different savings and value estimates should apply.
- Developing a set of protocols by which the savings and system value of conservation resources should be estimated with a process for applying the protocols to existing or new measures.
- Assisting the Council in assessing: 1) the current performance, cost and availability of new conservation technologies and measures; 2) technology development trends; and 3) the effect of these trends on the future performance, cost and availability of new conservation resources.
- Tracking regional progress toward the achievement of the region's conservation targets by collecting and reporting on regional research findings and energy savings annually.

When possible, Idaho Power uses the savings estimates, measure protocols, and supporting work documents provided by the RTF, and when the work products are applicable to the Idaho climate zones and load characteristics. In 2016, Idaho Power staff participated in all RTF meetings as a voting member and the RTF Policy Advisory Committee.

During 2016, RTF impacted measure changes include savings tier additions to DHPs, updates to multi-family weatherization and new construction measures, updates to low-flow showerhead savings, and the addition of connected or "smart" thermostats as a supported RTF measure. All implementations of changes were accounted for in planning and budgeting for 2017. Idaho Power considered the multi-family weatherization measure updates when it decided to sunset the Home Improvement Program. A complete list of RTF decisions in 2016 can be accessed at rtf.nwcouncil.org.

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 (REEEI) promotes energy efficiency to the residential sector. The company achieves this by creating and delivering educational materials and programs that result in wise and informed choices regarding energy use and increase Idaho Power's energy efficiency program participation.

REEEI continued to produce semiannual *Energy Efficiency Guide*s in 2016. Idaho Power distributed these guides primarily via insertion in local newspapers and at events across Idaho Power's service area. The *Winter Energy Efficiency Guide* was published and distributed by 16 newspapers in Idaho Power's service area the week of January 26, in accordance with the new distribution plan outlined in 2015. The *Boise Weekly* also inserted the guide, increasing circulation by 30,000, which focused on ways to find the truth about energy-saving claims, seven ways to improve a home's energy efficiency, ventilation and lighting for optimum health and efficiency, and tips for hiring a home improvement contractor. The information was applicable to all residential customers, but the design was adapted and enhanced for particular usefulness and appeal to the senior population. Idaho Power included a story from the guide in the January *News Briefs* and promoted it that month on KPVI during the energy efficiency news segment.

The *Summer Energy Efficiency Guide* was delivered nearly 222,000 homes the week of July 24, 2016. This guide focused on saving energy as a family and highlighted why Idaho Power promotes energy efficiency, energy-saving computer settings, behavior change, smart technology, and making saving energy fun for the whole family. The guide also featured a mini home assessment so customers could gauge how energy efficient their behaviors were.

The release of the summer guide received public relations support through numerous communication channels, including an item in Idaho Power's weekly *News Briefs* email to all media in the Idaho Power service area on July 18 and 25, promotion on KTVB and KPVI in the July energy efficiency news segments, on Idaho Power's social media accounts, and using banner ads and native ads on the Idaho Statesman website. A banner ad appears as a traditional advertisement; a native ad is formatted as an on-line news article, with several paragraphs of text, but is, in fact, paid media. The native ad includes a disclaimer that reads "Advertisement."

In 2016, the company distributed over 6,000 guides, including issues from past years, at energy efficiency presentations and events, which continued to reinforce the overall value of these guides. On its website, Idaho Power provides a link to the most current seasonal guide, and to a list of historical guides.

REEEI distributed energy efficiency messages through a variety of other communication methods during 2016. Idaho Power increased customer awareness of energy-saving ideas via continued distribution of the third printing of the 96-page booklet *30 Simple Things You Can Do to Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. In 2016, the program distributed 2,595 English and 480 Spanish copies directly to customers. This was accomplished via community events and local libraries; by customer representatives during in-home visits; by participating contractors in the Home Improvement Program, Energy House Calls program, H&CE Program, and Fridge and Freezer Recycling Program; through direct web requests; and in response to inquiries received by Idaho Power's Customer Service Center. Agency partners also used the books to educate clients about Energy Efficiency. Additionally, more than 34,000 customers had an opportunity to request the booklet and/or the most recent *Energy Efficiency Guide* when they ordered their ESK online.

Idaho Power continues to recognize that educated employees are effective advocates for energy efficiency and Idaho Power's energy efficiency programs. Idaho Power customer relations and energy-efficiency staff reached out to each of Idaho Power's geographical regions and the Customer Service Center to speak with customer representatives and other employees to discuss educational initiatives and answer questions about the company's energy efficiency programs.

The Kill A Watt™ Meter Program remained active in 2016. Idaho Power's Customer Service Center and field staff continued to encourage customers to learn about the energy used by specific appliances and activities within their homes by visiting a local library to check out a Kill A Watt meter. The Kill A Watt meters were mentioned on live television studio news programs on KTVB and KPVI in Idaho Power's monthly energy efficiency segments.

As in previous years, Idaho Power continued to strengthen the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2016, 16 teachers completed the four-day, two-credit professional development seminar, Energy for Future Citizens, facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Laboratory (INL). Among other things, participating teachers received a classroom kit containing Kill A Watt meters and other tools to facilitate student learning related to energy efficiency and wise energy use.

Idaho Power continued to engage customers in energy efficiency discussions at many community events throughout Idaho Power's service area. In February, Idaho Power participated in the Smart Women, Smart Money conference for the second year and educated nearly 2,000 women about the benefits of energy-efficient choices and LED lighting. In February, March, April, and May Idaho Power participated in the Twin Falls Home and Garden Show, the College of Southern Idaho's Sustainability Show, the Centennial Ribbon Cutting at the Twin Falls Visitor Center, Platt's Super Tool Day, Pocatello's Spring Home Show and the Portneuf Valley Community Environmental Fair—actively promoting wise energy use and participation in energy efficiency programs while distributing over 16,000 LED lightbulbs at these specific events.

In September 2016, Idaho Power participated in the FitOne Expo in Boise, Idaho. The event continued to be important to the initiative due to the size of the audience and because Idaho Power's prior participation confirmed the demographics of attendees appear to align with the company's residential energy efficiency target audience. In 2016, Idaho Power staff at the event once again focused attendee attention on the benefits of LED lighting technology, distributed LED lightbulbs, and promoted participation in the ESK program.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 92 outreach activities, including events, presentations, trainings, and other activities. In addition, Idaho Power customer representatives delivered 189 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2016, Idaho Power's Community Education team provided 91 presentations on *The Power to Make a Difference* to 2,350 students and 53 classroom presentations on *Saving a World Full of Energy* to 1,411 students. The community education representatives and other staff also completed 14 senior citizen presentations on energy efficiency programs and shared information about saving energy to 592 senior citizens in the company's service area. Additionally, Idaho Power's energy efficiency program managers responded with detailed answers to 364 customer questions about energy efficiency and related topics received via Idaho Power's website.

As part of National Energy Awareness Month in October, Idaho Power held its sixth annual student art contest in the Idaho Power service area, bringing energy education into the classroom and inspiring students and families to think more about energy. This year, the contest set a new record with more than 2,239 entries representing all regions. The contest, which featured "Ways to Save Energy" as one of the highlighted categories, was promoted in a late September *News Briefs* and results were publicized in *Connections*. Regional and overall winning students and their teachers were recognized.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and in support of Idaho Power's *#TipTuesday* posts. In addition to supplying information for various Idaho Power publications, such as the *News Scans* weekly employee newsletter, the *Connections* customer newsletter, and Idaho Power's Facebook page, energy efficiency tips, and content was provided for weekly *News Briefs* and monthly KTVB (Boise) and KPVI (Pocatello) live news segments.

The initiative completed the program design phase of the ESK program and implemented the new program. Each kit was shipped with a mini-home assessment to cross-market other energy efficiency programs, promote the use of myAccount and help families learn about other energy-saving behavior changes. Savings and expenses have been reported under Educational Distributions.

The initiative continued to coordinate LED lightbulb distributions aimed at getting the newest lighting technology into customer hands along with customer education and answers to their common questions. At events and presentations, company staff distributed over 24,900 LEDs in custom packaging that highlighted the advantages of energy-efficient lighting and encouraged participation in Idaho Power's myAccount on-line portal. LED lightbulbs were mentioned on nine of the news segments on KTVB and KPVI. The energy savings resulting from this effort and from the SEEK for the school year 2015 to 2016, are reported in the Educational Distributions program section of this report.

In 2016, the initiative implemented the Drying Rack Pilot Project—a behavioral change program with the goal of helping customers reduce their automatic clothes dryer use by 25 percent or more. Educational messages to support the behavior change were delivered to customers at the point of enrollment, when drying racks were picked up and during the project period. Additional information about the project can be found in the Educational Distributions program in this report.

In the fall, the initiative conducted a survey with the em**powered** community to learn more about customers' shower behaviors—in particular, details around how they warm up the water prior to taking a shower. Information from the survey may be used to improve potential future offerings such as the addition of a thermostatic shower valve as an educational distribution option. A copy of the survey can be found in *Supplement 2: Evaluation*.

The initiative's 2017 goals are to increase program participation and promote education and energy saving ideas that result in energy-efficient, conservation-oriented behaviors and choices. In addition to producing and distributing educational materials, the initiative will continue to manage the company's Educational Distributions program responsible for distributing educational measures that have associated savings. Examples of activities conducted under Educational Distributions include LED lighting education, distribution of LED lightbulbs to customers, the SEEK program, the Drying Rack Project and the ESK program. In addition to these activities, the initiative plans to implement a home energy report pilot project.

The initiative will continue to work with the PPG to explore additional behavioral program opportunities that may include distribution of thermostatic shower valves, increased promotion of myAccount, or a pilot program to test other behavioral messages.

Evaluation and Best Practices Review

In 2016, the company contracted with Leidos to perform a process evaluation and best practices review of the REEEI. Leidos found that REEEI is comprised of 23 different activities, efforts and elements that educate, inform, and persuade residential electric customers to install energy-efficient measures and to take other actions that decrease energy use. They also found the initiative both investigates and engages in various behavioral change strategies.

Leidos also found Idaho Power has a comprehensive presence on both traditional and social media channels. The 23 initiative elements reach over 415,000 customers in a variety of ways ranging from: 1) in-person contacts and presentations, courtesy of five community educational and approximately 20 customer representatives in the field daily; 2) newsletters, guides, mailers, conventional broadcasting, social media; and 3) gamification reward systems, sponsorships, educational materials and training.

Interviews with Idaho Power staff and initiative efforts indicate a strong focus on driving customers to use the myAccount on-line portal located on the company website, where customers check on energy use via near real-time smart-meters, billing and account information with links to tools, rebates and other resources that aid in understanding their energy use and reduction strategies. Daily customer logins to myAccount have steadily increased over the last four and a half years, from 2,000 logins in mid-2012, to about 5,000 in late-2016. Moreover, the number of myAccount registrations per month is also increasing, from 2,000 to4,000 accounts per month in 2010 through 2011, up to 3,000 to 5,000 per month more recently.

Idaho Power is marketing energy-savings programs and activities by linking them to home improvement, money savings, comfort, and other NEBs to capture interest in energy efficiency and move it to top-of-mind. Surveys conducted with external program managers, subject-matter experts, and Idaho Power staff rated their customers' non-energy motivational drivers on a 10-point scale.

"Saving money" was rated highest (9.4), followed by improved comfort (9.1), health and safety (7.6), and being/feeling "green" and reducing environmental impacts (7.3).

External program managers, subject-matter experts, and Idaho Power staff rated marketing channels that involve person-to-person interaction and active learning environments higher than more passive, informal channels, to reach and educate customers. On a 10-point scale, situations where strong in-group social identity exists were rated most effective/useful (8.0), followed by on-line customer utility accounts (7.7), universities and college settings (7.6), public or community events, on-line energy dashboards and smart or real-time meters (all 7.3).

Leidos estimates conservatively that Idaho Power staff conducted over 590 in-person (or webinar) outreach activities, training sessions and events recorded in the Outreach Tracker database (from early 2012 to mid-2016) with an average attendance of 8091 people per event.

The SEEK and *The Power to Make a Difference* presentation (given by Idaho Power staff 124 times to 3,359 students in 2015) are also features of REEEI. Both received numerous positive comments from customers and build strong customer-utility relations. "The children always express that they tried everything included [in the kits] with their parents or family members. The adults express they are happy to have the free materials especially the lightbulbs and showerheads…teachers cannot thank us enough for this program!" Eighteen high school teachers participated in a three-day professional development seminar (facilitated by iSTEM) that empowered teachers with information and classroom tools to teach students to think critically about energy, including; the science of energy, energy generation and sources, wise energy use and social impacts.

A literature review of best practices regarding energy education programs was performed and indicated there are four basic types of behavioral change programs and strategies: 1) informational programs, 2) socially interactive approaches, 3) education and training, and 4) a stacked approach. Leidos states the four types of behavioral change strategies are well represented in the breadth of REEEI elements described in the final report.

The final report can be found in *Supplement 2: Evaluation.*

University of Idaho Integrated Design Lab

Idaho Power is a founding supporter of the IDL. The IDL is dedicated to the development of high-performance, energy-efficient buildings in the Intermountain West. Idaho Power has worked with the IDL since its inception in 2004 to educate the public about how energy-efficient business practices benefit the business and the customer. In 2016, Idaho Power entered into an agreement with the IDL to perform the following tasks and services.

Foundational Services

The goal of this task was to provide energy efficiency technical assistance and project-based training to building industry professionals and customers. When the IDL receives requests for their involvement in building projects, the projects are categorized into one of three types. Phase I projects are simple requests that can be addressed with minimal IDL time. Phase II projects are more complex requests that require more involvement and resources from the lab. Phase III projects are significantly more complex and must be co-funded by the customer.

In 2016, the IDL provided technical assistance on a total of 38 projects in the Idaho Power service area. There were 32 Phase I projects, five Phase II projects, and one Phase III project. An additional three projects, currently in early stages, and the full scope of work is yet to be determined. Overall, 44 percent of the projects were on new buildings, 38 percent were on existing buildings and 18 percent were not building specific. The report is located in the IDL section of *Supplement 2: Evaluation*.

Lunch & Learn

The goal of the Lunch & Learn task was to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions.

In 2016, the IDL scheduled 20 technical training lunches in Boise, and Ketchum. The trainings were coordinated directly with architecture and engineering firms and organizations; a total of 161 architects, engineers, interior designers, project managers, and others attended.

Eighteen lunches were offered in Boise, and two in Ketchum. The topics of the lunches (and number of each) were: The Classroom of the Future: A DOE project (1); New Design Recommendations for Exterior Lighting (1); Case Study—Daimler Truck North America (1); Passive House Standard for Multifamily Projects (1); Life Sciences Building Path to High-Performance Design and Construction (1); Integrated Design Principles (1); Daylight Performance Metrics for Human Health, Productivity, and Satisfaction (1); Cold Feet: Managing Controls and Condensation with Simulating Radiant Slab Cooling (1); Daylight in Buildings: Schematic Design Methods (1); Radiant Heating and Cooling Design Considerations (1); Benchmarking and Energy Goal Setting (1); Integrated Design Case Studies (2); Hybrid Ground Source Heat Pump (2); and Daylight in Buildings: Getting the Details Right (5). The report is located in the IDL section of *Supplement 2: Evaluation*.

Building Simulation Users Group

The goal of this task was to facilitate the Idaho BSUG, which is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

In 2016, six monthly BSUG sessions were hosted by IDL. The sessions were attended by 73 professionals in person and were made available remotely, attended by 48 professionals. Evaluation forms were completed by attendees for each session. On a scale of 1 to 5, with 5 being “excellent” and 1 being “poor,” analyzing results from the first six questions, the average session rating was 4.34 for 2016. For the final question “The content of the presentation was…” on a scale of 1 to 5, with 1 being “too basic,” 3 being “just right,” and 5 being “too advanced,” the average session rating was 3.15 for 2016.

Each presentation was archived on the BSUG 2.0 website along with general BSUG-related content. The BSUG 2.0 site logged 994 page views with 234 specific to Idaho users in 2016. The report is located in the IDL section of *Supplement 2: Evaluation*.

New Construction (Building Efficiency) Verification

The goal of this task was to continue random installation verification of over 10 percent of New Construction program participants who received incentives. This consisted of conducting a full review of documentation and complete on-site inspections to validate whether noted systems and components had been installed. The purpose of this verification was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations.

This task also included the review of all daylight photo-control incentives to verify site conditions and improve the quality of design and installation.

The IDL completed on-site field verifications for the New Construction program as summarized in the New Construction Customer Satisfaction and Evaluations section presented earlier in this report. The verification report is located in the IDL section of *Supplement 2: Evaluation*.

Tool Loan Library

The TLL gives customers access to equipment that enables them to measure and monitor energy consumption on various systems within their operation. The goal of this task was to operate and maintain measurement equipment, including a web-based equipment tool loan-tracking system, and to provide technical training on how each tool is intended to be used.

The inventory of the TLL now consists of over 900 individual pieces of equipment. In 2016, two new tools and eight manuals were added to the library. Additionally, 25 tools were calibrated in 2016. The tools and manuals are available for customers, engineers, architects, and contractors in Idaho Power's service area to borrow at no cost to aid in the evaluation of energy efficiency projects and equipment they are considering.

There were 49 tool loan requests in 2016, which included a total of 206 tools loaned. The tools were loaned to 30 unique customers, including engineering firms, equipment representatives, educational institutions, industrial plants, and office/commercial facilities. The report is located in the IDL section of *Supplement 2: Evaluation*.

Building Metrics Labeling

The goal of this task was to continue the support and promotion of the Building Metrics Labeling (BML) sheet, a graphical display of four building metrics on a single sheet that was developed in a task that began in 2012. The metrics displayed are Energy Use Intensity, ENERGY STAR® score, Walk Score®, and Space Daylit Area. The purpose of the BML sheet is to increase awareness of building energy use and to promote energy efficiency during the sale or lease of commercial properties. The final version of the BML tool became available for public use in early 2014.

The IDL continued support and maintenance of the sheet in 2016. The tool was discussed and/or flyers were distributed at twenty Lunch & Learn presentations to architecture or engineering firms and organizations, multiple Central Addition Planning meetings hosted by the USGBC, six BSUG events, and during calls or visits to five building owners within the Central Addition (LIV District). One-on-one support was also available if requested, but no requests were made in 2016. The report is located in the IDL section of *Supplement 2: Evaluation*.

Heat Pump Calculator/Climate Design Tools

This task was a continuation of work done in a task that began in 2013 and continued through 2016. The goal of the original task was to develop an Excel-based heat pump analysis tool to calculate energy use and savings based on site-specific variables for commercial buildings. Previously, IDL identified a lack of sophisticated heat pump energy-use calculators available with the capability of comparing the energy use of heat pumps in commercial buildings against other technologies in a quick, simple fashion.

The calculator has been updated to reflect feedback from validation testing, including an improved user interface and the ability to integrate Typical Meteorological Year, version three (TMY3) weather files for locations where that data is available. A few years ago, the IDL completed a set of Climate Design Tools intended to inform sustainable design and calculate the impacts of five innovative types of systems: earth tubes, passive heating, cross ventilation, stack ventilation, and night flush ventilation/thermal mass. In 2015, the IDL integrated three of the five climate design tools into the Heat Pump Calculator. This unification produced a single platform life-cycle analysis tool for several energy efficiency measures not currently well-supported with other tools in the industry.

The work in 2016 included the unification of two additional climate design tools to the calculator and the addition of seven unique weather files for sites around Idaho. The report for this task is located in the IDL section of *Supplement 2: Evaluation*.

Daylight Training

New in 2016, this task involved advance preparation work to provide daylight training sessions for local professionals in 2017. The training will enhance knowledge of, and appreciation for, daylight, and keep professionals informed of the latest advances in daylighting technologies.

The 2016 preparation included recommissioning lighting controls in the IDL, gathering of installed lighting controls manuals, writing a protocol for demonstration, and reviewing new lighting control technologies. A market-needs assessment was performed in the third quarter of 2016 to determine the need for a daylight training class, as well as to help develop the curriculum. Initial marketing began in November 2016 for the 2017 sessions. The report for this task is located in the IDL section of *Supplement 2: Evaluation*.

2017 IDL Strategies

In 2017, the IDL will continue or expand work on the Foundational Services, Lunch & Learn sessions, BSUG, Building Efficiency Verifications, TLL, Heat Pump Calculator, and Daylight Training tasks. IDL will also provide work on one new task in 2017, an Absorption Chiller Feasibility Study.

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REGULATORY OVERVIEW

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. By working with its stakeholders and regulators through negotiations and filings, Idaho Power seeks to move DSM regulatory treatment toward achieving all of these goals.

Timely Recovery of DSM Program Costs: Energy Efficiency Rider and Prudence Determination of Expenditures

Since 2002, Idaho Power has recovered most of its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM expenditures. In addition, since January 1, 2012, Idaho demand response program incentives expenses have been included in base rates and tracked in the annual PCA mechanism.

Annual DSM Expense Review Filing and Order No. 33583

On March 15, 2016, Idaho Power filed Case No. IPC-E-16-03 with the IPUC requesting an order finding the company had prudently incurred $35,196,964 in DSM expenses in 2015, including $28,495,701 in Rider expenses and $6,701,263 in demand response program incentives. The filing included three reports: *Demand-Side Management 2015 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*. Due to previous IPUC decisions in Order Nos. 32667, 32690, and 32953 to defer Idaho Power's request to deem prudent the increases in the company's Rider-funded labor-related expenses for 2011and 2012, Idaho Power did not request a prudence determination for labor-related expenses of $441,856 in the 2015 filing. The 2015 labor-related expenses of $441,856 bring the cumulative balance of increases in Rider-funded labor-related expenses that have not yet received a prudence determination to $1,313,407 through 2015. Idaho Power plans to request a prudence determination on these amounts in its 2016 DSM prudence request.

In Order No. 33583, dated September 14, 2016, the IPUC deemed $35,196,964 as prudently incurred.

Since 2012, the company has experienced a mismatch in Rider funding levels compared to expenditures in that the Rider has been collecting more than the company has been spending on its DSM efforts. As part of Order No. 33583, the IPUC directed Idaho Power to work with staff and other stakeholders to examine an adjustment to the Rider percentage and to submit a proposal for revising the Rider percentage to the commission no later than December 30, 2016.

Following collaboration with the parties to the case (staff, Industrial Customers of Idaho Power [ICIP] and Idaho Conservation League [ICL]) and a conference call with EEAG, on December 22, 2016, Idaho Power filed an application in Case No. IPC-E-16-33 requesting an order approving: 1) a decrease to the Rider collection percentage from 4 to 3.75 percent of base rate revenues, effective March 1, 2017; 2) a $13 million refund of previously collected Rider funds to be included in the 2017/2018 PCA effective June 1, 2017, and 3) the elimination of the annual transfer of $4 million of Rider funds through the PCA. The annual transfer of $4 million of Rider funds through the PCA is more fully described in the following paragraph.

Energy Efficiency Rider-Funds Transfer

On April 15, 2016, Idaho Power filed the annual PCA Case No. IPC-E-16-08 with the IPUC. As part of that case, the company proposed that the commission approve a transfer of $3,970,036 from the Rider to customers as a credit, or reduction, in the 2016/2017 PCA on customers' bills. In Order No. 33526, the commission approved the transfer. This transfer is needed to maintain the revenue neutrality associated with the June 2014 update to the normalized level of net power supply expense included in base rates approved by Order No. 33000.

Removal of Financial Disincentives: Fixed-Cost Adjustment

To address the removal of financial disincentives, Idaho Power has in place a fixed-cost adjustment (FCA) mechanism in Idaho. Under the FCA, rates for Idaho residential and small general-service customers are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent general rate case and the fixed costs Idaho Power received the previous year through actual energy sales. This mechanism removes the financial disincentive that exists when Idaho Power promotes energy efficiency programs designed to reduce customer usage. The FCA addresses, for residential and small general-service customers, the percentage of fixed costs that are recovered through their volumetric energy charges.

On May 27, 2016, the IPUC issued Order No. 33527 approving the company's request to implement FCA rates beginning June 1, 2016, for the 2015 fixed-cost deferrals. The overall rate adjustment was a 2.2 percent increase for residential and small general-service customers to collect a combined $28 million. This adjustment was an increase of $11 million from the previous year's FCA. Residential customers pay an FCA of 0.5416 cents per kWh, while small general-service customers pay an FCA of 0.6875 cents per kWh. The rate will be in place until May 31, 2017.

Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power believes rates offered to customers should reflect their cost of service to provide cost-based price signals, and encourage the wise and efficient use of energy.

Since 2012, Idaho Power has offered a Time-of-Day (TOD) Pilot pricing plan to residential customers in Idaho. The overall goal of this TOD pricing plan is to use the AMI system to offer customers a choice of pricing plans while providing them with tools to manage their energy use, to provide the company with the opportunity to further study the effects of a time-variant rate on customers' use, and to help shape the company's future communication efforts. The plan provides participants the opportunity to shift their usage from higher-priced, on-peak time periods to lower-priced, off-peak time periods and possibly lower their bills. As of the end of 2016, approximately 1,300 Idaho customers were TOD plan participants. A description of this plan is at Idaho Power's website (idahopower.com/TOD).

GLOSSARY OF ACRONYMS

A/C—Air Conditioning/Air Conditioners
ADM—ADM Associates, Inc.
Ads—Advertisement
AEG—Applied Energy Group
AMI—Advanced Metering Infrastructure
aMW—Average Megawatt
ARCA—Appliance Recycling Center of America
ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers
B/C—Benefit/Cost
BCA—Building Contractors Association
BCASEI—Building Contractors Association of Southeast Idaho
BCASWI—Building Contractors Association of Southwestern Idaho
BML—Building Metrics Labeling
BOMA—Building Owners and Managers Association
BOP—Builder Option Package
BPA—Bonneville Power Administration
BPI—Building Performance Institute
BSUG—Building Simulation Users Group
CAP—Community Action Partnership
CAPAI—Community Action Partnership Association of Idaho, Inc.
CAZ—Combustion Appliance Zone
CCE—Commercial Code Enhancement
CCOA—Aging, Weatherization and Human Services
CCNO—Community Connection of Northeast Oregon, Inc.
CEI—Continuous Energy Improvement
CEL—Cost-Effective Limit
CFL—Compact Fluorescent Lamp/Lightbulb
CFM—Cubic Feet per Minute
CHQ—Corporate Headquarters (Idaho Power)
CINA—Community in Action
CLEAResult—CLEAResult Consulting, Inc.
COP—Coefficient of Performance
CR&EE—Customer Relations and Energy Efficiency
CRES—Certified Refrigeration Energy Specialist
DHP—Ductless Heat Pump
DOE—Department of Energy
DSM—Demand-Side Management
EA5—EA5 Energy Audit Program
EBR—Existing Building Renewal
ECM—Electronically Commutated Motors

EEAG—Energy Efficiency Advisory Group
EICAP—Eastern Idaho Community Action Partnership
EL ADA—El Ada Community Action Partnership
EM&V—Evaluation, Measurement, and Verification
EPA—Environmental Protection Agency
ESK—Energy-Savings Kit
EV—Electric Vehicle
FCA—Fixed-Cost Adjustment
ft^2—Square Feet
ft^3—Cubic Feet
GIS—Geographic Information System
GMI—Green Motors Initiative
GMPG—Green Motors Practice Group
gpm—Gallons per Minute
H&CE—Heating & Cooling Efficiency Program
HP—Hewlett Packard
hp—Horsepower
HPS—Home Performance Specialist
HPWH—Heat Pump Water Heater
HSPF—Heating Seasonal Performance Factor
HUD—Housing and Urban Development
HVAC—Heating, Ventilation, and Air Conditioning
IBCA—Idaho Building Contractors Association
IBOA—International Building Operators Association
ICIP—Industrial Customers of Idaho Power
ICL—Idaho Conservation League
IDHW—Idaho Department of Health and Welfare
IDL—Integrated Design Lab (in Boise)
IECC—International Energy Conservation Code
INL—Idaho National Laboratory
IPMVP—International Performance Measurement and Verification Protocol
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
ISHE—International Society of Healthcare Engineers
iSTEM—Idaho Science, Technology, Engineering and Mathematics
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
MOU—Memorandum of Understanding
MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association
MW—Megawatt
MWh—Megawatt-hour
MWSOC—Municipal Water Supply Optimization Cohort
n/a—Not Applicable
NEB—Non-Energy Benefit
NEEA—Northwest Energy Efficiency Alliance
NEEM—Northwest Energy Efficient Manufactured
NEMA—National Electrical Manufacturers Association
NPR—National Public Radio
NSH—Next Step Home
NTG—Net to Gross
NWPCC—Northwest Power and Conservation Council
O&M—Operation and Maintenance
OHCS—Oregon Housing and Community Services
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statute
OSV—On-Site Verification
PCA—Power Cost Adjustment
PCT—Participant Cost Test
PLC—Powerline Carrier
PNWS–AWWA—Pacific Northwest Section American Water Works Association
PPG—Program Planning Group
PRV—Pressure Regulating Valve
PSC—Permanent Split Capacitor
PTCS—Performance Tested Comfort System
QA—Quality Assurance
QC—Quality Control
RAP—Resource Action Programs
RBSA—Residential Building Stock Assessment
REEEI—Residential Energy Efficiency Education Initiative
RESNET—Residential Services Network
RETA—Refrigerating Engineers and Technicians Association
RETAC—Regional Emerging Technologies Advisory Committee
Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider
RIM—Ratepayer Impact Measure
RPP—Retail Products Platform
RTF—Regional Technical Forum
RWLR—Reduced Wattage Lamp Replacement
SCCAP—South Central Community Action Partnership
SCE—Streamlined Custom Efficiency
SEEK—Students for Energy Efficiency Kit
SEEM—Simplified Energy Enthalpy Model

SEICAA—Southeastern Idaho Community Action Agency
SEM—Strategic Energy Management
SIR—Savings-to-Investment Ratio
SRVBCA—Snake River Valley Building Contractors Association
SWIOS—Southwest Idaho Operators Conference
TLED—Tube LED
TLL—Tool Loan Library
TMY3—Typical Meteorological Year, version three
TOD—Time of Day
TRC—Total Resource Cost
TRM—Technical Reference Manual
TTTA—Top-Tier Trade Ally
UC—Utility Cost
UES—Unit Energy Savings
UM—Utility Miscellaneous
US—United States
USGBC—US Green Building Council
VFD—Variable-Frequency Drive
VRF—Variable Refrigerant Flow
W—Watt
WAP—Weatherization Assistance Program
WAQC—Weatherization Assistance for Qualified Customers
WEFTEC—Water Environment Federation Technical Exhibition and Conference
WHF—Whole-House Fan
WSOC—Water Supply Optimization Cohort
WWEEC—Wastewater Energy Efficiency Cohort

APPENDICES

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Appendix 1. Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December 2016)

Idaho Energy Efficiency Rider [a]		
2016 Beginning Balance	$	6,554,074
2016 Funding plus Accrued Interest as of 12-31-16		39,437,692
Total 2016 Funds		**45,991,766**
2016 Expenses as of 12-31-16		(31,291,579)
Rider Transfer to PCA (IPUC Order 33306)		(3,970,036)
Ending Balance as of 12-31-2016	**$**	**10,730,151**
Oregon Energy Efficiency Rider		
2016 Beginning Balance	$	(4,482,485)
2016 Funding plus Accrued Interest as of 12-31-16		1,099,211
Total 2016 Funds		**(3,383,273)**
2016 Expenses as of 12-31-16		(2,168,868)
Ending Balance as of 12-31-2016	**$**	**(5,552,141)**
NEEA Payments		
2016 NEEA Payments as of 12-31-2016	$	2,676,387
Total	**$**	**2,676,387**

[a] Liability accounts

Appendix 2. 2016 DSM expenses by funding source (dollars)

Sector/Program	Idaho Rider	Oregon Rider	Non-Rider Funds	Total
Energy Efficiency/Demand Response				
Residential				
A/C Cool Credit	$ 632,079	$ 41,833	$ 429,383	$ 1,103,295
Easy Savings	–	–	127,587	127,587
Educational Distributions	2,334,206	56,164	2,514	2,392,884
Energy Efficient Lighting	3,009,970	63,200	7,538	3,080,708
Energy House Calls	188,253	15,815	2,368	206,437
ENERGY STAR® Homes Northwest	138,203	1,510	2,445	142,158
Fridge and Freezer Recycling Program (See ya later, refrigerator®)	250,535	4,555	2,826	257,916
Heating & Cooling Efficiency Program/DHP Pilot	545,454	27,184	22,275	594,913
Home Energy Audit	278,959	–	10,853	289,812
Home Improvement Program	309,799	–	14,225	324,024
Multifamily Energy Savings Program	55,758	–	3,288	59,046
Oregon Residential Weatherization	–	3,906	24	3,930
Rebate Advantage	103,056	6,392	1,602	111,050
Shade Tree Program	70,669	–	5,973	76,642
Simple Steps, Smart Savings™	147,055	3,535	3,194	153,784
Weatherization Assistance for Qualified Customers	–	–	1,289,809	1,289,809
Weatherization Solutions for Eligible Customers	1,226,540	56,571	40,681	1,323,793
Commercial/Industrial				
Building Efficiency	1,863,584	42,559	25,079	1,931,222
Custom Efficiency	7,664,563	237,146	80,916	7,982,624
Easy Upgrades	4,791,852	228,834	19,505	5,040,190
Flex Peak Program	105,116	247,897	414,984	767,997
Oregon Commercial Audit	–	7,717	–	7,717
Irrigation				
Irrigation Efficiency Rewards	1,672,328	634,101	65,923	2,372,352
Irrigation Peak Rewards	1,082,113	218,906	6,299,056	7,600,076
Energy Efficiency/Demand Response Total	**$ 26,470,093**	**$ 1,897,824**	**$ 8,872,049**	**$ 37,239,965**
Market Transformation				
NEEA	2,542,567	133,820	–	2,676,387
Market Transformation Total	**$ 2,542,567**	**$ 133,820**	**$ –**	**$ 2,676,387**
Other Programs and Activities				
Residential Energy Efficiency Education Initiative	259,301	12,071	18,806	290,179
Energy Efficiency Direct Program Overhead	238,767	16,965	37,307	293,039
Other Programs and Activities Total	**$ 498,068**	**$ 29,036**	**$ 56,114**	**$ 583,218**
Indirect Program Expenses				
Commercial/Industrial Energy Efficiency Overhead	222,704	16,653	86,715	326,072
Energy Efficiency Accounting & Analysis	848,975	49,358	251,197	1,149,530
Energy Efficiency Advisory Group	14,365	806	954	16,125
Residential Energy Efficiency Overhead	783,384	44,818	35,987	864,189
Special Accounting Entries	(88,576)	(3,447)	–	(92,024)
Indirect Program Expenses Total	**$ 1,780,851**	**$ 108,187**	**$ 374,854**	**$ 2,263,893**
Grand Total	**$ 31,291,579**	**$ 2,168,868**	**$ 9,303,017**	**$ 42,763,464**

Appendix 3. 2016 DSM program activity

Program	Participants		Total Costs: Utility [b]	Total Costs: Resource [c]	Savings: Annual Energy (kWh)	Savings: Peak Demand [d] (MW)	Measure Life (Years)	Nominal Levelized Costs [a]: Utility ($/kWh)	Nominal Levelized Costs [a]: Total Resource ($/kWh)
Demand Response									
A/C Cool Credit[1]	28,315	homes	$ 1,103,295	$ 1,103,295	n/a	34	n/a	n/a	n/a
Flex Peak Program[1]	137	sites	767,997	767,997	n/a	42	n/a	n/a	n/a
Irrigation Peak Rewards[1]	2,286	service points	7,600,076	7,600,076	n/a	303	n/a	n/a	n/a
Total			**$ 9,471,367**	**$ 9,471,367**	**n/a**	**378**			
Energy Efficiency									
Residential									
Easy Savings	2,001	kits	$ 127,587	$127,587	402,961		9	$0.035	$0.035
Educational Distributions	67,065	kits/lightbulbs	2,392,884	2,392,884	15,149,605		10	0.016	0.016
Energy Efficient Lighting	1,442,561	lightbulbs	3,080,708	10,770,703	21,093,813		11	0.014	0.049
Energy House Calls	375	homes	206,437	206,437	509,859		18	0.029	0.029
ENERGY STAR® Homes Northwest	110	homes	142,158	297,518	150,282		36	0.051	0.107
Fridge and Freezer Recycling Program (See ya later, refrigerator®)	1,539	refrigerators/freezers	257,916	257,916	632,186		6	0.062	0.062
Heating & Cooling Efficiency Program	486	projects	594,913	1,404,625	1,113,574		20	0.036	0.085
Home Energy Audit	539	audits	289,812	289,812	207,249		11	n/a	n/a
Home Improvement Program	482	projects	324,024	1,685,301	500,280		45	0.034	0.178
Multifamily Energy Savings Program	3	projects	59,046	59,046	149,760		10	0.040	0.040
Oregon Residential Weatherization	7	homes	3,930	5,900	2,847		30	0.079	0.118
Rebate Advantage	66	homes	111,050	148,142	411,272		25	0.016	0.022
Simple Steps, Smart Savings™	7,880	appliances/showerheads	153,784	379,752	577,320		11	0.025	0.063
Weatherization Assistance for Qualified Customers	246	homes/non-profits	1,289,809	1,934,415	746,162		25	0.105	0.158
Weatherization Solutions for Eligible Customers	232	homes	1,323,793	1,323,793	621,653		25	0.130	0.130
Sector Total			**$ 10,357,850**	**$21,283,831**	**42,259,823**		**8**	**$ 0.029**	**$ 0.059**
Commercial									
Custom Projects (Custom Efficiency)	196	projects	$ 7,982,624	$ 16,123,619	47,518,871		11	$ 0.013	$ 0.026
Green Motors—Industrial	14	motor rewinds			123,700		16	n/a	n/a
New Construction (Building Efficiency)	116	projects	1,931,222	4,560,826	12,393,249		12	0.014	0.033
Retrofits (Easy Upgrades)	1,577	projects	5,040,190	8,038,791	28,124,779		11	0.016	0.026
Sector Total			**$ 14,954,036**	**$ 28,723,235**	**88,160,599**		**14**	**$ 0.014**	**$ 0.026**

Appendix 3. 2016 DSM program activity (continued)

Program	Participants		Total Costs: Utility [b]	Total Costs: Resource [c]	Savings: Annual Energy (kWh)	Savings: Peak Demand [d] (MW)	Measure Life (Years)	Nominal Levelized Costs [a]: Utility ($/kWh)	Nominal Levelized Costs [a]: Total Resource ($/kWh)
Irrigation									
Green Motors—Irrigation	23	motor rewinds			73,617		11	n/a	n/a
Irrigation Efficiency Reward	851	projects	$ 2,372,352	$ 8,162,206	15,673,513		8	$ 0.018	$ 0.063
Sector Total			**$ 2,372,352**	**$ 8,162,206**	**15,747,130**		**8**	**$ 0.018**	**$ 0.062**
Energy Efficiency Portfolio Total			**$ 27,684,239**	**$ 58,169,272**	**146,176,552**		**12**	**$ 0.017**	**$ 0.036**
Market Transformation									
Northwest Energy Efficiency Alliance			$ 2,676,387	$ 2,676,387	24,615,600				
Other Programs and Activities									
Residential									
Residential Energy Efficiency Education Initiative			$ 290,179	$ 290,179					
Shade Tree Project	2,070	trees	76,642	76,642					
Commercial									
Oregon Commercial Audits	7	audits	7,717	7,717					
Other									
Energy Efficiency Direct Program Overhead			293,039	293,039					
Total Program Direct Expense			**$ 40,499,570**	**$ 70,984,603**	**170,792,152**	**378**			
Indirect Program Expenses			2,263,893						
Total DSM Expense			**$ 42,763,464**						

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP, and calculations include line-loss adjusted energy savings.
[b] The Total Utility Cost is the cost incurred by Idaho Power to implement and manage a DSM program.
[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
[d] Demand response program reductions are reported with 9.7-percent peak loss assumptions.
[1] Peak demand is the peak performance of the program during summer 2016.
[2] Savings are preliminary estimates provided by NEEA. Final savings for 2016 will be provided by NEEA May 2017.

Appendix 4. Historical DSM expense and performance, 2002–2016

Program/Year	Participants	Total Costs: Utility Cost [c]	Total Costs: Resource Cost [d]	Savings and Demand Reductions: Annual Energy (kWh)	Savings and Demand Reductions: Average Energy [e] (aMW)	Savings and Demand Reductions: Peak Demand [f] (MW)	Measure Life (Years)	Levelized Costs [a]: Total Utility ($/kWh)	Levelized Costs [a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios [b]: Utility	Program Life Benefit/Cost Ratios [b]: 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					
2006	5,369	1,235,476	1,235,476			6					
2007	13,692	2,426,154	2,426,154			12					
2008	20,195	2,969,377	2,969,377			26					
2009	30,391	3,451,988	3,451,988			39					
2010	30,803	2,002,546	2,002,546			39					
2011	37,728	2,896,542	2,896,542			24					
2012	36,454	5,727,994	5,727,994			45					
2013	n/a	663,858	663,858			n/a					
2014	29,642	1,465,646	1,465,646			44					
2015	29,000	1,148,935	1,148,935			36					
2016	28,315	1,103,295	1,103,295			34					
Total		**$26,408,770**	**$ 26,408,770**								
Flex Peak Program											
2009	33	528,681	528,681			19					
2010	60	1,902,680	1,902,680			48					
2011	111	2,057,730	2,057,730			59					
2012	102	3,009,822	3,009,822			53					
2013	100	2,743,615	2,743,615			48					
2014	93	1,563,211	1,563,211			40					
2015	72	592,872	592,872			26					
2016	137	767,997	767,997			42					
Total		**$13,166, 608**	**$ 13,166,608**								
Irrigation Peak Rewards											
2004	58	344,714	344,714			6					
2005	894	1,468,282	1,468,282			40					
2006	906	1,324,418	1,324,418			32					

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
Irrigation Peak Rewards											
2007	947	$ 1,615,881	$ 1,615,881			37					
2008	897	1,431,840	1,431,840			35					
2009	1,512	9,655,283	9,655,283			160					
2010	2,038	13,330,826	13,330,826			250					
2011	2,342	12,086,222	12,086,222			320					
2012	2,433	12,423,364	12,423,364			340					
2013	n/a	2,072,107	2,072,107			n/a					
2014	2,225	7,597,213	7,597,213			295					
2015	2,259	7,258,831	7,258,831			305					
2016	2,286	7,600,076	7,600,076			303					
Total		**$ 78,209,056**	**$ 78,209,056**								
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		
2013	215	237,575	992,440	589,142	0.07		15	0.032	0.132		
2014	179	251,446	884,211	462,747	0.05		15	0.042	0.148		
Total	**852**	**$ 1,231,307**	**$ 3,935,681**	**2,728,069**			**15**	**$ 0.044**	**$ 0.138**		
Easy Savings Kits											
2015	2,068	127,477	127,477	624,536			10	0.021	0.021		
2016	2,001	127,587	127,587	402,961			9	0.035	0.035		
Total	**4,069**	**$ 255,063**	**$ 255,063**	**1,027,497**			**9**	**$0.033**	**$0.033**	**2.24**	**2.24**
Educational Distributions											
2015	28,197	432,185	432,185	1,669,495			10	0.026	0.026		
2016	67,065	2,392,884	2,392,884	15,149,605			10	0.016	0.016		
Total		**$ 2,825,069**	**$ 2,825,069**	**16,819,100**			**10**	**$0.021**	**$0.021**	**3.41**	**3.41**

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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 Efficiency Packets											
2002	2,925	755	755	155,757			7	0.001	0.001		
Total	**2,925**	**$ 755**	**$ 755**	**155,757**			**7**	**$ 0.001**	**$ 0.001**	**4.24**	**2.05**
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		
2013	1,085,225	1,356,926	4,889,501	9,995,753	1.14		8	0.016	0.058		
2014	1,161,553	1,909,823	7,148,427	12,882,151	1.47		8	0.018	0.066		
2015	1,343,255	2,063,383	4,428,676	15,876,117	1.81		10	0.013	0.028		
2016	1,442,561	3,080,708	10,770,703	21,093,813	2.41		11	0.014	0.049		
Total	**9,640,321**	**$ 17,470,970**	**$ 40,491,837**	**174,194,487**			**8**	**$ 0.012**	**$ 0.027**	**4.32**	**1.87**
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		
2010	1,602	762,330	762,330	1,198,655	0.14		20	0.054	0.054		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
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		
2013	411	199,995	199,995	837,261	0.10		18	0.016	0.016		
2014	297	197,987	197,987	579,126	0.07		18	0.030	0.030		
2015	362	214,103	214,103	754,646	0.09		18	0.020	0.020		
2016	375	206,437	206,437	509,859	0.06		18	0.029	0.029		
Total	**11,516**	**$ 5,361,876**	**$ 5,361,877**	**14,328,911**			**18**	**$ 0.032**	**$ 0.032**	**2.47**	**2.47**
ENERGY STAR® Homes Northwest											
2003		13,597	13,597	0							
2004	44	140,165	335,437	101,200	0.01		25	0.103	0.246		
2005	200	253,105	315,311	415,600	0.05		25	0.045	0.056		
2006	439	469,609	602,651	912,242	0.10		25	0.038	0.049		
2007	303	475,044	400,637	629,634	0.07		25	0.056	0.047		
2008	254	302,061	375,007	468,958	0.05		25	0.048	0.059		
2009	474	355,623	498,622	705,784	0.08		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		
2013	267	352,882	697,682	365,370	0.04		36	0.053	0.104		
2014	243	343,277	689,021	332,682	0.04		36	0.055	0.111		
2015	598	653,674	1,412,126	773,812	0.09		36	0.046	0.099		
2016	110	142,158	297,518	150,282	0.02		36	0.051	0.107		
Total	**4,280**	**$ 4,589,747**	**$ 7,739,664**	**7,004,301**			**36**	**$ 0.043**	**$ 0.073**	**2.48**	**1.47**
ENERGY STAR Homes Northwest (gas heated)											
2014	282			195,372	0.04		22				
2015	69			46,872	0.09		22				
Total	**351**			**242,244**							

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
Fridge and Freezer Recycling Program/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		
2013	3,307	589,054	589,054	1,442,344	0.16		6	0.061	0.061		
2014	3,194	576,051	576,051	1,390,760	0.16		6	0.062	0.062		
2015	1,630	227,179	227,179	720,208	0.08		6	0.048	0.048		
2016	1,539	257,916	257,916	632,186	0.07		6	0.062	0.062		
Total	**21,108**	**$ 3,788,219**	**$ 3,788,219**	**10,174,885**			**6**	**$ 0.068**	**$ 0.068**	**1.21**	**1.21**
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		
2013	210	329,674	741,586	1,003,730	0.11		20	0.022	0.050		
2014	230	362,014	1,247,560	1,099,464	0.13		20	0.022	0.075		
2015	427	626,369	2,064,055	1,502,172	0.17		20	0.028	0.092		
2016	486	594,913	1,404,625	1,113,574	0.13		20	0.036	0.085		
Total	**2,553**	**$ 4,076,270**	**$ 9,699,358**	**9,083,561**			**20**	**$ 0.037**	**$ 0.087**	**2.87**	**1.20**
Home Energy Audit											
2013		88,740	88,740								
2014	354	170,648	170,648	141,077			10				
2015	351	201,957	201,957	136,002			10				
2016	539	289,812	289,812	207,249			11				
Total	**1,244**	**$ 751,157**	**$ 776,006**	**483,569**			**11**				

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
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		
2013	365	299,497	1,061,314	616,044	0.07		45	0.025	0.090		
2014	555	324,717	896,246	838,929	0.10		45	0.020	0.055		
2015	408	272,509	893,731	303,580	0.03		45	0.046	0.152		
2016	482	324,024	1,685,301	500,280	0.06		45	0.034	0.177		
Total	**9,932**	**$ 3,661,190**	**$ 10,874,986**	**9,267,594**			**45**	**$ 0.025**	**$ 0.074**	**4.30**	**1.45**
Multifamily Energy Savings Program											
2016	3	59,046	59,046	149,760	0.02		10	0.040	0.040		
Total	**3**	**$ 59,046**	**$ 59,046**	**149,760**			**10**	**$ 0. 040**	**$ 0.040**	**1.43**	**1.43**
Oregon Residential Weatherization											
2002	24	(662)	23,971	4,580			25	0.010	0.389		
2003		(943)									
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								
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		
2013	14	9,017	14,369	14,907	0.00		30	0.035	0.055		
2014	13	5,462	9,723	11,032	0.00		30	0.028	0.050		
2015	19	5,808	10,388	11,910	0.00		30	0.028	0.050		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
Oregon Residential Weatherization											
2016	7	$ 3,930	$ 5,900	2,847	0.00		30	$ 0.079	$ 0.118		
Total	**89**	**$ 65,742**	**$ 144,033**	**122,490**			**30**	**$ 0.037**	**$ 0.082**	**2.94**	**1.34**
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		
2013	42	60,770	92,690	269,891	0.03		25	0.014	0.021		
2014	44	63,231	89,699	269,643	0.03		25	0.014	0.020		
2015	58	85,438	117,322	358,683	0.04		25	0.014	0.020		
2016	66	111,050	148,142	411,272	0.05		25	0.016	0.022		
Total	**970**	**$ 868,688**	**$ 1,682,906**	**4,291,409**			**25**	**$ 0.015**	**$ 0.029**	**7.40**	**3.82**
Simple Steps Smart Savings											
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		
2013	13,792	405,515	702,536	885,980	0.10		12	0.041	0.071		
2014	10,061	227,176	302,289	652,129	0.07		12	0.031	0.041		
2015	9,343	139,096	408,032	770,822	0.09		10	0.018	0.053		
2016	7,880	153,784	379,752	577,320	0.07		11	0.025	0.063		
Total	**102,502**	**$ 3,826,535**	**$ 6,468,669**	**8,882,032**			**11**	**$ 0.050**	**$ 0.085**	**1.93**	**1.14**

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

Program/Year	Participants	Total Costs: Utility Cost [c]	Total Costs: Resource Cost [d]	Savings and Demand Reductions: Annual Energy (kWh)	Savings and Demand Reductions: Average Energy [e] (aMW)	Savings and Demand Reductions: Peak Demand [f] (MW)	Measure Life (Years)	Levelized Costs [a]: Total Utility ($/kWh)	Levelized Costs [a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios [b]: Utility	Program Life Benefit/Cost Ratios [b]: Total Resource
Residential Efficiency											
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		
2013	166	1,267,791	1,267,791	303,116	0.03		25	0.240	0.240		
2014	118	791,344	791,344	290,926	0.03		25	0.163	0.163		
2015	171	1,243,269	1,243,269	432,958	0.05		25	0.175	0.175		
2016	232	1,323,793	1,323,793	621,653	0.07		25	0.130	0.130		
Total	**1,049**	**$ 6,929,127**	**$ 6,929,128**	**3,644,021**			**30**	**$ 0.132**	**$ 0.132**	**0.74**	**0.74**
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**		
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	0.029	0.050		
2005	570	1,402,487	1,927,424	3,179,311	0.36		25	0.033	0.045		
2006	540	1,455,373	2,231,086	2,958,024	0.34		25	0.037	0.056		
2007	397	1,292,930	1,757,105	3,296,019	0.38		25	0.029	0.040		
2008	439	1,375,632	1,755,749	4,064,301	0.46		25	0.025	0.032		
2009	427	$ 1,260,922	$ 1,937,578	4,563,832	0.52		25	0.021	0.033		
2010	373	1,205,446	2,782,597	3,452,025	0.39		25	0.026	0.060		
2011	273	1,278,112	1,861,836	2,648,676	0.30		25	0.036	0.053		
2012	228	1,321,927	1,743,863	621,464	0.07		25	0.159	0.210		
2013	245	1,336,742	1,984,173	657,580	0.08		25	0.152	0.226		
2014	244	1,267,212	1,902,615	509,620	0.06		25	0.185	0.277		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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—(WAQC)											
WAQC—Idaho											
2015	233	$ 1,278,159	$ 2,072,901	529,426	0.06		25	$ 0.179	$ 0.291		
2016	234	1,254,338	1,870,481	722,430	0.08		25	0.129	0.192		
Total	**4,877**	**$ 16,690,936**	**$ 25,662,398**	**28,474,386**			**25**	**$ 0.043**	**$ 0.067**	**2.79**	**1.82**
WAQC—Oregon											
2002	31	24,773	47,221	68,323	0.01		25	0.027	0.051		
2003	29	22,255	42,335	102,643	0.01		25	0.016	0.031		
2004	17	13,469	25,452	28,436	0.00		25	0.035	0.067		
2005	28	44,348	59,443	94,279	0.01		25	0.035	0.047		
2006							25				
2007	11	30,694	41,700	42,108	0.00		25	0.054	0.074		
2008	14	43,843	74,048	73,841	0.01		25	0.040	0.068		
2009	10	33,940	46,513	114,982	0.01		25	0.023	0.031		
2010	27	115,686	147,712	289,627	0.03		25	0.030	0.038		
2011	14	46,303	63,981	134,972	0.02		25	0.026	0.035		
2012	10	48,214	76,083	26,840	0.00		25	0.134	0.212		
2013	9	54,935	67,847	24,156	0.00		25	0.170	0.210		
2014	11	52,900	94,493	24,180	0.00		25	0.162	0.290		
2015	10	36,873	46,900	20,595	0.00		25	0.133	0.169		
2016	12	35,471	63,934	23,732	0.00		25	0.111	0.200		
Total	**233**	**$ 603,703**	**$ 897,662**	**1,068,714**			**25**	**$ 0.042**	**$ 0.062**	**2.79**	**1.87**
WAQC—BPA Supplemental											
2002	75	55,966	118,255	311,347	0.04		25	0.013	0.028		
2003	57	49,895	106,915	223,591	0.03		25	0.017	0.036		
2004	40	69,409	105,021	125,919	0.01		25	0.041	0.062		
Total	**172**	**$ 175,270**	**$ 330,191**	**660,857**			**25**	**$ 0.020**	**$ 0.037**	**5.75**	**3.05**
WAQC Total		**$ 17,469,910**	**$ 26,890,251**	**30,203,957**			**25**	**$ 0.043**	**$ 0.066**	**2.83**	**1.84**

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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**		
New Construction (Building Efficiency)											
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		
2013	59	1,507,035	3,942,880	10,988,934	1.25	1.1	12	0.012	0.032		
2014	69	1,258,273	3,972,822	9,458,059	1.08	1.2	12	0.012	0.037		
2015	81	2,162,001	6,293,071	23,232,017	2.65		12	0.008	0.024		
2016	116	1,931,222	4,560,826	12,393,249	1.41		12	0.014	0.033		
Total	**748**	**$ 14,900,273**	**$ 39,163,849**	**115,616,825**			**12**	**$ 0.014**	**$ 0.037**	**5.55**	**2.11**
Retrofits (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		12	0.011	0.022		
2012	1,838	5,349,753	9,245,297	41,568,672	4.75		12	0.012	0.020		
2013	1,392	3,359,790	6,738,645	21,061,946	2.40		12	0.014	0.029		
2014	1,095	3,150,942	5,453,380	19,118,494	2.18		12	0.015	0.025		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
Retrofits (Easy Upgrades)											
2015	1,222	$ 4,350,865	$ 7,604,200	23,594,701	2.69		12	$ 0.017	$ 0.029		
2016	1,577	5,040,190	8,038,791	28,124,779	3.21		12	0.016	0.026		
Total	**12,385**	**$ 37,006,495**	**$ 76,341,791**	**274,299,786**			**12**	**$ 0.015**	**$ 0.031**	**5.36**	**2.60**
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**	**2.89**	**1.50**
Oregon Commercial Audit											
2002	24	5,200	5,200								
2003	21	4,000	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								
2013	18	5,090	5,090								
2014	16	9,464	9,464								
2015	17	4,251	4,251								
2016	7	7,717	7,717								
Total	**212**	**$ 95,059**	**$ 95,059**								
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**		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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
Industrial											
Custom Projects (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		
2013	73	2,466,225	5,771,640	21,370,350	2.43	2.4	12	0.010	0.024		
2014	131	7,173,054	13,409,922	50,363,052	5.75	5.6	12	0.013	0.024		
2015	160	9,012,628	20,533,742	55,247,192	6.31		11	0.016	0.035		
2016	196	7,982,624	16,123,619	47,518,871	5.42		16	0.013	0.026		
Total	**1,422**	**$ 67,424,957**	**$148,052,531**	**522,434,936**			**12**	**$ 0.014**	**$ 0.031**	**5.75**	**2.62**
Irrigation											
Irrigation Efficiency Rewards											
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		
2013	995	2,441,386	15,223,928	18,511,221	2.11	3.0	8	0.016	0.098		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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 Rewards											
2014	1,128	$ 2,446,507	$ 18,459,781	18,463,611	2.11	4.6	8	$ 0.016	$ 0.119		
2015	902	1,835,711	9,939,842	14,027,411	1.60	1.6	8	0.016	0.085		
2016	851	2,372,352	8,162,206	15,673,513	1.79		8	0.018	0.063		
Total	**9,713**	**$ 25,521,929**	**$114,541,128**	**160,287,765**			**8**	**$ 0.023**	**$ 0.105**	**4.93**	**1.61**
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								
2013		66,790	66,790								
2014		76,606	76,606								
2015		65,250	65,250								
Total		**$ 669,360**	**$ 669,360**								
Comprehensive Lighting											
2011		2,404	2,404								
2012		64,094	64,094								
Total		**$ 66,498**	**$ 66,498**								

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
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								
2013		380,957	380,957								
2014		478,658	478,658								
2015		272,858	272,858								
2016		293,039	293,039								
Total		**$ 2,431,591**	**$ 2,431,591**								
Green Motors Rewind—Industrial				123,700			7				
2016											
Total				**123,700**			**7**			**n/a**	**n/a**
Green Motors Rewind—Irrigation				73,617			19				
2016											
Total				**73,617**			**19**			**n/a**	**n/a**
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		

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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											
Local Energy Efficiency Fund											
2008	2	22,714	60,100	115,931	0.01		15	0.019	0.049		
2009	1	5,870	4,274	10,340	0.00		12	0.064	0.047		
2010	1	251	251		0.00						
2011	1	1,026	2,052	2,028			30	0.036	0.071		
2012											
2013											
2014	1	9,100	9,100	95,834			18				
Total	**545**	**$ 93,385**	**$ 142,061**	**330,160**			**14**	**$ 0.028**	**$ 0.043**	**2.80**	**1.84**
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**								
Residential Economizer Pilot											
2011		101,713	101,713								
2012		93,491	93,491								
2013		74,901	74,901								
Total		**$ 270,105**	**$ 270,105**								
Residential Education Initiative											
2005		7,498	7,498								
2006		56,727	56,727								
2007											
2008		150,917	150,917								
2009		193,653	193,653								

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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 Education Initiative											
2010		$ 222,092	$ 222,092								
2011		159,645	159,645								
2012		174,738	174,738								
2013		416,166	416,166								
2014	6,312	423,091	423,091	1,491,225			10				
2015		149,903	149,903								
2016		290,179	290,179								
Total	**6,312**	**$ 2,244,609**	**$ 2,244,609**	**1,491,225**			**10**				
Shade Tree Project											
2014	2,041	147,290	147,290								
2015	1,925	105,392	105,392								
2016	2,070	76,642	76,642								
Total	**6,036**	**$ 329,324**	**$ 329,324**								
Solar 4R Schools											
2009		42,522	42,522								
Total		**$ 42,522**	**$ 42,522**								
Market Transformation											
Consumer Electronic Initiative											
2002		160,762	160,762								
Total		**$ 160,762**	**$ 160,762**								
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						

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reductions			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)	Peak Demand [f] (MW)		Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Market Transformation											
NEEA											
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	20,161,728	2.30						
2012		3,379,756	3,379,756	19,567,984	2.23						
2013		3,313,058	3,313,058	20,567,965	2.35						
2014		3,305,917	3,305,917	26,805,600	3.06						
2015		2,582,919	2,582,919	23,038,800	2.50						
2016		2,676,387	2,676,387	24,615,600	2.81						
Total		**$ 28,804,600**	**$ 28,804,600**	**289,653,011**							
Annual Totals											
2002		1,932,520	2,366,591	16,791,100	1.92	0					
2003		2,566,228	3,125,572	18,654,343	2.12	0					
2004		3,827,213	4,860,912	19,202,780	2.19	7					
2005		6,523,348	10,383,577	37,978,035	4.34	44					
2006		11,174,181	20,950,110	67,026,303	7.65	44					
2007		14,896,816	27,123,018	91,145,357	10.40	59					
2008		20,213,216	44,775,829	128,508,579	14.67	75					
2009		33,821,062	53,090,852	143,146,365	16.34	236					
2010		44,643,541	68,981,324	193,592,637	22.10	358					
2011		44,877,117	79,436,532	183,476,312	20.94	420					
2012		47,991,350	77,336,341	172,054,327	19.64	454					
2013		26,100,091	54,803,353	109,505,690	12.23	55					
2014		35,648,260	71,372,414	145,475,713	16.40	390					
2015		37,149,893	70,467,082	163,671,955	18.27	367					
2016		41,705,957	70,984,603	170,792,152	19.50	379					
Total Direct Program		**$ 373,070,793**	**$ 660,058,113**	**1,661,021,647**							

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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**
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									
2013		741,287									
2014		1,065,072									
2015		1,891,042									
2016		2,263,893									
Total		**$ 13,363,923**									
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									

Appendix 4. Historical DSM expense and performance, 2002–2016 (continued)

		Total Costs		Savings and Demand Reductions				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
Total Expenses											
2013		$ 26,841,378									
2014		36,713,333									
2015		39,040,935									
2016		42,763,464									
Total 2002–2016		**$ 385,228,330**									

[a] Levelized Costs are based on financial inputs from Idaho Power's *2013 Integrated Resource Plan* and calculations include line loss adjusted energy savings.

[b] Program life benefit/cost ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power 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] Savings are preliminary funder share estimates. Final results will be provided by NEEA in May 2017.

Appendix 5. 2016 DSM program activity by state jurisdiction

	Idaho			Oregon		
Program	**Participants**	**Utility Costs**	**Demand Reduction/ Annual Energy Savings (MW)**	**Participants**	**Utility Costs [a]**	**Demand Reduction/ Annual Energy Savings(MW)**
Demand Response						
A/C Cool Credit	27,947 homes	$ 1,061,450	33	368 homes	$ 41,845	0.4
Flex Peak Program	128 sites	520,088	29	9 sites	247,909	13
Irrigation Peak Rewards	2,236 service points	7,378,725	295	50 service points	221,351	7
Total		**$ 8,960,263**	**357**		**$ 511,104**	**21**
Energy Efficiency						
Residential						
Easy Savings	2,001 kits	127,587	402,961	– kits	–	–
Educational Distributions	65,749 kits/bulbs	2,336,721	14,680,660	1,316 kits/bulbs	56,164	468,945
Energy Efficient Lighting	1,405,052 bulbs	3,017,507	20,646,094	37,509 bulbs	63,200	447,719
Energy House Calls	343 homes	190,621	470,535	32 homes	15,815	39,324
ENERGY STAR® Homes Northwest	110 homes	140,648	150,282	– homes	1,510	–
Fridge and Freezer Recycling Program	1,527 refrigerators/ freezers	253,362	627,104	12 refrigerators/freezers	4,555	5,082
Heating & Cooling Efficiency Program	469 projects	567,729	1,073,380	17 projects	27,184	40,194
Home Energy Audit	539 audits	289,812	207,249	audits		
Home Improvement Program	482 projects	324,024	500,280	projects		
Multifamily Energy Savings Program	3 projects	59,046	149,760	projects		
Oregon Residential Weatherization				7 homes	3,930	2,847
Rebate Advantage	62 homes	104,658	385,528	4 homes	6,392	25,744
Simple Steps, Smart Savings™	7,822 appliances/ showerheads	150,249	570,581	94 appliances/showerheads	3,535	6,739
Weatherization Assistance for Qualified Customers	234 homes/ non-profits	1,254,338	722,430	12 homes/non-profits	35,471	23,732
Weatherization Solutions for Eligible Customers	232 homes	1,323,793	621,653	homes		
Sector Total		**$ 10,140,095**	**41,208,496**		**$ 217,756**	**1,060,326**
Commercial						
Custom Projects (Custom Efficiency)	185 projects	7,745,408	46,614,955	11 projects	237,216	903,916
Green Motors—Industrial	2 motor rewinds		50,955	2 motor rewinds	0	72,745
New Construction (Building Efficiency)	113 projects	1,888,663	12,254,358	3 projects	42,559	138,891
Retrofits (Easy Upgrades)	1,518 projects	4,811,357	27,040,532	59 projects	228,834	1,084,247
Sector Total		**$ 14,445,428**	**85,960,800**		**$ 508,608**	**2,199,799**

Appendix 5. 2016 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
Irrigation								
Green Motors—Irrigation	22	motor rewinds		72,871	1	motor rewind		746
Irrigation Efficiency Rewards	798	projects	$ 1,737,168	12,860,872	53	projects	$ 635,185	2,812,641
Sector Total			**$ 1,737,168**	**12,933,743**			**$ 635,185**	**2,813,387**
Market Transformation								
Northwest Energy Efficiency Alliance [1]			2,542,567	23,384,820			133,820	1,230,780
Other Programs and Activities								
Residential								
Energy Efficiency Education Initiative			278,108				12,071	
Shade Tree Project			76,642				–	
Commercial								
Oregon Commercial Audits			–				7,717	
Other								
Energy Efficiency Direct Program Overhead			276.074				16,964	
Total Program Direct Expense			**$ 38,456,344**				**$ 2,043,225**	
Indirect Program Expenses			2,147,479				116,414	
Total Annual Savings				**163,487,859**				**7,304,292**
Total DSM Expense			**$ 40,603,823**				**$ 2,159,639**	

[a] Levelized Costs are based on financial inputs from Idaho Power's *2013 Integrated Resource Plan* and calculations include line loss adjusted energy savings.

[1] Savings are preliminary funder share estimates provided by NEEA. Final savings for 2016 will be provided by NEEA May 2017.

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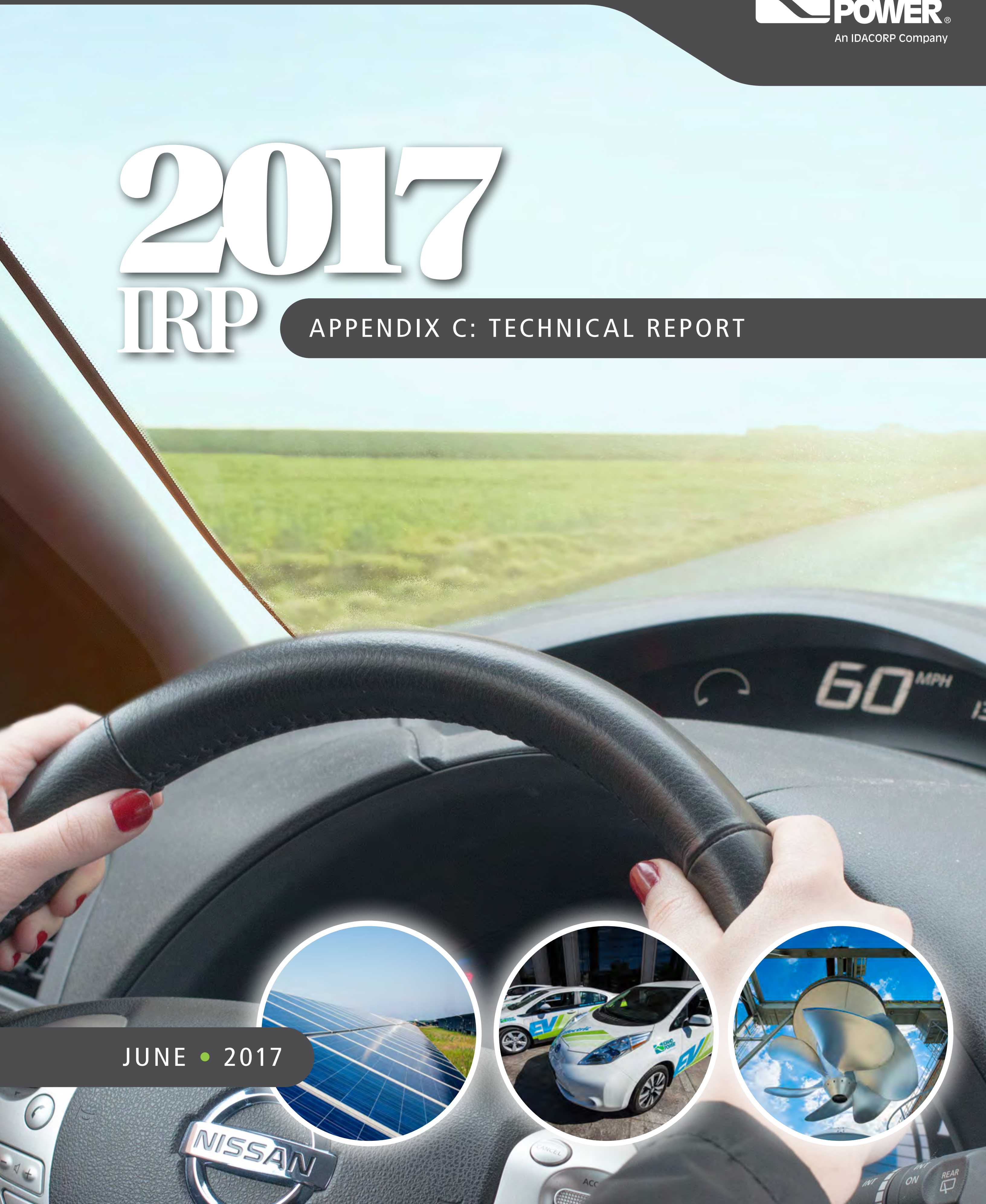
INTEGRATED RESOURCE PLAN

IDAHO POWER
An IDACORP Company

2017 IRP

APPENDIX C: TECHNICAL REPORT

JUNE • 2017



SAFE HARBOR STATEMENT

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

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INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2017 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2017 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 2014 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2017.

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 is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted 8 IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

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

Customer Representatives

Agricultural Representative	Sid Erwin
Boise State University	Barry Burbank
Idaho National Laboratory	Kurt Myers
Micron	Clancy Kelley
Simplot	Don Sturtevant

Public Interest Representatives

Boise Metro Chamber of Commerce	Ray Stark
Boise State University Energy Policy Institute	David Solan
City of Boise	Steve Burgos
Idaho Conservation League	Ben Otto
Idaho Legislature	Representative Robert Anderst
Idaho Office of Energy and Mineral Resources	John Chatburn/Scott Pugrud
Idaho Sierra Club	Mike Heckler/Zack Waterman/Casey Mattoon
Idaho Technology Council	Jay Larsen
Idaho Water Resource Board	Roger Chase
Northwest Power and Conservation Council	Shirley Lindstrom/Jim Yost
Oil and Gas Industry Advisor	David Hawk
Oregon State University—Malheur Experiment Station	Clint Shock
Snake River Alliance	Wendy Wilson/Chad Worth
University of Idaho Center for Ecohydraulics Research	Daniele Tonina

Regulatory Commission Representatives

Idaho Public Utilities Commission	Stacey Donohue
Public Utility Commission of Oregon	Nadine Hanhan

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2016	Thursday, September 8	Introductions/meeting overview Welcome and opening remarks IRP process explanation Pilot projects update Clean Power Plan update Natural gas forecast
2016	Thursday, October 13	Review of September IRPAC meeting T&D deferral benefit Demand-side resources Streamflow forecast Hydro production forecast
2016	Thursday, November 10	Review of October IRPAC meeting Transmission system overview Boardman-Hemingway/Gateway West update Load forecast Contract purchased power forecast
2016	Thursday, December 19	Deferral of Distribution Investment Workshop
2017	Thursday, January 12	Review of November IRPAC meeting Energy efficiency potential study Recap/review Resource stack of IRP resources Final load and resource balance Resource portfolio design
2017	Thursday, March 9	Review of January IRPAC meeting Revisit of natural gas price forecast AURORA and portfolio analysis NW Power and Conservation Council Regional Perspective Flexibility analysis 500 kV transmission projects update Overview of remaining steps
2017	Thursday, April 13	Review of March IRPAC meeting Stochastic risk analysis results Demand response as a resource Resource stack costs – IRP resources Qualitative risk analysis discussion Closing-remaining schedule

Meeting Dates		Agenda Items
2017	Thursday, May 11	Action plan (2017—2020) Hells Canyon Complex relicensing Spring runoff and power system operations Energy imbalance market (EIM) overview IPC sustainability programs Loss-of-load analysis Closing comments

Sales and Load Forecast Data

Average Annual Forecast Growth Rates

	2017–2022	2017–2027	2017–2036
Sales			
Residential Sales	1.48%	1.40%	1.24%
Commercial Sales	0.87%	0.79%	0.75%
Irrigation Sales	0.62%	0.59%	0.59%
Industrial Sales	1.29%	0.90%	0.73%
Additional Firm Sales	0.94%	1.40%	0.76%
System Sales	1.13%	1.04%	0.91%
Total Sales	1.13%	1.04%	0.91%
Loads			
Residential Load	1.48%	1.40%	1.22%
Commercial Load	0.86%	0.78%	0.74%
Irrigation Load	0.62%	0.59%	0.58%
Industrial Load	1.25%	0.89%	0.70%
Additional Firm Sales	0.94%	1.40%	0.76%
System Load Losses	1.12%	1.03%	0.91%
System Load	1.12%	1.04%	0.89%
Total Load	1.12%	1.04%	0.89%
Peaks			
System Peak	1.57%	1.49%	1.36%
Total Peak	1.57%	1.49%	1.36%
Winter Peak	1.22%	1.05%	0.88%
Summer Peak	1.78%	1.66%	1.53%
Customers			
Residential Customers	2.11%	2.02%	1.78%
Commercial Customers	1.86%	1.90%	1.77%
Irrigation Customers	1.42%	1.37%	1.29%
Industrial Customers	0.50%	0.65%	0.59%

Expected-Case Load Forecast

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	814	671	592	506	446	512	621	588	469	455	650	799
Commercial	494	466	434	430	429	462	503	499	467	444	460	499
Irrigation	2	3	9	130	345	587	643	503	328	73	5	3
Industrial	281	279	277	263	268	292	285	289	286	289	279	278
Additional Firm	113	111	106	106	105	102	108	108	107	104	112	114
Loss	145	129	118	120	135	169	189	172	140	113	126	144
System Load	**1,850**	**1,658**	**1,537**	**1,555**	**1,728**	**2,123**	**2,350**	**2,159**	**1,796**	**1,477**	**1,631**	**1,836**
Light Load	1,718	1,527	1,408	1,405	1,564	1,930	2,118	1,913	1,616	1,316	1,505	1,695
Heavy Load	1,964	1,757	1,630	1,675	1,858	2,265	2,549	2,337	1,941	1,604	1,733	1,957
Total Load	**1,850**	**1,658**	**1,537**	**1,555**	**1,728**	**2,123**	**2,350**	**2,159**	**1,796**	**1,477**	**1,631**	**1,836**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,408	2,279	2,018	2,009	2,663	3,395	3,566	3,213	2,767	2,072	2,264	2,517
Total Peak Load	**2,408**	**2,279**	**2,018**	**2,009**	**2,663**	**3,395**	**3,566**	**3,213**	**2,767**	**2,072**	**2,264**	**2,517**

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	682	602	514	455	522	634	601	478	463	661	813
Commercial	501	471	438	435	434	467	509	506	473	449	465	504
Irrigation	2	3	9	131	347	590	647	506	330	73	5	3
Industrial	289	288	285	271	276	300	294	298	294	297	287	282
Additional Firm	115	113	108	107	107	103	110	110	109	106	114	116
Loss	148	131	120	122	137	171	191	175	143	114	128	146
System Load	**1,884**	**1,688**	**1,563**	**1,581**	**1,756**	**2,155**	**2,385**	**2,195**	**1,826**	**1,502**	**1,660**	**1,864**
Light Load	1,749	1,554	1,432	1,428	1,589	1,958	2,150	1,945	1,642	1,339	1,531	1,721
Heavy Load	1,990	1,788	1,657	1,703	1,887	2,299	2,587	2,375	1,986	1,621	1,763	1,987
Total Load	**1,884**	**1,688**	**1,563**	**1,581**	**1,756**	**2,155**	**2,385**	**2,195**	**1,826**	**1,502**	**1,660**	**1,864**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,454	2,315	2,053	2,037	2,701	3,453	3,630	3,269	2,818	2,100	2,292	2,554
Total Peak Load	**2,454**	**2,315**	**2,053**	**2,037**	**2,701**	**3,453**	**3,630**	**3,269**	**2,818**	**2,100**	**2,292**	**2,554**

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	844	695	612	523	464	533	648	614	487	470	672	823
Commercial	505	475	442	439	438	471	513	511	477	453	470	508
Irrigation	3	3	9	132	350	595	652	510	332	74	5	3
Industrial	294	292	289	275	280	305	298	302	299	302	291	285
Additional Firm	117	115	109	109	108	104	111	111	110	107	115	117
Loss	150	133	122	124	139	174	194	177	144	116	130	147
System Load	**1,912**	**1,711**	**1,583**	**1,601**	**1,778**	**2,182**	**2,416**	**2,225**	**1,849**	**1,521**	**1,682**	**1,883**
Light Load	1,776	1,576	1,450	1,447	1,609	1,983	2,178	1,971	1,663	1,356	1,551	1,739
Heavy Load	2,020	1,813	1,688	1,714	1,911	2,341	2,604	2,408	2,012	1,641	1,787	2,007
Total Load	**1,912**	**1,711**	**1,583**	**1,601**	**1,778**	**2,182**	**2,416**	**2,225**	**1,849**	**1,521**	**1,682**	**1,883**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,497	2,347	2,084	2,062	2,735	3,505	3,692	3,322	2,861	2,122	2,316	2,572
Total Peak Load	2,497	2,347	2,084	2,062	2,735	3,505	3,692	3,322	2,861	2,122	2,316	2,572

[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 2017 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]	1/2020	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	851	676	616	526	468	539	656	621	492	473	676	831
Commercial	510	462	444	442	441	475	517	515	481	456	473	512
Irrigation	3	3	9	133	352	599	656	513	334	74	5	3
Industrial	297	285	292	278	283	308	301	305	302	305	294	287
Additional Firm	118	112	110	109	108	105	112	111	110	108	116	118
Loss	151	129	122	125	140	175	196	179	146	117	131	149
System Load	**1,929**	**1,665**	**1,594**	**1,613**	**1,792**	**2,200**	**2,437**	**2,245**	**1,865**	**1,533**	**1,695**	**1,899**
Light Load	1,791	1,533	1,460	1,457	1,622	1,999	2,197	1,989	1,677	1,365	1,563	1,753
Heavy Load	2,038	1,762	1,699	1,727	1,939	2,346	2,626	2,446	2,015	1,653	1,810	2,014
Total Load	**1,929**	**1,665**	**1,594**	**1,613**	**1,792**	**2,200**	**2,437**	**2,245**	**1,865**	**1,533**	**1,695**	**1,899**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,517	2,360	2,097	2,076	2,758	3,538	3,745	3,364	2,890	2,136	2,329	2,576
Total Peak Load	**2,517**	**2,360**	**2,097**	**2,076**	**2,758**	**3,538**	**3,745**	**3,364**	**2,890**	**2,136**	**2,329**	**2,576**

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	861	707	621	531	473	546	665	630	498	477	682	843
Commercial	514	481	447	445	445	478	520	519	485	459	477	516
Irrigation	3	3	9	134	354	601	659	516	336	75	5	3
Industrial	298	297	294	279	284	310	303	307	303	306	296	288
Additional Firm	118	116	111	110	109	105	112	112	111	108	116	119
Loss	153	135	123	126	141	176	197	180	147	117	132	150
System Load	**1,946**	**1,738**	**1,605**	**1,625**	**1,806**	**2,216**	**2,456**	**2,264**	**1,879**	**1,544**	**1,708**	**1,918**
Light Load	1,807	1,601	1,470	1,468	1,634	2,014	2,214	2,006	1,690	1,375	1,575	1,771
Heavy Load	2,066	1,841	1,702	1,739	1,954	2,364	2,647	2,467	2,031	1,676	1,814	2,034
Total Load	**1,946**	**1,738**	**1,605**	**1,625**	**1,806**	**2,216**	**2,456**	**2,264**	**1,879**	**1,544**	**1,708**	**1,918**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,529	2,372	2,105	2,087	2,780	3,570	3,797	3,406	2,917	2,149	2,343	2,596
Total Peak Load	**2,529**	**2,372**	**2,105**	**2,087**	**2,780**	**3,570**	**3,797**	**3,406**	**2,917**	**2,149**	**2,343**	**2,596**

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	875	718	630	539	482	556	678	643	507	485	692	856
Commercial	518	485	450	449	448	482	524	524	489	463	481	520
Irrigation	3	3	9	134	356	605	663	519	338	75	5	3
Industrial	300	298	295	281	286	311	304	308	305	308	297	290
Additional Firm	119	117	112	111	110	106	113	113	111	109	117	120
Loss	155	136	125	127	143	178	199	182	148	119	133	152
System Load	**1,970**	**1,757**	**1,621**	**1,641**	**1,824**	**2,239**	**2,482**	**2,290**	**1,899**	**1,558**	**1,726**	**1,940**
Light Load	1,829	1,618	1,485	1,483	1,650	2,034	2,238	2,029	1,708	1,388	1,592	1,791
Heavy Load	2,091	1,861	1,719	1,756	1,973	2,388	2,693	2,478	2,052	1,692	1,833	2,058
Total Load	**1,970**	**1,757**	**1,621**	**1,641**	**1,824**	**2,239**	**2,482**	**2,290**	**1,899**	**1,558**	**1,726**	**1,940**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,558	2,393	2,124	2,104	2,807	3,612	3,854	3,453	2,952	2,165	2,361	2,614
Total Peak Load	**2,558**	**2,393**	**2,124**	**2,104**	**2,807**	**3,612**	**3,854**	**3,453**	**2,952**	**2,165**	**2,361**	**2,614**

[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 2017 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]	1/2023	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	890	729	640	547	490	566	691	656	516	492	702	869
Commercial	522	488	452	452	452	485	528	528	493	466	484	523
Irrigation	3	3	9	135	358	609	668	522	340	76	5	3
Industrial	301	300	297	282	288	313	306	310	307	310	299	291
Additional Firm	122	120	114	113	112	108	115	115	113	111	120	123
Loss	157	138	126	128	144	180	202	184	150	120	135	154
System Load	**1,995**	**1,778**	**1,638**	**1,658**	**1,843**	**2,262**	**2,509**	**2,316**	**1,919**	**1,574**	**1,745**	**1,963**
Light Load	1,853	1,637	1,501	1,498	1,668	2,056	2,262	2,052	1,726	1,402	1,610	1,812
Heavy Load	2,118	1,883	1,737	1,786	1,982	2,413	2,722	2,507	2,073	1,709	1,854	2,093
Total Load	**1,995**	**1,778**	**1,638**	**1,658**	**1,843**	**2,262**	**2,509**	**2,316**	**1,919**	**1,574**	**1,745**	**1,963**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,586	2,415	2,143	2,123	2,835	3,654	3,912	3,501	2,987	2,183	2,382	2,630
Total Peak Load	**2,586**	**2,415**	**2,143**	**2,123**	**2,835**	**3,654**	**3,912**	**3,501**	**2,987**	**2,183**	**2,382**	**2,630**

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	903	714	648	555	498	576	704	668	524	498	711	879
Commercial	526	474	454	455	455	488	531	532	497	469	487	527
Irrigation	3	3	10	136	360	613	671	525	342	76	5	3
Industrial	303	291	298	284	289	315	308	312	308	311	300	293
Additional Firm	133	126	123	121	119	116	122	121	119	118	130	133
Loss	159	135	127	130	146	182	204	187	152	121	136	156
System Load	**2,026**	**1,742**	**1,660**	**1,680**	**1,866**	**2,289**	**2,539**	**2,345**	**1,942**	**1,593**	**1,770**	**1,991**
Light Load	1,881	1,604	1,521	1,518	1,689	2,080	2,289	2,078	1,747	1,419	1,633	1,838
Heavy Load	2,141	1,844	1,770	1,798	2,006	2,456	2,737	2,538	2,113	1,719	1,881	2,122
Total Load	**2,026**	**1,742**	**1,660**	**1,680**	**1,866**	**2,289**	**2,539**	**2,345**	**1,942**	**1,593**	**1,770**	**1,991**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,621	2,441	2,168	2,145	2,867	3,699	3,974	3,554	3,025	2,206	2,410	2,653
Total Peak Load	**2,621**	**2,441**	**2,168**	**2,145**	**2,867**	**3,699**	**3,974**	**3,554**	**3,025**	**2,206**	**2,410**	**2,653**

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	913	747	653	560	504	583	713	677	530	502	717	888
Commercial	530	494	457	458	458	491	534	537	501	472	491	531
Irrigation	3	3	10	137	362	616	675	528	344	76	5	3
Industrial	305	303	300	285	291	316	309	313	310	313	302	294
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	160	141	128	130	147	183	205	188	153	122	137	157
System Load	**2,043**	**1,817**	**1,671**	**1,691**	**1,880**	**2,305**	**2,559**	**2,365**	**1,957**	**1,603**	**1,783**	**2,007**
Light Load	1,897	1,674	1,530	1,528	1,701	2,095	2,307	2,096	1,760	1,429	1,644	1,853
Heavy Load	2,159	1,925	1,781	1,810	2,021	2,474	2,758	2,577	2,114	1,730	1,904	2,128
Total Load	**2,043**	**1,817**	**1,671**	**1,691**	**1,880**	**2,305**	**2,559**	**2,365**	**1,957**	**1,603**	**1,783**	**2,007**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,635	2,454	2,177	2,156	2,888	3,731	4,026	3,595	3,051	2,218	2,423	2,659
Total Peak Load	**2,635**	**2,454**	**2,177**	**2,156**	**2,888**	**3,731**	**4,026**	**3,595**	**3,051**	**2,218**	**2,423**	**2,659**

[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 2017 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]	1/2026	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	923	754	659	565	509	590	723	687	536	506	724	899
Commercial	534	498	459	461	461	495	538	541	505	475	495	535
Irrigation	3	3	10	137	364	619	678	531	345	77	5	3
Industrial	306	304	301	287	292	318	311	315	311	314	303	296
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	162	142	129	131	148	185	207	190	154	123	138	158
System Load	**2,060**	**1,831**	**1,681**	**1,702**	**1,893**	**2,322**	**2,579**	**2,385**	**1,972**	**1,614**	**1,795**	**2,024**
Light Load	1,913	1,686	1,540	1,538	1,713	2,110	2,325	2,113	1,773	1,438	1,656	1,869
Heavy Load	2,177	1,939	1,792	1,822	2,048	2,477	2,779	2,599	2,130	1,741	1,917	2,146
Total Load	**2,060**	**1,831**	**1,681**	**1,702**	**1,893**	**2,322**	**2,579**	**2,385**	**1,972**	**1,614**	**1,795**	**2,024**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,649	2,464	2,185	2,167	2,910	3,763	4,078	3,636	3,078	2,229	2,435	2,675
Total Peak Load	**2,649**	**2,464**	**2,185**	**2,167**	**2,910**	**3,763**	**4,078**	**3,636**	**3,078**	**2,229**	**2,435**	**2,675**

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	935	763	666	571	516	599	735	698	544	512	732	910
Commercial	539	501	462	465	465	498	542	546	509	479	498	538
Irrigation	3	3	10	138	366	623	682	534	348	77	5	3
Industrial	308	306	303	288	293	319	312	316	313	316	305	297
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	163	143	130	132	149	186	209	192	156	124	140	160
System Load	**2,080**	**1,846**	**1,694**	**1,716**	**1,909**	**2,342**	**2,602**	**2,408**	**1,989**	**1,626**	**1,810**	**2,042**
Light Load	1,932	1,700	1,551	1,550	1,727	2,128	2,346	2,134	1,789	1,448	1,669	1,885
Heavy Load	2,208	1,956	1,796	1,836	2,065	2,498	2,805	2,624	2,149	1,765	1,922	2,166
Total Load	**2,080**	**1,846**	**1,694**	**1,716**	**1,909**	**2,342**	**2,602**	**2,408**	**1,989**	**1,626**	**1,810**	**2,042**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,672	2,481	2,200	2,181	2,934	3,800	4,132	3,680	3,109	2,243	2,450	2,689
Total Peak Load	**2,672**	**2,481**	**2,200**	**2,181**	**2,934**	**3,800**	**4,132**	**3,680**	**3,109**	**2,243**	**2,450**	**2,689**

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	947	746	673	577	523	608	746	709	551	517	739	920
Commercial	542	486	464	468	468	501	545	550	512	482	501	542
Irrigation	3	3	10	139	368	627	687	537	350	78	5	3
Industrial	309	297	305	290	295	321	314	318	315	318	307	299
Additional Firm	134	126	123	121	119	116	123	122	120	118	130	134
Loss	165	139	131	133	151	188	211	194	157	125	141	161
System Load	**2,100**	**1,797**	**1,706**	**1,728**	**1,924**	**2,361**	**2,625**	**2,430**	**2,005**	**1,637**	**1,824**	**2,059**
Light Load	1,950	1,655	1,562	1,562	1,741	2,146	2,366	2,153	1,803	1,459	1,682	1,901
Heavy Load	2,229	1,902	1,809	1,862	2,069	2,518	2,847	2,630	2,166	1,778	1,937	2,195
Total Load	**2,100**	**1,797**	**1,706**	**1,728**	**1,924**	**2,361**	**2,625**	**2,430**	**2,005**	**1,637**	**1,824**	**2,059**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,695	2,496	2,214	2,195	2,958	3,837	4,187	3,725	3,140	2,257	2,465	2,701
Total Peak Load	**2,695**	**2,496**	**2,214**	**2,195**	**2,958**	**3,837**	**4,187**	**3,725**	**3,140**	**2,257**	**2,465**	**2,701**

[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 2017 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]	1/2029	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	958	780	678	582	529	615	756	719	558	521	746	929
Commercial	547	507	467	471	471	505	549	554	517	485	505	546
Irrigation	3	3	10	140	370	630	690	540	352	78	5	3
Industrial	311	309	306	292	297	323	316	320	317	320	308	301
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	166	145	132	134	152	189	213	195	158	126	142	163
System Load	**2,118**	**1,875**	**1,717**	**1,740**	**1,939**	**2,379**	**2,646**	**2,451**	**2,021**	**1,648**	**1,837**	**2,075**
Light Load	1,966	1,727	1,573	1,572	1,754	2,162	2,386	2,172	1,817	1,468	1,694	1,916
Heavy Load	2,237	1,986	1,820	1,874	2,084	2,537	2,871	2,653	2,198	1,778	1,951	2,212
Total Load	**2,118**	**1,875**	**1,717**	**1,740**	**1,939**	**2,379**	**2,646**	**2,451**	**2,021**	**1,648**	**1,837**	**2,075**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,712	2,509	2,224	2,207	2,981	3,871	4,240	3,768	3,169	2,269	2,478	2,713
Total Peak Load	**2,712**	**2,509**	**2,224**	**2,207**	**2,981**	**3,871**	**4,240**	**3,768**	**3,169**	**2,269**	**2,478**	**2,713**

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	967	787	683	586	534	622	765	728	563	525	751	937
Commercial	551	510	469	474	475	508	552	559	521	488	509	550
Irrigation	3	3	10	141	373	634	694	543	354	79	5	3
Industrial	313	311	308	293	299	325	318	322	318	322	310	303
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	168	146	133	135	153	191	214	197	159	126	143	164
System Load	**2,135**	**1,888**	**1,727**	**1,751**	**1,952**	**2,396**	**2,667**	**2,471**	**2,035**	**1,658**	**1,848**	**2,090**
Light Load	1,982	1,739	1,582	1,582	1,766	2,177	2,404	2,190	1,831	1,477	1,705	1,929
Heavy Load	2,255	2,000	1,840	1,874	2,098	2,571	2,874	2,675	2,214	1,789	1,963	2,228
Total Load	**2,135**	**1,888**	**1,727**	**1,751**	**1,952**	**2,396**	**2,667**	**2,471**	**2,035**	**1,658**	**1,848**	**2,090**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,730	2,522	2,235	2,218	3,002	3,903	4,292	3,809	3,195	2,280	2,489	2,722
Total Peak Load	**2,730**	**2,522**	**2,235**	**2,218**	**3,002**	**3,903**	**4,292**	**3,809**	**3,195**	**2,280**	**2,489**	**2,722**

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	976	793	687	590	539	629	774	737	569	528	756	944
Commercial	555	513	472	478	478	511	556	563	524	491	512	553
Irrigation	3	3	10	142	375	637	698	546	356	79	5	3
Industrial	315	313	310	295	300	327	320	324	320	323	312	304
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	169	147	133	136	154	192	216	199	161	127	144	165
System Load	**2,151**	**1,900**	**1,736**	**1,761**	**1,965**	**2,412**	**2,686**	**2,491**	**2,049**	**1,667**	**1,859**	**2,103**
Light Load	1,997	1,750	1,590	1,591	1,778	2,192	2,421	2,207	1,843	1,486	1,715	1,942
Heavy Load	2,262	2,013	1,850	1,885	2,100	2,588	2,877	2,714	2,200	1,799	1,975	2,220
Total Load	**2,151**	**1,900**	**1,736**	**1,761**	**1,965**	**2,412**	**2,686**	**2,491**	**2,049**	**1,667**	**1,859**	**2,103**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,747	2,534	2,245	2,230	3,023	3,935	4,344	3,851	3,222	2,292	2,501	2,725
Total Peak Load	**2,747**	**2,534**	**2,245**	**2,230**	**3,023**	**3,935**	**4,344**	**3,851**	**3,222**	**2,292**	**2,501**	**2,725**

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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	983	770	691	593	543	634	782	744	573	530	760	953
Commercial	559	499	474	481	481	514	559	567	528	495	516	557
Irrigation	3	3	10	142	377	640	702	549	357	80	6	3
Industrial	316	304	311	296	302	328	321	325	322	325	314	305
Additional Firm	133	126	123	121	119	116	123	122	120	118	130	134
Loss	170	143	134	137	155	193	218	200	162	128	144	166
System Load	**2,165**	**1,845**	**1,744**	**1,770**	**1,976**	**2,427**	**2,704**	**2,508**	**2,062**	**1,676**	**1,869**	**2,119**
Light Load	2,010	1,699	1,597	1,599	1,788	2,206	2,437	2,223	1,855	1,493	1,724	1,956
Heavy Load	2,277	1,963	1,849	1,895	2,125	2,589	2,896	2,734	2,214	1,820	1,975	2,236
Total Load	**2,165**	**1,845**	**1,744**	**1,770**	**1,976**	**2,427**	**2,704**	**2,508**	**2,062**	**1,676**	**1,869**	**2,119**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,755	2,544	2,248	2,237	3,042	3,963	4,394	3,890	3,245	2,301	2,511	2,737
Total Peak Load	**2,755**	**2,544**	**2,248**	**2,237**	**3,042**	**3,963**	**4,394**	**3,890**	**3,245**	**2,301**	**2,511**	**2,737**

Monthly Summary[1]	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Average Load (aMW)–50th Percentile												
Residential	994	806	696	597	548	642	792	754	580	534	766	963
Commercial	563	520	477	484	485	518	563	572	532	498	520	561
Irrigation	3	3	10	143	379	644	706	552	360	80	6	3
Industrial	318	316	313	298	303	330	323	327	323	327	315	307
Additional Firm	134	131	124	121	119	117	123	122	120	119	130	134
Loss	172	150	135	138	156	195	219	202	163	129	145	168
System Load	**2,184**	**1,925**	**1,754**	**1,781**	**1,991**	**2,445**	**2,725**	**2,530**	**2,078**	**1,686**	**1,882**	**2,136**
Light Load	2,027	1,773	1,607	1,610	1,801	2,222	2,457	2,242	1,869	1,502	1,736	1,972
Heavy Load	2,307	2,039	1,860	1,907	2,140	2,608	2,937	2,738	2,231	1,831	1,989	2,255
Total Load	**2,184**	**1,925**	**1,754**	**1,781**	**1,991**	**2,445**	**2,725**	**2,530**	**2,078**	**1,686**	**1,882**	**2,136**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,775	2,554	2,260	2,249	3,064	3,997	4,447	3,932	3,274	2,313	2,524	2,752
Total Peak Load	**2,775**	**2,554**	**2,260**	**2,249**	**3,064**	**3,997**	**4,447**	**3,932**	**3,274**	**2,313**	**2,524**	**2,752**

Monthly Summary[1]	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Average Load (aMW)–50th Percentile												
Residential	1,007	814	702	603	555	650	803	765	587	539	773	975
Commercial	568	524	479	488	488	521	567	577	537	502	523	566
Irrigation	3	3	10	144	381	648	710	556	362	81	6	3
Industrial	319	318	315	299	305	332	324	329	325	328	317	309
Additional Firm	134	131	124	121	119	117	123	122	120	119	130	134
Loss	173	151	136	139	157	196	221	204	164	130	147	169
System Load	**2,204**	**1,940**	**1,766**	**1,794**	**2,006**	**2,464**	**2,748**	**2,553**	**2,094**	**1,697**	**1,896**	**2,155**
Light Load	2,046	1,787	1,617	1,621	1,815	2,240	2,478	2,262	1,884	1,512	1,748	1,990
Heavy Load	2,328	2,055	1,872	1,932	2,143	2,629	2,962	2,763	2,248	1,843	2,003	2,286
Total Load	**2,204**	**1,940**	**1,766**	**1,794**	**2,006**	**2,464**	**2,748**	**2,553**	**2,094**	**1,697**	**1,896**	**2,155**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,799	2,571	2,274	2,263	3,088	4,034	4,502	3,978	3,305	2,327	2,539	2,765
Total Peak Load	**2,799**	**2,571**	**2,274**	**2,263**	**3,088**	**4,034**	**4,502**	**3,978**	**3,305**	**2,327**	**2,539**	**2,765**

[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 2017 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]	1/2035	2/2035	3/2035	4/2035	5/2035	6/2035	7/2035	8/2035	9/2035	10/2035	11/2035	12/2035
Average Load (aMW)–50th Percentile												
Residential	1,019	823	709	608	561	658	814	777	594	544	780	987
Commercial	573	527	482	491	492	525	571	582	541	505	528	570
Irrigation	3	3	10	145	384	652	715	559	364	81	6	3
Industrial	321	319	316	301	306	333	326	330	326	330	318	310
Additional Firm	134	131	124	122	120	117	123	122	120	119	131	134
Loss	175	152	137	140	159	198	223	206	166	130	148	171
System Load	**2,225**	**1,956**	**1,778**	**1,806**	**2,021**	**2,484**	**2,772**	**2,576**	**2,112**	**1,709**	**1,910**	**2,176**
Light Load	2,066	1,801	1,629	1,632	1,829	2,258	2,499	2,283	1,899	1,523	1,762	2,009
Heavy Load	2,340	2,072	1,885	1,946	2,160	2,650	2,987	2,788	2,281	1,844	2,019	2,308
Total Load	**2,225**	**1,956**	**1,778**	**1,806**	**2,021**	**2,484**	**2,772**	**2,576**	**2,112**	**1,709**	**1,910**	**2,176**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,820	2,585	2,286	2,276	3,112	4,072	4,557	4,023	3,336	2,340	2,553	2,783
Total Peak Load	**2,820**	**2,585**	**2,286**	**2,276**	**3,112**	**4,072**	**4,557**	**4,023**	**3,336**	**2,340**	**2,553**	**2,783**

Monthly Summary[1]	1/2036	2/2036	3/2036	4/2036	5/2036	6/2036	7/2036	8/2036	9/2036	10/2036	11/2036	12/2036
Average Load (aMW)–50th Percentile												
Residential	1,034	805	716	614	568	668	827	789	602	549	789	1,000
Commercial	578	513	486	495	496	530	575	587	546	509	532	575
Irrigation	3	3	10	146	386	657	720	563	367	82	6	3
Industrial	323	310	318	302	308	335	328	332	328	331	320	311
Additional Firm	134	126	124	122	120	117	123	122	120	119	131	134
Loss	177	148	138	141	160	200	225	208	167	131	149	173
System Load	**2,248**	**1,905**	**1,791**	**1,820**	**2,038**	**2,506**	**2,798**	**2,602**	**2,130**	**1,722**	**1,926**	**2,197**
Light Load	2,087	1,755	1,641	1,644	1,844	2,277	2,522	2,305	1,916	1,534	1,776	2,028
Heavy Load	2,364	2,017	1,909	1,948	2,178	2,688	2,997	2,835	2,287	1,857	2,046	2,319
Total Load	**2,248**	**1,905**	**1,791**	**1,820**	**2,038**	**2,506**	**2,798**	**2,602**	**2,130**	**1,722**	**1,926**	**2,197**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,846	2,604	2,301	2,291	3,138	4,112	4,613	4,070	3,370	2,354	2,569	2,801
Total Peak Load	**2,846**	**2,604**	**2,301**	**2,291**	**3,138**	**4,112**	**4,613**	**4,070**	**3,370**	**2,354**	**2,569**	**2,801**

[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 2017 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

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Billed Sales (MWh)–50th Percentile										
Residential	5,192,299	5,288,270	5,387,516	5,433,174	5,493,900	5,587,539	5,680,823	5,764,006	5,826,598	5,889,242
Commercial	4,076,548	4,123,898	4,161,677	4,191,974	4,224,260	4,256,416	4,288,363	4,316,202	4,344,798	4,377,647
Irrigation	1,932,624	1,943,945	1,958,945	1,970,715	1,979,560	1,993,436	2,005,655	2,016,870	2,027,030	2,037,054
Industrial	2,451,735	2,524,052	2,560,579	2,586,116	2,601,172	2,614,083	2,629,176	2,643,507	2,656,723	2,669,379
Additional Firm	945,167	961,532	972,050	979,308	982,862	990,453	1,011,238	1,083,805	1,086,225	1,085,654
System Sales	14,598,372	14,841,697	15,040,768	15,161,288	15,281,755	15,441,927	15,615,255	15,824,391	15,941,373	16,058,976
Total Sales	**14,598,372**	**14,841,697**	**15,040,768**	**15,161,288**	**15,281,755**	**15,441,927**	**15,615,255**	**15,824,391**	**15,941,373**	**16,058,976**
Generation Month Sales (MWh)–50th Percentile										
Residential	5,199,316	5,295,568	5,390,883	5,437,684	5,500,755	5,594,373	5,686,930	5,768,617	5,831,239	5,895,050
Commercial	4,079,292	4,126,078	4,163,415	4,193,828	4,226,101	4,258,242	4,289,946	4,317,830	4,346,675	4,379,442
Irrigation	1,932,630	1,943,953	1,958,952	1,970,720	1,979,568	1,993,443	2,005,661	2,016,876	2,027,036	2,037,061
Industrial	2,457,663	2,527,046	2,562,672	2,587,350	2,602,230	2,615,320	2,630,351	2,644,590	2,657,760	2,670,478
Additional Firm	945,167	961,532	972,050	979,308	982,862	990,453	1,011,238	1,083,805	1,086,225	1,085,654
System Sales	14,614,068	14,854,177	15,047,972	15,168,890	15,291,516	15,451,831	15,624,126	15,831,717	15,948,935	16,067,685
Total Sales	**14,614,068**	**14,854,177**	**15,047,972**	**15,168,890**	**15,291,516**	**15,451,831**	**15,624,126**	**15,831,717**	**15,948,935**	**16,067,685**
Loss	1,242,079	1,261,466	1,277,968	1,288,110	1,298,996	1,313,309	1,327,880	1,342,679	1,353,186	1,364,020
Required Generation	15,856,147	16,115,643	16,325,941	16,457,000	16,590,511	16,765,141	16,952,006	17,174,396	17,302,121	17,431,705
Average Load (aMW)–50th Percentile										
Residential	594	605	615	619	628	639	649	657	666	673
Commercial	466	471	475	477	482	486	490	492	496	500
Irrigation	221	222	224	224	226	228	229	230	231	233
Industrial	281	288	293	295	297	299	300	301	303	305
Additional Firm	108	110	111	111	112	113	115	123	124	124
Loss	142	144	146	147	148	150	152	153	154	156
System Load	1,810	1,840	1,864	1,874	1,894	1,914	1,935	1,955	1,975	1,990
Light Load	1,644	1,671	1,693	1,702	1,720	1,738	1,758	1,776	1,794	1,808
Heavy Load	1,941	1,972	1,997	2,008	2,030	2,051	2,075	2,095	2,117	2,133
Total Load	**1,810**	**1,840**	**1,864**	**1,874**	**1,894**	**1,914**	**1,935**	**1,955**	**1,975**	**1,990**
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	3,566	3,630	3,692	3,745	3,797	3,854	3,912	3,974	4,026	4,078
Total Peak Load	**3,566**	**3,630**	**3,692**	**3,745**	**3,797**	**3,854**	**3,912**	**3,974**	**4,026**	**4,078**

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Billed Sales (MWh)–50th Percentile										
Residential	5,967,300	6,042,091	6,107,379	6,164,550	6,217,671	6,262,116	6,326,691	6,399,357	6,472,617	6,556,711
Commercial	4,409,099	4,436,214	4,469,871	4,500,782	4,530,660	4,560,429	4,593,200	4,626,751	4,662,614	4,701,216
Irrigation	2,050,468	2,062,925	2,074,075	2,086,155	2,097,975	2,107,907	2,120,788	2,134,429	2,147,505	2,162,226
Industrial	2,682,789	2,698,620	2,714,704	2,730,194	2,745,660	2,759,437	2,772,278	2,786,182	2,800,272	2,813,726
Additional Firm	1,086,654	1,089,273	1,087,891	1,087,891	1,087,891	1,088,891	1,089,891	1,089,891	1,091,891	1,091,891
System Sales	16,196,310	16,329,123	16,453,920	16,569,573	16,679,857	16,778,781	16,902,848	17,036,610	17,174,899	17,325,771
Total Sales	**16,196,310**	**16,329,123**	**16,453,920**	**16,569,573**	**16,679,857**	**16,778,781**	**16,902,848**	**17,036,610**	**17,174,899**	**17,325,771**
Generation Month Sales (MWh)–50th Percentile										
Residential	5,972,903	6,047,037	6,111,779	6,168,711	6,221,263	6,267,266	6,332,524	6,405,338	6,479,512	6,563,740
Commercial	4,410,638	4,438,137	4,471,632	4,502,482	4,532,353	4,562,298	4,595,114	4,628,801	4,664,824	4,703,281
Irrigation	2,050,475	2,062,931	2,074,082	2,086,162	2,097,981	2,107,914	2,120,796	2,134,436	2,147,513	2,162,234
Industrial	2,684,087	2,699,938	2,715,974	2,731,462	2,746,789	2,760,490	2,773,418	2,787,337	2,801,375	2,814,823
Additional Firm	1,086,654	1,089,273	1,087,891	1,087,891	1,087,891	1,088,891	1,089,891	1,089,891	1,091,891	1,091,891
System Sales	16,204,757	16,337,317	16,461,358	16,576,708	16,686,278	16,786,859	16,911,743	17,045,803	17,185,114	17,335,969
Total Sales	**16,204,757**	**16,337,317**	**16,461,358**	**16,576,708**	**16,686,278**	**16,786,859**	**16,911,743**	**17,045,803**	**17,185,114**	**17,335,969**
Loss	1,376,496	1,388,365	1,399,639	1,410,019	1,419,853	1,428,827	1,440,150	1,452,371	1,464,969	1,478,800
Required Generation	17,581,253	17,725,682	17,860,997	17,986,727	18,106,130	18,215,685	18,351,893	18,498,173	18,650,084	18,814,769
Average Load (aMW)–50th Percentile										
Residential	682	688	698	704	710	713	723	731	740	747
Commercial	503	505	510	514	517	519	525	528	533	535
Irrigation	234	235	237	238	239	240	242	244	245	246
Industrial	306	307	310	312	314	314	317	318	320	320
Additional Firm	124	124	124	124	124	124	124	124	125	124
Loss	157	158	160	161	162	163	164	166	167	168
System Load	2,007	2,018	2,039	2,053	2,067	2,074	2,095	2,112	2,129	2,142
Light Load	1,823	1,833	1,852	1,865	1,877	1,884	1,903	1,918	1,934	1,946
Heavy Load	2,151	2,164	2,186	2,201	2,209	2,216	2,239	2,258	2,275	2,289
Total Load	**2,007**	**2,018**	**2,039**	**2,053**	**2,067**	**2,074**	**2,095**	**2,112**	**2,129**	**2,142**
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	4,132	4,187	4,240	4,292	4,344	4,394	4,447	4,502	4,557	4,613
Total Peak Load	**4,132**	**4,187**	**4,240**	**4,292**	**4,344**	**4,394**	**4,447**	**4,502**	**4,557**	**4,613**

70th Percentile Annual Forecast Growth Rates

	2017–2022	2017–2027	2017–2036
Sales			
Residential Sales	1.49%	1.41%	1.24%
Commercial Sales	0.88%	0.80%	0.77%
Irrigation Sales	0.58%	0.56%	0.56%
Industrial Sales	1.29%	0.90%	0.73%
Additional Firm Sales	0.94%	1.40%	0.76%
System Sales	1.13%	1.05%	0.91%
Total Sales	1.13%	1.05%	0.91%
Loads			
Residential Load	1.49%	1.40%	1.22%
Commercial Load	0.88%	0.80%	0.75%
Irrigation Load	0.58%	0.56%	0.54%
Industrial Load	1.25%	0.89%	0.70%
Additional Firm Sales	0.94%	1.40%	0.76%
System Load Losses	1.12%	1.03%	0.91%
System Load	1.12%	1.04%	0.89%
Total Load	1.12%	1.04%	0.89%
Peaks			
System Peak	1.57%	1.49%	1.37%
Total Peak	1.57%	1.49%	1.37%
Winter Peak	1.20%	1.03%	0.87%
Summer Peak	1.57%	1.49%	1.37%
Customers			
Residential Customers	2.11%	2.02%	1.78%
Commercial Customers	1.86%	1.90%	1.77%
Irrigation Customers	1.42%	1.37%	1.29%
Industrial Customers	0.50%	0.65%	0.59%

70th Percentile Load Forecast

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	845	690	604	513	460	542	653	614	483	463	664	819
Commercial	504	472	437	433	435	471	511	504	474	447	463	504
Irrigation	2	3	10	152	394	633	664	516	341	78	5	3
Industrial	281	279	277	263	268	292	285	289	286	289	279	278
Additional Firm	113	111	106	106	105	102	108	108	107	104	112	114
Loss	149	131	120	123	142	177	194	176	144	114	128	146
System Load	**1,894**	**1,686**	**1,555**	**1,591**	**1,803**	**2,217**	**2,415**	**2,207**	**1,834**	**1,495**	**1,650**	**1,863**
Light Load	1,759	1,553	1,424	1,437	1,631	2,015	2,177	1,956	1,650	1,332	1,522	1,720
Heavy Load	2,011	1,786	1,649	1,714	1,938	2,365	2,620	2,389	1,982	1,624	1,753	1,986
Total Load	**1,894**	**1,686**	**1,555**	**1,591**	**1,803**	**2,217**	**2,415**	**2,207**	**1,834**	**1,495**	**1,650**	**1,863**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,441	2,358	2,067	2,020	2,686	3,431	3,586	3,248	2,781	2,091	2,307	2,611
Total Peak Load	**2,441**	**2,358**	**2,067**	**2,020**	**2,686**	**3,431**	**3,586**	**3,248**	**2,781**	**2,091**	**2,307**	**2,611**

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	860	702	614	522	469	553	667	627	492	471	674	833
Commercial	510	477	442	438	440	477	517	511	480	452	469	509
Irrigation	2	3	10	153	396	636	667	519	343	78	5	3
Industrial	289	288	285	271	276	300	294	298	294	297	287	282
Additional Firm	115	113	108	107	107	103	110	110	109	106	114	116
Loss	152	133	122	125	144	180	197	179	146	116	130	148
System Load	**1,929**	**1,716**	**1,581**	**1,617**	**1,831**	**2,250**	**2,452**	**2,243**	**1,864**	**1,521**	**1,679**	**1,891**
Light Load	1,791	1,580	1,448	1,461	1,657	2,045	2,211	1,988	1,677	1,355	1,548	1,745
Heavy Load	2,038	1,818	1,676	1,742	1,969	2,400	2,660	2,428	2,028	1,640	1,783	2,015
Total Load	**1,929**	**1,716**	**1,581**	**1,617**	**1,831**	**2,250**	**2,452**	**2,243**	**1,864**	**1,521**	**1,679**	**1,891**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,487	2,393	2,101	2,048	2,724	3,489	3,651	3,305	2,833	2,118	2,335	2,648
Total Peak Load	**2,487**	**2,393**	**2,101**	**2,048**	**2,724**	**3,489**	**3,651**	**3,305**	**2,833**	**2,118**	**2,335**	**2,648**

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	876	714	624	530	478	565	682	642	502	478	685	843
Commercial	515	481	445	442	444	481	521	516	485	456	473	513
Irrigation	3	3	11	154	399	641	672	523	346	79	5	3
Industrial	294	292	289	275	280	305	298	302	299	302	291	285
Additional Firm	117	115	109	109	108	104	111	111	110	107	115	117
Loss	154	135	123	127	146	182	200	181	148	117	131	150
System Load	**1,958**	**1,740**	**1,601**	**1,637**	**1,854**	**2,278**	**2,485**	**2,274**	**1,889**	**1,540**	**1,701**	**1,910**
Light Load	1,818	1,602	1,467	1,480	1,678	2,070	2,240	2,015	1,699	1,372	1,569	1,764
Heavy Load	2,068	1,843	1,707	1,753	1,993	2,444	2,678	2,461	2,055	1,661	1,807	2,036
Total Load	**1,958**	**1,740**	**1,601**	**1,637**	**1,854**	**2,278**	**2,485**	**2,274**	**1,889**	**1,540**	**1,701**	**1,910**
Peak Load (MW)–95th Percentile												
System Peak (1 hour	2,530	2,426	2,132	2,073	2,758	3,540	3,713	3,359	2,876	2,141	2,359	2,666
Total Peak Load	**2,530**	**2,426**	**2,132**	**2,073**	**2,758**	**3,540**	**3,713**	**3,359**	**2,876**	**2,141**	**2,359**	**2,666**

[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 2017 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]	1/2020	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	883	695	628	534	483	571	690	650	507	481	690	851
Commercial	519	468	448	446	447	485	525	520	489	460	477	517
Irrigation	3	3	11	155	401	645	676	526	348	79	5	3
Industrial	297	285	292	278	283	308	301	305	302	305	294	287
Additional Firm	118	112	110	109	108	105	112	111	110	108	116	118
Loss	155	131	124	128	147	183	202	183	149	118	132	151
System Load	**1,975**	**1,693**	**1,613**	**1,650**	**1,869**	**2,297**	**2,506**	**2,295**	**1,904**	**1,551**	**1,714**	**1,926**
Light Load	1,834	1,559	1,477	1,490	1,691	2,087	2,259	2,034	1,713	1,382	1,581	1,778
Heavy Load	2,086	1,792	1,719	1,766	2,022	2,450	2,701	2,501	2,057	1,673	1,831	2,043
Total Load	**1,975**	**1,693**	**1,613**	**1,650**	**1,869**	**2,297**	**2,506**	**2,295**	**1,904**	**1,551**	**1,714**	**1,926**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,550	2,438	2,146	2,087	2,780	3,574	3,766	3,402	2,904	2,154	2,373	2,671
Total Peak Load	**2,550**	**2,438**	**2,146**	**2,087**	**2,780**	**3,574**	**3,766**	**3,402**	**2,904**	**2,154**	**2,373**	**2,671**

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	893	727	634	539	489	579	701	659	513	486	696	863
Commercial	524	488	450	449	451	488	529	525	493	463	481	521
Irrigation	3	3	11	156	402	647	679	528	349	80	5	3
Industrial	298	297	294	279	284	310	303	307	303	306	296	288
Additional Firm	118	116	111	110	109	105	112	112	111	108	116	119
Loss	157	137	125	129	148	185	203	185	150	119	133	153
System Load	**1,993**	**1,768**	**1,624**	**1,662**	**1,883**	**2,315**	**2,527**	**2,316**	**1,920**	**1,562**	**1,727**	**1,946**
Light Load	1,850	1,628	1,488	1,501	1,704	2,104	2,278	2,052	1,727	1,392	1,593	1,796
Heavy Load	2,115	1,872	1,722	1,779	2,038	2,469	2,723	2,524	2,074	1,696	1,835	2,064
Total Load	**1,993**	**1,768**	**1,624**	**1,662**	**1,883**	**2,315**	**2,527**	**2,316**	**1,920**	**1,562**	**1,727**	**1,946**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,562	2,450	2,153	2,098	2,803	3,606	3,819	3,444	2,932	2,168	2,387	2,691
Total Peak Load	**2,562**	**2,450**	**2,153**	**2,098**	**2,803**	**3,606**	**3,819**	**3,444**	**2,932**	**2,168**	**2,387**	**2,691**

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	908	738	643	547	498	590	715	673	522	493	706	877
Commercial	528	492	453	453	455	492	533	530	497	466	484	525
Irrigation	3	3	11	156	405	652	684	532	352	80	5	3
Industrial	300	298	295	281	286	311	304	308	305	308	297	290
Additional Firm	119	117	112	111	110	106	113	113	111	109	117	120
Loss	159	139	126	130	150	187	206	187	152	120	135	155
System Load	**2,017**	**1,787**	**1,640**	**1,678**	**1,902**	**2,338**	**2,554**	**2,342**	**1,939**	**1,577**	**1,745**	**1,968**
Light Load	1,872	1,645	1,502	1,516	1,721	2,125	2,303	2,075	1,744	1,405	1,610	1,817
Heavy Load	2,141	1,892	1,739	1,796	2,058	2,494	2,771	2,535	2,095	1,712	1,854	2,087
Total Load	**2,017**	**1,787**	**1,640**	**1,678**	**1,902**	**2,338**	**2,554**	**2,342**	**1,939**	**1,577**	**1,745**	**1,968**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,591	2,472	2,173	2,116	2,830	3,647	3,876	3,492	2,966	2,184	2,405	2,708
Total Peak Load	**2,591**	**2,472**	**2,173**	**2,116**	**2,830**	**3,647**	**3,876**	**3,492**	**2,966**	**2,184**	**2,405**	**2,708**

[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 2017 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]	1/2023	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	923	750	652	555	507	602	729	687	532	500	716	889
Commercial	533	495	456	456	458	496	537	534	501	470	488	529
Irrigation	3	3	11	157	407	655	688	535	354	81	6	3
Industrial	301	300	297	282	288	313	306	310	307	310	299	291
Additional Firm	122	120	114	113	112	108	115	115	113	111	120	123
Loss	161	140	128	131	151	189	208	189	154	121	136	156
System Load	**2,043**	**1,808**	**1,657**	**1,695**	**1,922**	**2,363**	**2,582**	**2,369**	**1,960**	**1,592**	**1,765**	**1,991**
Light Load	1,896	1,665	1,518	1,532	1,739	2,147	2,328	2,100	1,763	1,419	1,628	1,838
Heavy Load	2,168	1,915	1,757	1,826	2,066	2,520	2,801	2,564	2,118	1,729	1,875	2,123
Total Load	**2,043**	**1,808**	**1,657**	**1,695**	**1,922**	**2,363**	**2,582**	**2,369**	**1,960**	**1,592**	**1,765**	**1,991**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,619	2,493	2,192	2,134	2,858	3,690	3,934	3,541	3,002	2,202	2,426	2,725
Total Peak Load	**2,619**	**2,493**	**2,192**	**2,134**	**2,858**	**3,690**	**3,934**	**3,541**	**3,002**	**2,202**	**2,426**	**2,725**

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	936	733	660	563	515	612	742	699	540	506	725	900
Commercial	537	481	458	459	461	499	540	538	505	473	491	532
Irrigation	3	3	11	158	409	659	692	538	356	81	6	3
Industrial	303	291	298	284	289	315	308	312	308	311	300	293
Additional Firm	133	126	123	121	119	116	122	121	119	118	130	133
Loss	163	137	129	133	153	191	210	191	155	123	138	158
System Load	**2,074**	**1,771**	**1,679**	**1,717**	**1,945**	**2,390**	**2,614**	**2,400**	**1,984**	**1,612**	**1,790**	**2,019**
Light Load	1,926	1,631	1,538	1,551	1,760	2,172	2,356	2,126	1,784	1,436	1,651	1,864
Heavy Load	2,191	1,875	1,790	1,838	2,091	2,565	2,817	2,597	2,158	1,739	1,902	2,152
Total Load	**2,074**	**1,771**	**1,679**	**1,717**	**1,945**	**2,390**	**2,614**	**2,400**	**1,984**	**1,612**	**1,790**	**2,019**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,654	2,520	2,217	2,156	2,890	3,735	3,998	3,594	3,040	2,225	2,454	2,747
Total Peak Load	**2,654**	**2,520**	**2,217**	**2,156**	**2,890**	**3,735**	**3,998**	**3,594**	**3,040**	**2,225**	**2,454**	**2,747**

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	946	767	666	568	521	620	753	709	546	510	731	909
Commercial	541	501	460	462	464	502	543	542	509	476	495	536
Irrigation	3	3	11	159	411	662	695	540	357	81	6	3
Industrial	305	303	300	285	291	316	309	313	310	313	302	294
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	164	143	130	134	154	192	212	193	156	124	139	159
System Load	**2,091**	**1,848**	**1,690**	**1,728**	**1,959**	**2,408**	**2,635**	**2,420**	**1,999**	**1,622**	**1,803**	**2,035**
Light Load	1,942	1,702	1,548	1,562	1,773	2,189	2,375	2,145	1,798	1,445	1,663	1,879
Heavy Load	2,209	1,957	1,801	1,850	2,106	2,584	2,839	2,638	2,159	1,750	1,926	2,158
Total Load	**2,091**	**1,848**	**1,690**	**1,728**	**1,959**	**2,408**	**2,635**	**2,420**	**1,999**	**1,622**	**1,803**	**2,035**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,668	2,533	2,226	2,167	2,911	3,766	4,050	3,636	3,066	2,236	2,466	2,754
Total Peak Load	**2,668**	**2,533**	**2,226**	**2,167**	**2,911**	**3,766**	**4,050**	**3,636**	**3,066**	**2,236**	**2,466**	**2,754**

[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 2017 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]	1/2026	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	956	774	671	573	527	628	763	720	553	515	738	919
Commercial	545	505	463	465	468	506	547	547	513	479	499	540
Irrigation	3	3	11	159	412	665	698	543	359	82	6	3
Industrial	306	304	301	287	292	318	311	315	311	314	303	296
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	166	144	131	135	155	194	214	195	158	124	140	161
System Load	**2,109**	**1,861**	**1,700**	**1,740**	**1,973**	**2,426**	**2,656**	**2,441**	**2,014**	**1,633**	**1,815**	**2,052**
Light Load	1,958	1,714	1,558	1,572	1,786	2,205	2,394	2,163	1,811	1,455	1,674	1,895
Heavy Load	2,228	1,971	1,813	1,863	2,135	2,588	2,862	2,660	2,176	1,761	1,939	2,177
Total Load	**2,109**	**1,861**	**1,700**	**1,740**	**1,973**	**2,426**	**2,656**	**2,441**	**2,014**	**1,633**	**1,815**	**2,052**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,682	2,542	2,233	2,178	2,933	3,798	4,102	3,678	3,093	2,248	2,479	2,769
Total Peak Load	**2,682**	**2,542**	**2,233**	**2,178**	**2,933**	**3,798**	**4,102**	**3,678**	**3,093**	**2,248**	**2,479**	**2,769**

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	968	784	679	579	534	638	776	732	561	520	746	930
Commercial	550	508	466	469	472	509	551	552	517	483	502	544
Irrigation	3	3	11	160	415	669	703	547	361	82	6	3
Industrial	308	306	303	288	293	319	312	316	313	316	305	297
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	167	146	132	136	156	195	216	197	159	125	141	162
System Load	**2,129**	**1,877**	**1,713**	**1,753**	**1,990**	**2,447**	**2,680**	**2,465**	**2,031**	**1,645**	**1,830**	**2,071**
Light Load	1,977	1,729	1,569	1,584	1,800	2,224	2,416	2,184	1,827	1,465	1,688	1,912
Heavy Load	2,260	1,988	1,817	1,877	2,153	2,610	2,888	2,686	2,195	1,786	1,944	2,196
Total Load	**2,129**	**1,877**	**1,713**	**1,753**	**1,990**	**2,447**	**2,680**	**2,465**	**2,031**	**1,645**	**1,830**	**2,071**
Peak Load (MW)–95th Percentile												
System Peak (1 hour	2,705	2,559	2,248	2,192	2,957	3,836	4,157	3,723	3,124	2,262	2,493	2,784
Total Peak Load	**2,705**	**2,559**	**2,248**	**2,192**	**2,957**	**3,836**	**4,157**	**3,723**	**3,124**	**2,262**	**2,493**	**2,784**

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	980	765	685	585	541	647	788	743	568	525	753	941
Commercial	554	494	468	472	475	512	554	556	521	486	506	548
Irrigation	3	3	11	161	417	673	707	550	363	83	6	3
Industrial	309	297	305	290	295	321	314	318	315	318	307	299
Additional Firm	134	126	123	121	119	116	123	122	120	118	130	134
Loss	169	142	133	137	158	197	218	199	161	126	142	164
System Load	**2,149**	**1,827**	**1,725**	**1,766**	**2,005**	**2,467**	**2,704**	**2,488**	**2,048**	**1,656**	**1,844**	**2,088**
Light Load	1,995	1,682	1,580	1,596	1,815	2,242	2,438	2,205	1,842	1,476	1,701	1,928
Heavy Load	2,281	1,934	1,829	1,902	2,156	2,632	2,933	2,692	2,213	1,799	1,959	2,226
Total Load	**2,149**	**1,827**	**1,725**	**1,766**	**2,005**	**2,467**	**2,704**	**2,488**	**2,048**	**1,656**	**1,844**	**2,088**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,728	2,574	2,263	2,206	2,981	3,872	4,212	3,768	3,155	2,276	2,509	2,796
Total Peak Load	**2,728**	**2,574**	**2,263**	**2,206**	**2,981**	**3,872**	**4,212**	**3,768**	**3,155**	**2,276**	**2,509**	**2,796**

[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 2017 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]	1/2029	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	991	800	691	591	548	656	799	754	575	530	760	949
Commercial	558	515	471	475	478	516	558	561	525	489	509	552
Irrigation	3	3	11	162	419	676	711	553	365	83	6	3
Industrial	311	309	306	292	297	323	316	320	317	320	308	301
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	171	148	134	138	159	199	220	201	162	127	144	165
System Load	**2,167**	**1,906**	**1,736**	**1,778**	**2,020**	**2,486**	**2,726**	**2,510**	**2,064**	**1,667**	**1,857**	**2,104**
Light Load	2,012	1,756	1,590	1,607	1,828	2,259	2,458	2,224	1,856	1,485	1,713	1,942
Heavy Load	2,290	2,019	1,841	1,915	2,172	2,652	2,957	2,716	2,246	1,799	1,973	2,243
Total Load	**2,167**	**1,906**	**1,736**	**1,778**	**2,020**	**2,486**	**2,726**	**2,510**	**2,064**	**1,667**	**1,857**	**2,104**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,745	2,588	2,273	2,218	3,004	3,906	4,265	3,811	3,183	2,288	2,521	2,807
Total Peak Load	**2,745**	**2,588**	**2,273**	**2,218**	**3,004**	**3,906**	**4,265**	**3,811**	**3,183**	**2,288**	**2,521**	**2,807**

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	1,000	807	696	595	553	663	809	764	581	533	765	958
Commercial	563	518	473	479	482	520	562	565	529	492	513	555
Irrigation	3	3	11	163	421	680	715	556	367	84	6	3
Industrial	313	311	308	293	299	325	318	322	318	322	310	303
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	172	149	134	139	160	200	222	202	163	128	144	166
System Load	**2,184**	**1,919**	**1,746**	**1,789**	**2,034**	**2,504**	**2,748**	**2,531**	**2,079**	**1,677**	**1,869**	**2,119**
Light Load	2,028	1,768	1,600	1,617	1,841	2,276	2,477	2,243	1,870	1,494	1,724	1,956
Heavy Load	2,307	2,033	1,861	1,915	2,187	2,687	2,961	2,739	2,262	1,809	1,985	2,259
Total Load	**2,184**	**1,919**	**1,746**	**1,789**	**2,034**	**2,504**	**2,748**	**2,531**	**2,079**	**1,677**	**1,869**	**2,119**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,763	2,601	2,284	2,230	3,025	3,939	4,317	3,853	3,210	2,299	2,533	2,817
Total Peak Load	**2,763**	**2,601**	**2,284**	**2,230**	**3,025**	**3,939**	**4,317**	**3,853**	**3,210**	**2,299**	**2,533**	**2,817**

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	1,009	813	700	599	558	671	819	773	586	537	770	965
Commercial	567	522	476	482	485	523	566	569	533	496	517	559
Irrigation	3	3	11	164	423	683	719	559	369	84	6	3
Industrial	315	313	310	295	300	327	320	324	320	323	312	304
Additional Firm	133	130	123	121	119	116	122	122	120	118	130	134
Loss	173	150	135	139	161	202	223	204	164	129	145	168
System Load	**2,200**	**1,931**	**1,755**	**1,799**	**2,048**	**2,522**	**2,768**	**2,551**	**2,094**	**1,687**	**1,880**	**2,132**
Light Load	2,043	1,779	1,608	1,626	1,853	2,292	2,496	2,261	1,883	1,503	1,734	1,969
Heavy Load	2,314	2,046	1,871	1,926	2,188	2,706	2,965	2,780	2,247	1,819	1,997	2,251
Total Load	**2,200**	**1,931**	**1,755**	**1,799**	**2,048**	**2,522**	**2,768**	**2,551**	**2,094**	**1,687**	**1,880**	**2,132**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,780	2,613	2,294	2,241	3,047	3,971	4,370	3,896	3,237	2,311	2,545	2,820
Total Peak Load	**2,780**	**2,613**	**2,294**	**2,241**	**3,047**	**3,971**	**4,370**	**3,896**	**3,237**	**2,311**	**2,545**	**2,820**

[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 2017 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]	1/2032	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	1,017	790	703	602	563	677	827	781	591	539	774	973
Commercial	571	507	478	485	489	526	569	574	537	499	520	563
Irrigation	3	3	11	164	425	686	722	562	371	84	6	3
Industrial	316	304	311	296	302	328	321	325	322	325	314	305
Additional Firm	133	126	123	121	119	116	123	122	120	118	130	134
Loss	175	146	136	140	162	203	225	206	165	129	146	169
System Load	**2,215**	**1,875**	**1,763**	**1,809**	**2,060**	**2,537**	**2,787**	**2,570**	**2,107**	**1,695**	**1,890**	**2,148**
Light Load	2,057	1,727	1,615	1,634	1,864	2,306	2,512	2,277	1,895	1,510	1,743	1,983
Heavy Load	2,330	1,996	1,870	1,936	2,214	2,707	2,985	2,800	2,261	1,841	1,997	2,267
Total Load	**2,215**	**1,875**	**1,763**	**1,809**	**2,060**	**2,537**	**2,787**	**2,570**	**2,107**	**1,695**	**1,890**	**2,148**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,788	2,623	2,297	2,248	3,065	3,998	4,420	3,935	3,260	2,320	2,555	2,832
Total Peak Load	**2,788**	**2,623**	**2,297**	**2,248**	**3,065**	**3,998**	**4,420**	**3,935**	**3,260**	**2,320**	**2,555**	**2,832**

Monthly Summary[1]	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Average Load (aMW)–70th Percentile												
Residential	1,028	826	709	606	569	685	838	792	598	543	780	984
Commercial	576	528	481	488	492	530	573	579	542	502	524	567
Irrigation	3	3	11	165	427	690	726	565	373	85	6	3
Industrial	318	316	313	298	303	330	323	327	323	327	315	307
Additional Firm	134	131	124	121	119	117	123	122	120	119	130	134
Loss	176	152	137	141	163	205	227	207	167	130	147	170
System Load	**2,234**	**1,956**	**1,774**	**1,820**	**2,074**	**2,557**	**2,809**	**2,592**	**2,123**	**1,705**	**1,903**	**2,166**
Light Load	2,074	1,802	1,625	1,645	1,877	2,323	2,533	2,297	1,909	1,519	1,755	2,000
Heavy Load	2,360	2,072	1,881	1,948	2,230	2,727	3,028	2,805	2,279	1,852	2,011	2,286
Total Load	**2,234**	**1,956**	**1,774**	**1,820**	**2,074**	**2,557**	**2,809**	**2,592**	**2,123**	**1,705**	**1,903**	**2,166**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,808	2,633	2,309	2,260	3,087	4,032	4,474	3,979	3,288	2,332	2,567	2,847
Total Peak Load	**2,808**	**2,633**	**2,309**	**2,260**	**3,087**	**4,032**	**4,474**	**3,979**	**3,288**	**2,332**	**2,567**	**2,847**

Monthly Summary[1]	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Average Load (aMW)–70th Percentile												
Residential	1,040	835	715	612	575	694	850	804	605	548	787	995
Commercial	581	532	484	492	496	534	577	583	546	506	528	572
Irrigation	3	3	11	166	430	694	731	568	376	85	6	3
Industrial	319	318	315	299	305	332	324	329	325	328	317	309
Additional Firm	134	131	124	121	119	117	123	122	120	119	130	134
Loss	178	154	138	142	165	206	229	209	168	131	148	172
System Load	**2,254**	**1,972**	**1,786**	**1,832**	**2,090**	**2,577**	**2,834**	**2,615**	**2,140**	**1,717**	**1,916**	**2,185**
Light Load	2,093	1,816	1,636	1,656	1,891	2,342	2,554	2,318	1,924	1,530	1,768	2,017
Heavy Load	2,381	2,088	1,894	1,974	2,234	2,749	3,054	2,831	2,297	1,864	2,025	2,317
Total Load	**2,254**	**1,972**	**1,786**	**1,832**	**2,090**	**2,577**	**2,834**	**2,615**	**2,140**	**1,717**	**1,916**	**2,185**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,832	2,649	2,323	2,274	3,112	4,070	4,529	4,025	3,319	2,346	2,582	2,860
Total Peak Load	**2,832**	**2,649**	**2,323**	**2,274**	**3,112**	**4,070**	**4,529**	**4,025**	**3,319**	**2,346**	**2,582**	**2,860**

[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 2017 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]	1/2035	2/2035	3/2035	4/2035	5/2035	6/2035	7/2035	8/2035	9/2035	10/2035	11/2035	12/2035
Average Load (aMW)–70th Percentile												
Residential	1,053	844	721	617	582	703	862	815	612	552	794	1,008
Commercial	585	536	487	496	500	538	581	589	551	510	532	576
Irrigation	3	3	11	167	432	698	735	572	378	86	6	3
Industrial	321	319	316	301	306	333	326	330	326	330	318	310
Additional Firm	134	131	124	122	120	117	123	122	120	119	131	134
Loss	180	155	139	143	166	208	231	211	170	132	150	174
System Load	**2,275**	**1,988**	**1,798**	**1,845**	**2,106**	**2,598**	**2,858**	**2,640**	**2,157**	**1,728**	**1,931**	**2,205**
Light Load	2,113	1,830	1,647	1,667	1,905	2,361	2,577	2,339	1,940	1,540	1,781	2,036
Heavy Load	2,393	2,105	1,906	1,988	2,251	2,771	3,080	2,857	2,331	1,865	2,041	2,339
Total Load	**2,275**	**1,988**	**1,798**	**1,845**	**2,106**	**2,598**	**2,858**	**2,640**	**2,157**	**1,728**	**1,931**	**2,205**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,853	2,664	2,334	2,287	3,135	4,107	4,584	4,070	3,350	2,359	2,597	2,878
Total Peak Load	**2,853**	**2,664**	**2,334**	**2,287**	**3,135**	**4,107**	**4,584**	**4,070**	**3,350**	**2,359**	**2,597**	**2,878**

Monthly Summary[1]	1/2036	2/2036	3/2036	4/2036	5/2036	6/2036	7/2036	8/2036	9/2036	10/2036	11/2036	12/2036
Average Load (aMW)–70th Percentile												
Residential	1,067	825	729	623	589	713	875	828	620	558	803	1,021
Commercial	591	521	490	500	504	542	586	594	556	514	537	581
Irrigation	3	3	11	168	435	703	740	576	380	87	6	3
Industrial	323	310	318	302	308	335	328	332	328	331	320	311
Additional Firm	134	126	124	122	120	117	123	122	120	119	131	134
Loss	182	151	140	144	167	210	233	214	171	133	151	175
System Load	**2,299**	**1,936**	**1,811**	**1,859**	**2,123**	**2,620**	**2,885**	**2,666**	**2,176**	**1,741**	**1,947**	**2,227**
Light Load	2,134	1,783	1,659	1,680	1,921	2,381	2,601	2,362	1,957	1,551	1,796	2,056
Heavy Load	2,417	2,049	1,931	1,990	2,269	2,811	3,090	2,905	2,336	1,878	2,068	2,350
Total Load	**2,299**	**1,936**	**1,811**	**1,859**	**2,123**	**2,620**	**2,885**	**2,666**	**2,176**	**1,741**	**1,947**	**2,227**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,879	2,682	2,350	2,302	3,161	4,148	4,641	4,118	3,384	2,373	2,612	2,896
Total Peak Load	**2,879**	**2,682**	**2,350**	**2,302**	**3,161**	**4,148**	**4,641**	**4,118**	**3,384**	**2,373**	**2,612**	**2,896**

[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 2017 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.

LOAD AND RESOURCE BALANCE DATA

Monthly Average Energy Load and Resource Balance

	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—included EE	10	11	10	10	12	14	15	15	13	12	11	10
Load Forecast (70th% w/EE)	(1,894)	(1,686)	(1,555)	(1,591)	(1,803)	(2,217)	(2,415)	(2,207)	(1,834)	(1,495)	(1,650)	(1,863)
Adjustment for EE Potential Study Forecast	1	1	1	1	1	1	1	1	1	1	1	1
Net Load Forecast (70th% w/ EE)	(1,893)	(1,685)	(1,554)	(1,590)	(1,802)	(2,216)	(2,414)	(2,206)	(1,834)	(1,494)	(1,649)	(1,862)
Existing Resources												
Total Coal	958	958	926	751	754	958	958	958	958	958	958	958
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	582	647	591	729	870	591	536	367	413	442	347	453
Hydro (70th%)—Other	202	214	211	266	318	328	283	212	223	198	182	189
Total Hydro (70th%)	784	861	801	995	1,187	919	819	578	636	640	529	642
CSPP (PURPA)	230	303	328	411	418	414	397	362	334	291	271	247
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**75**	**75**	**58**	**53**	**65**	**68**	**66**	**59**	**58**	**37**	**57**	**77**
Transmission Capacity available for Market Purchases	203	245	320	285	222	399	313	335	175	290	237	182
Existing Resource Subtotal	**2,777**	**2,728**	**2,713**	**2,776**	**2,925**	**3,268**	**3,060**	**2,801**	**2,439**	**2,496**	**2,335**	**2,634**
Monthly Surplus/Deficit	**884**	**1,043**	**1,159**	**1,186**	**1,123**	**1,052**	**646**	**595**	**605**	**1,002**	**686**	**772**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**884**	**1,043**	**1,159**	**1,186**	**1,123**	**1,052**	**646**	**595**	**605**	**1,002**	**686**	**772**

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
Load Forecast—included EE	21	21	20	21	24	27	28	28	24	23	21	21
Load Forecast (70th% w/EE)	(1,929)	(1,716)	(1,581)	(1,617)	(1,831)	(2,250)	(2,452)	(2,243)	(1,864)	(1,521)	(1,679)	(1,891)
Adjustment for EE Potential Study Forecast	4	4	4	4	5	5	5	5	5	4	4	4
Net Load Forecast (70th% w/ EE)	(1,925)	(1,712)	(1,577)	(1,613)	(1,827)	(2,245)	(2,447)	(2,238)	(1,860)	(1,516)	(1,674)	(1,887)
Existing Resources												
Total Coal	958	958	926	751	754	958	958	958	958	958	958	958
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	582	647	591	729	870	591	536	367	413	442	347	453
Hydro (70th%)—Other	202	214	211	266	318	328	283	212	223	198	182	189
Total Hydro (70th%)	784	861	801	995	1,187	919	819	578	636	640	529	642
CSPP (PURPA)	230	303	328	411	418	414	397	362	334	291	271	247
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**75**	**75**	**58**	**53**	**65**	**68**	**66**	**59**	**58**	**37**	**57**	**77**
Transmission Capacity available for Market Purchases	202	243	318	284	220	399	313	333	174	289	236	182
Existing Resource Subtotal	**2,760**	**2,776**	**2,689**	**2,788**	**2,956**	**3,285**	**3,060**	**2,798**	**2,438**	**2,495**	**2,328**	**2,641**
Monthly Surplus/Deficit	**835**	**1,064**	**1,112**	**1,175**	**1,129**	**1,040**	**613**	**560**	**579**	**979**	**654**	**754**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**835**	**1,064**	**1,112**	**1,175**	**1,129**	**1,040**	**613**	**560**	**579**	**979**	**654**	**754**

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
Load Forecast—included EE	32	31	30	31	36	40	41	41	36	35	32	31
Load Forecast (70th% w/EE)	(1,958)	(1,740)	(1,601)	(1,637)	(1,854)	(2,278)	(2,485)	(2,274)	(1,889)	(1,540)	(1,701)	(1,910)
Adjustment for EE Potential Study Forecast	8	8	8	8	9	11	11	11	10	9	8	8
Net Load Forecast (70th% w/ EE)	(1,950)	(1,732)	(1,594)	(1,629)	(1,845)	(2,268)	(2,474)	(2,264)	(1,879)	(1,530)	(1,693)	(1,902)
Existing Resources												
Total Coal	956	956	909	838	733	956	956	956	956	956	956	956
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	560	670	590	742	872	614	536	366	407	443	346	459
Hydro (70th%)—Other	194	252	215	285	323	332	284	213	224	198	174	182
Total Hydro (70th%)	755	921	805	1,027	1,195	946	820	579	631	642	520	641
CSPP (PURPA)	230	303	328	411	418	414	397	362	334	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**75**	**75**	**58**	**53**	**65**	**68**	**66**	**59**	**58**	**37**	**57**	**77**
Transmission Capacity available for Market Purchases	201	242	317	293	226	387	302	332	177	288	236	183
Existing Resource Subtotal	**2,744**	**2,783**	**2,695**	**2,902**	**2,916**	**3,281**	**3,048**	**2,796**	**2,434**	**2,496**	**2,325**	**2,633**
Monthly Surplus/Deficit	**795**	**1,052**	**1,102**	**1,273**	**1,071**	**1,013**	**574**	**533**	**555**	**966**	**632**	**731**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**795**	**1,052**	**1,102**	**1,273**	**1,071**	**1,013**	**574**	**533**	**555**	**966**	**632**	**731**

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
Load Forecast—included EE	46	48	44	47	53	59	61	60	54	51	47	45
Load Forecast (70th% w/EE)	(1,975)	(1,693)	(1,613)	(1,650)	(1,869)	(2,297)	(2,506)	(2,295)	(1,904)	(1,551)	(1,714)	(1,926)
Adjustment for EE Potential Study Forecast	7	7	6	7	8	9	9	9	8	7	7	7
Net Load Forecast (70th% w/ EE)	(1,968)	(1,686)	(1,606)	(1,643)	(1,861)	(2,288)	(2,497)	(2,286)	(1,896)	(1,543)	(1,707)	(1,920)
Existing Resources												
Total Coal	841	842	843	698	633	841	841	841	841	841	841	841
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	561	670	590	742	874	615	536	365	406	443	346	460
Hydro (70th%)—Other	194	256	215	286	323	332	284	213	224	198	174	182
Total Hydro (70th%)	755	925	805	1,028	1,198	946	819	578	630	641	520	642
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**75**	**75**	**58**	**53**	**65**	**68**	**66**	**59**	**58**	**37**	**57**	**77**
Transmission Capacity available for Market Purchases	201	243	317	293	227	387	301	331	176	288	235	182
Existing Resource Subtotal	**2,631**	**2,675**	**2,632**	**2,767**	**2,823**	**3,170**	**2,936**	**2,683**	**2,320**	**2,381**	**2,209**	**2,518**
Monthly Surplus/Deficit	**663**	**989**	**1,026**	**1,125**	**961**	**882**	**439**	**397**	**423**	**838**	**502**	**599**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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**	**989**	**1,026**	**1,125**	**961**	**882**	**439**	**397**	**423**	**838**	**502**	**599**

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
Load Forecast—included EE	5	5	5	6	9	12	12	12	8	6	5	5
Load Forecast (70th% w/EE)	(1,894)	(1,686)	(1,555)	(1,591)	(1,803)	(2,217)	(2,415)	(2,207)	(1,834)	(1,495)	(1,650)	(1,863)
Adjustment for EE Potential Study Forecast	0	0	0	0	1	1	1	1	1	0	0	0
Net Load Forecast (70th% w/ EE)	(1,894)	(1,686)	(1,554)	(1,590)	(1,802)	(2,216)	(2,414)	(2,206)	(1,834)	(1,495)	(1,650)	(1,862)
Existing Resources												
Total Coal	787	787	700	563	608	787	787	787	787	787	787	787
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	558	668	590	744	873	612	536	365	403	443	346	458
Hydro (70th%)—Other	191	251	213	288	324	331	284	212	223	198	174	180
Total Hydro (70th%)	749	919	803	1,032	1,197	944	819	577	627	641	520	638
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	261	302	376	352	285	445	360	389	234	348	294	242
Existing Resource Subtotal	**2,625**	**2,667**	**2,559**	**2,706**	**2,845**	**3,161**	**2,930**	**2,679**	**2,316**	**2,406**	**2,230**	**2,515**
Monthly Surplus/Deficit	**640**	**907**	**943**	**1,052**	**970**	**856**	**414**	**374**	**405**	**852**	**511**	**577**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**640**	**907**	**943**	**1,052**	**970**	**856**	**414**	**374**	**405**	**852**	**511**	**577**

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
Load Forecast—included EE	70	70	68	72	82	92	94	93	82	77	72	70
Load Forecast (70th% w/EE)	(2,017)	(1,787)	(1,640)	(1,678)	(1,902)	(2,338)	(2,554)	(2,342)	(1,939)	(1,577)	(1,745)	(1,968)
Adjustment for EE Potential Study Forecast	9	9	9	9	10	12	12	12	10	10	9	9
Net Load Forecast (70th% w/ EE)	(2,008)	(1,778)	(1,631)	(1,668)	(1,891)	(2,326)	(2,542)	(2,330)	(1,929)	(1,567)	(1,736)	(1,959)
Existing Resources												
Total Coal	787	787	684	603	650	787	787	787	787	787	787	787
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	562	671	590	725	873	601	535	364	403	442	346	461
Hydro (70th%)—Other	197	245	212	248	324	331	283	212	222	197	174	183
Total Hydro (70th%)	759	916	802	973	1,197	932	818	576	625	639	520	644
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	260	302	375	352	284	444	357	389	233	347	293	241
Existing Resource Subtotal	**2,634**	**2,664**	**2,541**	**2,687**	**2,886**	**3,148**	**2,926**	**2,678**	**2,313**	**2,403**	**2,230**	**2,521**
Monthly Surplus/Deficit	**627**	**886**	**911**	**1,019**	**995**	**821**	**384**	**348**	**385**	**836**	**494**	**561**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**627**	**886**	**911**	**1,019**	**995**	**821**	**384**	**348**	**385**	**836**	**494**	**561**

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
Load Forecast—included EE	82	83	79	82	94	107	110	112	96	92	84	82
Load Forecast (70th% w/EE)	(2,043)	(1,808)	(1,657)	(1,695)	(1,922)	(2,363)	(2,582)	(2,369)	(1,960)	(1,592)	(1,765)	(1,991)
Adjustment for EE Potential Study Forecast	10	11	10	10	12	14	14	14	12	12	11	11
Net Load Forecast (70th% w/ EE)	(2,032)	(1,797)	(1,647)	(1,685)	(1,910)	(2,349)	(2,568)	(2,355)	(1,948)	(1,581)	(1,755)	(1,981)
Existing Resources												
Total Coal	787	787	717	602	759	787	787	787	787	787	787	787
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	562	670	590	725	875	600	534	363	396	443	347	459
Hydro (70th%)—Other	197	244	211	248	324	330	283	212	221	197	173	183
Total Hydro (70th%)	758	914	801	973	1,199	930	817	575	617	639	520	642
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	259	301	375	352	283	443	356	388	232	346	292	240
Existing Resource Subtotal	**2,632**	**2,661**	**2,573**	**2,686**	**2,996**	**3,145**	**2,924**	**2,675**	**2,304**	**2,401**	**2,229**	**2,517**
Monthly Surplus/Deficit	**600**	**864**	**926**	**1,002**	**1,087**	**796**	**355**	**320**	**356**	**821**	**474**	**536**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	600	864	926	1,002	1,087	796	355	320	356	821	474	536

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
Load Forecast—included EE	95	100	91	96	109	122	128	128	110	105	97	92
Load Forecast (70th% w/EE)	(2,074)	(1,771)	(1,679)	(1,717)	(1,945)	(2,390)	(2,614)	(2,400)	(1,984)	(1,612)	(1,790)	(2,019)
Adjustment for EE Potential Study Forecast	12	13	12	12	14	16	16	16	14	13	12	12
Net Load Forecast (70th% w/ EE)	(2,062)	(1,758)	(1,668)	(1,705)	(1,931)	(2,375)	(2,597)	(2,383)	(1,970)	(1,598)	(1,778)	(2,007)
Existing Resources												
Total Coal	786	763	744	602	616	690	786	786	786	786	786	786
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	561	669	589	725	875	599	534	363	392	443	346	456
Hydro (70th%)—Other	196	241	211	248	324	330	282	211	220	196	173	183
Total Hydro (70th%)	757	910	800	973	1,199	929	816	573	612	639	519	639
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	293	272	248
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	258	300	375	351	282	442	355	387	232	345	292	240
Existing Resource Subtotal	**2,630**	**2,632**	**2,598**	**2,684**	**2,852**	**3,045**	**2,921**	**2,672**	**2,299**	**2,400**	**2,226**	**2,514**
Monthly Surplus/Deficit	**568**	**874**	**931**	**980**	**921**	**670**	**324**	**289**	**329**	**801**	**449**	**506**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**568**	**874**	**931**	**980**	**921**	**670**	**324**	**289**	**329**	**801**	**449**	**506**

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
Load Forecast—included EE	109	110	104	111	125	140	146	145	126	120	110	109
Load Forecast (70th% w/EE)	(2,091)	(1,848)	(1,690)	(1,728)	(1,959)	(2,408)	(2,635)	(2,420)	(1,999)	(1,622)	(1,803)	(2,035)
Adjustment for EE Potential Study Forecast	13	13	12	13	14	16	17	17	15	14	13	13
Net Load Forecast (70th% w/ EE)	(2,079)	(1,835)	(1,678)	(1,716)	(1,945)	(2,392)	(2,618)	(2,403)	(1,984)	(1,608)	(1,790)	(2,022)
Existing Resources												
Total Coal	786	763	744	602	616	690	786	786	786	786	786	786
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	560	669	587	725	875	598	533	362	388	443	347	453
Hydro (70th%)—Other	196	238	210	248	324	329	282	210	219	195	172	182
Total Hydro (70th%)	756	907	798	972	1,199	927	814	571	607	638	519	636
CSPP (PURPA)	231	304	330	414	421	417	401	365	337	290	269	245
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	259	300	374	351	280	440	354	385	230	345	292	239
Existing Resource Subtotal	**2,630**	**2,629**	**2,595**	**2,684**	**2,850**	**3,041**	**2,919**	**2,669**	**2,292**	**2,396**	**2,223**	**2,506**
Monthly Surplus/Deficit	**551**	**794**	**918**	**968**	**905**	**649**	**301**	**265**	**308**	**788**	**433**	**484**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**551**	**794**	**918**	**968**	**905**	**649**	**301**	**265**	**308**	**788**	**433**	**484**

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
Load Forecast—included EE	123	123	117	125	140	157	165	162	142	132	124	122
Load Forecast (70th% w/EE)	(2,109)	(1,861)	(1,700)	(1,740)	(1,973)	(2,426)	(2,656)	(2,441)	(2,014)	(1,633)	(1,815)	(2,052)
Adjustment for EE Potential Study Forecast	10	10	10	10	12	13	14	13	12	11	10	10
Net Load Forecast (70th% w/ EE)	(2,099)	(1,851)	(1,691)	(1,730)	(1,962)	(2,413)	(2,642)	(2,428)	(2,002)	(1,622)	(1,805)	(2,042)
Existing Resources												
Total Coal	673	650	641	502	502	576	673	673	673	673	673	673
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	559	665	587	723	876	596	532	361	384	443	347	449
Hydro (70th%)—Other	196	235	209	247	324	329	281	209	219	194	171	182
Total Hydro (70th%)	755	900	796	970	1,201	925	813	570	602	637	518	631
CSPP (PURPA)	228	301	323	408	417	415	399	363	333	288	265	241
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	258	299	373	350	280	440	353	385	229	344	291	240
Existing Resource Subtotal	**2,512**	**2,504**	**2,484**	**2,575**	**2,734**	**2,923**	**2,801**	**2,552**	**2,169**	**2,279**	**2,105**	**2,385**
Monthly Surplus/Deficit	**413**	**653**	**793**	**846**	**772**	**510**	**159**	**124**	**167**	**657**	**300**	**343**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**613**	**853**	**993**	**1,346**	**1,272**	**1,010**	**659**	**624**	**667**	**857**	**500**	**543**

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
Load Forecast—included EE	136	136	131	139	156	176	183	179	157	146	138	136
Load Forecast (70th% w/EE)	(2,129)	(1,877)	(1,713)	(1,753)	(1,990)	(2,447)	(2,680)	(2,465)	(2,031)	(1,645)	(1,830)	(2,071)
Adjustment for EE Potential Study Forecast	8	8	8	8	9	10	11	10	9	8	8	8
Net Load Forecast (70th% w/ EE)	(2,121)	(1,869)	(1,705)	(1,745)	(1,981)	(2,437)	(2,670)	(2,454)	(2,022)	(1,636)	(1,822)	(2,063)
Existing Resources												
Total Coal	673	650	641	502	502	576	673	673	673	673	673	673
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	558.3	655.9	586.4	721.6	874.6	594.3	530.6	359.4	379.3	443.7	346.4	443.2
Hydro (70th%)—Other	195.2	228.9	207.4	246.5	324.8	328.1	280.5	208.9	217.6	193.8	170.5	181.3
Total Hydro (70th%)	754	885	794	968	1,199	922	811	568	597	637	517	624
CSPP (PURPA)	224	297	323	408	417	415	399	363	333	288	265	241
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**70**	**69**	**71**	**64**	**55**	**57**	**56**	**52**	**54**	**56**	**74**	**73**
Transmission Capacity available for Market Purchases	257	299	373	349	279	438	352	384	229	344	291	239
Existing Resource Subtotal	**2,505**	**2,486**	**2,481**	**2,572**	**2,732**	**2,919**	**2,798**	**2,549**	**2,164**	**2,279**	**2,104**	**2,378**
Monthly Surplus/Deficit	**384**	**617**	**776**	**827**	**751**	**482**	**129**	**95**	**142**	**643**	**282**	**315**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**584**	**817**	**976**	**1,327**	**1,251**	**982**	**629**	**595**	**642**	**843**	**482**	**515**

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
Load Forecast—included EE	150	151	144	147	170	191	200	203	172	162	151	150
Load Forecast (70th% w/EE)	(2,149)	(1,827)	(1,725)	(1,766)	(2,005)	(2,467)	(2,704)	(2,488)	(2,048)	(1,656)	(1,844)	(2,088)
Adjustment for EE Potential Study Forecast	6	6	6	6	7	7	8	8	7	6	6	6
Net Load Forecast (70th% w/ EE)	(2,143)	(1,821)	(1,720)	(1,760)	(1,999)	(2,460)	(2,696)	(2,480)	(2,041)	(1,650)	(1,838)	(2,082)
Existing Resources												
Total Coal	673	650	641	502	502	576	673	673	673	673	673	673
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	556	647	585	721	875	593	530	358	376	443	347	442
Hydro (70th%)—Other	195	216	203	246	325	327	280	208	217	193	170	181
Total Hydro (70th%)	751	863	788	967	1,199	920	810	566	593	636	516	622
CSPP (PURPA)	224	297	323	408	417	415	399	363	333	288	265	241
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	257	299	372	349	277	437	351	383	228	344	290	239
Existing Resource Subtotal	**2,467**	**2,429**	**2,435**	**2,536**	**2,697**	**2,881**	**2,760**	**2,514**	**2,129**	**2,248**	**2,061**	**2,337**
Monthly Surplus/Deficit	**324**	**608**	**716**	**776**	**699**	**421**	**64**	**34**	**88**	**598**	**223**	**254**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**524**	**808**	**916**	**1,276**	**1,199**	**921**	**564**	**534**	**588**	**798**	**423**	**454**

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
Load Forecast—included EE	164	164	156	162	186	208	220	221	186	177	164	163
Load Forecast (70th% w/EE)	(2,167)	(1,906)	(1,736)	(1,778)	(2,020)	(2,486)	(2,726)	(2,510)	(2,064)	(1,667)	(1,857)	(2,104)
Adjustment for EE Potential Study Forecast	3	3	2	3	3	3	3	3	3	3	3	3
Net Load Forecast (70th% w/ EE)	(2,165)	(1,904)	(1,734)	(1,776)	(2,017)	(2,483)	(2,723)	(2,506)	(2,061)	(1,664)	(1,854)	(2,101)
Existing Resources												
Total Coal	505	487	481	377	377	432	505	505	505	505	505	505
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	553	637	584	719	875	592	529	357	373	443	346	441
Hydro (70th%)—Other	195	212	201	244	324	326	280	207	216	192	169	178
Total Hydro (70th%)	748	849	785	964	1,199	918	808	564	589	635	515	620
CSPP (PURPA)	216	286	312	391	403	402	389	355	324	277	252	228
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	256	298	372	348	276	435	350	382	226	343	290	238
Existing Resource Subtotal	**2,286**	**2,241**	**2,261**	**2,390**	**2,556**	**2,720**	**2,580**	**2,335**	**1,945**	**2,067**	**1,879**	**2,152**
Monthly Surplus/Deficit	**121**	**337**	**527**	**614**	**539**	**237**	**(143)**	**(172)**	**(116)**	**403**	**24**	**51**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**321**	**537**	**727**	**1,114**	**1,039**	**737**	**357**	**328**	**384**	**603**	**224**	**251**

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
Load Forecast—included EE	180	180	170	179	203	227	242	240	203	192	179	178
Load Forecast (70th% w/EE)	(2,184)	(1,919)	(1,746)	(1,789)	(2,034)	(2,504)	(2,748)	(2,531)	(2,079)	(1,677)	(1,869)	(2,119)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,184)	(1,919)	(1,746)	(1,789)	(2,034)	(2,504)	(2,748)	(2,531)	(2,079)	(1,677)	(1,869)	(2,119)
Existing Resources												
Total Coal	505	487	481	377	377	432	505	505	505	505	505	505
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	551	630	583	719	874	590	528	356	370	443	347	440
Hydro (70th%)—Other	193	205	195	242	323	325	279	206	215	191	168	178
Total Hydro (70th%)	743	835	778	961	1,197	916	806	562	584	634	515	618
CSPP (PURPA)	213	283	309	391	403	394	383	350	317	270	243	219
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	255	298	371	349	275	435	349	381	226	343	289	238
Existing Resource Subtotal	**2,278**	**2,223**	**2,250**	**2,388**	**2,554**	**2,710**	**2,570**	**2,327**	**1,935**	**2,059**	**1,868**	**2,142**
Monthly Surplus/Deficit	**94**	**304**	**503**	**599**	**519**	**205**	**(177)**	**(204)**	**(144)**	**382**	**(1)**	**23**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	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	**294**	**504**	**703**	**1,099**	**1,019**	**705**	**323**	**296**	**356**	**582**	**199**	**223**

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
Load Forecast—included EE	195	195	184	195	220	247	263	258	220	207	193	195
Load Forecast (70th% w/EE)	(2,200)	(1,931)	(1,755)	(1,799)	(2,048)	(2,522)	(2,768)	(2,551)	(2,094)	(1,687)	(1,880)	(2,132)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,200)	(1,931)	(1,755)	(1,799)	(2,048)	(2,522)	(2,768)	(2,551)	(2,094)	(1,687)	(1,880)	(2,132)
Existing Resources												
Total Coal	505	487	481	377	377	432	505	505	505	505	505	505
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	551	628	582	718	872	588	527	355	365	443	348	439
Hydro (70th%)—Other	197	206	197	241	322	323	278	205	214	190	168	179
Total Hydro (70th%)	748	835	779	958	1,194	911	805	560	579	633	516	617
CSPP (PURPA)	182	208	237	315	333	336	335	309	273	217	172	151
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	255	297	372	348	275	434	348	380	226	342	289	237
Existing Resource Subtotal	**2,252**	**2,147**	**2,180**	**2,308**	**2,481**	**2,646**	**2,520**	**2,282**	**1,885**	**2,004**	**1,798**	**2,072**
Monthly Surplus/Deficit	**51**	**215**	**424**	**508**	**433**	**124**	**(248)**	**(269)**	**(209)**	**317**	**(82)**	**(60)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	20	0	0	0	0	20	20	20	20	0	0	20
New Resource Subtotal	220	200	200	500	500	520	520	520	520	200	200	220
Monthly Surplus/Deficit	**271**	**415**	**624**	**1,008**	**933**	**644**	**272**	**251**	**311**	**517**	**118**	**160**

Monthly Average Energy 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—included EE	210	216	200	212	238	268	282	276	237	219	210	202
Load Forecast (70th% w/EE)	(2,215)	(1,875)	(1,763)	(1,809)	(2,060)	(2,537)	(2,787)	(2,570)	(2,107)	(1,695)	(1,890)	(2,148)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,215)	(1,875)	(1,763)	(1,809)	(2,060)	(2,537)	(2,787)	(2,570)	(2,107)	(1,695)	(1,890)	(2,148)
Existing Resources												
Total Coal	505	487	481	377	377	432	505	505	505	505	505	505
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	550	620	580	716	870	585	525	354	361	443	347	438
Hydro (70th%)—Other	196	201	189	237	321	322	278	204	213	190	167	178
Total Hydro (70th%)	746	822	769	952	1,191	907	803	558	574	632	514	616
CSPP (PURPA)	140	191	221	296	325	329	329	303	267	210	172	151
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	254	297	371	348	274	433	347	380	225	342	289	237
Existing Resource Subtotal	**2,206**	**2,117**	**2,153**	**2,284**	**2,469**	**2,634**	**2,511**	**2,274**	**1,873**	**1,996**	**1,796**	**2,071**
Monthly Surplus/Deficit	**(9)**	**242**	**390**	**475**	**409**	**96**	**(276)**	**(295)**	**(234)**	**301**	**(94)**	**(77)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	40	0	0	0	0	40	40	40	40	0	0	40
New Resource Subtotal	240	200	200	500	500	540	540	540	540	200	200	240
Monthly Surplus/Deficit	**231**	**442**	**590**	**975**	**909**	**636**	**264**	**245**	**306**	**501**	**106**	**162**

Monthly Average Energy Load and Resource Balance (continued)

	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Load Forecast—included EE	225	224	215	227	257	289	301	296	253	233	225	226
Load Forecast (70th% w/EE)	(2,234)	(1,956)	(1,774)	(1,820)	(2,074)	(2,557)	(2,809)	(2,592)	(2,123)	(1,705)	(1,903)	(2,166)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,234)	(1,956)	(1,774)	(1,820)	(2,074)	(2,557)	(2,809)	(2,592)	(2,123)	(1,705)	(1,903)	(2,166)
Existing Resources												
Total Coal	336	325	320	251	251	288	336	336	336	336	336	336
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	549	618	580	715	870	583	524	352	357	443	347	437
Hydro (70th%)—Other	193	199	187	232	321	321	277	204	212	189	167	177
Total Hydro (70th%)	743	818	767	947	1,192	904	801	556	568	632	514	615
CSPP (PURPA)	98	134	164	231	276	284	290	271	229	167	122	103
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	254	296	370	347	272	431	345	378	224	341	288	237
Existing Resource Subtotal	**1,993**	**1,893**	**1,932**	**2,087**	**2,293**	**2,440**	**2,300**	**2,070**	**1,661**	**1,784**	**1,576**	**1,853**
Monthly Surplus/Deficit	**(241)**	**(63)**	**158**	**267**	**219**	**(117)**	**(509)**	**(522)**	**(462)**	**78**	**(326)**	**(313)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	292	286	280	281	279	276	272	273	277	281	284	292
2030s Reciprocating Gas Engines	40	0	0	0	0	40	40	40	40	0	0	40
New Resource Subtotal	532	486	480	781	779	816	812	813	817	481	484	532
Monthly Surplus/Deficit	**291**	**423**	**638**	**1,048**	**998**	**699**	**302**	**291**	**355**	**559**	**158**	**219**

Monthly Average Energy Load and Resource Balance (continued)

	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Load Forecast—included EE	242	243	229	235	270	303	324	327	272	253	239	242
Load Forecast (70th% w/EE)	(2,254)	(1,972)	(1,786)	(1,832)	(2,090)	(2,577)	(2,834)	(2,615)	(2,140)	(1,717)	(1,916)	(2,185)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,254)	(1,972)	(1,786)	(1,832)	(2,090)	(2,577)	(2,834)	(2,615)	(2,140)	(1,717)	(1,916)	(2,185)
Existing Resources												
Total Coal	336	325	320	251	251	288	336	336	336	336	336	336
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	549	616	579	712	869	581	523	351	353	442	347	436
Hydro (70th%)—Other	193	198	186	221	321	320	276	203	211	188	166	177
Total Hydro (70th%)	741	814	765	933	1,190	901	800	554	564	631	513	613
CSPP (PURPA)	98	134	164	231	276	284	290	271	229	167	122	103
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	254	296	370	347	272	430	344	377	223	341	288	237
Existing Resource Subtotal	**1,992**	**1,889**	**1,930**	**2,073**	**2,291**	**2,435**	**2,298**	**2,067**	**1,655**	**1,782**	**1,576**	**1,851**
Monthly Surplus/Deficit	**(262)**	**(82)**	**144**	**240**	**201**	**(141)**	**(536)**	**(549)**	**(485)**	**66**	**(341)**	**(334)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	292	286	280	281	279	276	272	273	277	281	284	292
2030s Reciprocating Gas Engines	40	0	0	0	0	40	40	40	40	0	0	40
New Resource Subtotal	532	486	480	781	779	816	812	813	817	481	484	532
Monthly Surplus/Deficit	**269**	**404**	**624**	**1,021**	**980**	**674**	**276**	**264**	**332**	**547**	**143**	**198**

Monthly Average Energy Load and Resource Balance (continued)

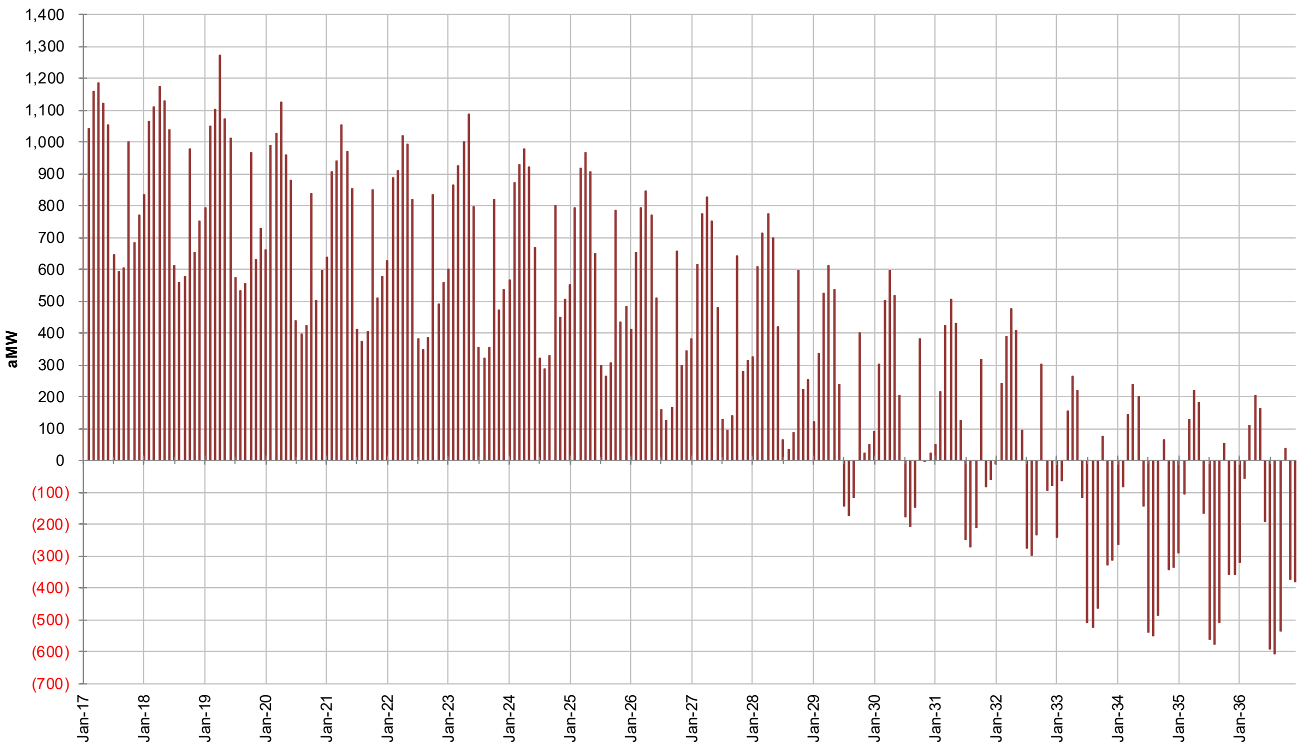
	1/2035	2/2035	3/2035	4/2035	5/2035	6/2035	7/2035	8/2035	9/2035	10/2035	11/2035	12/2035
Load Forecast—included EE	260	258	244	253	288	322	347	347	287	270	254	258
Load Forecast (70th% w/EE)	(2,275)	(1,988)	(1,798)	(1,845)	(2,106)	(2,598)	(2,858)	(2,640)	(2,157)	(1,728)	(1,931)	(2,205)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,275)	(1,988)	(1,798)	(1,845)	(2,106)	(2,598)	(2,858)	(2,640)	(2,157)	(1,728)	(1,931)	(2,205)
Existing Resources												
Total Coal	336	325	320	251	251	288	336	336	336	336	336	336
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	548	612	578	712	867	580	522	350	348	443	348	435
Hydro (70th%)—Other	191	197	185	215	321	319	276	202	210	187	165	176
Total Hydro (70th%)	738	809	763	927	1,188	898	798	552	558	630	513	611
CSPP (PURPA)	98	134	164	231	276	284	290	271	229	167	122	103
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	253	296	369	346	271	430	344	377	222	341	287	236
Existing Resource Subtotal	**1,988**	**1,885**	**1,927**	**2,065**	**2,288**	**2,433**	**2,296**	**2,065**	**1,648**	**1,782**	**1,574**	**1,849**
Monthly Surplus/Deficit	**(288)**	**(103)**	**129**	**220**	**182**	**(165)**	**(562)**	**(575)**	**(509)**	**54**	**(357)**	**(357)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	292	286	280	281	279	276	272	273	277	281	284	292
2030s Reciprocating Gas Engines	69	0	0	0	0	69	69	69	69	0	0	69
New Resource Subtotal	561	486	480	781	779	845	841	842	846	481	484	561
Monthly Surplus/Deficit	**274**	**383**	**609**	**1,001**	**961**	**681**	**279**	**268**	**338**	**535**	**127**	**205**

Monthly Average Energy Load and Resource Balance (continued)

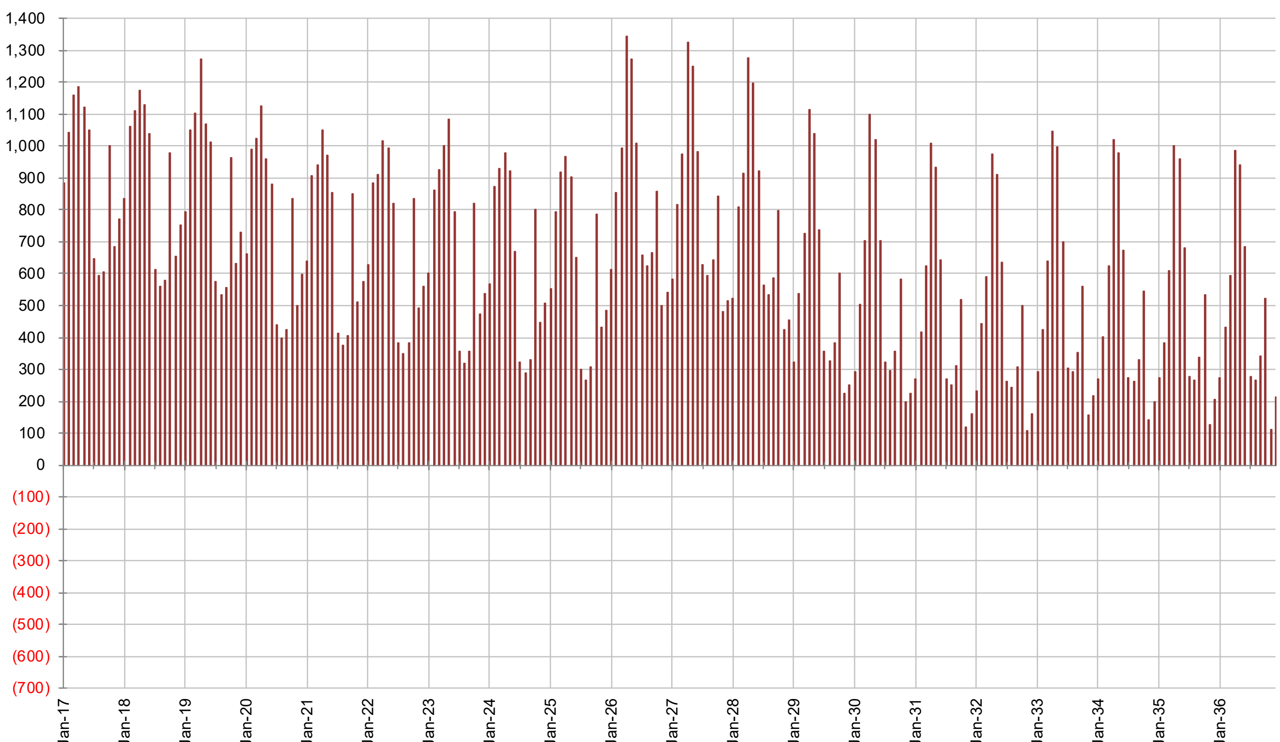
	1/2036	2/2036	3/2036	4/2036	5/2036	6/2036	7/2036	8/2036	9/2036	10/2036	11/2036	12/2036
Load Forecast—included EE	277	284	258	273	306	343	372	364	306	285	269	266
Load Forecast (70th% w/EE)	(2,299)	(1,936)	(1,811)	(1,859)	(2,123)	(2,620)	(2,885)	(2,666)	(2,176)	(1,741)	(1,947)	(2,227)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(2,299)	(1,936)	(1,811)	(1,859)	(2,123)	(2,620)	(2,885)	(2,666)	(2,176)	(1,741)	(1,947)	(2,227)
Existing Resources												
Total Coal	336	325	320	251	251	288	336	336	336	336	336	336
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	546	609	577	710	868	578	521	349	343	443	347	435
Hydro (70th%)—Other	185	197	184	214	320	318	275	201	209	187	165	176
Total Hydro (70th%)	731	806	761	924	1,188	896	796	550	552	629	512	611
CSPP (PURPA)	98	134	164	231	276	284	290	271	229	167	122	103
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity available for Market Purchases	252	295	368	346	270	429	343	375	222	341	287	236
Existing Resource Subtotal	**1,980**	**1,881**	**1,924**	**2,063**	**2,287**	**2,430**	**2,293**	**2,061**	**1,642**	**1,781**	**1,573**	**1,848**
Monthly Surplus/Deficit	**(319)**	**(55)**	**113**	**204**	**164**	**(190)**	**(592)**	**(605)**	**(533)**	**40**	**(373)**	**(379)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	292	286	280	281	279	276	272	273	277	281	284	292
2030s Reciprocating Gas Engines	99	0	0	0	0	99	99	99	99	0	0	99
New Resource Subtotal	591	486	480	781	779	875	871	872	876	481	484	591
Monthly Surplus/Deficit	**272**	**431**	**593**	**985**	**943**	**685**	**279**	**267**	**343**	**521**	**111**	**212**

Monthly Average Energy Surplus/Deficit Charts

Average energy monthly surpluses and deficits with IRP DSM and existing resources



Average energy monthly surpluses and deficits with IRP DSM, existing resources, and IRP Resources



Peak-Hour Load and Resource Balance

	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)	(2,449)	(2,367)	(2,078)	(2,032)	(2,702)	(3,444)	(3,605)	(3,266)	(2,801)	(2,105)	(2,315)	(2,620)
Load Forecast—included EE	9	9	11	12	16	13	18	18	20	15	8	9
Load Forecast (95th% w/DSM and EE)	(2,441)	(2,358)	(2,067)	(2,020)	(2,686)	(3,431)	(3,586)	(3,248)	(2,781)	(2,091)	(2,307)	(2,611)
Adjustment for EE Potential Study Forecast	1	1	1	1	1	1	1	1	1	1	1	1
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,440)	(2,357)	(2,066)	(2,019)	(2,685)	(3,040)	(3,195)	(2,910)	(2,780)	(2,090)	(2,307)	(2,611)
Existing Resources												
Total Coal	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	190	195	172	203	291	301	285	208	215	197	185	189
Total Hydro (90th%)	1,140	1,095	1,122	1,053	1,341	1,301	1,285	1,008	965	947	835	1,089
CSPP (PURPA)	66	69	152	194	234	311	314	307	210	174	151	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	45	46	23	23	38	38	35	32	34	12	21	43
Transmission Capacity Available for Market Purchases	203	245	320	285	222	399	313	335	175	290	237	182
Existing Resource Subtotal	**3,190**	**3,190**	**3,354**	**3,291**	**3,571**	**3,785**	**3,684**	**3,420**	**3,120**	**3,160**	**2,979**	**3,119**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**750**	**833**	**1,288**	**1,272**	**886**	**745**	**489**	**510**	**340**	**1,070**	**672**	**508**

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)	(2,449)	(2,367)	(2,078)	(2,032)	(2,702)	(3,444)	(3,605)	(3,266)	(2,801)	(2,105)	(2,315)	(2,620)
Load Forecast—included EE	9	9	11	12	16	13	18	18	20	15	8	9
Load Forecast (95th% w/DSM and EE)	(2,441)	(2,358)	(2,067)	(2,020)	(2,686)	(3,431)	(3,586)	(3,248)	(2,781)	(2,091)	(2,307)	(2,611)
Adjustment for EE Potential Study Forecast	1	1	1	1	1	1	1	1	1	1	1	1
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,440)	(2,357)	(2,066)	(2,019)	(2,685)	(3,040)	(3,195)	(2,910)	(2,780)	(2,090)	(2,307)	(2,611)
Existing Resources												
Total Coal	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	190	195	172	203	291	301	285	208	215	197	185	189
Total Hydro (90th%)	1,140	1,095	1,122	1,053	1,341	1,301	1,285	1,008	965	947	835	1,089
CSPP (PURPA)	66	69	152	194	234	311	314	307	210	174	151	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	45	46	23	23	38	38	35	32	34	12	21	43
Transmission Capacity Available for Market Purchases	202	243	318	284	220	399	313	333	174	289	236	182
Existing Resource Subtotal	3,187	3,188	3,351	3,291	3,575	3,790	3,684	3,418	3,120	3,160	2,973	3,117
Monthly Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	704	799	1,254	1,247	857	697	429	456	293	1,047	641	473

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)	(2,561)	(2,458)	(2,164)	(2,107)	(2,798)	(3,585)	(3,760)	(3,405)	(2,916)	(2,182)	(2,391)	(2,699)
Load Forecast—included EE	31	32	31	34	40	45	47	46	40	41	31	32
Load Forecast (95th% w/DSM and EE)	(2,530)	(2,426)	(2,132)	(2,073)	(2,758)	(3,540)	(3,713)	(3,359)	(2,876)	(2,141)	(2,359)	(2,666)
Adjustment for EE Potential Study Forecast	8	9	8	9	11	12	12	12	11	11	8	9
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,521)	(2,417)	(2,124)	(2,065)	(2,747)	(3,139)	(3,310)	(3,010)	(2,865)	(2,130)	(2,351)	(2,658)
Existing Resources												
Total Coal	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	181	186	172	204	301	309	285	209	216	198	177	177
Total Hydro (90th%)	1,131	1,086	1,122	1,054	1,351	1,309	1,285	1,009	966	948	827	1,077
CSPP (PURPA)	66	69	152	194	234	311	314	307	210	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**45**	**46**	**23**	**23**	**38**	**38**	**35**	**32**	**34**	**12**	**21**	**43**
Transmission Capacity Available for Market Purchases	201	242	317	293	226	387	302	332	177	288	236	183
Existing Resource Subtotal	**3,179**	**3,178**	**3,350**	**3,300**	**3,584**	**3,781**	**3,673**	**3,417**	**3,123**	**3,161**	**2,972**	**3,109**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**657**	**761**	**1,226**	**1,236**	**838**	**643**	**362**	**407**	**258**	**1,031**	**621**	**451**

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)	(2,598)	(2,487)	(2,192)	(2,136)	(2,840)	(3,641)	(3,836)	(3,469)	(2,962)	(2,215)	(2,420)	(2,720)
Load Forecast—included EE	48	49	46	50	59	67	70	67	58	60	48	49
Load Forecast (95th% w/DSM and EE)	(2,550)	(2,438)	(2,146)	(2,087)	(2,780)	(3,574)	(3,766)	(3,402)	(2,904)	(2,154)	(2,373)	(2,671)
Adjustment for EE Potential Study Forecast	7	7	7	7	9	10	10	10	8	9	7	7
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,543)	(2,431)	(2,139)	(2,080)	(2,772)	(3,174)	(3,366)	(3,055)	(2,896)	(2,145)	(2,366)	(2,664)
Existing Resources												
Total Coal	889	889	889	889	889	889	889	889	889	889	889	889
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	181	180	172	205	300	308	285	209	215	198	177	178
Total Hydro (90th%)	1,131	1,080	1,122	1,055	1,350	1,308	1,285	1,009	965	948	827	1,078
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**45**	**46**	**23**	**23**	**38**	**38**	**35**	**32**	**34**	**12**	**21**	**43**
Transmission Capacity Available for Market Purchases	332	374	448	425	359	518	433	463	308	419	366	314
Existing Resource Subtotal	**3,179**	**3,173**	**3,353**	**3,303**	**3,587**	**3,785**	**3,676**	**3,421**	**3,124**	**3,161**	**2,971**	**3,108**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**636**	**742**	**1,213**	**1,223**	**815**	**611**	**311**	**366**	**229**	**1,015**	**605**	**444**

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)	(2,624)	(2,513)	(2,212)	(2,161)	(2,877)	(3,691)	(3,908)	(3,529)	(3,004)	(2,243)	(2,448)	(2,754)
Load Forecast—included EE	61	63	58	63	74	86	90	85	72	76	61	63
Load Forecast (95th% w/DSM and EE)	(2,562)	(2,450)	(2,153)	(2,098)	(2,803)	(3,606)	(3,819)	(3,444)	(2,932)	(2,168)	(2,387)	(2,691)
Adjustment for EE Potential Study Forecast	8	8	8	8	10	11	12	11	10	10	8	8
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,554)	(2,442)	(2,145)	(2,090)	(2,793)	(3,205)	(3,417)	(3,096)	(2,922)	(2,157)	(2,379)	(2,683)
Existing Resources												
Total Coal	835	835	835	835	835	835	835	835	835	835	835	835
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	175	183	173	205	299	307	285	209	215	198	177	175
Total Hydro (90th%)	1,125	1,083	1,123	1,055	1,349	1,307	1,285	1,009	965	948	827	1,075
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	392	433	507	484	417	576	492	521	366	479	425	374
Existing Resource Subtotal	**3,174**	**3,175**	**3,371**	**3,320**	**3,580**	**3,777**	**3,671**	**3,417**	**3,124**	**3,185**	**2,993**	**3,108**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**620**	**733**	**1,226**	**1,230**	**787**	**572**	**255**	**322**	**202**	**1,028**	**614**	**425**

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)	(2,666)	(2,548)	(2,244)	(2,191)	(2,919)	(3,750)	(3,985)	(3,595)	(3,053)	(2,275)	(2,479)	(2,785)
Load Forecast—included EE	75	76	71	76	89	103	109	103	87	91	74	76
Load Forecast (95th% w/DSM and EE)	(2,591)	(2,472)	(2,173)	(2,116)	(2,830)	(3,647)	(3,876)	(3,492)	(2,966)	(2,184)	(2,405)	(2,708)
Adjustment for EE Potential Study Forecast	10	10	9	10	11	13	14	13	11	12	9	10
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,582)	(2,462)	(2,164)	(2,106)	(2,818)	(3,244)	(3,472)	(3,142)	(2,955)	(2,172)	(2,395)	(2,699)
Existing Resources												
Total Coal	835	835	835	835	835	835	835	835	835	835	835	835
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	183	187	172	205	300	304	284	207	214	197	177	183
Total Hydro (90th%)	1,133	1,087	1,122	1,055	1,350	1,304	1,284	1,007	964	947	827	1,083
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	40	40	36	34	28	27	25	25	30	31	38	39
Transmission Capacity Available for Market Purchases	391	433	506	484	416	575	489	521	365	478	424	373
Existing Resource Subtotal	**3,181**	**3,179**	**3,370**	**3,320**	**3,580**	**3,773**	**3,667**	**3,416**	**3,122**	**3,184**	**2,992**	**3,114**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**599**	**717**	**1,206**	**1,214**	**761**	**529**	**195**	**275**	**167**	**1,012**	**596**	**415**

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)	(2,707)	(2,582)	(2,275)	(2,222)	(2,961)	(3,809)	(4,064)	(3,661)	(3,103)	(2,306)	(2,511)	(2,814)
Load Forecast—included EE	88	89	83	88	103	120	129	120	101	104	86	89
Load Forecast (95th% w/DSM and EE)	(2,619)	(2,493)	(2,192)	(2,134)	(2,858)	(3,690)	(3,934)	(3,541)	(3,002)	(2,202)	(2,426)	(2,725)
Adjustment for EE Potential Study Forecast	11	11	11	11	13	15	16	15	13	13	11	11
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,608)	(2,482)	(2,181)	(2,122)	(2,845)	(3,284)	(3,528)	(3,188)	(2,989)	(2,189)	(2,415)	(2,713)
Existing Resources												
Total Coal	835	835	835	835	835	835	835	835	835	835	835	835
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	182	187	172	205	299	303	284	207	214	197	176	183
Total Hydro (90th%)	1,132	1,087	1,122	1,055	1,349	1,303	1,284	1,007	964	947	826	1,083
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	390	432	506	484	415	574	488	520	364	477	423	372
Existing Resource Subtotal	**3,179**	**3,178**	**3,370**	**3,319**	**3,578**	**3,771**	**3,666**	**3,415**	**3,120**	**3,182**	**2,990**	**3,113**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**571**	**696**	**1,188**	**1,197**	**734**	**487**	**138**	**226**	**132**	**994**	**576**	**399**

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)	(2,755)	(2,621)	(2,312)	(2,257)	(3,007)	(3,871)	(4,147)	(3,731)	(3,155)	(2,342)	(2,552)	(2,849)
Load Forecast—included EE	101	101	95	100	117	136	149	137	116	117	98	102
Load Forecast (95th% w/DSM and EE)	(2,654)	(2,520)	(2,217)	(2,156)	(2,890)	(3,735)	(3,998)	(3,594)	(3,040)	(2,225)	(2,454)	(2,747)
Adjustment for EE Potential Study Forecast	13	13	12	13	15	17	19	17	15	15	12	13
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,641)	(2,507)	(2,205)	(2,144)	(2,875)	(3,328)	(3,589)	(3,240)	(3,025)	(2,210)	(2,442)	(2,735)
Existing Resources												
Total Coal	835	835	835	835	835	835	835	835	835	835	835	835
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	182	181	172	205	299	302	283	206	213	196	175	182
Total Hydro (90th%)	1,132	1,081	1,122	1,055	1,349	1,302	1,283	1,006	963	946	825	1,082
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	177	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	389	431	506	483	414	573	487	519	364	476	423	372
Existing Resource Subtotal	**3,178**	**3,171**	**3,369**	**3,318**	**3,577**	**3,769**	**3,665**	**3,413**	**3,120**	**3,181**	**2,990**	**3,112**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**537**	**664**	**1,164**	**1,175**	**702**	**441**	**76**	**174**	**95**	**971**	**548**	**378**

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)	(2,783)	(2,648)	(2,333)	(2,281)	(3,043)	(3,920)	(4,221)	(3,791)	(3,198)	(2,368)	(2,577)	(2,869)
Load Forecast—included EE	115	115	108	114	132	153	172	156	132	131	110	115
Load Forecast (95th% w/DSM and EE)	(2,668)	(2,533)	(2,226)	(2,167)	(2,911)	(3,766)	(4,050)	(3,636)	(3,066)	(2,236)	(2,466)	(2,754)
Adjustment for EE Potential Study Forecast	13	13	13	13	15	18	20	18	15	15	13	13
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,655)	(2,519)	(2,213)	(2,154)	(2,896)	(3,359)	(3,640)	(3,281)	(3,051)	(2,221)	(2,454)	(2,741)
Existing Resources												
Total Coal	835	835	835	835	835	835	835	835	835	835	835	835
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	181	186	171	204	298	301	283	206	212	195	175	181
Total Hydro (90th%)	1,131	1,086	1,121	1,054	1,348	1,301	1,283	1,006	962	945	825	1,081
CSPP (PURPA)	66	69	154	196	236	316	319	312	213	176	153	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	390	431	505	483	412	571	486	517	362	476	423	371
Existing Resource Subtotal	**3,178**	**3,176**	**3,368**	**3,318**	**3,574**	**3,766**	**3,663**	**3,411**	**3,117**	**3,180**	**2,989**	**3,110**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**524**	**657**	**1,155**	**1,164**	**678**	**408**	**23**	**130**	**66**	**959**	**535**	**370**

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)	(2,814)	(2,674)	(2,357)	(2,308)	(3,082)	(3,972)	(4,301)	(3,856)	(3,245)	(2,396)	(2,604)	(2,901)
Load Forecast—included EE	133	131	124	130	149	174	199	178	152	148	125	131
Load Forecast (95th% w/DSM and EE)	(2,682)	(2,542)	(2,233)	(2,178)	(2,933)	(3,798)	(4,102)	(3,678)	(3,093)	(2,248)	(2,479)	(2,769)
Adjustment for EE Potential Study Forecast	11	11	10	11	12	14	16	15	13	12	10	11
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,671)	(2,531)	(2,223)	(2,167)	(2,920)	(3,394)	(3,695)	(3,326)	(3,080)	(2,236)	(2,469)	(2,759)
Existing Resources												
Total Coal	703	703	703	703	703	703	703	703	703	703	703	703
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	181	185	171	204	298	300	282	205	211	195	174	181
Total Hydro (90th%)	1,131	1,085	1,121	1,054	1,348	1,300	1,282	1,005	961	945	824	1,081
CSPP (PURPA)	66	68	153	195	236	316	318	312	212	176	152	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	521	562	636	613	543	703	616	648	492	607	554	503
Existing Resource Subtotal	**3,176**	**3,174**	**3,365**	**3,316**	**3,573**	**3,764**	**3,661**	**3,410**	**3,114**	**3,177**	**2,987**	**3,110**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(34)**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**705**	**843**	**1,342**	**1,649**	**1,153**	**870**	**466**	**584**	**533**	**1,142**	**718**	**552**

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)	(2,854)	(2,706)	(2,387)	(2,338)	(3,123)	(4,029)	(4,383)	(3,923)	(3,295)	(2,426)	(2,633)	(2,931)
Load Forecast—included EE	149	147	139	146	166	194	227	201	172	164	139	147
Load Forecast (95th% w/DSM and EE)	(2,705)	(2,559)	(2,248)	(2,192)	(2,957)	(3,836)	(4,157)	(3,723)	(3,124)	(2,262)	(2,493)	(2,784)
Adjustment for EE Potential Study Forecast	9	9	8	8	10	11	13	12	10	10	8	9
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,696)	(2,551)	(2,240)	(2,184)	(2,947)	(3,434)	(3,753)	(3,374)	(3,114)	(2,252)	(2,485)	(2,776)
Existing Resources												
Total Coal	703	703	703	703	703	703	703	703	703	703	703	703
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	180	185	170	204	296	298	282	205	210	194	174	181
Total Hydro (90th%)	1,130	1,085	1,120	1,054	1,346	1,298	1,282	1,005	960	944	824	1,081
CSPP (PURPA)	65	68	153	195	236	316	318	312	212	176	152	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**40**	**40**	**36**	**34**	**28**	**27**	**25**	**25**	**30**	**31**	**38**	**39**
Transmission Capacity Available for Market Purchases	520	562	636	612	542	701	615	647	492	607	554	502
Existing Resource Subtotal	**3,174**	**3,173**	**3,365**	**3,314**	**3,570**	**3,761**	**3,659**	**3,408**	**3,113**	**3,177**	**2,986**	**3,109**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(94)**	**0**	**(1)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**678**	**823**	**1,325**	**1,631**	**1,123**	**826**	**406**	**534**	**499**	**1,124**	**701**	**534**

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)	(2,894)	(2,737)	(2,417)	(2,368)	(3,165)	(4,085)	(4,467)	(3,991)	(3,346)	(2,455)	(2,661)	(2,957)
Load Forecast—included EE	166	163	155	161	183	213	255	223	192	179	153	162
Load Forecast (95th% w/DSM and EE)	(2,728)	(2,574)	(2,263)	(2,206)	(2,981)	(3,872)	(4,212)	(3,768)	(3,155)	(2,276)	(2,509)	(2,796)
Adjustment for EE Potential Study Forecast	6	6	6	6	7	8	10	9	7	7	6	6
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,721)	(2,568)	(2,257)	(2,200)	(2,974)	(3,474)	(3,812)	(3,422)	(3,147)	(2,269)	(2,503)	(2,789)
Existing Resources												
Total Coal	703	703	703	703	703	703	703	703	703	703	703	703
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	180	179	170	204	295	296	281	204	209	193	173	181
Total Hydro (90th%)	1,130	1,079	1,120	1,054	1,345	1,296	1,281	1,004	959	943	823	1,081
CSPP (PURPA)	65	68	153	195	236	316	318	312	212	176	152	68
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	520	562	635	612	540	700	614	646	491	607	553	502
Existing Resource Subtotal	**3,169**	**3,163**	**3,358**	**3,309**	**3,562**	**3,753**	**3,653**	**3,401**	**3,106**	**3,171**	**2,979**	**3,104**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(159)**	**(21)**	**(41)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**648**	**795**	**1,302**	**1,609**	**1,088**	**779**	**341**	**479**	**459**	**1,102**	**677**	**514**

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)	(2,929)	(2,767)	(2,444)	(2,396)	(3,205)	(4,139)	(4,551)	(4,058)	(3,397)	(2,483)	(2,688)	(2,985)
Load Forecast—included EE	184	179	172	178	201	233	286	247	213	195	167	178
Load Forecast (95th% w/DSM and EE)	(2,745)	(2,588)	(2,273)	(2,218)	(3,004)	(3,906)	(4,265)	(3,811)	(3,183)	(2,288)	(2,521)	(2,807)
Adjustment for EE Potential Study Forecast	3	3	3	3	3	4	5	4	3	3	3	3
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,742)	(2,585)	(2,270)	(2,215)	(3,001)	(3,513)	(3,870)	(3,470)	(3,180)	(2,285)	(2,519)	(2,805)
Existing Resources												
Total Coal	527	527	527	527	527	527	527	527	527	527	527	527
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	179	184	169	203	293	295	281	203	208	192	172	180
Total Hydro (90th%)	1,129	1,084	1,119	1,053	1,343	1,295	1,281	1,003	958	942	822	1,080
CSPP (PURPA)	63	66	151	193	233	313	316	309	209	173	149	65
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	519	561	635	611	539	698	613	645	489	606	553	501
Existing Resource Subtotal	**2,989**	**2,988**	**3,180**	**3,129**	**3,381**	**3,571**	**3,473**	**3,221**	**2,924**	**2,991**	**2,800**	**2,924**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(397)**	**(249)**	**(256)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**448**	**603**	**1,110**	**1,414**	**881**	**559**	**103**	**251**	**244**	**906**	**482**	**319**

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)	(2,965)	(2,797)	(2,473)	(2,425)	(3,245)	(4,192)	(4,636)	(4,125)	(3,447)	(2,511)	(2,715)	(3,012)
Load Forecast—included EE	203	197	189	196	220	253	318	272	237	211	182	195
Load Forecast (95th% w/DSM and EE)	(2,763)	(2,601)	(2,284)	(2,230)	(3,025)	(3,939)	(4,317)	(3,853)	(3,210)	(2,299)	(2,533)	(2,817)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,763)	(2,601)	(2,284)	(2,230)	(3,025)	(3,549)	(3,927)	(3,516)	(3,210)	(2,299)	(2,533)	(2,817)
Existing Resources												
Total Coal	527	527	527	527	527	527	527	527	527	527	527	527
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	179	183	169	203	293	294	280	203	207	192	172	179
Total Hydro (90th%)	1,129	1,083	1,119	1,053	1,343	1,294	1,280	1,003	957	942	822	1,079
CSPP (PURPA)	63	65	151	193	233	311	314	307	207	171	148	63
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	518	561	634	612	538	698	612	644	489	606	552	501
Existing Resource Subtotal	**2,988**	**2,987**	**3,178**	**3,130**	**3,380**	**3,568**	**3,470**	**3,218**	**2,922**	**2,988**	**2,797**	**2,921**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(458)**	**(299)**	**(288)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	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 Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**425**	**586**	**1,094**	**1,400**	**855**	**519**	**42**	**201**	**212**	**889**	**464**	**304**

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)	(3,001)	(2,827)	(2,501)	(2,454)	(3,285)	(4,244)	(4,723)	(4,193)	(3,497)	(2,538)	(2,741)	(3,031)
Load Forecast—included EE	222	214	207	213	238	274	353	297	261	227	196	211
Load Forecast (95th% w/DSM and EE)	(2,780)	(2,613)	(2,294)	(2,241)	(3,047)	(3,971)	(4,370)	(3,896)	(3,237)	(2,311)	(2,545)	(2,820)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,780)	(2,613)	(2,294)	(2,241)	(3,047)	(3,581)	(3,980)	(3,559)	(3,237)	(2,311)	(2,545)	(2,820)
Existing Resources												
Total Coal	527	527	527	527	527	527	527	527	527	527	527	527
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	179	183	169	203	292	292	279	202	206	191	171	179
Total Hydro (90th%)	1,129	1,083	1,119	1,053	1,342	1,292	1,279	1,002	956	941	821	1,079
CSPP (PURPA)	58	55	141	183	222	302	305	298	198	162	137	53
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	518	560	635	611	538	697	611	643	489	605	552	500
Existing Resource Subtotal	**2,983**	**2,976**	**3,169**	**3,119**	**3,368**	**3,556**	**3,459**	**3,207**	**2,911**	**2,977**	**2,786**	**2,910**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**(24)**	**(521)**	**(352)**	**(325)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	36	0	0	0	0	36	36	36	36	0	0	36
New Resource Subtotal	236	200	200	500	500	536	536	536	536	200	200	236
Monthly Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**439**	**563**	**1,076**	**1,378**	**821**	**512**	**15**	**184**	**211**	**866**	**441**	**326**

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)	(3,029)	(2,853)	(2,522)	(2,479)	(3,321)	(4,291)	(4,807)	(4,258)	(3,545)	(2,562)	(2,765)	(3,059)
Load Forecast—included EE	240	231	225	230	256	293	387	323	285	242	210	227
Load Forecast (95th% w/DSM and EE)	(2,788)	(2,623)	(2,297)	(2,248)	(3,065)	(3,998)	(4,420)	(3,935)	(3,260)	(2,320)	(2,555)	(2,832)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,788)	(2,623)	(2,297)	(2,248)	(3,065)	(3,608)	(4,030)	(3,598)	(3,260)	(2,320)	(2,555)	(2,832)
Existing Resources												
Total Coal	527	527	527	527	527	527	527	527	527	527	527	527
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	179	177	169	202	291	290	279	201	205	190	170	179
Total Hydro (90th%)	1,129	1,077	1,119	1,052	1,341	1,290	1,279	1,001	955	940	820	1,079
CSPP (PURPA)	50	53	138	180	221	301	303	297	197	161	137	53
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	517	560	634	611	537	696	610	643	488	605	552	500
Existing Resource Subtotal	**2,974**	**2,968**	**3,165**	**3,116**	**3,364**	**3,552**	**3,456**	**3,205**	**2,908**	**2,975**	**2,785**	**2,909**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**(56)**	**(574)**	**(393)**	**(352)**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	72	0	0	0	0	72	72	72	72	0	0	72
New Resource Subtotal	272	200	200	500	500	572	572	572	572	200	200	272
Monthly Deficit	0	0	0	0	0	0	(2)	0	0	0	0	0
Monthly Surplus/Deficit	**458**	**545**	**1,068**	**1,367**	**799**	**516**	**(2)**	**179**	**220**	**855**	**430**	**349**

Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

Peak-Hour Load and Resource Balance (continued)

	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Load Forecast (95th% w/no DSM)	(3,066)	(2,879)	(2,550)	(2,507)	(3,359)	(4,343)	(4,894)	(4,325)	(3,596)	(2,587)	(2,790)	(3,089)
Load Forecast—included EE	258	247	242	247	272	311	421	347	308	255	222	242
Load Forecast (95th% w/DSM and EE)	(2,808)	(2,633)	(2,309)	(2,260)	(3,087)	(4,032)	(4,474)	(3,979)	(3,288)	(2,332)	(2,567)	(2,847)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,808)	(2,633)	(2,309)	(2,260)	(3,087)	(3,642)	(4,084)	(3,642)	(3,288)	(2,332)	(2,567)	(2,847)
Existing Resources												
Total Coal	352	352	352	352	352	352	352	352	352	352	352	352
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	178	182	168	200	290	289	278	200	204	189	170	178
Total Hydro (90th%)	1,128	1,082	1,118	1,050	1,340	1,289	1,278	1,000	954	939	820	1,078
CSPP (PURPA)	41	44	130	171	212	292	295	288	188	152	128	44
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	517	559	633	610	535	694	608	641	487	604	551	500
Existing Resource Subtotal	**2,789**	**2,787**	**2,979**	**2,928**	**3,177**	**3,364**	**3,269**	**3,017**	**2,721**	**2,789**	**2,598**	**2,724**
Monthly Deficit	**(20)**	**0**	**0**	**0**	**0**	**(279)**	**(815)**	**(624)**	**(567)**	**0**	**0**	**(123)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
2030s Reciprocating Gas Engine	72	0	0	0	0	72	72	72	72	0	0	72
New Resource Subtotal	572	500	500	800	800	872	872	872	872	500	500	572
Monthly Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**552**	**654**	**1,171**	**1,468**	**890**	**593**	**57**	**248**	**305**	**957**	**531**	**449**

Peak-Hour Load and Resource Balance (continued)

	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Load Forecast (95th% w/no DSM)	(3,108)	(2,912)	(2,582)	(2,537)	(3,400)	(4,398)	(4,985)	(4,396)	(3,652)	(2,613)	(2,816)	(3,117)
Load Forecast—included EE	276	262	259	263	288	328	455	371	332	267	234	257
Load Forecast (95th% w/DSM and EE)	(2,832)	(2,649)	(2,323)	(2,274)	(3,112)	(4,070)	(4,529)	(4,025)	(3,319)	(2,346)	(2,582)	(2,860)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,832)	(2,649)	(2,323)	(2,274)	(3,112)	(3,680)	(4,139)	(3,688)	(3,319)	(2,346)	(2,582)	(2,860)
Existing Resources												
Total Coal	352	352	352	352	352	352	352	352	352	352	352	352
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	177	181	168	200	289	286	278	200	202	188	169	177
Total Hydro (90th%)	1,127	1,081	1,118	1,050	1,339	1,286	1,278	1,000	952	938	819	1,077
CSPP (PURPA)	41	44	130	171	212	292	295	288	188	152	128	44
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	517	559	633	610	535	693	607	640	486	604	551	500
Existing Resource Subtotal	**2,787**	**2,786**	**2,979**	**2,928**	**3,176**	**3,360**	**3,267**	**3,016**	**2,719**	**2,788**	**2,598**	**2,723**
Monthly Deficit	**(45)**	**0**	**0**	**0**	**0**	**(320)**	**(872)**	**(672)**	**(601)**	**0**	**0**	**(137)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
2030s Reciprocating Gas Engine	72	0	0	0	0	72	72	72	72	0	0	72
New Resource Subtotal	572	500	500	800	800	872	872	872	872	500	500	572
Monthly Deficit	0	0	0	0	0	0	(0)	0	0	0	0	0
Monthly Surplus/Deficit	**527**	**637**	**1,156**	**1,454**	**864**	**552**	**(0)**	**200**	**271**	**942**	**515**	**435**

Peak-Hour Load and Resource Balance (continued)

	1/2035	2/2035	3/2035	4/2035	5/2035	6/2035	7/2035	8/2035	9/2035	10/2035	11/2035	12/2035
Load Forecast (95th% w/no DSM)	(3,147)	(2,942)	(2,611)	(2,566)	(3,440)	(4,453)	(5,076)	(4,466)	(3,707)	(2,638)	(2,843)	(3,149)
Load Forecast—included EE	294	278	276	280	305	345	492	396	357	280	246	272
Load Forecast (95th% w/DSM and EE)	(2,853)	(2,664)	(2,334)	(2,287)	(3,135)	(4,107)	(4,584)	(4,070)	(3,350)	(2,359)	(2,597)	(2,878)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,853)	(2,664)	(2,334)	(2,287)	(3,135)	(3,717)	(4,194)	(3,733)	(3,350)	(2,359)	(2,597)	(2,878)
Existing Resources												
Total Coal	352	352	352	352	352	352	352	352	352	352	352	352
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	176	181	167	200	287	284	277	199	201	188	168	177
Total Hydro (90th%)	1,126	1,081	1,117	1,050	1,337	1,284	1,277	999	951	938	818	1,077
CSPP (PURPA)	41	44	130	171	212	292	295	288	188	152	128	44
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	516	559	632	609	534	693	607	640	485	604	550	499
Existing Resource Subtotal	**2,786**	**2,786**	**2,977**	**2,927**	**3,173**	**3,358**	**3,267**	**3,015**	**2,716**	**2,787**	**2,596**	**2,721**
Monthly Deficit	**(67)**	**0**	**0**	**0**	**0**	**(359)**	**(928)**	**(718)**	**(634)**	**0**	**(1)**	**(156)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
2030s Reciprocating Gas Engine	126	0	0	0	0	126	126	126	126	0	0	126
New Resource Subtotal	626	500	500	800	800	926	926	926	926	500	500	626
Monthly Deficit	0	0	0	0	0	0	(2)	0	0	0	0	0
Monthly Surplus/Deficit	**559**	**622**	**1,143**	**1,440**	**838**	**567**	**(2)**	**208**	**292**	**928**	**499**	**470**

Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

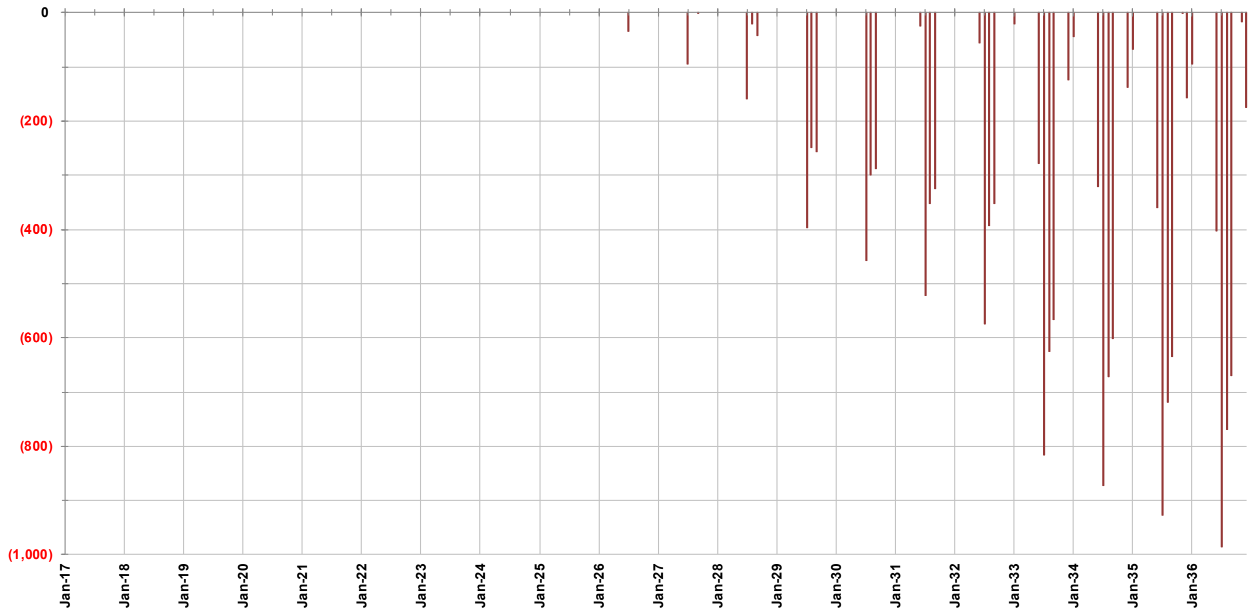
Peak-Hour Load and Resource Balance (continued)

	1/2036	2/2036	3/2036	4/2036	5/2036	6/2036	7/2036	8/2036	9/2036	10/2036	11/2036	12/2036
Load Forecast (95th% w/no DSM)	(3,193)	(2,978)	(2,646)	(2,599)	(3,484)	(4,512)	(5,172)	(4,541)	(3,769)	(2,666)	(2,871)	(3,183)
Load Forecast—included EE	314	295	296	298	323	364	531	423	384	293	259	288
Load Forecast (95th% w/DSM and EE)	(2,879)	(2,682)	(2,350)	(2,302)	(3,161)	(4,148)	(4,641)	(4,118)	(3,384)	(2,373)	(2,612)	(2,896)
Adjustment for EE Potential Study Forecast	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,879)	(2,682)	(2,350)	(2,302)	(3,161)	(3,758)	(4,251)	(3,781)	(3,384)	(2,373)	(2,612)	(2,896)
Existing Resources												
Total Coal	352	352	352	352	352	352	352	352	352	352	352	352
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	175	175	166	200	286	282	276	198	200	187	167	176
Total Hydro (90th%)	1,125	1,075	1,116	1,050	1,336	1,282	1,276	998	950	937	817	1,076
CSPP (PURPA)	41	44	130	171	212	292	295	288	188	152	128	44
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
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	**35**	**35**	**31**	**29**	**23**	**22**	**20**	**20**	**25**	**26**	**33**	**34**
Transmission Capacity Available for Market Purchases	515	558	631	609	533	692	606	638	485	604	550	499
Existing Resource Subtotal	**2,784**	**2,779**	**2,976**	**2,927**	**3,170**	**3,355**	**3,265**	**3,012**	**2,715**	**2,786**	**2,595**	**2,721**
Monthly Deficit	**(95)**	**0**	**0**	**0**	**0**	**(403)**	**(986)**	**(769)**	**(669)**	**0**	**(17)**	**(175)**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2033 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
2030s Reciprocating Gas Engine	180	0	0	0	0	180	180	180	180	0	0	180
New Resource Subtotal	680	500	500	800	800	980	980	980	980	500	500	680
Monthly Deficit	0	0	0	0	0	0	(6)	0	0	0	0	0
Monthly Surplus/Deficit	**585**	**597**	**1,126**	**1,425**	**809**	**577**	**(6)**	**211**	**311**	**913**	**483**	**505**

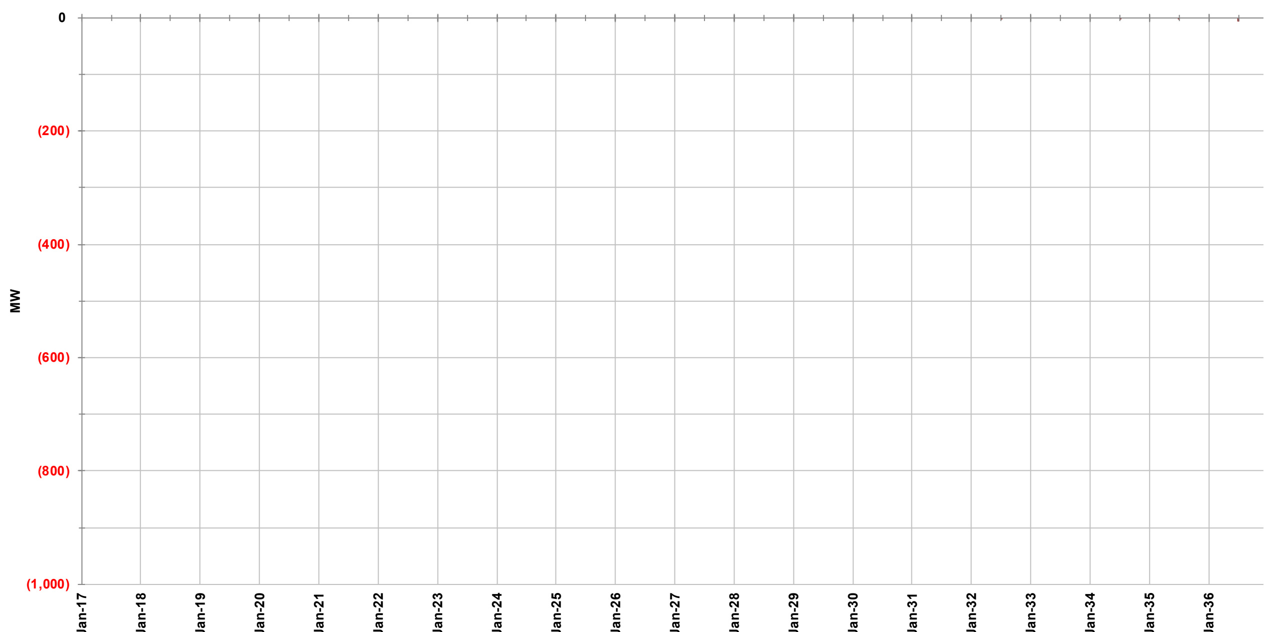
Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

Peak-Hour Surplus/Deficit Charts

Peak-hour monthly deficits with existing DSM and existing resources



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's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test provides value when evaluating program performance. If a specific measure or program is found to be not cost-effective from each of the three tests. For resource planning Idaho Power primarily uses the total resource cost (TRC) test and the utility cost (UC) tests to determine the cost-effective energy efficiency for inclusion in the IRP. Each energy efficiency program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho Public Utilities Commission and Public Utilities Commission of Oregon. More information on Idaho Power's programs and cost-effectiveness is included in the *Demand-Side Management 2016 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (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 value of DSM alternative costs.

For the 2017 IRP, non-energy related benefits (NEB) were included in the cost-effectiveness analysis of the program forecasts. NEB include savings from water savings, deferred maintenance and operational costs, avoided supplemental fuels, and other quantifiable benefits. NEB values from the 2016 portfolio of programs was used in the calculation of cost-effectiveness at the sector level. For a complete list of NEB and sources that Idaho Power currently uses for its program cost-effectiveness, see *Demand-Side Management 2016 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

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) *Understanding Cost-Effectiveness of Energy Efficiency Programs,* 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 like supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

Resource Development and Evaluation

When developing energy efficiency programs, Idaho Power uses data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program parameters. This is accomplished through discussions with other utilities' program managers and researchers. Idaho Power also uses electric industry research organizations, such as E Source, the Consortium for Energy Efficiency (CEE), American Council for an Energy-Efficient Economy (ACEEE), and the Association of Energy Service Professionals (AESP), to identify similar programs and their results.

All programs are included in an ongoing evaluation schedule where a third-party consultant verifies the claimed savings from the program. Programs are also evaluated to review the program processes to assess 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. Recent evaluations from the 2016 program year can be found in the *Demand-Side Management 2016 Annual Report* and its *Supplement 2: Evaluations,* (idahopower.com/EnergyEfficiency/reports.cfm).

Planning Assumptions and Alternate Costs

All financial assumptions used in the cost-effectiveness analysis for energy efficiency resources included in the 2017 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 energy costs are based on either IRP forecast of fuel costs of a natural gas peaking unit for peak summer hours or future energy prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT) 35-year levelized cost.

The AURORAxmp® model is an electricity forecasting tool that simulates hourly economic dispatch of supply-side resources considering demand-side, and transmission resources. Idaho Power's planning model forecasts electric market prices throughout southern Idaho and theWestern Electricity Coordinating Council (WECC) region. Idaho Power modeled hourly, marginal electricity costs for the years 2017 through 2036 to estimate the potential system benefit of avoiding future cost production energy. An initial run of DSM Alternative costs is estimated during the preliminary analysis phase of the IRP process. The preliminary runs combined updated planning assumptions including load and natural gas price forecasts run using the preferred resource portfolio from the 2015 IRP. After the selection of the preferred portfolio a final run of marginal prices will be run which, once acknowledged, become the DSM alternative energy prices for energy efficiency valuation until the next IRP analysis is completed and acknowledged.

To simplify cost-effectiveness calculations, the DSM alternative costs are averaged and placed into five pricing categories. The resulting pricing categories include the following:

- 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 when valuing energy efficiency. The estimated levelized capacity cost of a new SCCT is $122 per kW/Year over a 35-year period. The $122 per kW/Year avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours.

Forecast and Cost-Effectiveness Data

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis.

Table DSM-1. IRP financial assumptions

DSM Analysis Assumptions	
Avoided 35-Year Levelized Capacity Costs	
SCCT	$122/kW/year
Financial Assumptions	
Weighted average cost of capital (2016 year ending after tax)	6.74%
Financial escalation factor	2.10%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Table DSM-2 shows the planning results of averaging forward energy prices over the 20-year planning period.

Table DSM-2. DSM alternate costs by pricing period

Year	Summer On-Peak[1] (SONP)	Summer Mid-Peak (SMP)	Summer Off-Peak (SOFP)	Non-Summer Mid-Peak (NSMP)	Non-Summer Off-Peak (NSOFP)	Annual Average[2]
2017	$48.14	$29.55	$26.33	$28.28	$26.47	$42.76
2018	$53.96	$31.32	$28.28	$29.94	$27.92	$44.64
2019	$54.40	$32.35	$29.33	$30.75	$28.81	$45.48
2020	$55.59	$32.56	$30.53	$30.75	$28.99	$45.73
2021	$57.00	$33.08	$30.94	$30.75	$29.05	$45.96
2022	$57.70	$33.04	$31.59	$30.60	$28.35	$45.74
2023	$58.80	$34.20	$33.75	$32.99	$31.92	$48.29
2024	$61.08	$35.90	$35.82	$34.52	$33.55	$49.90
2025	$63.75	$36.67	$36.46	$35.53	$34.19	$50.87
2026	$66.15	$38.74	$38.40	$37.98	$36.43	$53.21
2027	$68.26	$41.86	$41.04	$41.18	$39.35	$56.19
2028	$71.36	$45.21	$44.09	$44.44	$42.35	$59.28
2029	$73.79	$46.30	$44.94	$47.07	$44.23	$61.38
2030	$75.69	$48.53	$47.23	$49.11	$46.31	$63.45
2031	$77.07	$50.56	$48.01	$51.00	$48.22	$65.24
2032	$78.34	$51.91	$48.94	$52.49	$49.82	$66.69
2033	$78.88	$52.02	$48.16	$53.35	$50.36	$67.23
2034	$78.79	$52.71	$47.92	$53.80	$51.02	$67.67
2035	$77.22	$51.71	$46.89	$53.08	$50.46	$66.90
2036	$75.80	$51.20	$45.74	$51.83	$49.59	$65.80

[1] Estimated average annual variable operations and management costs of a 170 MW capacity SCCT.
[2] Annual average across all hours includes 35 year levelized capacity value of a 170 MW SCCT.

Tables DSM-3 and DSM-4 shows the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

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

Tables DSM-5 lists the 20-year cumulative forecasted of average energy (aMW) by customer class and total on-peak reduction potential (MW).

Table DSM-5. Cumulative existing energy efficiency forecast 2017–2036
(aMW w/transmission losses and peak contributions [MW])

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total	On Peak (MW)
2017	2	9	2	13	20
2018	6	19	3	28	40
2019	10	29	5	44	60
2020	12	40	6	59	80
2021	14	51	8	73	102
2022	16	63	9	89	123
2023	18	75	11	104	146
2024	21	86	12	120	168
2025	24	98	14	135	192
2026	27	105	15	147	216
2027	31	112	17	160	240
2028	34	120	19	173	265
2029	38	126	20	184	290
2030	42	133	22	196	316
2031	46	140	23	208	343
2032	50	146	25	220	370
2033	54	154	26	234	397
2034	58	162	28	247	425
2035	62	169	29	261	454
2036	66	175	31	273	483

Table DSM-6 details the 20-year estimated utility or program administrator costs of the achievable potential energy efficiency forecast by customer class.

Table DSM-6. Energy Efficiency Total Utility (Program Administrator) Costs 2017–2036 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2017	$3,828	$12,199	$1,868	$17,896
2018	$5,718	$13,638	$1,916	$21,273
2019	$6,821	$14,977	$1,957	$23,754
2020	$3,907	$15,785	$1,999	$21,691
2021	$3,998	$16,350	$2,032	$22,380
2022	$3,840	$17,482	$2,087	$23,410
2023	$4,323	$18,094	$2,126	$24,544
2024	$5,690	$18,174	$2,167	$26,031
2025	$6,546	$18,123	$2,207	$26,877
2026	$8,183	$11,837	$2,251	$22,271
2027	$8,832	$12,546	$2,328	$23,706
2028	$9,297	$12,886	$2,365	$24,548
2029	$9,736	$11,140	$2,395	$23,272
2030	$11,500	$12,028	$2,472	$26,001
2031	$11,490	$11,627	$2,517	$25,635
2032	$11,983	$12,178	$2,572	$26,733
2033	$12,696	$14,815	$2,627	$30,138
2034	$13,278	$14,982	$2,684	$30,943
2035	$13,954	$14,828	$2,741	$31,523
2036	$14,616	$12,726	$2,800	$30,142
20-Year NPV	**$78,908**	**$157,520**	**$23,828**	**$260,255**

Table DSM-7 details the 20-year estimated total resource costs of the achievable potential energy efficiency forecast by customer class.

Table DSM-7. Energy Efficiency Total Resource Costs 2017–2036 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2017	$8,015	$23,432	$6,428	$37,874
2018	$12,137	$26,196	$6,594	$44,926
2019	$14,548	$28,767	$6,733	$50,048
2020	$8,242	$30,320	$6,877	$45,439
2021	$8,331	$31,405	$6,990	$46,727
2022	$7,887	$33,579	$7,180	$48,647
2023	$8,731	$34,754	$7,316	$50,801
2024	$11,338	$34,909	$7,454	$53,701
2025	$12,891	$34,811	$7,595	$55,296
2026	$15,995	$22,736	$7,745	$46,475
2027	$17,132	$24,098	$8,008	$49,238
2028	$17,896	$24,751	$8,138	$50,784
2029	$18,614	$21,398	$8,240	$48,253
2030	$21,884	$23,103	$8,507	$53,493
2031	$21,758	$22,333	$8,661	$52,753
2032	$22,584	$23,392	$8,848	$54,824
2033	$23,821	$28,456	$9,038	$61,315
2034	$24,816	$28,776	$9,233	$62,825
2035	$25,990	$28,482	$9,431	$63,903
2036	$27,144	$24,443	$9,634	$61,221
20-Year NPV	**$155,425**	**$302,559**	**$81,981**	**$539,964**

Table DSM-8 shows the cost-effectiveness analysis and levelized cost of saved energy for achievable potential energy efficiency by sector through the IRP planning period.

Table DSM-8. Total Energy Efficiency Benefits 2017–2036 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2017	$15,350	$40,747	$9,459	$65,555
2018	$22,620	$43,135	$9,265	$75,020
2019	$25,730	$44,722	$8,988	$79,440
2020	$13,491	$44,331	$8,668	$66,490
2021	$12,535	$43,077	$8,281	$63,894
2022	$10,887	$43,208	$8,001	$62,096
2023	$10,996	$41,986	$7,673	$60,655
2024	$13,068	$39,472	$7,313	$59,853
2025	$13,625	$36,775	$6,950	$57,350
2026	$15,557	$22,459	$6,613	$44,629
2027	$15,384	$22,268	$6,387	$44,038
2028	$14,873	$21,412	$6,071	$42,356
2029	$14,345	$17,333	$5,751	$37,428
2030	$15,667	$17,508	$5,548	$38,723
2031	$14,495	$15,844	$5,283	$35,622
2032	$14,017	$15,555	$5,057	$34,629
2033	$13,760	$17,738	$4,842	$36,340
2034	$13,368	$15,940	$4,643	$33,950
2035	$13,038	$13,930	$4,447	$31,415
2036	$12,675	$10,483	$4,260	$27,418
20-Year NPV	**$295,479**	**$567,923**	**$133,497**	**$996,900**

DSM-9. Total energy efficiency cost-effectiveness summary

	2036 Load Reduction (aMW)	Utility Costs ($000s) (20-Year NPV)	Resource Costs ($000s) (20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	66	$78,908	$155,425	$295,479	1.9	6.7
Industrial/Commercial/ Special Contract	176	$157,520	$302,559	$567,923	1.9	3.9
Irrigation	31	$23,828	$81,981	$133,498	1.6	6.7
Total	**273**	**$260,255**	**$539,964**	**$996,900**	**1.8**	**4.8**

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	Expected Life of the Asset
Discount rate (weighted average cost of capital[1])	6.74%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	2.10%
Emission 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)	7.72%

[1] Incorporates tax effects.

Emission Intensity Rate (lbs per MMBtu by technology)	
	CO_2
Small frame SCCT	125
Large frame SCCT	118
CCCT 1x1	119
Reciprocating engines	119
Pulverized coal	210

Fuel Forecast Base Case (Nominal, $ per MMBtu)		
Year	Natural Gas	Nuclear
2017	$2.75	$0.57
2018	$3.28	$0.58
2019	$3.28	$0.59
2020	$3.35	$0.60
2021	$3.45	$0.61
2022	$3.47	$0.63
2023	$3.53	$0.64
2024	$3.71	$0.65
2025	$3.92	$0.67
2026	$4.10	$0.68
2027	$4.26	$0.70
2028	$4.51	$0.71
2029	$4.70	$0.73
2030	$4.83	$0.74
2031	$4.91	$0.76
2032	$4.98	$0.77
2033	$4.98	$0.79
2034	$4.91	$0.81
2035	$4.70	$0.81
2036	$4.51	$0.82
2037	$4.53	$0.82
2038	$4.56	$0.83
2039	$4.59	$0.83
2040	$4.62	$0.84
2041	$4.64	$0.84
2042	$4.67	$0.85
2043	$4.70	$0.85
2044	$4.73	$0.86
2045	$4.76	$0.87
2046	$4.78	$0.87

Cost Inputs and Operating Assumptions

(All costs in 2017 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	Other $/MWh	Heat Rate Btu/kWh	Economic Life
Biomass Indirect—Anaerobic Digester (35 MW)	35	6,522	144	$6,666	$7,133	3	16	0	14,500	30
Boardman to Hemingway (250 MW)	350	0	734	$734	$734	0	0	0	0	55
Canal Drop Hydro (1 MW)	1	3,753	70	$3,823	$4,550	2	0	0	0	75
CCCT (1x1) F Class (300 MW)	300	1,246	98	$1,344	$1,574	1	0	0	6,714	30
CCCT (2x1) F Class (550 MW)	550	1,150	109	$1,259	$1,474	1	3	0	6,700	30
CHP (35 MW)	35	2,213	35	$2,248	$2,406	4	5	0	6,060	40
Demand Response—Additional (25 MW)	25	0	0	$0	$0	51	0	0	0	20
Geothermal (30 MW)	35	4,675	144	$4,819	$5,342	18	5	0	0	25
Reciprocating Gas Engine (18.8 MW)	18	775	112	$887	$945	1	7	0	8,370	40
SCCT—Frame F Class (170 MW)	170	878	117	$995	$1,060	1	11	0	10,300	35
Small Modular Nuclear (50 MW)	50	6,126	663	$6,789	$10,279	8	2	0	11,493	40
Solar PV—Rooftop C&I (1 MW)	1	2,925	0	$2,925	$3,040	1	0	1	0	25
Solar PV—Rooftop Residential (0.005 MW)	0	2,400	0	$2,400	$2,495	2	0	1	0	25
Solar PV—Utility Scale 1-Axis Tracking (30 MW)	30	1,375	144	$1,519	$1,579	1	0	1	0	25
Storage—Ice Thermal Storage (10 MW)	10	2,000	0	$2,000	$2,039	3	0	0	0	20
Storage—Li Battery Residential (10 MW)	10	3,114	0	$3,114	$3,175	4	0	0	0	10
Storage—Pumped-Hydro (300 MW)	300	2,352	183	$2,535	$3,017	4	0	0	0	50
Storage—V Flow Battery (10 MW)	10	3,736	0	$3,736	$3,809	6	0	0	0	10
Storage—Zn Battery (10 MW)	10	2,010	0	$2,010	$2,049	3	0	0	0	10
Wind (100 MW)	100	1,475	117	$1,592	$1,700	3	0	16	0	25

[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)

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
Biomass Indirect—Anaerobic Digester				
35	$144	Assume distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	Assume $3.5 million of distribution feeder upgrades and $1.167 million in substation upgrades.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Geothermal (binary-cycle)—Idaho				
35	$144	Assume Raft River area location; displaces equivalent MW of portfolio resources in same region.	Requires 5-mile 138-kV line to nearby station with new 138-kV substation line terminal bay.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Hydro—Canal Drop (Seasonal)				
1	$70	Assume Magic Valley location connecting to 46-kV sub-transmission or local feeder.	Assume 4 miles of distribution rebuild at $150 thousand per mile plus $100 thousand in substation upgrades.	No backbone upgrades required.
Natural Gas—SCCT Frame F Class (Idaho Power's peaker plants use this technology)				
170	$117	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2 mi of 230 kV line required to connect to nearby station.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Natural Gas—Reciprocating Gas Engine Wartsila 34SG				
18	$112	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Interconnecting at RTSN 230-kV station.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Natural Gas—CCCT (1x1) F Class with Duct Firing				
300	$98	Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region.	Assume 2 miles of 230-kV line required to connect to nearby station.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Natural Gas—CCCT (2x1) F Class				
550	$109	Build new facility south of Boise (assume Simco Road area).	New 230-kV switching station with a 22-mile; 230-kV line to Boise Bench Substation and wrap 230-kV DNPR-HRBD line into new station.	Rebuild RTSN-DRAM 230 kV line, BOBN-DRAM 230 kV line, MCRN-BOBN 138 kV line, and replace BOMT-SWPO wave trap.
Natural Gas—Combined Heat and Power (CHP)				
35	$35	Assumed location in Treasure Valley.	Assume 1 mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—Small Modular Reactor (SMR)				
50	$663	Assume tie into ANTS 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise.	Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at ANTS.	New parallel 55-mile, 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Pumped Storage—new upper reservoir and generation/pumping plant, pump water from existing lower reservoir to new upper reservoir and run water through new power plant)				
300	$183	Assume Anderson Ranch location; displaces equivalent MW of portfolio resources in same region.	18 mi 230-kV line to connect to RTSN.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Solar PV—Utility Scale 1-Axis Tracking				
30	$144	Assume Magic Valley location; displaces equivalent MW of portfolio resources in same region.	Assume 1 mile 230 kV line and associated stations equipment.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.
Wind—Idaho				
100	$117	Assume location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region.	Assume 5 mi of 230-kV transmission from MPSN to project site.	Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources.

Levelized Cost of Energy

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[1]	Fuel	Wholesale Energy	Net of Tax Credit/Steam sales/Integration/ Transmission Revenue	Total Cost per MWh	Capacity Factor
Biomass Indirect—Anaerobic Digester (35 MW)	$98	$35	$0	$0	$0	$133	85%
Boardman to Hemingway (250 MW)	$18	$3	$0	$28	-$9	$39	33%
Canal Drop Hydro (1 MW)	$140	$25	$0	$0	$0	$165	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59	70%
CCCT (2x1) F Class (550 MW)	$25	$7	$28	$0	$0	$59	70%
CHP (35 MW)	$33	$20	$25	$0	-$6	$71	80%
Demand Response—Additional (25 MW)	$0	$706	$0	$0	$0	$706	1%
Geothermal (30 MW)	$64	$47	$0	$0	$0	$111	88%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94	25%
SCCT—Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197	10%
Small Modular Nuclear (50 MW)	$124	$31	$8	$0	$0	$163	90%
Solar PV—Rooftop C&I (1 MW)	$153	$25	$0	$0	$1	$179	21%
Solar PV—Rooftop Residential (0.005 MW)	$126	$26	$0	$0	$1	$153	21%
Solar PV—Utility Scale 1-Axis Tracking (30 MW)	$62	$12	$0	$0	$1	$74	27%
Storage—Ice Thermal Storage (10 MW)	$595	$147	$0	$0	$0	$742	4%
Storage—Li Battery Residential (10 MW)	$400	$60	$0	$0	$0	$460	14%
Storage—Pumped-Hydro (300 MW)	$158	$57	$0	$0	$0	$214	20%
Storage—V Flow Battery (10 MW)	$1,679	$317	$0	$0	$0	$1,996	4%
Storage—Zn Battery (10 MW)	$516	$92	$0	$0	$0	$608	7%
Wind (100 MW)	$64	$24	$0	$0	$22	$111	28%

[1] Non Fuel O&M includes fixed and variable costs, property taxes.

30-Year Levelized Capacity (fixed) Cost per kW/Month

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Net of Tax Credit/Steam sales/Integration/ Transmission Revenue	Total Cost per kW
Biomass Indirect—Anaerobic Digester (35 MW)	$61	$9	$0	$0	$70
Boardman to Hemingway (250 MW)	$5	$1	$0	-$2	$4
Canal Drop Hydro (1 MW)	$34	$6	$0	$0	$40
CCCT (1x1) F Class (300 MW)	$13	$3	$0	$0	$16
CCCT (2x1) F Class (550 MW)	$13	$2	$0	$0	$14
CHP (35 MW)	$19	$7	$0	$0	$26
Demand Response—Additional (25 MW)	$0	$5	$0	$0	$5
Geothermal (30 MW)	$41	$26	$0	$0	$67
Reciprocating Gas Engine (18.8 MW)	$7	$2	$0	$0	$9
SCCT—Frame F Class (170 MW)	$9	$2	$0	$0	$10
Small Modular Nuclear (50 MW)	$81	$18	$0	$0	$100
Solar PV—Rooftop C&I (1 MW)	$24	$4	$0	$0	$27
Solar PV—Rooftop Residential (0.005 MW)	$19	$4	$0	$0	$23
Solar PV—Utility Scale 1-Axis Tracking (30 MW)	$12	$2	$0	$0	$14
Storage—Ice Thermal Storage (10 MW)	$17	$4	$0	$0	$22
Storage—Li Battery Residential (10 MW)	$41	$6	$0	$0	$47
Storage—Pumped-Hydro (300 MW)	$23	$8	$0	$0	$31
Storage—V Flow Battery (10 MW)	$49	$9	$0	$0	$58
Storage—Zn Battery (10 MW)	$26	$5	$0	$0	$31
Wind (100 MW)	$13	$5	$0	$0	$18

Peak-Hour Capacity Credit (Contribution to Peak)

Solar and Wind Resources

Peak hour capacity credit (contribution to peak) for new IRP intermittent generation resources:

New IRP intermittent generation—Peak hour capacity credit

Resource	Peak Hour Capacity Credit
PV solar south orientation	28.4%
PV solar southwest orientation	45.4%
PV solar single-axis tracking	51.3%
Wind	5.0%

Energy Shape—Solar

2017 IRP Assumed Solar Capacity Factors

Total nameplate: 298.3 MW
Total annual capacity factor: 27%

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5:00 AM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6:00 AM	0.0	0.0	0.4	0.1	8.4	15.9	9.7	0.4	0.0	0.0	0.0	0.0
7:00 AM	0.0	0.6	16.2	16.6	47.7	69.8	57.7	32.9	8.7	0.3	2.4	0.0
8:00 AM	6.5	29.6	47.9	66.4	126.5	154.3	138.3	104.9	57.7	25.0	29.6	7.3
9:00 AM	34.9	90.7	108.1	142.9	203.1	229.6	225.0	194.1	144.8	84.5	65.5	37.2
10:00 AM	73.0	143.8	173.4	197.6	228.2	259.5	252.5	253.0	226.2	163.0	109.9	79.5
11:00 AM	87.1	151.7	197.9	219.0	240.8	262.4	265.0	258.0	236.4	196.7	130.3	91.4
12:00 PM	84.0	148.3	199.3	228.1	243.9	272.8	260.3	263.8	235.3	196.9	129.9	88.5
1:00 PM	92.4	149.0	196.4	225.6	249.1	267.5	258.1	256.0	232.5	192.2	120.1	89.4
2:00 PM	94.0	146.5	199.9	228.6	239.4	263.5	266.2	250.9	232.1	184.1	117.0	96.6
3:00 PM	93.0	153.6	193.1	230.1	242.6	254.4	264.8	249.4	226.1	187.5	111.4	87.4
4:00 PM	88.2	146.3	190.2	210.6	222.8	234.5	262.9	250.2	225.0	178.4	81.7	62.0
5:00 PM	35.4	93.2	158.0	199.3	218.9	213.8	246.2	243.5	220.7	162.2	28.1	2.7
6:00 PM	0.4	16.1	108.3	180.4	189.3	196.6	221.7	222.9	178.6	82.2	9.3	0.0
7:00 PM	0.0	0.0	49.5	107.2	147.1	157.8	177.8	145.7	73.3	6.3	0.0	0.0
8:00 PM	0.0	0.0	2.3	30.5	69.8	96.8	101.6	53.7	3.1	0.0	0.0	0.0
9:00 PM	0.0	0.0	0.0	0.0	2.6	17.9	14.4	1.3	0.0	0.0	0.0	0.0
10:00 PM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11:00 PM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	28.7	52.9	76.7	95.1	111.7	123.6	125.9	115.9	95.9	69.1	39.0	26.7
MWh per Day	688.9	1269.3	1841.0	2282.9	2680.3	2967.1	3022.4	2781.0	2300.6	1659.3	935.2	641.9
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
MWh per Month	21,355	35,541	57,070	68,488	83,088	89,013	93,695	86,211	69,019	51,438	28,057	19,898
MWh for year	702,875											
Average	28.7	52.9	76.7	95.1	111.7	123.6	125.9	115.9	95.9	69.1	39.0	26.7

Idaho Schedule 87/Oregon Schedule 85—Integration Costs for Solar and Wind Resources

Solar

0–100 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates*
2016	0.04	2016	0.04
2017	0.04	2017	0.04
2018	0.04	2018	0.04
2019	0.05	2019	0.04
2020	0.05	2020	0.04
2021	0.05	2021	0.04
		2022	0.04
		2023	0.04
		2024	0.04
		2025	0.04
		2026	0.04
		2027	0.05
		2028	0.05
		2029	0.05
		2030	0.05
		2031	0.05
		2032	0.05
		2033	0.05
		2034	0.05
		2035	0.05
		2036	0.06
		2037	0.06
		2038	0.06
		2039	0.06
		2040	0.06
		2041	0.06

*$/MWh

101–200 MW Solar Capacity Penetration Level			
Levelized		**Non Levelized**	
On-line Year	**20-Year Contract Term Levelized Rates***	**Contract year**	**Non-Levelized Rates**
2016	0.19	2016	0.16
2017	0.20	2017	0.17
2018	0.20	2018	0.17
2019	0.21	2019	0.18
2020	0.21	2020	0.18
2021	0.22	2021	0.18
		2022	0.19
		2023	0.19
		2024	0.20
		2025	0.20
		2026	0.20
		2027	0.21
		2028	0.21
		2029	0.22
		2030	0.22
		2031	0.23
		2032	0.23
		2033	0.24
		2034	0.24
		2035	0.25
		2036	0.25
		2037	0.26
		2038	0.27
		2039	0.27
		2040	0.28
		2041	0.28

*$/MWh

201–300 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	0.41	2016	0.34
2017	0.42	2017	0.35
2018	0.43	2018	0.36
2019	0.44	2019	0.37
2020	0.44	2020	0.38
2021	0.45	2021	0.38
		2022	0.39
		2023	0.40
		2024	0.41
		2025	0.42
		2026	0.43
		2027	0.44
		2028	0.45
		2029	0.46
		2030	0.47
		2031	0.48
		2032	0.49
		2033	0.50
		2034	0.51
		2035	0.52
		2036	0.53
		2037	0.54
		2038	0.56
		2039	0.57
		2040	0.58
		2041	0.59

*$/MWh

301–400 MW Solar Capacity Penetration Level			
Levelized		**Non Levelized**	
On-line Year	**20-Year Contract Term Levelized Rates***	**Contract year**	**Non-Levelized Rates**
2016	0.64	2016	0.54
2017	0.65	2017	0.55
2018	0.67	2018	0.56
2019	0.68	2019	0.57
2020	0.70	2020	0.59
2021	0.71	2021	0.60
		2022	0.61
		2023	0.63
		2024	0.64
		2025	0.66
		2026	0.67
		2027	0.68
		2028	0.70
		2029	0.71
		2030	0.73
		2031	0.75
		2032	0.76
		2033	0.78
		2034	0.80
		2035	0.81
		2036	0.83
		2037	0.85
		2038	0.87
		2039	0.89
		2040	0.91
		2041	0.93

*$/MWh

401–500 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	0.84	2016	0.71
2017	0.86	2017	0.73
2018	0.88	2018	0.75
2019	0.90	2019	0.76
2020	0.92	2020	0.78
2021	0.94	2021	0.80
		2022	0.81
		2023	0.83
		2024	0.85
		2025	0.87
		2026	0.89
		2027	0.91
		2028	0.93
		2029	0.95
		2030	0.97
		2031	0.99
		2032	1.01
		2033	1.03
		2034	1.06
		2035	1.08
		2036	1.10
		2037	1.13
		2038	1.15
		2039	1.18
		2040	1.20
		2041	1.23

*$/MWh

501–600 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	**20-Year Contract Term Levelized Rates***	**Contract year**	**Non-Levelized Rates**
2016	1.01	2016	0.86
2017	1.03	2017	0.87
2018	1.06	2018	0.89
2019	1.08	2019	0.91
2020	1.10	2020	0.93
2021	1.13	2021	0.95
		2022	0.97
		2023	1.00
		2024	1.02
		2025	1.04
		2026	1.06
		2027	1.09
		2028	1.11
		2029	1.13
		2030	1.16
		2031	1.19
		2032	1.21
		2033	1.24
		2034	1.26
		2035	1.29
		2036	1.32
		2037	1.35
		2038	1.38
		2039	1.41
		2040	1.44
		2041	1.47

*$/MWh

601–700 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.12	2016	0.95
2017	1.15	2017	0.97
2018	1.17	2018	0.99
2019	1.20	2019	1.01
2020	1.22	2020	1.03
2021	1.25	2021	1.06
		2022	1.08
		2023	1.10
		2024	1.13
		2025	1.15
		2026	1.18
		2027	1.20
		2028	1.23
		2029	1.26
		2030	1.29
		2031	1.31
		2032	1.34
		2033	1.37
		2034	1.40
		2035	1.43
		2036	1.46
		2037	1.50
		2038	1.53
		2039	1.56
		2040	1.60
		2041	1.63

*$/MWh

701–800 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.17	2016	0.99
2017	1.20	2017	1.01
2018	1.22	2018	1.03
2019	1.25	2019	1.06
2020	1.28	2020	1.08
2021	1.30	2021	1.10
		2022	1.13
		2023	1.15
		2024	1.18
		2025	1.20
		2026	1.23
		2027	1.26
		2028	1.28
		2029	1.31
		2030	1.34
		2031	1.37
		2032	1.40
		2033	1.43
		2034	1.46
		2035	1.49
		2036	1.53
		2037	1.56
		2038	1.60
		2039	1.63
		2040	1.67
		2041	1.70

*$/MWh

801–900 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.16	2016	0.98
2017	1.19	2017	1.00
2018	1.21	2018	1.03
2019	1.24	2019	1.05
2020	1.27	2020	1.07
2021	1.30	2021	1.09
		2022	1.12
		2023	1.14
		2024	1.17
		2025	1.19
		2026	1.22
		2027	1.25
		2028	1.28
		2029	1.30
		2030	1.33
		2031	1.36
		2032	1.39
		2033	1.42
		2034	1.45
		2035	1.48
		2036	1.52
		2037	1.55
		2038	1.59
		2039	1.62
		2040	1.66
		2041	1.69

*$/MWh

901–1,000 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.12	2016	0.94
2017	1.14	2017	0.96
2018	1.17	2018	0.99
2019	1.19	2019	1.01
2020	1.22	2020	1.03
2021	1.25	2021	1.05
		2022	1.08
		2023	1.10
		2024	1.12
		2025	1.15
		2026	1.17
		2027	1.20
		2028	1.23
		2029	1.25
		2030	1.28
		2031	1.31
		2032	1.34
		2033	1.37
		2034	1.40
		2035	1.43
		2036	1.46
		2037	1.49
		2038	1.52
		2039	1.56
		2040	1.59
		2041	1.63

*$/MWh

1,001–1,100 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.06	2016	0.90
2017	1.08	2017	0.92
2018	1.11	2018	0.94
2019	1.13	2019	0.96
2020	1.16	2020	0.98
2021	1.18	2021	1.00
		2022	1.02
		2023	1.04
		2024	1.07
		2025	1.09
		2026	1.11
		2027	1.14
		2028	1.16
		2029	1.19
		2030	1.22
		2031	1.24
		2032	1.27
		2033	1.30
		2034	1.33
		2035	1.36
		2036	1.39
		2037	1.42
		2038	1.45
		2039	1.48
		2040	1.51
		2041	1.54

*$/MWh

1,101–1,200 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.03	2016	0.87
2017	1.05	2017	0.89
2018	1.08	2018	0.91
2019	1.10	2019	0.93
2020	1.12	2020	0.95
2021	1.15	2021	0.97
		2022	0.99
		2023	1.01
		2024	1.04
		2025	1.06
		2026	1.08
		2027	1.11
		2028	1.13
		2029	1.16
		2030	1.18
		2031	1.21
		2032	1.23
		2033	1.26
		2034	1.29
		2035	1.32
		2036	1.35
		2037	1.37
		2038	1.41
		2039	1.44
		2040	1.47
		2041	1.50

*$/MWh

1,201–1,300 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.07	2016	0.90
2017	1.09	2017	0.92
2018	1.12	2018	0.94
2019	1.14	2019	0.97
2020	1.17	2020	0.99
2021	1.19	2021	1.01
		2022	1.03
		2023	1.05
		2024	1.08
		2025	1.10
		2026	1.12
		2027	1.15
		2028	1.17
		2029	1.20
		2030	1.23
		2031	1.25
		2032	1.28
		2033	1.31
		2034	1.34
		2035	1.37
		2036	1.40
		2037	1.43
		2038	1.46
		2039	1.49
		2040	1.52
		2041	1.56

*$/MWh

1,301–1,400 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.24	2016	1.05
2017	1.27	2017	1.07
2018	1.30	2018	1.10
2019	1.33	2019	1.12
2020	1.36	2020	1.15
2021	1.39	2021	1.17
		2022	1.20
		2023	1.22
		2024	1.25
		2025	1.28
		2026	1.31
		2027	1.33
		2028	1.36
		2029	1.39
		2030	1.42
		2031	1.46
		2032	1.49
		2033	1.52
		2034	1.55
		2035	1.59
		2036	1.62
		2037	1.66
		2038	1.70
		2039	1.73
		2040	1.77
		2041	1.81

*$/MWh

1,401–1,500 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	1.61	2016	1.36
2017	1.65	2017	1.39
2018	1.69	2018	1.42
2019	1.72	2019	1.46
2020	1.76	2020	1.49
2021	1.80	2021	1.52
		2022	1.55
		2023	1.59
		2024	1.62
		2025	1.66
		2026	1.70
		2027	1.73
		2028	1.77
		2029	1.81
		2030	1.85
		2031	1.89
		2032	1.93
		2033	1.97
		2034	2.02
		2035	2.06
		2036	2.11
		2037	2.15
		2038	2.20
		2039	2.25
		2040	2.30
		2041	2.35

*$/MWh

1,501–1,600 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2016	2.26	2016	1.91
2017	2.31	2017	1.95
2018	2.36	2018	2.00
2019	2.41	2019	2.04
2020	2.47	2020	2.09
2021	2.52	2021	2.13
		2022	2.18
		2023	2.23
		2024	2.28
		2025	2.33
		2026	2.38
		2027	2.43
		2028	2.48
		2029	2.54
		2030	2.59
		2031	2.65
		2032	2.71
		2033	2.77
		2034	2.83
		2035	2.89
		2036	2.95
		2037	3.02
		2038	3.09
		2039	3.15
		2040	3.22
		2041	3.29

*$/MWh

Wind

0–100 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	0.27	2014	0.21
2015	0.27	2015	0.22
2016	0.28	2016	0.23
2017	0.29	2017	0.23
2018	0.30	2018	0.24
2019	0.31	2019	0.25
		2020	0.25
		2021	0.26
		2022	0.27
		2023	0.28
		2024	0.29
		2025	0.29
		2026	0.30
		2027	0.31
		2028	0.32
		2029	0.33
		2030	0.34
		2031	0.35
		2032	0.36
		2033	0.37
		2034	0.38
		2035	0.40
		2036	0.41
		2037	0.42
		2038	0.43
		2039	0.45

*$/MWh

101–200 MW Wind Capacity Penetration Level			
Levelized		**Non Levelized**	
On-line Year	**20-Year Contract Term Levelized Rates***	**Contract year**	**Non-Levelized Rates**
2014	1.22	2014	0.98
2015	1.25	2015	1.00
2016	1.29	2016	1.04
2017	1.33	2017	1.07
2018	1.37	2018	1.10
2019	1.41	2019	1.13
		2020	1.16
		2021	1.20
		2022	1.24
		2023	1.27
		2024	1.31
		2025	1.35
		2026	1.39
		2027	1.43
		2028	1.48
		2029	1.52
		2030	1.57
		2031	1.61
		2032	1.66
		2033	1.71
		2034	1.76
		2035	1.81
		2036	1.87
		2037	1.93
		2038	1.98
		2039	2.04

*$/MWh

201–300 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	2.78	2014	2.23
2015	2.87	2015	2.30
2016	2.95	2016	2.37
2017	3.04	2017	2.44
2018	3.13	2018	2.51
2019	3.23	2019	2.59
		2020	2.67
		2021	2.75
		2022	2.83
		2023	2.92
		2024	3.00
		2025	3.09
		2026	3.19
		2027	3.28
		2028	3.38
		2029	3.48
		2030	3.59
		2031	3.69
		2032	3.80
		2033	3.92
		2034	4.04
		2035	4.16
		2036	4.28
		2037	4.41
		2038	4.54
		2039	4.68

*$/MWh

301–400 MW Wind Capacity Penetration Level			
Levelized		**Non Levelized**	
On-line Year	**20-Year Contract Term Levelized Rates***	**Contract year**	**Non-Levelized Rates**
2014	4.95	2014	3.98
2015	5.10	2015	4.10
2016	5.26	2016	4.22
2017	5.41	2017	4.35
2018	5.58	2018	4.48
2019	5.74	2019	4.61
		2020	4.75
		2021	4.89
		2022	5.04
		2023	5.19
		2024	5.34
		2025	5.51
		2026	5.67
		2027	5.84
		2028	6.02
		2029	6.20
		2030	6.38
		2031	6.57
		2032	6.77
		2033	6.97
		2034	7.18
		2035	7.40
		2036	7.62
		2037	7.85
		2038	8.08
		2039	8.33

*$/MWh

401–500 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	7.71	2014	6.19
2015	7.95	2015	6.38
2016	8.18	2016	6.57
2017	8.43	2017	6.77
2018	8.68	2018	6.97
2019	8.94	2019	7.18
		2020	7.39
		2021	7.62
		2022	7.84
		2023	8.08
		2024	8.32
		2025	8.57
		2026	8.83
		2027	9.09
		2028	9.37
		2029	9.65
		2030	9.94
		2031	10.23
		2032	10.54
		2033	10.86
		2034	11.18
		2035	11.52
		2036	11.86
		2037	12.22
		2038	12.59
		2039	12.96

*$/MWh

501–600 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	11.05	2014	8.87
2015	11.38	2015	9.13
2016	11.72	2016	9.41
2017	12.07	2017	9.69
2018	12.43	2018	9.98
2019	12.81	2019	10.28
		2020	10.59
		2021	10.91
		2022	11.23
		2023	11.57
		2024	11.92
		2025	12.28
		2026	12.64
		2027	13.02
		2028	13.41
		2029	13.82
		2030	14.23
		2031	14.66
		2032	15.10
		2033	15.55
		2034	16.02
		2035	16.50
		2036	16.99
		2037	17.50
		2038	18.03
		2039	18.57

*$/MWh

601–700 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	14.94	2014	11.99
2015	15.39	2015	12.35
2016	15.85	2016	12.72
2017	16.33	2017	13.10
2018	16.82	2018	13.50
2019	17.32	2019	13.90
		2020	14.32
		2021	14.75
		2022	15.19
		2023	15.65
		2024	16.12
		2025	16.60
		2026	17.10
		2027	17.61
		2028	18.14
		2029	18.68
		2030	19.24
		2031	19.82
		2032	20.42
		2033	21.03
		2034	21.66
		2035	22.31
		2036	22.98
		2037	23.67
		2038	24.38
		2039	25.11

*$/MWh

701–800 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	19.38	2014	15.55
2015	19.96	2015	16.02
2016	20.56	2016	16.50
2017	21.17	2017	17.00
2018	21.81	2018	17.51
2019	22.46	2019	18.03
		2020	18.57
		2021	19.13
		2022	19.70
		2023	20.29
		2024	20.90
		2025	21.53
		2026	22.18
		2027	22.84
		2028	23.53
		2029	24.23
		2030	24.96
		2031	25.71
		2032	26.48
		2033	27.27
		2034	28.09
		2035	28.93
		2036	29.80
		2037	30.70
		2038	31.62
		2039	32.57

*$/MWh

801–900 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	24.34	2014	19.54
2015	25.07	2015	20.13
2016	25.83	2016	20.73
2017	26.60	2017	21.35
2018	27.40	2018	21.99
2019	28.22	2019	22.65
		2020	23.33
		2021	24.03
		2022	24.75
		2023	25.50
		2024	26.26
		2025	27.05
		2026	27.86
		2027	28.70
		2028	29.56
		2029	30.44
		2030	31.36
		2031	32.30
		2032	33.27
		2033	34.26
		2034	35.29
		2035	36.35
		2036	37.44
		2037	38.56
		2038	39.72
		2039	40.91

*$/MWh

901–1,000 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	29.82	2014	23.94
2015	30.72	2015	24.66
2016	31.64	2016	25.40
2017	32.59	2017	26.16
2018	33.57	2018	26.94
2019	34.57	2019	27.75
		2020	28.59
		2021	29.44
		2022	30.33
		2023	31.24
		2024	32.17
		2025	33.14
		2026	34.13
		2027	35.16
		2028	36.21
		2029	37.30
		2030	38.42
		2031	39.57
		2032	40.76
		2033	41.98
		2034	43.24
		2035	44.54
		2036	45.87
		2037	47.25
		2038	48.66
		2039	50.12

*$/MWh

1,001–1,100 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	35.81	2014	28.74
2015	36.88	2015	29.60
2016	37.99	2016	30.49
2017	39.13	2017	31.41
2018	40.30	2018	32.35
2019	41.51	2019	33.32
		2020	34.32
		2021	35.35
		2022	36.41
		2023	37.50
		2024	38.63
		2025	39.78
		2026	40.98
		2027	42.21
		2028	43.47
		2029	44.78
		2030	46.12
		2031	47.51
		2032	48.93
		2033	50.40
		2034	51.91
		2035	53.47
		2036	55.07
		2037	56.72
		2038	58.43
		2039	60.18

*$/MWh

1,101–1,200 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	42.27	2014	33.93
2015	43.54	2015	34.95
2016	44.85	2016	36.00
2017	46.19	2017	37.08
2018	47.58	2018	38.19
2019	49.01	2019	39.34
		2020	40.52
		2021	41.73
		2022	42.98
		2023	44.27
		2024	45.60
		2025	46.97
		2026	48.38
		2027	49.83
		2028	51.33
		2029	52.87
		2030	54.45
		2031	56.09
		2032	57.77
		2033	59.50
		2034	61.29
		2035	63.12
		2036	65.02
		2037	66.97
		2038	68.98
		2039	71.05

*$/MWh

PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P7

Resource Portfolio P7

Date	Resource	Installed Capacity	Peak-Hour Capacity (MW)
2026	B2H	500, 200*	500
2031	Reciprocating engines	36	36
2032	Reciprocating engines	36	36
2033	Combined-cycle combustion turbine (1x1)	300	300
2035	Reciprocating engines	54	54
2036	Reciprocating engines	54	54
Total		980	980

*April–Sep, Oct–Mar transfer capacity

2. Deficiency period under preferred portfolio

   1st capacity deficit = (34) MW July 2026
   1st energy deficit = (143) MW July 2029

3. Intermittent generation integration costs

   See integration cost schedule included in *Appendix C—Technical Appendix*, section *Idaho Schedule 87/Oregon Schedule 85—Integration Costs for Solar and Wind Resources*.

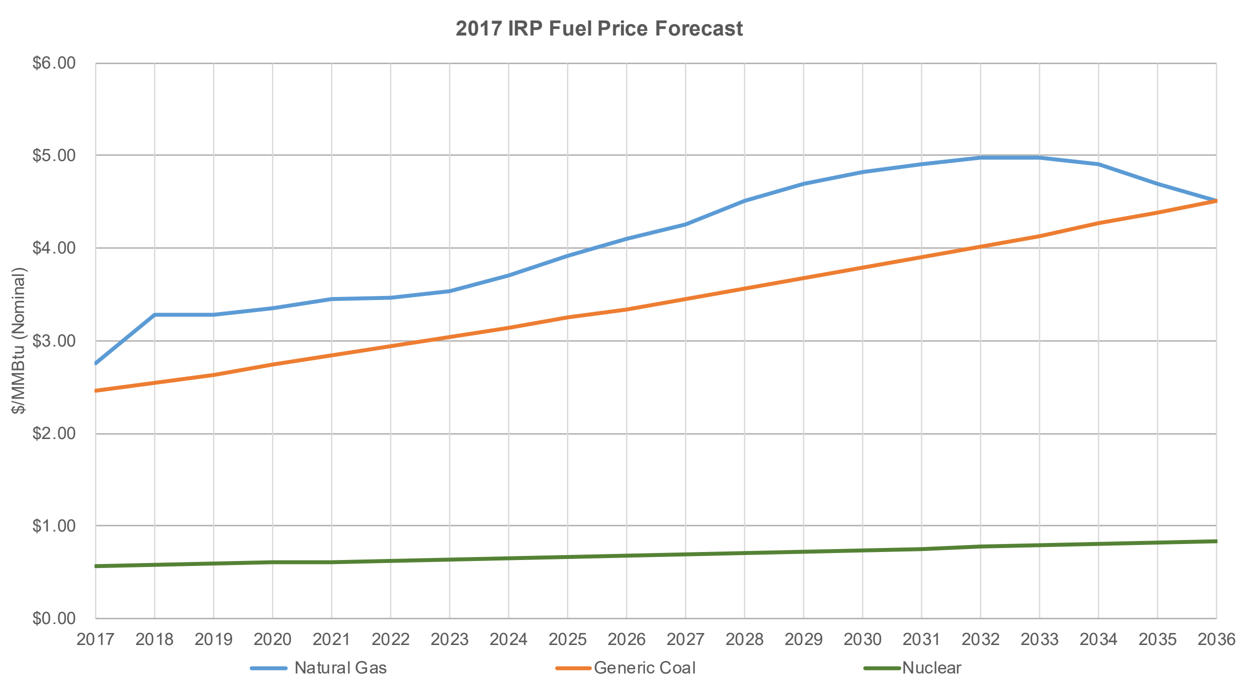
Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2017	4.59
2018	4.86
2019	4.91
2020	5.23
2021	5.55
2022	5.92
2023	6.29
2024	6.67
2025	7.05
2026	7.46
2027	7.85
2028	8.25
2029	8.67
2030	9.08
2031	9.51
2032	9.95
2033	10.40
2034	10.85
2035	11.32
2036	11.79

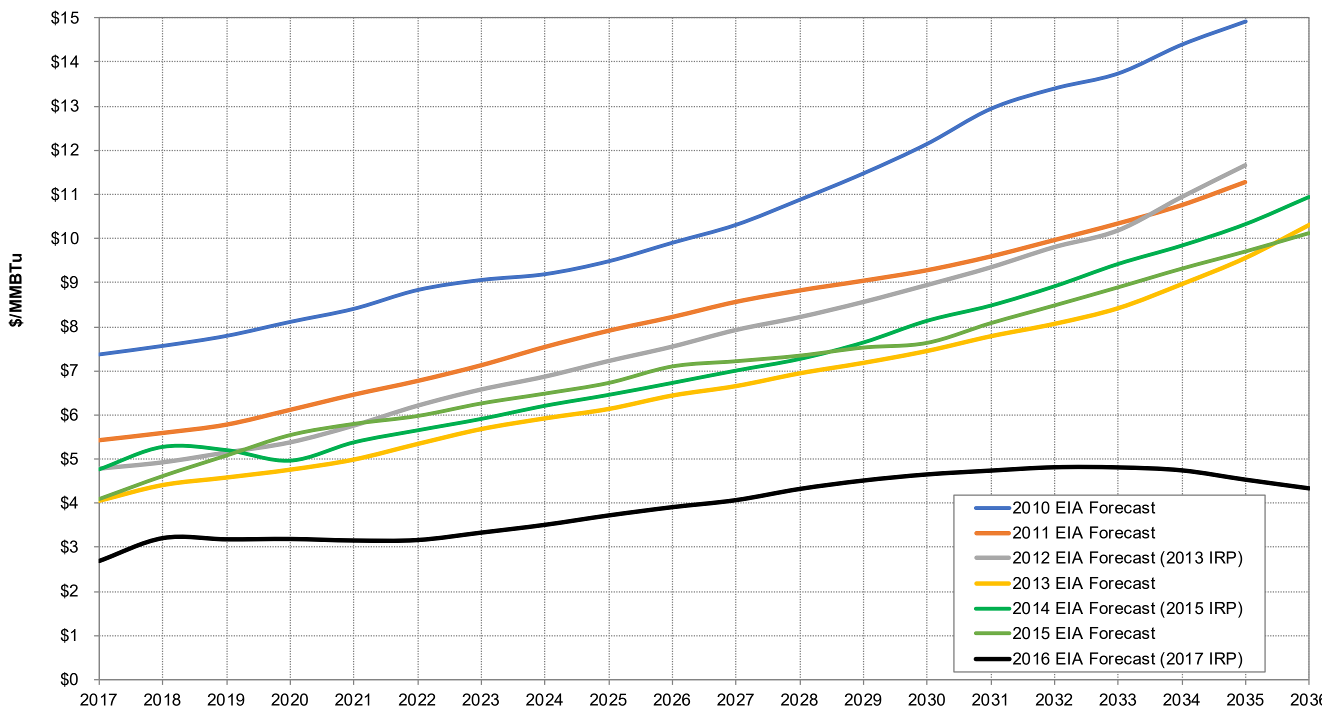
Fuel Price Forecast

Natural Gas, Coal, and Nuclear Price Forecast (nominal $/MMBtu)

Year	Idaho Citygate Natural Gas	Generic Coal	Nuclear
2017	$2.75	$2.46	$0.57
2018	$3.28	$2.55	$0.58
2019	$3.28	$2.64	$0.59
2020	$3.35	$2.74	$0.60
2021	$3.45	$2.85	$0.61
2022	$3.47	$2.94	$0.63
2023	$3.53	$3.04	$0.64
2024	$3.71	$3.14	$0.65
2025	$3.92	$3.25	$0.67
2026	$4.10	$3.34	$0.68
2027	$4.26	$3.46	$0.70
2028	$4.51	$3.57	$0.71
2029	$4.70	$3.67	$0.73
2030	$4.83	$3.79	$0.74
2031	$4.91	$3.90	$0.76
2032	$4.98	$4.02	$0.77
2033	$4.98	$4.13	$0.79
2034	$4.91	$4.27	$0.81
2035	$4.70	$4.39	$0.82
2036	$4.51	$4.51	$0.84



EIA Henry Hub Spot Price Forecasts (Nominal Dollars)



Existing Resource Data

Hydroelectric and Thermal Plant Data

	Nameplate			
Hydroelectric Power Plans	**kVA**	**kW**	**Normal Rating kW[4]**	**Emergency Rating kW[5]**
American Falls	102,600	92,340	92,340	106,190
Bliss	86,250	75,038	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[1]	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**	**1,709,083**		

[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 6,125 kVA on which the nameplate rating is assumed.

[2] The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW have been taken out of 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 different than the nameplate rating. To operate at the Normal Rating, appropriate water and ambient conditions must exist and the FERC license requirements permit.

[5] The Emergency Rating is defined as 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] The Shoshone Falls Unit #2 is out of service due to an exciter condition.

Thermal, Natural Gas, and Diesel Power Plans	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC)[6,7] kW	Summer kW	Winter kW
Bridger (Idaho Power share)	811,053	770,500		707,667	707,667
Boardman (Idaho Power share)	67,600	64,199		57,550	58,050
Valmy (Idaho Power share)	315,000	283,500		260,000	260,000
Total Thermal	**1,193,653**	**1,118,199**			
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	6,250	5,000	5,500		
Total IPC Generation	**3,964,599**	**3,594,434**			

[1] Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

[2] Net Dependable Capacity (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. 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 when not restricted by seasonal or other de-ratings.

[3] Evander Andrews Power Plant is also known to Idaho Power as Danskin Power Plant (DNPR).

[4] Performance test numbers provided by the contractor corrected for the following rating conditions: 90.0 Deg. F, Relative Humidity 20%, Barometric pressure 13.378 psia, Duct Burners ON. Performance numbers were obtained from the Siemens report EC-12087, Thermal performance test results of SGT6-5000F GAs turbine in fuel gas at Langley Gulch, New Plymouth, ID for IPC (Unit # 1—Shop Order Number GT378521)

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects
Status as of April 1, 2017.

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	Little Wood Rvr Res	2.85	Feb-1985	Feb-2020
Baker City Hydro	0.24	Sep-2015	Sep-2030	Littlewood/Arkoosh	0.87	Aug-1986	Aug-2021
Barber Dam	3.70	Apr-1989	Apr-2024	Low Line Canal	7.97	May-1985	May-2020
Birch Creek	0.05	Nov-1984	Nov-2019	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Black Canyon #3	0.14	Apr-1984	Apr-2019	Lowline #2	2.79	Apr-1988	Apr-2023
Black Canyon Bliss Hydro	0.03	Nov-2014	Oct-2035	Magic Reservoir	9.07	Jun-1989	Jun-2024
Blind Canyon	1.63	Dec-2014	Dec-2034	Malad River	0.62	May-1984	May-2019
Box Canyon	0.36	Feb-1984	Feb-2019	Marco Ranches	1.20	Aug-1985	Aug-2020
Briggs Creek	0.60	Oct-1985	Oct-2020	Mile 28	1.50	Jun-1994	Jun-2029
Bypass	9.96	Jun-1988	Jun-2023	Mill Creek Hydroelectric	0.80	Oct-2011	Jun-2017
Canyon Springs	0.13	Oct-1984	As delivered	Mitchell Butte	2.09	May-1989	Dec-2033
Cedar Draw	1.55	Jun-1984	Jun-2019	Mora Drop Small Hydro Fac	1.85	Sep-2006	Sep-2026
Clark Canyon Hydroelectric	7.55	Jun-2017	Estimated	Mud Creek/S&S	0.52	Feb-1982	Jan-2017
Clear Springs Trout	0.52	Nov-1983	Nov-2018	Mud Creek/White	0.21	Jan-1986	Jan-2021
Crystal Springs	2.44	Apr-1986	Apr-2021	North Gooding Main	1.30	Oct-2016	Oct-2036
Curry Cattle Company	0.22	Jun-1983	Jun-2018	Owyhee Dam Cspp	5.00	Aug-1985	May-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pigeon Cove	1.89	Oct-1984	Oct-2019
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #1	0.13	May-2005	May-2015
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3	0.20	May-2005	May-2015
Falls River	9.10	Aug-1993	Aug-2028	Reynolds Irrigation	0.26	May-1986	May-2021
Fargo Drop Hydroelectric	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	Apr-2024
Fisheries Dev.	0.26	Jul-1990	Jul-2040	Sagebrush	0.43	Sep-1985	Sep-2020
Geo-Bon #2	0.93	Nov-1986	Nov-2021	Sahko Hydro	0.50	Feb-2011	Feb-2021
Hailey Cspp	0.06	Jun-1985	Jun-2020	Schaffner	0.53	Aug-1986	Aug-2021
Hazelton A	8.10	Mar-2011	Mar-2026	Shingle Creek	0.22	Aug-1983	Aug-2017
Hazelton B	7.60	May-1993	May-2028	Shoshone #2	0.58	May-1996	May-2031
Head of U Canal Project	1.28	May-2015	Jun-2035	Shoshone Cspp	0.37	Jun-1982	Feb-2017
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snake River Pottery	0.07	Nov-1984	Nov-2019
Jim Knight	0.34	Jun-1985	Jun-2020	Snedigar	0.54	Jan-1985	Jan-2020
Kasel & Witherspoon	0.90	Mar-1984	Mar-2019	Tiber Dam	7.50	Jun-2004	Jun-2024
Koyle Small Hydro	1.25	Apr-1984	Apr-2019	Trout-Co	0.24	Dec-1986	Dec-2021
Lateral # 10	2.06	May-1985	May-2020	Tunnel #1	7.00	Jun-1993	Feb-2035
Lemoyne	0.08	Jun-1985	Jun-2020	White Water Ranch	0.16	Aug-1985	Aug-2020
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035	Wilson Lake Hydro	8.40	May-1993	May-2028
Total Hydro Nameplate Rating 155.32 MW							

Thermal Projects	MW	On-line Date	End Date
Simplot Pocatello Cogen	15.90	Mar-2013	Feb-2016
TASCO—Nampa Natural Gas	2	Sep-2003	As Delivered
TASCO—Twin Falls Natural Gas	3	Aug-2001	As Delivered
Total Thermal Nameplate Rating 20.90 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-2010	Aug-2020	Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027
Bannock County Landfill	3.20	May-2014	May-2034	Pocatello Waste	0.46	Dec-1985	Dec-2020
Bettencourt Dry Creek BioFactory	2.25	May-2010	May-2020	Rock Creek Dairy	4.00	Aug-2012	Aug-2027
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	SISW LFGE	5.00	Oct-2018	Estimated
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	5.00	Jun-1983	Jun-2018
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029				
Total Biomass Nameplate Rating 34.45 MW							
Solar Projects							
American Falls Solar II, LLC	20.00	Mar-2017	Mar-2037	Murphy Flat Power, LLC	20.00	Mar-2017	Mar-2037
American Falls Solar, LLC	40.00	Mar-2017	Mar-2037	Open Range Solar Center, LLC	20.00	Mar-2017	Mar-2037
Brush Solar	2.75	Oct-2019	Estimated	Orchard Ranch Solar, LLC	10.00	Oct-2016	Oct-2036
Grand View PV Solar Two	80.00	Dec-2016	Dec-2036	Railroad Solar Center, LLC	4.50	Dec-2016	Dec-2036
Grove Solar Center, LLC	6.00	Oct-2016	Oct-2036	Simco Solar, LLC	20.00	Mar-2017	Mar-2037
Hyline Solar Center, LLC	9.00	Nov-2016	Nov-2036	Thunderegg Solar Center, LLC	10.00	Nov-2016	Nov-2036
ID Solar 1	40.00	Aug-2016	Jan-2036	Vale Air Solar Center, LLC	10.00	Nov-2016	Nov-2036
Morgan Solar	3.00	Oct-2019	Estimated	Vale 1 Solar	3.00	Oct-2019	Estimated
Mt. Home Solar 1, LLC	20.00	Mar-2017	Mar-2037				
Total Solar Nameplate Rating 298.25 MW							
Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Mainline Windfarm	23.00	Dec-2012	Dec-2032
Benson Creek Windfarm	10.00	Mar-2017	Mar-2037	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031	Oregon Trail Wind Park	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 LLC	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Prospector Windfarm	10.00	Mar-2017	Mar-2037
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Durbin Creek Windfarm	10.00	Mar-2017	Mar-2037	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 Park	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 Park	12.00	Jan-2011	Jan-2031
High Mesa Wind Project	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	May-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Jett Creek Windfarm	10.00	Mar-2017	Mar-2037	Willow Spring Windfarm	10.00	Mar-2017	Mar-2037
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW							
Total Nameplate Rating 1,135.84 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of April 1, 2017. 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, 2017			
		Contract	
Project	**MW**	**On-Line Date**	**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	November 2012	November 2037
Total geothermal nameplate MW rating	35		
Total nameplate MW rating	136		

1. 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.
2. Not included in the above table is the energy exchange agreement between Idaho Power and the Clatskanie PUD. Under the exchange, Idaho Power receives energy from the 18-MW power plant at Arrowrock Dam on the Boise River and returns to Clatskanie PUD energy of an equivalent value delivered seasonally. The agreement began in January 2010 and extends through 2020. Idaho Power retains the right to renew the agreement through 2025.

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 updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. 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.

Model Inputs

The inputs for the 2017 IRP were derived from management practices outlined in an agreement between the Surface Water Coalition and Idaho Groundwater Appropriators (IGWA). The agreement set out specific targets for several management practices that include aquifer recharge, system conversions, and a total reduction in ground water diversions of 240,000 acre feet (acft). The 2017 IRP modeling also recognized ongoing declines in specific reaches and additional surface water from weather modification activities.

Recharge modeled for the 2017 IRP included new recharge diversions that have the capability of completely drying the Snake River below Milner Dam during the winter months. These diversions can have a significant impact to flows downstream of Milner Dam. Recharge diversions increased from 2017 and peaked at close to 249,000 acft in IRP year 2022. In IRP year 2022, approximately 67,000 acft of recharge occurs above American Falls Reservoir and 182,000 acft is diverted at Milner Dam. Recharge diversions are held steady until 2031 when declines in reach gains reduce the amount of water available for recharge operations.

System conversion projects involve the conversion of ground water supplied irrigated land 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 16,687 acres of converted land on the ESPA with a total water savings of 2.0 acre-ft or water per acre of irrigated land (acre-ft/acre). Diversions for conversion projects peak at approximately 33,000 acft. Diversions for conversion projects generally decline after 2021 as declines in reach gains reduces water availability for diversion.

The model accounted for a 240,000 acft decreases in ground water pumping from the Eastern Snake Plain Aquifer (ESPA). The decreases were spread evenly over ground water irrigated lands that are subject to the agreement between the Surface Water Coalition and the IGWA. This reduction in ground water diversions resulted in increased reach gains throughout much of the mid-Snake River.

The goal of the Surface Water Coalition agreement was to provide additional water to those entities diverting Snake River water from Minidoka Dam to Milner Dam. To simulate this delivery of additional water, a new diversion was added to the model. This diversion is not delivered to a specific entity in the model but is designed to simulate additional surface water diversions at Milner. The amount of this diversion was calculated to ensure that surface water diverters would receive water amounting to the 25 percent exceedance of diversions for years 1995 – 2009. These additional diversions were not allowed if either storage water or natural flow were not available in excess of existing modeled diversions. Water was not available in all years to fill these diversions.

Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dam demonstrated a statistically significant decline for the period of 1986 to 2015. On average, reach gains into American Falls Reservoir declined 29 cubic feet per second per year. Reach gains from Milner Dam to Lower Salmon Falls Dam declined on average 28 cubic feet per second per year. 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 different levels of development. For IRP years 2017 through 2019, weather modification was increased to reflect projected levels of fully built-out programs in Eastern Idaho, the Wood River Valley and the Boise Basin. Beyond IRP year 2019, weather modification levels in these three basins were held constant through the rest of the IRP forecast period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP forecast period.

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 2017 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 a decrease in ground water pumping 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 inflow to Brownlee Reservoir increases from IRP year 2017 through 2018. These increases are a response to increased weather modification in the Upper Snake, Wood and Boise River Basins and increased reach gains resulting from a decrease in pumping on the ESPA. Flows peak in 2018 with the 50 percent exceedance flows into Brownlee Reservoir at just over 11.72 million acre-ft/year. In 2036, those flows have declined to approximately 11.3 million acre-ft/year. For the April through July volume the peak occurs in 2021 with a volume of 5.32 million acre-ft/year. By 2036 the April through July inflow to Brownlee decreases to 5.17 million acre-ft/year. The decline in inflow to Brownlee Reservoir after 2018 is likely due to the increased diversions for recharge, particularly winter time diversions that reduce flow at Milner Dam to zero. April through July volumes continue to increase as new reach gains from recharge and a decline in ground water pumping yield at springs tributary to the Snake River. However, there is a long-term decrease in Snake River flows which is attributable to declining flows into American Falls and the Milner to Lower Salmon Falls reach. These long-term declines eventually overwhelm any new reach gains from management practices on the ESPA.

2017 Model Parameters

IRP Year	Managed Recharge (acft/yr)			Weather Modification (acft/yr)	System Conversions (Ac)	CREP (Ac)	Reach Declines (acft/yr)	
	Above American Falls	Below American Falls	Total				American Falls Inflows	Below Milner Inflows
2017	700	56,444	57,144	888,301	16,700	240,000	167,000	161,700
2018	4,900	70,748	75,648	990,779	16,700	240,000	187,700	181,900
2019	36,379	144,079	180,459	1,031,541	16,376	240,000	208,500	201,400
2020	39,309	143,957	183,266	1,031,541	16,574	240,000	229,300	222,400
2021	39,310	167,259	206,568	1,031,541	16,700	240,000	250,100	242,600
2022	67,427	181,352	248,779	1,031,541	16,490	240,000	270,900	263,100
2023	67,427	181,352	248,779	1,031,541	16,490	240,000	291,900	283,000
2024	67,427	181,352	248,779	1,031,541	16,490	240,000	312,800	303,200
2025	67,427	181,352	248,779	1,031,541	16,490	240,000	333,400	323,300
2026	67,427	181,352	248,779	1,031,541	16,490	240,000	354,300	343,900
2027	67,427	181,352	248,779	1,031,541	16,490	240,000	375,500	364,000
2028	67,427	181,352	248,779	1,031,541	16,490	240,000	396,100	384,200
2029	67,427	181,352	248,779	1,031,541	16,490	240,000	417,000	404,400
2030	67,427	181,352	248,779	1,031,541	16,490	240,000	437,900	424,600
2031	65,871	176,055	241,926	1,031,541	16,238	240,000	458,600	444,600
2032	65,871	176,055	241,926	1,031,541	16,238	240,000	479,600	465,000
2033	65,871	176,055	241,926	1,031,541	16,238	240,000	500,600	485,100
2034	65,871	176,055	241,926	1,031,541	16,238	240,000	521,300	505,300
2035	65,871	176,055	241,926	1,031,541	16,238	240,000	542,200	525,600
2036	65,871	176,055	241,926	1,031,541	16,238	240,000	562,900	545,300

Hydro Modeling Results (PDR580)

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*	308.0	348.1	344.5	453.3	399.4	415.5	251.3	162.5	221.4	184.0	144.7	240.8	289.5
Oxbow	HCC	126.9	150.0	156.1	199.5	163.7	168.7	106.8	74.4	100.1	85.1	66.2	102.2	125.0
Hells Canyon	HCC	249.6	298.0	315.2	408.1	338.4	340.6	211.7	146.3	195.5	168.1	132.2	202.8	250.5
American Falls	ROR	22.6	24.1	24.4	56.2	84.4	92.5	86.7	66.3	42.4	13.6	–	10.2	43.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.3	47.3	42.0	55.4	48.0	41.8	35.5	28.7	37.4	38.2	36.5	40.8	41.6
C .J. Strike	ROR	61.5	62.6	56.0	69.9	61.1	51.2	37.2	31.8	44.8	48.5	47.7	51.5	52.0
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.9	32.9	27.9	38.5	33.7	28.1	23.1	16.2	23.7	24.5	22.8	26.3	27.6
Milner	ROR	34.9	36.0	20.3	42.8	31.1	15.4	6.4	–	–	–	–	14.7	16.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.7	12.0	10.5
Swan Falls	ROR	19.8	20.1	18.2	22.6	19.9	16.8	13.0	11.2	15.0	15.9	15.8	17.0	17.1
Twin Falls	ROR	35.1	36.0	22.6	45.5	32.0	20.1	10.7	–	–	–	5.9	17.8	18.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	18.0	19.1	17.6	18.0	14.1	9.0	14.5	15.0	13.6	16.5	16.2
Upper Salmon 3&4	ROR	17.7	17.7	16.6	17.7	17.7	16.2	13.3	8.9	13.6	14.0	12.9	15.3	15.1
HCC Total		**684.5**	**796.1**	**815.8**	**1,060.9**	**901.5**	**924.8**	**569.8**	**383.2**	**516.9**	**437.2**	**343.1**	**545.8**	**665.0**
ROR Total		**330.3**	**335.6**	**287.7**	**413.0**	**391.6**	**350.4**	**288.9**	**219.5**	**235.1**	**206.0**	**192.4**	**249.4**	**291.7**
Total		**1,014.8**	**1,131.7**	**1,103.5**	**1,473.9**	**1,293.1**	**1,275.2**	**858.7**	**602.7**	**752.0**	**643.2**	**535.5**	**795.2**	**956.6**

*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*	299.6	350.8	344.3	455.2	402.9	420.5	252.0	162.6	221.9	184.2	144.8	245.5	290.4
Oxbow	HCC	124.0	151.4	156.7	201.8	165.2	170.7	107.1	74.5	100.3	85.3	66.3	104.2	125.6
Hells Canyon	HCC	244.0	300.6	316.3	412.7	341.3	344.5	212.2	146.5	196.0	168.3	132.4	206.8	251.8
American Falls	ROR	24.3	24.8	25.4	59.7	85.7	94.1	86.9	66.5	42.5	13.6	–	14.5	44.8
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.4	47.6	42.5	56.0	49.2	42.4	35.7	28.5	37.5	38.3	36.8	42.6	42.0
C .J. Strike	ROR	61.7	63.3	56.7	72.5	62.8	52.6	37.2	31.8	45.0	48.6	47.7	53.5	52.8
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	33.3	33.5	28.2	39.4	35.2	29.0	23.2	16.2	23.6	24.5	22.7	29.1	28.2
Milner	ROR	36.5	36.4	22.6	45.1	35.0	18.2	6.4	–	–	–	–	23.7	18.7
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.6	12.0	10.5
Swan Falls	ROR	19.8	20.2	18.5	23.1	20.3	17.2	13.0	11.1	15.1	16.0	15.9	17.6	17.3
Twin Falls	ROR	36.9	36.3	24.3	47.8	35.3	21.8	10.7	–	–	–	5.9	25.3	20.4
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	17.7	17.7	16.8	17.7	17.7	16.2	13.3	8.9	13.6	14.0	12.8	17.2	15.3
Upper Salmon 3&4	ROR	19.1	19.1	18.2	19.0	17.6	18.7	14.2	9.0	14.5	15.0	13.6	18.7	16.4
HCC Total		**667.6**	**802.8**	**817.3**	**1,069.7**	**909.3**	**935.7**	**571.3**	**383.6**	**518.1**	**437.8**	**343.5**	**556.5**	**667.8**
ROR Total		**336.0**	**338.6**	**294.9**	**425.6**	**404.9**	**360.5**	**289.5**	**219.4**	**235.5**	**206.3**	**192.5**	**281.5**	**298.8**
Total		**1,003.6**	**1,141.4**	**1,112.2**	**1,495.3**	**1,314.2**	**1,296.2**	**860.8**	**603.0**	**753.6**	**644.1**	**536.0**	**838.0**	**966.5**

*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*	297.4	349.1	343.4	454.0	405.5	422.9	252.2	162.7	221.6	184.7	144.5	243.7	290.1
Oxbow	HCC	123.1	150.7	156.3	201.2	166.2	171.7	107.2	74.5	100.2	85.5	66.1	103.4	125.5
Hells Canyon	HCC	242.2	299.1	315.5	411.5	343.3	346.4	212.4	146.6	195.6	168.7	132.0	205.2	251.5
American Falls	ROR	24.4	25.0	22.5	60.5	86.6	95.2	87.1	66.6	42.6	13.6	–	15.9	45.0
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.9	47.7	40.5	56.2	50.1	43.4	35.7	28.6	37.5	38.3	36.3	43.2	42.0
C .J. Strike	ROR	61.4	63.1	53.9	71.3	62.9	54.4	37.3	31.9	45.0	48.7	47.1	54.3	52.6
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	
Lower Salmon	ROR	32.8	33.1	26.0	39.5	35.5	29.3	23.2	16.3	23.6	24.5	22.4	29.6	28.0
Milner	ROR	35.0	35.0	15.2	44.9	35.7	21.2	6.4	–	–	–	–	25.3	18.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.5	12.0	10.4
Swan Falls	ROR	19.6	20.2	17.7	23.1	20.4	17.7	13.0	11.2	15.1	16.0	15.6	17.8	17.3
Twin Falls	ROR	35.6	35.5	18.6	47.4	35.9	24.0	10.7	–	–	–	4.7	27.0	20.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	17.7	17.7	15.4	17.7	17.7	16.2	13.4	8.9	13.5	14.0	12.6	17.5	15.2
Upper Salmon 3&4	ROR	19.2	19.1	16.5	19.0	17.6	18.9	14.2	9.0	14.4	15.0	13.3	19.1	16.3
HCC Total		**662.7**	**798.9**	**815.2**	**1,066.7**	**915.0**	**941.0**	**571.8**	**383.8**	**517.3**	**438.9**	**342.6**	**552.3**	**667.2**
ROR Total		**331.9**	**336.1**	**268.0**	**424.9**	**408.5**	**370.6**	**289.9**	**219.9**	**235.4**	**206.4**	**188.0**	**289.0**	**285.2**
Total		**994.6**	**1,135.0**	**1,083.2**	**1,491.6**	**1,323.5**	**1,311.6**	**861.7**	**603.7**	**752.7**	**645.3**	**530.6**	**841.3**	**952.4**

*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*	297.8	338.0	343.4	454.2	405.7	422.7	252.1	162.5	221.2	184.7	144.4	243.7	289.2
Oxbow	HCC	123.3	145.9	156.3	201.2	166.4	171.6	107.1	74.4	100.0	85.4	66.1	103.4	125.1
Hells Canyon	HCC	242.6	289.7	315.5	411.7	343.5	346.2	212.3	146.4	195.3	168.6	131.9	205.3	250.7
American Falls	ROR	24.5	24.4	22.3	60.7	86.6	95.2	87.1	66.6	42.6	13.6	–	16.1	45.0
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.0	46.2	40.5	56.3	50.2	43.4	35.7	28.5	37.4	38.3	36.3	43.3	41.9
C .J. Strike	ROR	61.6	61.0	53.8	71.4	63.1	54.4	37.3	31.8	44.8	48.7	47.1	54.5	52.5
Cascade	ROR	1.5	1.4	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.9	32.2	25.9	39.6	35.6	29.3	23.2	16.2	23.5	24.5	22.4	29.7	27.9
Milner	ROR	35.3	34.3	15.2	45.0	35.8	21.2	6.4	–	–	–	–	25.6	18.2
Shoshone Falls	ROR	12.0	11.6	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.6	19.5	17.7	23.1	20.4	17.8	13.0	11.1	15.0	16.0	15.6	17.9	17.2
Twin Falls	ROR	35.8	34.7	18.6	47.5	35.9	24.0	10.7	–	–	–	5.2	27.3	20.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	18.4	16.5	19.0	17.6	18.9	14.2	9.0	14.4	14.9	13.3	19.2	16.2
Upper Salmon 3&4	ROR	17.7	17.1	15.3	17.7	17.7	16.2	13.3	8.9	13.5	14.0	12.6	17.6	15.1
HCC Total		**663.7**	**773.6**	**815.2**	**1,067.1**	**915.7**	**940.5**	**571.5**	**383.3**	**516.4**	**438.7**	**342.4**	**552.4**	**665.0**
ROR Total		**332.9**	**327.1**	**267.5**	**425.6**	**409.0**	**370.7**	**289.8**	**219.5**	**234.9**	**206.3**	**188.8**	**290.5**	**296.9**
Total		**996.6**	**1,100.6**	**1,082.7**	**1,492.7**	**1,324.6**	**1,311.2**	**861.3**	**602.8**	**751.3**	**645.0**	**531.2**	**842.9**	**961.9**

*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*	296.8	348.7	343.9	454.9	406.0	422.7	252.1	162.4	216.4	184.8	144.6	242.5	289.6
Oxbow	HCC	122.9	150.5	156.5	201.5	166.6	171.6	107.1	74.4	99.6	85.4	66.1	102.9	125.4
Hells Canyon	HCC	241.8	298.8	315.9	412.3	343.8	346.1	212.3	146.3	195.4	168.6	132.1	204.3	251.5
American Falls	ROR	24.6	25.2	22.3	60.3	86.6	95.2	87.1	66.6	42.6	13.6	–	15.9	45.0
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.7	47.6	40.4	56.3	50.4	43.3	35.7	28.5	37.3	38.2	36.1	43.0	42.0
C .J. Strike	ROR	61.2	62.9	53.5	71.5	63.3	54.5	37.3	31.8	44.7	48.6	46.9	54.1	52.5
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.6	32.9	25.7	39.7	35.8	29.3	23.2	16.2	23.4	24.4	22.3	29.5	27.9
Milner	ROR	34.4	34.5	14.2	45.2	35.7	21.1	6.4	–	–	–	–	24.8	18.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.2	12.0	10.3
Swan Falls	ROR	19.5	20.2	17.6	23.1	20.4	17.8	13.0	11.1	15.0	16.0	15.6	17.8	17.3
Twin Falls	ROR	35.1	35.1	18.1	47.7	35.9	24.0	10.7	–	–	–	4.5	26.5	19.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.1	16.3	19.0	17.6	18.9	14.2	9.0	14.3	14.9	13.3	19.0	16.2
Upper Salmon 3&4	ROR	17.7	17.7	15.1	17.7	17.7	16.2	13.3	8.9	13.4	13.9	12.6	17.4	15.1
HCC Total		**661.5**	**798.0**	**816.3**	**1,068.7**	**916.4**	**940.4**	**571.5**	**383.1**	**511.3**	**438.8**	**342.8**	**549.7**	**666.5**
ROR Total		**330.3**	**334.9**	**264.9**	**425.8**	**409.5**	**370.6**	**289.8**	**219.5**	**234.4**	**205.9**	**187.0**	**287.3**	**296.6**
Total		**991.8**	**1,132.9**	**1,081.2**	**1,494.5**	**1,325.9**	**1,311.0**	**861.3**	**602.6**	**745.6**	**644.7**	**529.8**	**837.0**	**963.2**

*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*	298.8	351.2	343.6	441.1	407.1	422.4	251.8	162.2	215.7	184.8	144.7	244.0	288.9
Oxbow	HCC	123.7	151.5	156.3	195.4	167.0	171.5	107.0	74.3	99.2	85.4	66.2	103.6	125.1
Hells Canyon	HCC	243.4	300.8	315.5	400.1	344.5	345.9	212.1	146.1	194.7	168.5	132.2	205.6	250.8
American Falls	ROR	24.6	25.7	22.7	57.8	86.7	95.2	87.1	66.5	42.5	13.6	–	16.4	44.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.2	48.1	40.8	52.7	50.4	43.3	35.6	28.4	37.2	38.1	36.2	43.6	41.8
C .J. Strike	ROR	61.3	63.4	54.4	67.1	63.1	53.6	37.2	31.7	44.5	48.5	47.0	55.3	52.3
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	33.0	33.4	26.3	36.5	35.8	29.3	23.1	16.1	23.3	24.3	22.4	30.0	27.8
Milner	ROR	35.7	36.5	16.0	42.0	35.6	21.3	6.4	–	–	–	–	26.4	18.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.4	12.0	10.4
Swan Falls	ROR	19.7	20.3	17.9	21.6	20.4	17.5	13.0	11.1	14.9	15.9	15.6	18.1	17.2
Twin Falls	ROR	36.2	36.7	19.3	41.1	35.8	24.1	10.7	–	–	–	5.7	28.0	19.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.1	16.8	19.1	17.6	18.9	14.1	8.9	14.2	14.8	13.4	19.2	16.3
Upper Salmon 3&4	ROR	17.7	17.7	15.6	17.7	17.7	16.2	13.3	8.8	13.3	13.9	12.6	17.7	15.2
HCC Total		**665.9**	**803.5**	**815.4**	**1,036.6**	**918.5**	**939.8**	**570.9**	**382.6**	**509.5**	**438.7**	**343.1**	**553.2**	**664.8**
ROR Total		**333.9**	**340.6**	**271.5**	**400.9**	**409.2**	**369.7**	**289.4**	**218.9**	**233.6**	**205.4**	**189.8**	**294.0**	**296.4**
Total		**999.8**	**1,144.1**	**1,086.9**	**1,437.5**	**1,327.8**	**1,309.5**	**860.3**	**601.5**	**743.1**	**644.1**	**532.9**	**847.2**	**961.2**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2023**	**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*	298.6	350.6	343.4	440.8	407.4	422.0	251.5	161.8	214.7	184.8	144.6	243.7	288.7
Oxbow	HCC	123.6	151.3	156.2	195.3	167.1	171.3	106.9	74.1	98.7	85.4	66.1	103.5	125.0
Hells Canyon	HCC	243.2	300.4	315.3	399.7	344.8	345.7	211.8	145.8	193.7	168.5	132.1	205.3	250.5
American Falls	ROR	24.6	25.7	22.7	57.9	86.7	95.2	87.1	66.5	42.5	13.6	–	16.4	44.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.2	48.0	40.8	52.7	50.4	43.2	35.5	28.3	37.0	38.0	36.2	43.5	41.7
C .J. Strike	ROR	61.3	63.4	54.3	67.1	63.1	53.4	37.1	31.5	44.3	48.3	46.8	55.1	52.1
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	33.0	33.4	26.3	36.5	35.8	29.2	23.0	16.0	23.1	24.2	22.4	29.9	27.7
Milner	ROR	35.8	36.4	15.9	42.3	35.6	21.2	6.4	–	–	–	–	26.4	18.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.4	12.0	10.4
Swan Falls	ROR	19.7	20.3	17.8	21.6	20.4	17.5	13.0	11.1	14.9	15.9	15.6	18.1	17.2
Twin Falls	ROR	36.2	36.7	19.3	41.2	35.7	24.0	10.7	–	–	–	5.7	27.9	19.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.1	16.7	19.1	17.6	18.9	14.1	8.8	14.1	14.7	13.3	19.2	16.2
Upper Salmon 3&4	ROR	17.7	17.7	15.5	17.7	17.7	16.2	13.2	8.8	13.2	13.8	12.6	17.7	15.2
HCC Total		665.4	802.3	814.9	1,035.8	919.3	939.0	570.2	381.7	507.1	438.7	342.8	552.5	664.1
ROR Total		334.0	340.4	271.0	401.4	409.1	369.1	289.0	218.4	232.8	204.8	189.5	293.5	296.1
Total		999.4	1,142.7	1,085.9	1,437.2	1,328.4	1,308.1	859.2	600.1	739.8	643.5	532.3	846.0	960.2

*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*	298.3	337.4	343.1	440.6	407.3	421.5	251.2	161.4	213.2	184.9	144.6	243.8	287.3
Oxbow	HCC	123.5	145.6	156.0	195.2	167.1	171.1	106.7	73.9	97.9	85.3	66.1	103.5	124.3
Hells Canyon	HCC	243.0	289.1	315.0	399.6	344.7	345.2	211.5	145.4	192.1	168.3	131.9	205.4	249.3
American Falls	ROR	24.6	24.4	22.7	57.5	86.6	95.0	87.0	66.5	42.4	13.6	–	16.2	44.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.1	46.3	40.7	52.6	50.4	43.0	35.5	28.2	36.9	37.9	36.1	43.4	41.5
C .J. Strike	ROR	61.2	61.1	54.2	67.1	63.2	53.2	37.0	31.4	44.1	48.2	46.7	54.7	51.8
Cascade	ROR	1.5	1.4	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.9	32.2	26.2	36.4	35.8	29.1	23.0	15.9	23.0	24.1	22.3	29.8	27.6
Milner	ROR	35.7	34.7	15.8	42.5	35.4	21.0	6.4	–	–	–	–	26.0	18.1
Shoshone Falls	ROR	12.0	11.6	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.9	12.0	10.4
Swan Falls	ROR	19.7	19.6	17.8	21.6	20.4	17.4	12.9	11.0	14.8	15.8	15.6	17.9	17.0
Twin Falls	ROR	36.2	35.0	19.2	41.3	35.6	23.8	10.7	–	–	–	5.3	27.5	19.5
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	18.4	16.7	19.1	17.6	18.8	14.0	8.8	14.0	14.6	13.3	19.2	16.1
Upper Salmon 3&4	ROR	17.7	17.1	15.5	17.7	17.7	16.2	13.2	8.7	13.1	13.7	12.6	17.7	15.1
HCC Total		**664.8**	**772.0**	**814.1**	**1,035.4**	**919.2**	**937.8**	**569.4**	**380.7**	**503.1**	**438.5**	**342.6**	**552.7**	**660.9**
ROR Total		**333.6**	**328.0**	**270.5**	**401.1**	**408.8**	**367.8**	**288.6**	**217.9**	**232.0**	**204.2**	**188.3**	**291.7**	**294.4**
Total		**998.4**	**1,100.1**	**1,084.6**	**1,436.5**	**1,328.0**	**1,305.6**	**858.0**	**598.6**	**735.1**	**642.7**	**530.9**	**844.4**	**955.2**

*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*	297.9	348.8	342.7	440.5	407.0	420.8	250.8	161.0	211.9	184.8	144.9	243.5	287.9
Oxbow	HCC	123.3	150.5	155.9	195.2	166.9	170.8	106.6	73.7	97.2	85.1	66.2	103.4	124.6
Hells Canyon	HCC	242.7	298.9	314.7	399.6	344.5	344.7	211.2	145.1	190.8	168.1	132.2	205.1	249.8
American Falls	ROR	24.6	25.2	22.6	56.7	86.6	94.8	86.9	66.4	42.3	13.5	–	15.8	44.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	47.0	47.6	40.6	52.5	50.3	42.8	35.4	28.1	36.7	37.8	36.1	43.1	41.5
C .J. Strike	ROR	61.0	63.2	54.1	67.0	63.1	53.0	36.8	31.2	43.9	47.8	46.5	54.3	51.8
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.6	33.0	26.0	36.3	35.7	29.0	22.9	15.8	22.8	24.0	22.2	29.6	27.5
Milner	ROR	35.7	35.8	15.7	42.5	35.2	20.7	6.4	–	–	–	–	25.3	18.1
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.6	20.3	17.8	21.6	20.4	17.3	12.9	11.0	14.7	15.8	15.5	17.8	17.1
Twin Falls	ROR	36.2	36.2	19.1	41.4	35.4	23.6	10.7	–	–	–	5.2	27.0	19.6
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.1	16.6	19.1	17.6	18.7	13.9	8.7	13.8	14.5	13.2	19.1	16.1
Upper Salmon 3&4	ROR	17.7	17.7	15.4	17.7	17.7	16.2	13.1	8.6	13.0	13.6	12.5	17.5	15.1
HCC Total		**663.9**	**798.2**	**813.3**	**1,035.3**	**918.3**	**936.3**	**568.6**	**379.8**	**499.9**	**438.0**	**343.3**	**552.0**	**662.2**
ROR Total		**332.9**	**337.8**	**269.6**	**400.1**	**408.1**	**366.4**	**287.9**	**217.2**	**230.9**	**203.3**	**187.5**	**288.8**	**294.2**
Total		**996.8**	**1,136.0**	**1,082.9**	**1,435.4**	**1,326.4**	**1,302.7**	**856.5**	**597.0**	**730.8**	**641.3**	**530.8**	**840.8**	**956.4**

*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*	297.3	348.2	342.3	440.0	407.1	420.1	250.4	160.6	210.0	185.1	145.0	243.4	287.5
Oxbow	HCC	123.1	150.3	155.7	195.0	166.9	170.5	106.4	73.5	96.2	85.2	66.2	103.3	124.4
Hells Canyon	HCC	242.2	298.4	314.4	399.1	344.6	344.2	210.9	144.7	188.8	168.1	132.2	205.0	249.4
American Falls	ROR	23.9	25.2	22.5	56.7	86.5	94.7	86.9	66.4	42.3	13.5	–	15.3	44.5
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.9	47.1	40.4	52.4	50.3	42.5	35.3	27.9	36.5	37.6	36.0	42.7	41.3
C .J. Strike	ROR	60.8	62.9	53.8	66.3	63.1	52.7	36.7	31.1	43.6	47.6	46.3	53.9	51.6
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.3	32.9	25.9	36.2	35.7	28.9	22.8	15.7	22.7	23.8	22.2	29.2	27.4
Milner	ROR	34.9	35.8	15.6	42.5	35.0	20.4	6.4	–	–	–	–	24.5	17.9
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.6	20.1	17.7	21.4	20.4	17.3	12.8	10.9	14.7	15.7	15.4	17.7	17.0
Twin Falls	ROR	35.1	36.2	18.9	41.4	35.2	23.3	10.7	–	–	–	5.2	26.0	19.3
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.1	16.5	19.1	17.6	18.6	13.9	8.6	13.7	14.4	13.2	18.8	16.1
Upper Salmon 3&4	ROR	17.7	17.7	15.3	17.7	17.7	16.2	13.1	8.6	12.9	13.5	12.5	17.3	15.0
HCC Total		**662.6**	**796.9**	**812.4**	**1,034.1**	**918.7**	**934.8**	**567.7**	**378.8**	**494.9**	**438.4**	**343.4**	**551.7**	**661.2**
ROR Total		**329.7**	**336.7**	**268.3**	**399.0**	**407.6**	**364.9**	**287.5**	**216.6**	**230.1**	**202.4**	**187.1**	**284.7**	**292.9**
Total		**992.3**	**1,133.6**	**1,080.7**	**1,433.1**	**1,326.3**	**1,299.7**	**855.2**	**595.4**	**724.9**	**640.8**	**530.5**	**836.4**	**954.1**

*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*	296.7	347.4	342.1	439.9	407.3	419.6	249.9	160.1	208.6	185.1	145.4	241.7	287.0
Oxbow	HCC	122.8	149.9	155.6	194.8	167.0	170.3	106.2	73.3	95.4	85.0	66.4	102.6	124.1
Hells Canyon	HCC	241.7	297.7	314.1	398.9	344.7	343.8	210.5	144.3	187.4	167.8	132.5	203.6	248.9
American Falls	ROR	23.6	25.1	22.1	56.6	86.4	94.6	86.9	66.3	42.2	13.5	–	14.8	44.3
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.7	47.0	40.2	52.3	50.2	42.3	35.2	27.8	36.3	37.5	35.9	42.4	41.2
C .J. Strike	ROR	60.6	62.1	53.5	66.1	63.1	52.3	36.5	30.9	43.3	47.4	46.2	53.5	51.3
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.2	32.8	25.8	36.1	35.6	28.6	22.7	15.5	22.5	23.7	22.1	28.7	27.2
Milner	ROR	34.5	35.7	15.4	42.5	34.7	20.1	6.4	–	–	–	–	23.0	17.7
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.5	20.0	17.6	21.3	20.4	17.2	12.8	10.8	14.6	15.7	15.4	17.6	16.9
Twin Falls	ROR	34.6	36.1	18.8	41.3	35.0	23.7	10.7	–	–	–	5.2	24.7	19.2
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	16.4	19.1	17.6	18.4	13.8	8.5	13.6	14.3	13.1	18.3	16.0
Upper Salmon 3&4	ROR	17.7	17.7	15.2	17.7	17.7	16.2	13.0	8.5	12.8	13.5	12.4	16.9	14.9
HCC Total		**661.2**	**795.0**	**811.8**	**1,033.6**	**918.9**	**933.7**	**566.6**	**377.7**	**491.4**	**437.9**	**344.3**	**547.9**	**660.0**
ROR Total		**327.9**	**335.4**	**266.7**	**398.3**	**406.8**	**363.7**	**286.9**	**215.7**	**229.0**	**201.9**	**186.6**	**279.2**	**291.5**
Total		**989.1**	**1,130.4**	**1,078.5**	**1,431.9**	**1,325.7**	**1,297.4**	**853.5**	**593.4**	**720.3**	**639.8**	**530.9**	**827.1**	**951.5**

*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*	296.0	334.6	341.9	439.6	407.7	418.8	249.4	159.6	207.2	184.9	145.2	240.4	285.4
Oxbow	HCC	122.6	144.3	155.4	194.6	167.1	170.0	106.0	73.1	94.7	84.9	66.2	102.0	123.4
Hells Canyon	HCC	241.2	286.7	313.8	398.4	345.1	343.2	210.1	143.8	185.9	167.5	132.3	202.5	247.5
American Falls	ROR	23.3	24.1	21.7	56.6	86.3	94.5	86.9	66.3	42.1	13.5	–	14.2	44.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.6	45.2	39.7	52.2	50.1	42.1	35.0	27.7	36.1	37.3	35.8	41.9	40.8
C .J. Strike	ROR	60.4	59.8	53.3	65.9	63.0	52.0	36.4	30.7	43.0	47.2	46.1	53.1	50.9
Cascade	ROR	1.5	1.4	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	32.1	31.3	25.4	36.0	35.5	28.5	22.6	15.4	22.3	23.5	22.0	28.1	26.9
Milner	ROR	34.0	34.3	15.0	42.5	34.5	19.3	6.4	–	–	–	–	21.5	17.3
Shoshone Falls	ROR	12.0	11.6	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.5	19.2	17.5	21.3	20.4	17.1	12.8	10.8	14.5	15.6	15.3	17.5	16.8
Twin Falls	ROR	34.3	34.8	18.2	41.3	34.8	23.5	10.7	–	–	–	5.2	23.3	18.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	18.5	16.1	19.1	17.6	18.3	13.7	8.4	13.5	14.2	13.1	17.8	15.8
Upper Salmon 3&4	ROR	17.7	17.1	14.9	17.7	17.7	16.2	12.9	8.4	12.7	13.4	12.4	16.5	14.8
HCC Total		**659.8**	**765.6**	**811.1**	**1,032.6**	**919.9**	**932.0**	**565.5**	**376.5**	**487.8**	**437.3**	**343.7**	**544.9**	**656.4**
ROR Total		**326.4**	**323.5**	**263.5**	**397.9**	**406.0**	**361.8**	**286.3**	**215.1**	**227.9**	**201.0**	**186.2**	**273.2**	**289.1**
Total		**986.2**	**1,089.1**	**1,074.6**	**1,430.5**	**1,325.9**	**1,293.8**	**851.8**	**591.6**	**715.6**	**638.3**	**529.9**	**818.1**	**945.4**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	295.5	344.4	341.4	440.0	411.9	417.9	249.0	159.2	205.8	185.0	145.0	238.8	286.2
Oxbow	HCC	122.3	148.5	154.7	193.8	168.8	169.7	105.8	72.8	93.9	84.9	66.1	101.3	123.5
Hells Canyon	HCC	240.8	294.9	312.5	396.9	348.2	342.5	209.7	143.4	184.5	167.5	132.0	201.1	247.8
American Falls	ROR	22.9	24.9	21.3	56.4	86.3	94.5	86.8	66.1	42.0	13.4	–	13.7	44.0
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.4	46.7	39.2	52.0	50.0	42.0	34.9	27.5	35.9	37.2	35.5	41.1	40.7
C .J. Strike	ROR	60.2	61.7	53.1	65.7	63.0	51.6	36.2	30.5	42.7	47.0	46.0	52.6	50.9
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.9	32.3	25.0	35.9	35.4	28.3	22.5	15.3	22.2	23.4	21.9	27.4	26.8
Milner	ROR	33.5	35.4	14.4	42.4	34.2	19.0	6.4	–	–	–	–	19.3	17.1
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.8	12.0	10.4
Swan Falls	ROR	19.4	19.9	17.3	21.2	20.4	17.0	12.7	10.7	14.4	15.5	15.3	17.4	16.8
Twin Falls	ROR	34.0	35.9	17.6	41.2	34.6	23.3	10.7	–	–	–	5.2	21.7	18.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.8	19.1	17.6	18.1	13.6	8.3	13.3	14.1	12.9	17.3	15.7
Upper Salmon 3&4	ROR	17.7	17.7	14.7	17.7	17.7	16.2	12.8	8.3	12.6	13.3	12.3	16.0	14.8
HCC Total		**658.6**	**787.8**	**808.6**	**1,030.7**	**928.8**	**930.1**	**564.5**	**375.4**	**484.1**	**437.4**	**343.1**	**541.2**	**657.5**
ROR Total		**324.5**	**333.4**	**260.1**	**396.9**	**405.3**	**360.3**	**285.5**	**214.1**	**226.8**	**200.2**	**185.4**	**265.8**	**288.2**
Total		**983.1**	**1,121.2**	**1,068.7**	**1,427.6**	**1,334.1**	**1,290.4**	**850.0**	**589.5**	**710.9**	**637.6**	**528.5**	**807.0**	**945.7**

*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*	295.1	343.8	341.0	439.6	411.7	417.0	248.5	158.7	204.2	185.5	144.7	238.5	285.7
Oxbow	HCC	122.2	148.2	154.6	193.7	168.7	169.3	105.6	72.6	93.2	85.0	66.0	101.2	123.4
Hells Canyon	HCC	240.5	294.4	312.1	396.5	348.1	341.8	209.3	143.0	182.8	167.7	131.8	200.9	247.4
American Falls	ROR	22.7	24.8	21.1	56.3	86.2	94.5	86.9	66.0	41.9	13.4	–	13.0	43.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.2	46.5	38.9	51.4	49.9	41.8	34.8	27.4	35.8	37.0	35.3	40.3	40.4
C .J. Strike	ROR	59.9	61.5	52.8	65.5	62.9	51.3	36.0	30.3	42.5	46.8	45.6	51.7	50.6
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.8	32.1	24.9	35.8	35.3	28.1	22.3	15.2	22.0	23.3	21.5	26.6	26.6
Milner	ROR	33.2	35.3	14.1	42.2	33.9	18.7	6.4	–	–	–	–	17.3	16.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	8.5	12.0	10.4
Swan Falls	ROR	19.3	19.8	17.2	21.2	20.3	16.9	12.7	10.7	14.3	15.5	15.4	17.1	16.7
Twin Falls	ROR	33.9	35.8	17.5	41.1	34.3	23.1	10.7	–	–	–	4.8	19.9	18.4
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.7	19.1	17.6	18.0	13.5	8.2	13.2	14.0	12.6	16.7	15.6
Upper Salmon 3&4	ROR	17.7	17.7	14.6	17.7	17.7	16.2	12.8	8.2	12.5	13.2	12.0	15.5	14.7
HCC Total		**657.8**	**786.4**	**807.7**	**1,029.8**	**928.4**	**928.1**	**563.4**	**374.3**	**480.1**	**438.2**	**342.5**	**540.6**	**656.4**
ROR Total		**323.2**	**332.4**	**258.5**	**395.6**	**404.2**	**358.9**	**285.0**	**213.4**	**225.9**	**199.5**	**183.2**	**257.4**	**286.4**
Total		**981.0**	**1,118.8**	**1,066.2**	**1,425.4**	**1,332.6**	**1,287.0**	**848.4**	**587.7**	**706.0**	**637.7**	**525.7**	**798.0**	**942.9**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	294.7	343.1	342.7	439.2	411.3	415.6	248.0	158.2	202.5	185.4	144.8	238.2	285.3
Oxbow	HCC	122.0	147.9	155.3	193.5	168.5	168.8	105.4	72.4	92.2	84.8	66.0	101.0	123.2
Hells Canyon	HCC	240.1	293.8	313.6	396.2	347.8	340.7	208.9	142.5	181.1	167.4	131.7	200.6	247.0
American Falls	ROR	22.6	24.7	21.0	56.2	86.1	94.3	86.8	66.0	41.8	13.4	–	11.7	43.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	46.0	46.4	38.7	51.0	49.8	41.8	34.7	27.2	35.6	36.9	35.1	39.3	40.2
C .J. Strike	ROR	59.7	61.3	52.3	65.3	62.8	51.0	35.9	30.2	42.2	46.5	45.0	50.4	50.2
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.6	32.0	24.9	35.4	35.2	27.9	22.2	15.0	21.8	23.1	21.5	25.7	26.4
Milner	ROR	33.0	35.1	14.0	40.4	33.6	18.4	6.4	–	–	–	–	14.9	16.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.5	12.0	10.5
Swan Falls	ROR	19.3	19.7	17.2	21.1	20.3	16.8	12.7	10.6	14.3	15.4	15.2	16.7	16.6
Twin Falls	ROR	33.8	35.7	17.3	39.6	34.0	22.9	10.7	–	–	–	5.8	17.8	18.1
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.6	19.1	17.6	17.8	13.5	8.1	13.1	13.9	12.7	16.0	15.5
Upper Salmon 3&4	ROR	17.7	17.7	14.6	17.7	17.7	16.2	12.7	8.2	12.4	13.1	12.0	14.9	14.6
HCC Total		**656.8**	**784.8**	**811.6**	**1,028.9**	**927.5**	**925.1**	**562.3**	**373.1**	**475.8**	**437.6**	**342.5**	**539.8**	**655.5**
ROR Total		**322.2**	**331.5**	**257.3**	**391.1**	**403.2**	**357.4**	**284.5**	**212.7**	**224.9**	**198.6**	**184.3**	**246.7**	**284.5**
Total		**979.0**	**1,116.3**	**1,068.9**	**1,420.0**	**1,330.7**	**1,282.5**	**846.8**	**585.8**	**700.7**	**636.2**	**526.8**	**786.5**	**940.0**

*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*	294.3	330.5	342.3	438.7	410.9	414.5	247.5	157.6	200.5	185.9	145.2	236.8	283.7
Oxbow	HCC	121.9	142.5	155.1	193.3	168.4	168.3	105.2	72.1	91.2	84.9	66.1	100.4	122.4
Hells Canyon	HCC	239.8	283.1	313.2	395.8	347.5	339.8	208.5	142.0	179.1	167.6	132.0	199.4	245.6
American Falls	ROR	22.5	23.8	20.8	56.0	86.0	94.2	86.8	65.9	41.7	13.5	–	10.5	43.5
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	45.9	44.6	38.6	50.9	49.7	41.8	34.5	27.1	35.4	36.8	34.9	38.4	39.9
C .J. Strike	ROR	59.4	58.9	51.8	65.0	62.8	50.7	35.7	30.0	42.0	46.3	44.9	49.2	49.7
Cascade	ROR	1.5	1.4	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.5	30.7	24.7	35.2	35.1	27.7	22.1	14.9	21.6	23.0	21.3	24.9	26.1
Milner	ROR	32.8	33.7	13.9	39.3	33.3	18.2	6.4	–	–	–	–	12.6	15.8
Shoshone Falls	ROR	12.0	11.6	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.5	12.0	10.4
Swan Falls	ROR	19.2	19.0	17.1	21.1	20.3	16.7	12.6	10.5	14.2	15.4	15.2	16.2	16.5
Twin Falls	ROR	33.7	34.3	17.1	38.5	33.8	22.5	10.7	–	–	–	5.8	15.9	17.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	18.5	15.5	19.1	17.6	17.7	13.4	8.0	12.9	13.8	12.5	15.4	15.3
Upper Salmon 3&4	ROR	17.7	17.1	14.5	17.7	17.7	16.2	12.6	8.1	12.3	13.0	11.9	14.4	14.4
HCC Total		**656.0**	**756.1**	**810.6**	**1,027.8**	**926.7**	**922.6**	**561.2**	**371.7**	**470.8**	**438.4**	**343.3**	**536.6**	**651.8**
ROR Total		**321.2**	**319.8**	**255.7**	**388.1**	**402.4**	**356.0**	**283.7**	**211.9**	**223.8**	**198.1**	**183.5**	**236.8**	**281.7**
Total		**977.2**	**1,075.9**	**1,066.3**	**1,415.9**	**1,329.1**	**1,278.6**	**844.9**	**583.6**	**694.6**	**636.5**	**526.8**	**773.4**	**933.6**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	293.9	341.6	341.7	438.3	410.4	413.7	247.0	157.1	199.1	186.1	145.0	235.6	284.1
Oxbow	HCC	121.7	147.3	154.9	193.1	168.2	168.0	105.0	71.9	90.5	84.9	66.0	99.9	122.6
Hells Canyon	HCC	239.5	292.6	312.8	395.4	347.1	339.2	208.1	141.6	177.7	167.6	131.8	198.4	246.0
American Falls	ROR	22.3	24.5	20.7	54.1	85.9	94.0	86.7	65.8	41.6	13.2	–	9.1	43.2
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	45.7	46.0	38.5	50.7	49.6	41.8	34.4	26.9	35.2	36.6	34.8	37.4	39.8
C .J. Strike	ROR	59.1	60.1	51.4	64.1	62.7	50.4	35.5	29.8	41.7	46.1	44.8	47.8	49.5
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.4	31.7	24.5	35.1	35.0	27.5	22.0	14.8	21.5	22.8	21.2	24.0	26.0
Milner	ROR	32.7	34.8	13.5	39.1	32.9	17.7	6.4	–	–	–	–	10.8	15.7
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.5	12.0	10.5
Swan Falls	ROR	19.1	19.4	16.9	20.8	20.3	16.4	12.5	10.5	14.1	15.3	15.2	15.8	16.4
Twin Falls	ROR	33.6	35.4	16.9	38.4	33.5	21.4	10.7	–	–	–	5.8	13.7	17.5
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.4	19.1	17.6	17.5	13.3	7.9	12.8	13.6	12.4	14.7	15.2
Upper Salmon 3&4	ROR	17.7	17.7	14.4	17.7	17.7	16.2	12.6	8.0	12.1	12.9	11.8	13.8	14.4
HCC Total		**655.1**	**781.5**	**809.4**	**1,026.8**	**925.6**	**920.9**	**560.1**	**370.6**	**467.2**	**438.6**	**342.8**	**533.9**	**652.7**
ROR Total		**320.1**	**328.5**	**253.9**	**384.4**	**401.3**	**353.2**	**283.0**	**211.1**	**222.7**	**196.8**	**183.0**	**226.4**	**280.4**
Total		**975.2**	**1,110.0**	**1,063.3**	**1,411.2**	**1,326.9**	**1,274.1**	**843.1**	**581.7**	**689.9**	**635.4**	**525.8**	**760.3**	**933.1**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	293.2	340.9	341.1	437.8	409.9	412.8	246.5	156.6	197.2	186.7	145.1	234.4	283.5
Oxbow	HCC	121.4	147.0	154.6	192.9	168.0	167.7	104.8	71.6	89.4	85.0	66.0	99.4	122.3
Hells Canyon	HCC	239.0	292.0	312.2	395.0	346.7	338.5	207.7	141.2	175.7	167.8	131.8	197.4	245.4
American Falls	ROR	22.2	24.4	20.5	53.8	85.7	93.8	86.7	65.7	41.5	13.2	–	7.7	42.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	45.5	45.8	38.4	50.5	49.5	41.8	34.3	26.8	35.0	36.4	34.6	36.6	39.6
C .J. Strike	ROR	58.9	59.9	51.1	63.2	62.6	50.1	35.4	29.6	41.5	45.8	44.6	46.9	49.1
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.3	31.5	24.3	35.0	34.9	27.3	21.9	14.7	21.3	22.6	21.2	23.7	25.8
Milner	ROR	32.6	34.6	13.3	38.9	32.6	17.2	6.4	–	–	–	–	8.7	15.4
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.4	12.0	10.4
Swan Falls	ROR	19.0	19.4	16.8	20.3	20.3	16.4	12.5	10.4	14.1	15.2	15.1	15.6	16.3
Twin Falls	ROR	33.5	35.2	16.4	38.2	33.4	21.3	10.7	–	–	–	5.7	11.6	17.2
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.2	19.1	17.6	17.4	13.2	7.8	12.7	13.5	12.4	14.5	15.2
Upper Salmon 3&4	ROR	17.7	17.7	14.2	17.7	17.7	16.1	12.5	7.9	12.0	12.8	11.8	13.6	14.3
HCC Total		**653.6**	**779.9**	**807.9**	**1,025.7**	**924.5**	**919.0**	**559.0**	**369.4**	**462.3**	**439.5**	**342.9**	**531.2**	**651.2**
ROR Total		**319.2**	**327.4**	**251.9**	**382.0**	**400.4**	**351.7**	**282.5**	**210.3**	**221.8**	**195.8**	**182.3**	**218.2**	**278.6**
Total		**972.8**	**1,107.3**	**1,059.8**	**1,407.7**	**1,324.9**	**1,270.7**	**841.5**	**579.7**	**684.1**	**635.3**	**525.2**	**749.4**	**929.9**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2035**	**2/2035**	**3/2035**	**4/2035**	**5/2035**	**6/2035**	**7/2035**	**8/2035**	**9/2035**	**10/2035**	**11/2035**	**12/2035**	**aMW**
Brownlee	HCC*	292.4	340.1	340.4	437.2	408.0	411.9	246.1	156.2	195.0	187.0	145.7	233.2	282.8
Oxbow	HCC	121.1	146.7	154.3	192.6	167.2	167.3	104.6	71.4	88.3	85.0	66.2	98.9	122.0
Hells Canyon	HCC	238.3	291.4	311.6	394.4	345.1	337.9	207.3	140.7	173.5	167.8	132.2	196.4	244.7
American Falls	ROR	22.0	24.2	20.0	53.7	85.6	93.6	86.7	65.7	41.4	13.2	–	6.2	42.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	45.3	45.6	38.0	49.8	49.4	41.6	34.2	26.6	34.8	36.1	34.4	36.3	39.3
C .J. Strike	ROR	58.6	59.6	50.8	62.6	62.5	49.8	35.2	29.4	41.3	45.6	44.1	46.3	48.8
Cascade	ROR	1.5	1.5	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.2	31.3	24.1	34.7	34.8	27.3	21.8	14.5	21.1	22.5	21.1	23.7	25.7
Milner	ROR	32.5	34.4	12.8	37.7	32.3	16.8	6.4	–	–	–	–	6.5	15.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.4	12.0	10.4
Swan Falls	ROR	18.9	19.3	16.5	20.1	20.2	16.3	12.4	10.4	14.1	15.4	15.1	15.6	16.2
Twin Falls	ROR	33.4	35.0	15.7	37.2	33.2	21.1	10.7	–	–	–	5.7	10.4	16.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	19.2	15.1	19.1	17.6	17.3	13.1	7.7	12.5	13.4	12.3	14.5	15.1
Upper Salmon 3&4	ROR	17.7	17.7	14.1	17.7	17.7	16.0	12.4	7.8	11.9	12.7	11.7	13.6	14.3
HCC Total		**651.8**	**778.2**	**806.3**	**1,024.2**	**920.2**	**917.1**	**558.0**	**368.3**	**456.7**	**439.8**	**344.1**	**528.5**	**649.4**
ROR Total		**318.1**	**326.0**	**248.8**	**377.9**	**399.4**	**350.1**	**281.8**	**209.5**	**220.8**	**195.2**	**181.3**	**212.4**	**276.8**
Total		**969.9**	**1,104.2**	**1,055.1**	**1,402.1**	**1,319.6**	**1,267.2**	**839.8**	**577.8**	**677.5**	**635.0**	**525.4**	**740.9**	**926.2**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2036**	**2/2036**	**3/2036**	**4/2036**	**5/2036**	**6/2036**	**7/2036**	**8/2036**	**9/2036**	**10/2036**	**11/2036**	**12/2036**	**aMW**
Brownlee	HCC*	291.5	326.6	339.6	437.1	407.1	411.0	245.6	155.6	193.9	187.2	145.7	233.2	281.2
Oxbow	HCC	120.7	140.9	153.8	192.3	166.8	167.0	104.3	71.2	87.7	85.0	66.2	98.9	121.2
Hells Canyon	HCC	237.6	279.8	310.7	393.8	344.4	337.2	206.9	140.2	172.3	167.7	132.1	196.4	243.3
American Falls	ROR	21.7	23.3	19.8	53.5	84.4	93.3	86.7	65.7	41.3	13.1	–	–	41.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	45.1	43.9	37.8	49.6	49.2	41.1	34.0	26.5	34.6	35.9	34.3	36.3	39.0
C .J. Strike	ROR	58.3	57.2	50.5	62.3	62.4	49.5	35.1	29.2	41.1	45.4	44.0	46.1	48.4
Cascade	ROR	1.5	1.4	2.5	5.9	5.4	11.6	10.4	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	31.0	30.1	23.9	34.4	33.9	26.9	21.7	14.4	20.9	22.3	20.8	23.7	25.3
Milner	ROR	32.1	33.0	12.3	36.9	30.3	16.5	6.4	–	–	–	–	6.1	14.5
Shoshone Falls	ROR	12.0	11.6	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	9.4	12.0	10.4
Swan Falls	ROR	18.9	18.4	16.4	20.1	20.2	16.2	12.4	10.3	14.0	15.3	15.1	15.6	16.1
Twin Falls	ROR	33.1	33.7	15.3	36.4	31.6	20.5	10.7	–	–	–	5.7	10.4	16.4
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	19.2	18.5	14.9	19.1	17.6	17.0	13.0	7.6	12.4	13.3	12.1	14.5	14.9
Upper Salmon 3&4	ROR	17.7	17.1	14.0	17.7	17.7	15.8	12.3	7.7	11.8	12.6	11.6	13.6	14.1
HCC Total		**649.8**	**747.3**	**804.1**	**1,023.2**	**918.2**	**915.2**	**556.8**	**367.0**	**453.9**	**439.9**	**344.0**	**528.5**	**645.7**
ROR Total		**316.4**	**314.5**	**246.6**	**375.3**	**393.4**	**347.1**	**281.2**	**208.8**	**219.8**	**194.2**	**180.5**	**205.6**	**273.6**
Total		**966.2**	**1,061.8**	**1,050.7**	**1,398.5**	**1,311.6**	**1,262.3**	**838.0**	**575.8**	**673.6**	**634.1**	**524.5**	**734.1**	**919.3**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	257.2	286.1	251.4	319.5	385.2	258.9	237.4	155.6	175.9	190.1	148.0	200.6	238.8
Oxbow	HCC	108.9	121.3	111.6	135.3	159.8	108.8	100.5	71.1	80.0	84.7	66.4	84.6	102.7
Hells Canyon	HCC	215.6	239.8	227.7	274.0	324.5	223.1	198.2	139.8	156.9	167.0	132.2	167.8	205.5
American Falls	ROR	–	5.5	11.2	38.4	73.8	90.9	87.2	63.0	35.9	10.3	–	–	34.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.4	37.4	35.9	38.5	41.5	38.9	35.0	27.9	36.7	37.3	35.2	35.4	36.3
C .J. Strike	ROR	47.4	49.4	47.7	51.6	49.1	44.7	35.6	30.8	43.6	47.0	45.4	45.4	44.8
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.8	23.0	21.9	24.5	27.8	27.0	22.6	15.8	23.1	23.8	22.2	22.2	23.1
Milner	ROR	4.8	6.1	3.6	11.4	14.4	14.7	6.4	–	–	–	–	1.8	5.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	7.3	9.9	10.1
Swan Falls	ROR	15.5	16.0	15.8	17.1	16.2	15.1	12.6	10.8	14.7	15.6	15.3	15.3	15.0
Twin Falls	ROR	8.9	9.8	8.1	14.3	17.8	18.2	10.7	–	–	–	3.8	6.2	8.2
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.8	14.1	13.4	15.4	17.7	17.1	13.8	8.7	14.1	14.4	13.2	13.3	14.1
Upper Salmon 3&4	ROR	13.0	13.3	12.6	14.4	16.6	15.8	13.0	8.6	13.2	13.6	12.5	12.6	13.3
HCC Total		**581.7**	**647.2**	**590.7**	**728.8**	**869.5**	**590.8**	**536.1**	**366.5**	**412.7**	**441.8**	**346.6**	**453.0**	**547.1**
ROR Total		**201.9**	**214.2**	**210.7**	**266.2**	**317.7**	**328.2**	**282.8**	**211.7**	**223.5**	**197.9**	**182.3**	**189.4**	**235.5**
Total		**783.6**	**861.4**	**801.4**	**995.0**	**1,187.2**	**919.0**	**818.9**	**578.2**	**636.2**	**639.7**	**528.9**	**642.4**	**782.7**

*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*	249.6	296.3	252.8	324.7	384.9	264.9	237.0	155.1	176.1	189.9	147.7	205.0	289.5
Oxbow	HCC	106.1	125.6	112.3	137.6	159.8	111.4	100.4	70.9	80.0	84.7	66.3	86.4	125.0
Hells Canyon	HCC	210.2	248.2	229.0	278.4	324.4	228.0	197.9	139.3	157.0	166.9	132.0	171.4	250.5
American Falls	ROR	–	11.0	13.9	40.8	73.8	91.4	87.2	63.7	36.3	10.3	–	–	43.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.4	38.6	36.7	41.6	42.0	39.1	35.1	27.9	36.8	37.3	35.3	35.3	41.6
C .J. Strike	ROR	47.5	50.3	48.2	52.8	49.5	45.2	35.7	31.0	43.6	47.1	45.2	45.5	52.0
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	5.5
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.8	25.3	22.6	25.6	28.2	27.2	22.7	15.8	23.1	23.9	22.1	22.2	27.6
Milner	ROR	4.3	13.3	5.0	13.6	15.4	15.4	6.4	–	–	–	–	–	16.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	6.6	9.4	10.5
Swan Falls	ROR	15.5	16.2	15.8	17.4	16.5	15.3	12.7	10.8	14.7	15.6	15.3	15.2	17.1
Twin Falls	ROR	8.8	16.0	9.2	16.8	18.1	18.7	10.7	–	–	–	–	5.7	18.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.8	15.9	13.9	16.3	17.7	17.2	13.8	8.7	14.1	14.5	13.1	13.3	16.2
Upper Salmon 3&4	ROR	13.0	14.8	13.1	15.1	16.8	16.0	13.0	8.6	13.2	13.6	12.4	12.6	15.1
HCC Total		**565.9**	**670.1**	**594.1**	**740.7**	**869.1**	**604.3**	**535.3**	**365.3**	**413.1**	**441.5**	**346.0**	**462.8**	**665.0**
ROR Total		**201.3**	**241.0**	**218.9**	**280.6**	**320.8**	**331.3**	**283.2**	**212.6**	**224.0**	**198.2**	**177.4**	**186.5**	**291.7**
Total		**767.2**	**911.1**	**813.0**	**1,021.3**	**1,189.9**	**935.6**	**818.5**	**577.9**	**637.1**	**639.7**	**523.4**	**649.3**	**956.6**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2019**	**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*	247.0	296.0	250.8	325.1	386.3	269.2	237.3	155.2	173.8	191.0	147.7	203.3	240.2
Oxbow	HCC	105.1	125.5	111.5	137.8	160.3	113.2	100.5	70.9	78.8	84.9	66.2	85.7	103.4
Hells Canyon	HCC	208.1	248.0	227.4	278.9	325.5	231.5	198.2	139.5	154.6	167.4	131.9	170.0	206.8
American Falls	ROR	–	14.2	13.9	40.0	73.9	91.5	87.5	64.0	36.7	10.4	–	–	36.0
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.0	38.9	36.8	41.5	42.3	39.1	35.1	27.9	36.8	37.3	34.7	34.7	36.8
C .J. Strike	ROR	46.6	51.5	47.6	53.4	50.3	45.3	35.8	31.0	43.6	47.1	44.8	45.1	45.2
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.2	25.9	22.2	26.2	28.4	27.2	22.7	15.8	23.1	23.9	21.7	21.7	23.4
Milner	ROR	2.6	16.1	3.6	15.3	15.4	15.4	6.4	–	–	–	–	–	6.2
Shoshone Falls	ROR	11.2	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.3	9.7
Swan Falls	ROR	15.3	16.4	15.7	17.6	16.7	15.4	12.7	10.9	14.6	15.6	15.2	15.3	15.1
Twin Falls	ROR	7.3	17.8	8.3	18.2	18.2	18.9	10.7	–	–	–	–	4.5	8.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.4	16.3	13.6	16.7	17.7	17.2	13.8	8.7	14.0	14.5	12.8	12.9	14.3
Upper Salmon 3&4	ROR	12.6	15.2	12.8	15.5	17.0	16.0	13.0	8.7	13.2	13.6	12.2	12.2	13.5
HCC Total		**560.2**	**669.5**	**589.7**	**741.8**	**872.1**	**613.9**	**536.0**	**365.6**	**407.2**	**443.3**	**345.8**	**459.0**	**550.3**
ROR Total		**194.4**	**251.9**	**215.0**	**285.0**	**322.7**	**331.8**	**283.6**	**213.1**	**224.2**	**198.3**	**174.2**	**182.0**	**239.7**
Total		**754.6**	**921.4**	**804.7**	**1,026.8**	**1,194.8**	**945.7**	**819.6**	**578.7**	**631.4**	**641.6**	**520.0**	**641.0**	**790.0**

*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*	247.2	296.0	250.8	325.2	387.4	269.5	237.1	155.0	173.5	190.9	147.6	203.9	240.3
Oxbow	HCC	105.1	125.5	111.5	137.9	160.8	113.3	100.4	70.8	78.6	84.9	66.2	86.0	103.4
Hells Canyon	HCC	208.2	248.0	227.5	279.0	326.3	231.8	198.1	139.3	154.3	167.3	131.8	170.5	206.8
American Falls	ROR	–	14.8	13.9	40.3	73.9	91.5	87.5	64.0	36.7	10.4	–	–	36.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.0	39.3	36.9	41.6	42.4	39.1	35.1	27.9	36.7	37.3	34.6	34.7	36.8
C .J. Strike	ROR	46.6	51.5	47.7	53.5	50.5	45.2	35.8	31.0	43.4	47.0	44.8	45.1	45.2
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.2	26.0	22.2	26.3	28.4	27.1	22.7	15.8	23.0	23.8	21.7	21.7	23.4
Milner	ROR	2.6	17.3	3.6	15.5	15.4	15.4	6.4	–	–	–	–	–	6.4
Shoshone Falls	ROR	11.2	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.3	9.7
Swan Falls	ROR	15.3	16.5	15.8	17.6	16.8	15.4	12.7	10.8	14.6	15.6	15.2	15.3	15.1
Twin Falls	ROR	7.3	18.8	8.3	18.4	18.2	19.2	10.7	–	–	–	–	4.5	8.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.4	16.4	13.6	16.8	17.7	17.2	13.8	8.7	13.9	14.4	12.8	12.9	14.3
Upper Salmon 3&4	ROR	12.6	15.3	12.8	15.6	17.0	15.9	13.0	8.6	13.1	13.6	12.1	12.2	13.5
HCC Total		**560.5**	**669.5**	**589.8**	**742.1**	**874.5**	**614.6**	**535.6**	**365.1**	**406.4**	**443.1**	**345.6**	**460.4**	**550.6**
ROR Total		**194.4**	**255.5**	**215.3**	**286.2**	**323.1**	**331.8**	**283.6**	**212.9**	**223.6**	**198.0**	**174.0**	**182.0**	**240.0**
Total		**754.9**	**925.0**	**805.1**	**1,028.3**	**1,197.6**	**946.4**	**819.2**	**578.0**	**629.9**	**641.1**	**519.6**	**642.4**	**790.6**

*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*	246.1	295.1	250.9	326.1	386.7	268.5	237.1	154.9	172.2	191.1	147.8	202.8	239.9
Oxbow	HCC	104.7	125.2	111.6	138.3	160.5	112.9	100.4	70.8	78.1	84.9	66.2	85.5	103.3
Hells Canyon	HCC	207.3	247.3	227.6	279.7	325.9	231.0	198.1	139.2	153.1	167.3	131.9	169.6	206.5
American Falls	ROR	–	15.0	13.9	40.8	73.9	91.5	87.5	63.9	36.6	10.4	–	–	36.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.8	39.0	36.6	41.8	42.5	39.1	35.1	27.9	36.6	37.2	34.6	34.4	36.7
C .J. Strike	ROR	46.3	51.1	47.5	53.8	50.6	45.2	35.8	30.9	43.3	46.9	44.7	45.0	45.1
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.0	25.3	22.0	26.4	28.6	27.1	22.7	15.7	22.9	23.8	21.6	21.4	23.3
Milner	ROR	1.7	16.2	3.5	15.6	15.4	15.4	6.4	–	–	–	–	–	6.2
Shoshone Falls	ROR	10.1	12.0	11.4	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	7.9	9.6
Swan Falls	ROR	15.4	16.3	15.7	17.7	16.8	15.3	12.7	10.8	14.6	15.5	15.2	15.2	15.1
Twin Falls	ROR	6.3	17.9	7.4	18.5	18.2	18.9	10.7	–	–	–	–	4.2	8.5
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.2	15.9	13.4	16.9	17.7	17.2	13.8	8.6	13.9	14.4	12.7	12.6	14.2
Upper Salmon 3&4	ROR	12.5	14.8	12.7	15.7	17.1	15.9	13.0	8.6	13.1	13.5	12.1	12.0	13.4
HCC Total		**558.1**	**667.6**	**590.1**	**744.1**	**873.1**	**612.4**	**535.6**	**364.9**	**403.4**	**443.3**	**345.9**	**457.9**	**549.7**
ROR Total		**190.5**	**251.1**	**212.6**	**287.8**	**323.6**	**331.4**	**283.6**	**212.5**	**223.2**	**197.6**	**173.7**	**180.0**	**239.0**
Total		**748.6**	**918.7**	**802.7**	**1,031.9**	**1,196.7**	**943.8**	**819.2**	**577.4**	**626.5**	**640.9**	**519.6**	**637.9**	**788.7**

*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*	247.9	296.4	251.0	317.6	386.9	263.3	236.9	154.7	172.1	190.7	148.0	204.0	239.1
Oxbow	HCC	105.4	125.7	111.6	134.8	160.6	110.7	100.3	70.7	77.9	84.7	66.3	86.0	102.9
Hells Canyon	HCC	208.8	248.4	227.6	272.9	325.9	226.7	197.9	138.9	153.0	167.0	132.1	170.7	205.8
American Falls	ROR	–	12.0	13.7	38.0	74.3	91.5	87.4	63.9	36.2	10.3	–	–	35.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.1	39.2	36.3	37.2	42.3	39.0	35.0	27.8	36.5	37.2	34.7	34.9	36.4
C .J. Strike	ROR	46.9	51.6	47.4	50.9	50.7	45.1	35.7	30.8	43.1	46.8	44.6	45.3	44.9
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.4	25.3	22.1	22.9	28.6	27.0	22.6	15.6	22.7	23.7	21.6	21.8	23.0
Milner	ROR	3.2	13.5	3.4	5.1	15.4	15.4	6.4	–	–	–	–	–	5.2
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.7	9.7
Swan Falls	ROR	15.4	16.7	15.7	16.9	16.9	15.3	12.7	10.8	14.5	15.5	15.2	15.3	15.1
Twin Falls	ROR	7.7	16.4	7.3	8.8	18.2	18.9	10.7	–	–	–	–	4.9	7.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.5	15.9	13.5	14.2	17.7	17.2	13.7	8.6	13.8	14.3	12.7	13.0	14.0
Upper Salmon 3&4	ROR	12.7	14.8	12.8	13.4	17.2	15.9	12.9	8.5	13.0	13.4	12.1	12.3	13.3
HCC Total		**562.1**	**670.5**	**590.2**	**725.3**	**873.4**	**600.7**	**535.1**	**364.3**	**403.0**	**442.4**	**346.4**	**460.7**	**547.8**
ROR Total		**196.8**	**245.0**	**211.9**	**248.0**	**324.1**	**331.1**	**283.0**	**212.1**	**222.0**	**197.1**	**173.7**	**183.5**	**235.7**
Total		**758.9**	**915.5**	**802.1**	**973.3**	**1,197.4**	**931.8**	**818.1**	**576.4**	**624.9**	**639.5**	**520.1**	**644.2**	**783.5**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2023**	**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*	247.7	296.1	250.8	317.6	387.5	262.9	236.6	154.3	167.1	190.8	148.3	203.1	238.6
Oxbow	HCC	105.3	125.6	111.4	134.7	160.8	110.5	100.2	70.5	77.3	84.7	66.4	85.7	102.8
Hells Canyon	HCC	208.6	248.0	227.4	272.7	326.4	226.4	197.6	138.6	151.5	167.0	132.3	169.9	205.5
American Falls	ROR	–	11.6	13.7	38.4	74.3	91.5	87.4	63.9	36.1	10.3	–	–	35.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.1	39.3	36.2	37.2	42.4	38.9	35.0	27.7	36.3	37.1	34.6	34.8	36.3
C .J. Strike	ROR	46.8	51.4	47.3	51.0	50.7	45.0	35.6	30.7	42.9	46.7	44.5	45.2	44.8
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.3	25.4	22.0	22.9	28.7	26.9	22.5	15.5	22.6	23.6	21.5	21.7	23.0
Milner	ROR	3.2	13.0	3.3	5.0	15.4	15.4	6.4	–	–	–	–	–	5.1
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.7	9.7
Swan Falls	ROR	15.4	16.8	15.7	16.9	16.9	15.2	12.6	10.7	14.5	15.5	15.2	15.3	15.1
Twin Falls	ROR	7.7	16.4	7.3	8.7	18.2	18.9	10.7	–	–	–	–	4.9	7.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.5	16.0	13.5	14.2	17.7	17.1	13.7	8.5	13.7	14.2	12.7	12.9	14.0
Upper Salmon 3&4	ROR	12.7	14.9	12.7	13.3	17.2	15.8	12.9	8.5	12.9	13.4	12.0	12.3	13.2
HCC Total		**561.6**	**669.7**	**589.6**	**725.0**	**874.7**	**599.8**	**534.4**	**363.4**	**395.8**	**442.5**	**347.0**	**458.7**	**546.9**
ROR Total		**196.6**	**244.4**	**211.4**	**248.2**	**324.3**	**330.5**	**282.7**	**211.6**	**221.2**	**196.7**	**173.3**	**183.1**	**235.3**
Total		**758.2**	**914.1**	**801.0**	**973.2**	**1,199.0**	**930.3**	**817.1**	**575.0**	**617.0**	**639.2**	**520.3**	**641.8**	**782.2**

*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*	247.4	295.8	250.5	317.4	387.7	262.4	236.2	153.9	165.7	191.1	147.9	202.1	238.2
Oxbow	HCC	105.2	125.4	111.3	134.6	160.9	110.3	100.1	70.3	76.5	84.8	66.2	85.2	102.6
Hells Canyon	HCC	208.4	247.8	227.1	272.6	326.6	226.0	197.3	138.3	150.0	167.1	131.9	169.1	205.2
American Falls	ROR	–	10.8	13.6	38.6	74.3	91.5	87.3	63.7	36.1	10.3	–	–	35.5
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.1	38.9	36.1	37.1	42.4	38.8	34.9	27.6	36.1	37.0	34.5	34.7	36.2
C .J. Strike	ROR	46.7	50.8	47.2	51.0	50.7	44.8	35.5	30.5	42.7	46.5	44.3	45.1	44.7
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.3	25.0	21.9	22.8	28.7	26.8	22.4	15.4	22.5	23.4	21.4	21.6	22.9
Milner	ROR	3.2	12.5	3.2	5.0	15.4	15.4	6.4	–	–	–	–	–	5.1
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.7	9.7
Swan Falls	ROR	15.3	16.4	15.6	16.9	16.9	15.2	12.6	10.7	14.4	15.4	15.2	15.3	15.0
Twin Falls	ROR	7.7	16.4	7.3	8.6	18.2	18.9	10.7	–	–	–	–	4.9	7.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.4	15.7	13.4	14.1	17.7	17.0	13.6	8.4	13.5	14.1	12.6	12.9	13.9
Upper Salmon 3&4	ROR	12.7	14.6	12.6	13.3	17.2	15.8	12.8	8.4	12.8	13.3	12.0	12.2	13.1
HCC Total		**561.0**	**669.0**	**588.9**	**724.6**	**875.2**	**598.7**	**533.6**	**362.5**	**392.2**	**443.0**	**346.0**	**456.4**	**545.9**
ROR Total		**196.3**	**240.7**	**210.6**	**248.0**	**324.3**	**330.0**	**282.1**	**210.8**	**220.3**	**195.9**	**172.8**	**182.7**	**234.5**
Total		**757.3**	**909.7**	**799.5**	**972.6**	**1,199.5**	**928.7**	**815.7**	**573.3**	**612.5**	**638.9**	**518.8**	**639.1**	**780.5**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	Type	1/2025	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*	247.1	295.6	249.8	317.4	387.8	261.9	235.8	153.5	164.1	191.2	148.2	200.7	237.8
Oxbow	HCC	105.1	125.3	111.0	134.6	160.9	110.1	99.9	70.1	75.6	84.7	66.3	84.6	102.3
Hells Canyon	HCC	208.1	247.6	226.5	272.6	326.6	225.6	197.0	137.9	148.4	166.9	132.0	167.9	204.8
American Falls	ROR	–	10.5	13.5	38.7	74.3	91.5	87.3	63.6	36.1	10.3	–	–	35.5
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.0	38.2	36.0	37.1	42.4	38.8	34.8	27.4	36.0	36.9	34.3	34.6	36.0
C .J. Strike	ROR	46.6	50.4	47.1	50.9	50.6	44.6	35.3	30.4	42.5	46.3	44.2	45.1	44.5
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.2	24.8	21.9	22.8	28.7	26.7	22.3	15.3	22.3	23.3	21.3	21.6	22.8
Milner	ROR	3.2	12.3	3.1	4.9	15.4	15.4	6.4	–	–	–	–	–	5.1
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.7	9.7
Swan Falls	ROR	15.3	16.2	15.6	16.9	16.9	15.2	12.6	10.6	14.3	15.4	15.1	15.3	15.0
Twin Falls	ROR	7.7	16.1	7.3	8.4	18.2	18.9	10.7	–	–	–	–	4.9	7.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.3	15.5	13.4	14.1	17.7	16.9	13.5	8.3	13.4	14.0	12.5	12.8	13.8
Upper Salmon 3&4	ROR	12.6	14.5	12.6	13.3	17.2	15.7	12.8	8.3	12.7	13.2	11.9	12.1	13.1
HCC Total		**560.3**	**668.5**	**587.3**	**724.6**	**875.3**	**597.6**	**532.7**	**361.5**	**388.0**	**442.8**	**346.5**	**453.2**	**544.9**
ROR Total		**195.8**	**238.1**	**210.2**	**247.7**	**324.2**	**329.5**	**281.6**	**210.0**	**219.5**	**195.3**	**172.1**	**182.4**	**233.9**
Total		**756.1**	**906.6**	**797.5**	**972.3**	**1,199.4**	**927.1**	**814.3**	**571.5**	**607.5**	**638.1**	**518.6**	**635.6**	**778.7**

*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*	246.6	294.0	249.8	316.6	388.2	261.3	235.4	153.1	162.4	191.2	148.3	198.8	237.1
Oxbow	HCC	104.9	124.7	111.0	134.2	161.1	109.9	99.7	69.9	74.7	84.6	66.3	83.8	102.1
Hells Canyon	HCC	207.7	246.3	226.4	271.9	327.0	225.1	196.6	137.5	146.7	166.7	132.1	166.3	204.2
American Falls	ROR	–	10.1	13.4	38.8	74.3	91.5	87.3	63.5	36.0	10.2	–	–	35.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	36.0	37.2	35.9	36.9	42.5	38.7	34.7	27.3	35.8	36.8	34.2	34.5	35.9
C .J. Strike	ROR	46.5	50.0	46.9	50.8	50.6	44.5	35.2	30.2	42.2	46.1	43.9	45.0	44.3
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.1	24.5	21.8	22.8	28.8	26.6	22.2	15.2	22.1	23.1	21.1	21.5	22.7
Milner	ROR	3.2	12.1	2.6	4.7	15.4	15.4	6.4	–	–	–	–	–	5.0
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.7	9.7
Swan Falls	ROR	15.3	15.9	15.6	16.9	16.9	15.1	12.5	10.6	14.3	15.3	15.0	15.2	14.9
Twin Falls	ROR	7.7	15.5	7.3	8.3	18.2	18.9	10.7	–	–	–	–	4.8	7.6
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.3	15.3	13.3	14.1	17.7	16.8	13.5	8.2	13.3	13.9	12.4	12.7	13.7
Upper Salmon 3&4	ROR	12.6	14.3	12.6	13.3	17.2	15.6	12.7	8.3	12.6	13.1	11.8	12.1	13.0
HCC Total		**559.2**	**665.0**	**587.2**	**722.7**	**876.3**	**596.3**	**531.7**	**360.5**	**383.7**	**442.5**	**346.7**	**448.9**	**543.4**
ROR Total		**195.6**	**234.5**	**209.1**	**247.2**	**324.4**	**328.9**	**281.1**	**209.4**	**218.5**	**194.4**	**171.2**	**181.8**	**233.0**
Total		**754.8**	**899.5**	**796.3**	**969.9**	**1,200.6**	**925.2**	**812.8**	**569.9**	**602.2**	**636.9**	**517.9**	**630.7**	**776.4**

*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*	246.2	289.9	249.5	316.2	387.5	260.4	234.9	152.6	160.6	191.8	148.2	196.3	236.2
Oxbow	HCC	104.7	123.0	110.8	134.0	160.8	109.5	99.5	69.7	73.8	84.8	66.3	82.7	101.6
Hells Canyon	HCC	207.4	243.0	226.1	271.4	326.4	224.4	196.2	137.1	144.9	167.1	131.9	164.2	203.3
American Falls	ROR	–	9.5	13.2	38.7	74.2	91.3	87.3	63.5	35.9	10.3	–	–	35.3
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.9	36.7	35.5	36.8	42.5	38.6	34.5	27.2	35.6	36.6	34.1	34.4	35.7
C .J. Strike	ROR	46.4	49.5	46.5	50.7	51.0	44.3	35.1	30.1	42.0	45.9	43.7	44.9	44.2
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.1	23.6	21.7	22.8	28.8	26.5	22.1	15.1	22.0	23.0	21.0	21.4	22.5
Milner	ROR	3.3	11.3	2.5	4.5	15.4	15.4	6.4	–	–	–	–	–	4.9
Shoshone Falls	ROR	11.7	12.0	11.2	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.7
Swan Falls	ROR	15.2	15.8	15.4	16.8	17.0	15.1	12.5	10.5	14.2	15.3	14.9	15.2	14.8
Twin Falls	ROR	7.7	14.6	7.2	8.2	18.2	18.9	10.7	–	–	–	–	4.8	7.5
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.2	14.6	13.2	14.1	17.7	16.7	13.4	8.2	13.2	13.8	12.3	12.7	13.6
Upper Salmon 3&4	ROR	12.5	13.7	12.5	13.3	17.2	15.5	12.6	8.2	12.5	13.0	11.7	12.0	12.9
HCC Total		**558.3**	**655.9**	**586.4**	**721.6**	**874.6**	**594.3**	**530.6**	**359.4**	**379.3**	**443.7**	**346.4**	**443.2**	**541.1**
ROR Total		**195.2**	**228.9**	**207.4**	**246.5**	**324.8**	**328.1**	**280.5**	**208.9**	**217.6**	**193.8**	**170.5**	**181.3**	**232.0**
Total		**753.5**	**884.8**	**793.8**	**968.1**	**1,199.4**	**922.4**	**811.1**	**568.3**	**596.9**	**637.5**	**516.9**	**624.5**	**773.1**

*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*	245.0	285.9	249.0	315.9	387.5	259.9	234.5	152.1	159.4	191.7	148.3	195.6	235.4
Oxbow	HCC	104.2	121.3	110.5	133.8	160.7	109.2	99.3	69.5	73.2	84.6	66.3	82.4	101.2
Hells Canyon	HCC	206.4	239.7	225.6	271.1	326.4	223.9	195.8	136.7	143.7	166.8	132.0	163.6	202.6
American Falls	ROR	–	8.1	12.9	38.6	74.2	91.0	87.3	63.2	35.9	10.3	–	–	35.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.8	36.5	35.2	36.7	42.5	38.5	34.5	27.0	35.4	36.5	33.9	34.3	35.6
C .J. Strike	ROR	46.3	49.1	46.1	50.6	50.9	44.1	35.0	29.9	41.7	45.7	43.5	44.7	44.0
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.0	22.9	21.3	22.8	28.8	26.4	22.0	15.0	21.8	22.8	20.9	21.3	22.3
Milner	ROR	3.3	6.8	2.2	4.4	15.4	15.4	6.4	–	–	–	–	–	4.5
Shoshone Falls	ROR	11.7	12.0	10.0	12.0	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.6
Swan Falls	ROR	15.4	15.7	15.3	16.8	17.0	15.0	12.4	10.5	14.2	15.4	14.9	15.1	14.8
Twin Falls	ROR	7.7	10.0	6.3	8.1	18.2	18.8	10.7	–	–	–	–	4.8	7.1
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.2	14.1	12.9	14.1	17.7	16.6	13.3	8.1	13.0	13.7	12.2	12.6	13.5
Upper Salmon 3&4	ROR	12.5	13.2	12.2	13.3	17.2	15.4	12.6	8.1	12.4	12.9	11.6	12.0	12.8
HCC Total		**555.6**	**646.9**	**585.1**	**720.8**	**874.7**	**593.0**	**529.6**	**358.3**	**376.3**	**443.1**	**346.6**	**441.6**	**539.3**
ROR Total		**195.1**	**216.0**	**202.9**	**246.0**	**324.7**	**327.0**	**280.1**	**207.9**	**216.6**	**193.2**	**169.8**	**180.7**	**230.0**
Total		**750.7**	**862.9**	**788.0**	**966.8**	**1,199.3**	**920.0**	**809.7**	**566.2**	**592.9**	**636.3**	**516.4**	**622.3**	**769.3**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	244.0	281.7	248.6	315.2	387.6	259.2	234.0	151.6	158.1	191.5	148.2	195.4	234.6
Oxbow	HCC	103.8	119.5	110.3	133.5	160.7	109.0	99.1	69.2	72.5	84.5	66.2	82.3	100.9
Hells Canyon	HCC	205.5	236.2	225.2	270.5	326.4	223.4	195.5	136.3	142.5	166.5	131.9	163.4	201.9
American Falls	ROR	–	5.9	12.8	38.4	74.1	90.9	87.3	63.1	35.8	10.2	–	–	34.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.7	36.4	34.9	36.5	42.5	38.3	34.3	26.9	35.2	36.3	33.7	34.2	35.4
C .J. Strike	ROR	46.1	48.5	45.9	50.5	50.5	43.9	34.9	29.7	41.5	45.5	43.3	44.4	43.7
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.9	22.9	21.2	22.8	28.7	26.3	21.9	14.9	21.6	22.7	20.7	21.1	22.2
Milner	ROR	3.3	5.7	2.0	4.0	15.4	15.4	6.4	–	–	–	–	–	4.4
Shoshone Falls	ROR	11.7	12.0	9.8	11.8	12.0	12.0	12.0	6.9	6.7	6.3	5.4	7.9	9.5
Swan Falls	ROR	15.4	15.7	15.2	16.8	16.8	14.9	12.4	10.4	14.1	15.4	14.8	15.1	14.8
Twin Falls	ROR	7.7	10.0	6.0	7.8	18.2	18.8	10.7	–	–	–	–	4.3	7.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.1	14.0	12.8	14.1	17.7	16.5	13.2	8.0	12.9	13.6	12.1	12.4	13.4
Upper Salmon 3&4	ROR	12.4	13.2	12.2	13.2	17.2	15.4	12.5	8.0	12.2	12.8	11.5	11.8	12.7
HCC Total		**553.3**	**637.4**	**584.1**	**719.2**	**874.7**	**591.6**	**528.6**	**357.1**	**373.1**	**442.5**	**346.3**	**441.1**	**537.4**
ROR Total		**194.5**	**211.9**	**201.3**	**244.5**	**323.9**	**326.2**	**279.5**	**207.1**	**215.5**	**192.4**	**168.9**	**178.5**	**228.7**
Total		**747.8**	**849.3**	**785.4**	**963.7**	**1,198.6**	**917.8**	**808.1**	**564.2**	**588.6**	**634.9**	**515.2**	**619.6**	**766.1**

*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*	242.8	278.3	248.3	315.1	387.1	258.6	233.5	151.1	156.7	191.7	148.6	194.9	233.9
Oxbow	HCC	103.2	118.1	110.1	133.4	160.6	108.7	98.9	69.0	71.8	84.5	66.4	82.1	100.6
Hells Canyon	HCC	204.5	233.5	224.8	270.3	326.1	222.9	195.1	135.8	141.1	166.6	132.2	163.0	201.3
American Falls	ROR	–	–	11.2	37.2	74.1	90.9	87.3	63.0	35.8	10.2	–	–	34.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.3	36.3	33.9	36.4	42.5	38.2	34.2	26.7	35.0	36.1	33.6	34.1	35.2
C .J. Strike	ROR	46.0	47.8	45.5	50.3	50.5	43.7	34.7	29.5	41.3	45.2	43.1	44.2	43.5
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.8	22.8	20.8	22.8	28.6	26.1	21.8	14.7	21.5	22.5	20.6	21.0	22.1
Milner	ROR	2.5	5.6	–	3.8	15.1	15.4	6.4	–	–	–	–	–	4.1
Shoshone Falls	ROR	11.7	12.0	9.4	11.6	12.0	12.0	12.0	6.9	6.7	6.3	5.4	7.9	9.5
Swan Falls	ROR	15.3	15.6	15.4	16.7	16.8	14.9	12.3	10.4	14.1	15.3	14.7	15.0	14.7
Twin Falls	ROR	7.7	9.9	5.7	7.6	17.9	18.7	10.7	–	–	–	–	4.3	6.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.0	14.0	12.5	14.1	17.7	16.4	13.1	7.9	12.8	13.4	12.0	12.4	13.3
Upper Salmon 3&4	ROR	12.3	13.2	11.9	13.2	17.1	15.3	12.4	8.0	12.1	12.7	11.4	11.8	12.6
HCC Total		**550.5**	**629.9**	**583.2**	**718.8**	**873.8**	**590.2**	**527.5**	**355.9**	**369.5**	**442.8**	**347.2**	**440.0**	**535.8**
ROR Total		**192.8**	**204.8**	**194.8**	**242.3**	**323.1**	**325.4**	**278.8**	**206.3**	**214.8**	**191.3**	**168.2**	**178.0**	**226.7**
Total		**743.3**	**834.7**	**778.0**	**961.1**	**1,196.9**	**915.6**	**806.3**	**562.2**	**584.3**	**634.1**	**515.4**	**618.0**	**762.5**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	243.1	277.7	247.8	314.5	386.4	257.5	233.1	150.7	154.9	191.9	148.8	194.2	233.4
Oxbow	HCC	103.4	117.8	109.9	133.2	160.3	108.2	98.7	68.8	70.8	84.5	66.4	81.8	100.3
Hells Canyon	HCC	204.8	232.9	224.4	269.8	325.5	222.0	194.7	135.4	139.3	166.6	132.3	162.5	200.8
American Falls	ROR	–	–	11.0	36.8	74.1	90.8	87.3	62.9	35.8	10.2	–	–	34.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.1	36.2	33.8	36.3	42.5	38.0	34.1	26.6	34.8	35.9	33.5	34.0	35.1
C .J. Strike	ROR	46.0	47.4	45.2	50.2	49.9	43.5	34.6	29.3	41.0	45.0	43.3	44.1	43.3
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.1	22.8	20.7	22.8	28.6	26.0	21.7	14.6	21.3	22.4	20.5	21.0	22.0
Milner	ROR	4.0	7.5	1.6	3.6	14.6	14.6	6.4	–	–	–	–	–	4.4
Shoshone Falls	ROR	12.0	12.0	10.0	11.4	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.6
Swan Falls	ROR	15.3	15.5	15.3	16.5	16.8	14.8	12.3	10.3	14.1	15.2	14.7	15.0	14.7
Twin Falls	ROR	8.9	10.2	6.2	7.4	17.7	18.2	10.7	–	–	–	–	4.8	7.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.3	13.9	12.4	14.1	17.7	16.3	13.0	7.8	12.6	13.3	11.9	12.3	13.2
Upper Salmon 3&4	ROR	12.6	13.1	11.8	13.2	17.1	15.2	12.4	7.9	12.0	12.6	11.4	11.8	12.6
HCC Total		**551.3**	**628.4**	**582.1**	**717.5**	**872.2**	**587.7**	**526.5**	**354.9**	**364.9**	**443.0**	**347.5**	**438.5**	**534.5**
ROR Total		**196.5**	**206.2**	**196.5**	**240.9**	**321.8**	**323.2**	**278.4**	**205.5**	**213.8**	**190.5**	**168.1**	**178.9**	**226.7**
Total		**747.8**	**834.6**	**778.6**	**958.4**	**1,194.0**	**910.9**	**804.9**	**560.4**	**578.7**	**633.5**	**515.6**	**617.4**	**761.2**

*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*	242.7	268.8	247.1	313.8	385.3	256.1	232.6	150.1	153.4	191.8	148.5	194.2	232.0
Oxbow	HCC	103.2	117.5	109.6	132.9	159.8	107.7	98.5	68.5	70.0	84.4	66.3	81.8	100.0
Hells Canyon	HCC	204.5	234.1	223.7	269.2	324.7	220.9	194.3	134.9	137.8	166.3	132.0	162.4	200.4
American Falls	ROR	–	–	9.6	36.6	74.1	90.8	87.2	62.5	35.7	10.2	–	–	33.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	35.0	35.4	33.3	36.2	42.5	37.9	34.0	26.4	34.6	35.8	33.2	33.9	34.9
C .J. Strike	ROR	45.8	47.0	44.9	50.0	50.0	43.3	34.4	29.1	40.8	44.8	43.1	43.9	43.1
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	22.0	22.4	20.1	22.0	28.6	25.9	21.6	14.5	21.1	22.2	20.3	20.8	21.8
Milner	ROR	4.0	5.3	–	3.1	14.3	14.3	6.4	–	–	–	–	–	4.0
Shoshone Falls	ROR	12.0	12.0	8.8	10.7	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.5
Swan Falls	ROR	15.2	15.4	15.2	16.4	16.8	14.7	12.2	10.2	14.0	15.1	14.7	14.9	14.6
Twin Falls	ROR	8.9	9.8	5.2	6.8	17.5	18.2	10.7	–	–	–	–	4.8	6.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.2	13.6	11.9	13.5	17.7	16.2	13.0	7.7	12.5	13.2	11.8	12.2	13.0
Upper Salmon 3&4	ROR	12.5	12.8	11.4	12.7	17.1	15.1	12.3	7.8	11.9	12.5	11.3	11.6	12.4
HCC Total		**550.4**	**620.4**	**580.4**	**715.9**	**869.9**	**584.7**	**525.4**	**353.5**	**361.2**	**442.5**	**346.8**	**438.4**	**532.5**
ROR Total		**195.8**	**201.3**	**188.9**	**236.6**	**321.4**	**322.2**	**277.7**	**204.3**	**212.8**	**189.7**	**167.2**	**178.0**	**224.7**
Total		**746.2**	**821.7**	**769.3**	**952.5**	**1,191.3**	**906.9**	**803.1**	**557.8**	**573.9**	**632.2**	**514.0**	**616.4**	**757.1**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	242.2	267.9	246.8	313.3	385.6	255.1	232.0	149.6	151.5	192.1	148.7	193.7	231.5
Oxbow	HCC	103.0	117.1	109.4	132.6	159.9	107.3	98.3	68.3	69.1	84.4	66.3	81.6	99.8
Hells Canyon	HCC	204.1	233.3	223.4	268.6	324.8	220.1	193.9	134.4	136.0	166.4	132.0	162.0	199.9
American Falls	ROR	–	–	9.4	36.4	74.1	90.9	87.2	62.5	35.7	10.2	–	–	33.9
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	34.8	35.2	33.1	36.1	42.4	37.6	33.8	26.3	34.4	35.6	33.1	33.8	34.7
C .J. Strike	ROR	45.2	46.9	44.5	49.8	49.9	43.1	34.2	28.9	40.5	44.7	43.1	43.5	42.9
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.8	21.9	19.9	21.1	28.7	25.8	21.5	14.3	20.9	22.1	20.2	20.7	21.6
Milner	ROR	3.3	5.1	–	2.3	14.3	14.3	6.4	–	–	–	–	–	3.8
Shoshone Falls	ROR	12.0	12.0	8.6	10.4	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.4
Swan Falls	ROR	15.1	15.3	15.1	16.2	16.8	14.6	12.2	10.2	13.9	15.1	14.6	14.9	14.5
Twin Falls	ROR	8.5	9.4	4.8	6.6	17.5	18.2	10.7	–	–	–	–	4.8	6.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.1	13.3	11.8	12.8	17.7	16.2	12.9	7.6	12.4	13.1	11.6	12.1	12.9
Upper Salmon 3&4	ROR	12.4	12.5	11.3	12.1	17.2	15.0	12.2	7.7	11.8	12.4	11.2	11.6	12.3
HCC Total		**549.3**	**618.3**	**579.6**	**714.5**	**870.3**	**582.5**	**524.2**	**352.3**	**356.6**	**442.9**	**347.0**	**437.3**	**531.2**
ROR Total		**193.4**	**199.2**	**187.0**	**232.4**	**321.4**	**321.5**	**277.0**	**203.6**	**211.8**	**189.1**	**166.6**	**177.3**	**223.4**
Total		**742.7**	**817.5**	**766.6**	**946.9**	**1,191.7**	**904.0**	**801.2**	**555.9**	**568.3**	**632.0**	**513.6**	**614.6**	**754.6**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	241.8	266.9	246.7	312.2	384.9	254.4	231.6	149.1	150.1	191.9	148.8	193.2	231.0
Oxbow	HCC	102.9	116.6	109.3	132.1	159.6	107.0	98.1	68.0	68.3	84.3	66.4	81.4	99.5
Hells Canyon	HCC	203.8	232.4	223.3	267.8	324.2	219.5	193.5	134.0	134.5	166.1	132.1	161.6	199.4
American Falls	ROR	–	–	9.2	35.6	74.1	90.8	87.2	62.4	35.6	10.2	–	–	33.8
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	34.7	35.2	32.9	35.7	42.5	37.4	33.7	26.1	34.2	35.4	33.0	33.7	34.5
C .J. Strike	ROR	45.1	46.7	44.3	48.6	49.9	42.9	34.0	28.7	40.2	44.5	43.0	43.5	42.6
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.7	21.8	19.8	20.9	28.5	25.3	21.4	14.2	20.8	21.9	20.0	20.6	21.4
Milner	ROR	3.3	5.1	–	–	14.3	14.2	6.4	–	–	–	–	–	3.6
Shoshone Falls	ROR	12.0	12.0	8.3	7.3	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.1
Swan Falls	ROR	15.1	15.2	15.0	16.0	16.8	14.6	12.1	10.1	13.8	15.1	14.6	14.8	14.4
Twin Falls	ROR	8.5	8.8	4.6	3.8	17.3	18.2	10.7	–	–	–	–	4.8	6.4
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	13.0	13.1	11.7	12.6	17.7	15.8	12.8	7.5	12.2	13.0	11.5	12.0	12.7
Upper Salmon 3&4	ROR	12.3	12.4	11.2	12.0	17.1	14.7	12.1	7.6	11.7	12.3	11.1	11.5	12.2
HCC Total		**548.5**	**615.9**	**579.3**	**712.1**	**868.6**	**580.9**	**523.2**	**351.1**	**352.8**	**442.3**	**347.3**	**436.2**	**529.9**
ROR Total		**192.9**	**197.9**	**185.5**	**221.1**	**321.0**	**319.7**	**276.3**	**202.7**	**210.7**	**188.3**	**166.0**	**176.8**	**221.6**
Total		**741.4**	**813.8**	**764.8**	**933.2**	**1,189.7**	**900.6**	**799.5**	**553.8**	**563.5**	**630.6**	**513.3**	**613.0**	**751.4**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2035**	**2/2035**	**3/2035**	**4/2035**	**5/2035**	**6/2035**	**7/2035**	**8/2035**	**9/2035**	**10/2035**	**11/2035**	**12/2035**	**aMW**
Brownlee	HCC*	241.4	265.2	246.5	312.2	384.1	253.8	231.1	148.6	148.2	192.2	148.9	192.7	230.4
Oxbow	HCC	102.7	115.8	109.1	132.0	159.3	106.7	97.9	67.8	67.3	84.3	66.4	81.2	99.2
Hells Canyon	HCC	203.4	230.8	222.8	267.5	323.6	219.0	193.1	133.6	132.7	166.1	132.2	161.2	198.8
American Falls	ROR	–	–	9.1	35.5	73.9	90.7	87.2	62.4	35.6	10.3	–	–	33.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	34.6	34.9	32.8	35.5	42.4	37.2	33.6	26.0	34.0	35.3	32.8	33.6	34.4
C .J. Strike	ROR	44.9	46.6	44.0	47.6	49.9	42.7	33.9	28.6	40.0	44.2	42.8	43.5	42.4
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.2	21.7	19.7	20.8	28.4	25.1	21.3	14.1	20.6	21.8	19.9	20.5	21.3
Milner	ROR	3.3	5.1	–	–	14.3	14.2	6.4	–	–	–	–	–	3.6
Shoshone Falls	ROR	12.0	12.0	8.3	6.6	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.1
Swan Falls	ROR	15.1	15.2	14.9	15.9	16.8	14.5	12.1	10.0	13.8	15.0	14.5	14.8	14.4
Twin Falls	ROR	8.0	8.8	4.6	–	17.3	18.2	10.7	–	–	–	–	4.8	6.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.6	13.1	11.6	12.5	17.7	15.7	12.7	7.4	12.1	12.8	11.4	11.9	12.6
Upper Salmon 3&4	ROR	12.0	12.4	11.1	11.9	17.0	14.6	12.1	7.5	11.6	12.2	11.0	11.4	12.1
HCC Total		**547.5**	**611.8**	**578.4**	**711.7**	**867.0**	**579.5**	**522.1**	**350.0**	**348.1**	**442.6**	**347.5**	**435.1**	**528.4**
ROR Total		**190.9**	**197.4**	**184.6**	**214.9**	**320.5**	**318.7**	**275.9**	**202.1**	**209.9**	**187.5**	**165.2**	**176.4**	**220.3**
Total		**738.4**	**809.2**	**763.0**	**926.6**	**1,187.5**	**898.2**	**798.0**	**552.1**	**558.0**	**630.1**	**512.7**	**611.5**	**748.8**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2036**	**2/2036**	**3/2036**	**4/2036**	**5/2036**	**6/2036**	**7/2036**	**8/2036**	**9/2036**	**10/2036**	**11/2036**	**12/2036**	**aMW**
Brownlee	HCC*	240.8	264.2	245.9	311.6	384.5	253.1	230.6	148.1	146.3	192.4	148.8	192.6	229.9
Oxbow	HCC	102.4	115.3	108.8	131.6	159.5	106.4	97.6	67.6	66.3	84.3	66.3	81.1	98.9
Hells Canyon	HCC	202.9	229.9	222.2	266.8	323.8	218.4	192.6	133.1	130.9	166.1	132.0	161.1	198.3
American Falls	ROR	–	–	8.9	35.5	73.9	90.7	87.2	62.2	35.6	10.3	–	–	33.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	34.4	34.8	32.7	35.4	42.3	37.1	33.4	25.8	33.8	35.1	32.7	33.5	34.3
C .J. Strike	ROR	44.2	46.4	43.7	47.5	49.9	42.6	33.7	28.4	39.7	44.0	42.7	43.4	42.2
Cascade	ROR	1.4	1.4	1.3	1.2	2.1	7.1	7.4	12.0	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.7	21.6	19.6	20.7	28.4	25.0	21.2	14.0	20.4	21.6	19.8	20.4	21.1
Milner	ROR	2.5	5.1	–	–	14.3	14.2	6.4	–	–	–	–	–	3.5
Shoshone Falls	ROR	10.7	12.0	8.3	6.6	12.0	12.0	12.0	6.9	6.7	6.3	5.4	8.6	9.0
Swan Falls	ROR	15.0	15.1	14.8	15.8	16.8	14.4	12.0	10.0	13.7	14.9	14.5	14.7	14.3
Twin Falls	ROR	6.8	8.8	4.6	–	17.2	18.2	10.7	–	–	–	–	4.8	5.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.2	13.1	11.5	12.5	17.7	15.5	12.6	7.3	12.0	12.7	11.3	11.9	12.5
Upper Salmon 3&4	ROR	11.6	12.4	11.1	11.9	17.0	14.5	12.0	7.5	11.4	12.1	10.9	11.4	12.0
HCC Total		**546.1**	**609.4**	**576.9**	**710.0**	**867.8**	**577.9**	**520.8**	**348.8**	**343.4**	**442.8**	**347.1**	**434.8**	**527.1**
ROR Total		**185.3**	**196.9**	**183.7**	**214.5**	**320.3**	**318.0**	**275.1**	**201.3**	**208.8**	**186.6**	**164.7**	**176.0**	**219.3**
Total		**731.4**	**806.3**	**760.6**	**924.5**	**1,188.1**	**895.9**	**795.9**	**550.1**	**552.2**	**629.4**	**511.8**	**610.8**	**746.4**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	221.6	195.7	231.8	225.4	272.1	167.1	222.0	141.5	131.6	192.4	148.2	178.7	194.0
Oxbow	HCC	93.5	83.9	99.8	96.2	115.0	72.2	93.7	64.4	59.0	83.4	65.7	78.0	83.7
Hells Canyon	HCC	184.6	166.8	202.2	196.0	235.9	146.6	184.1	126.6	116.2	164.2	130.4	153.9	167.3
American Falls	ROR	0.0	0.0	0.0	29.7	69.4	86.9	87.0	56.5	27.3	8.1	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	33.4	33.6	32.0	32.4	37.4	35.7	33.9	26.7	35.4	36.1	33.9	33.8	33.7
C .J. Strike	ROR	42.0	41.9	41.0	40.9	43.1	39.0	32.4	29.5	39.1	43.1	42.7	41.7	39.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.0	21.3	19.5	20.0	24.9	24.0	22.0	15.1	22.1	23.0	21.4	21.3	21.3
Milner	ROR	1.9	3.1	0.0	0.0	8.3	8.2	6.4	0.0	0.0	0.0	0.0	0.0	2.3
Shoshone Falls	ROR	9.9	10.9	4.8	4.0	12.0	12.0	12.0	6.5	6.5	6.2	7.3	9.7	8.5
Swan Falls	ROR	14.4	14.3	14.1	14.1	14.7	13.4	11.7	10.4	13.9	14.8	14.6	14.4	13.7
Twin Falls	ROR	6.1	7.0	0.0	0.0	11.1	12.0	10.3	0.0	0.0	0.0	3.7	5.9	4.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.4	12.8	11.5	11.9	15.7	14.8	13.3	8.1	13.3	13.8	12.6	12.6	12.7
Upper Salmon 3&4	ROR	11.8	12.2	11.0	11.4	14.6	13.8	12.5	8.2	12.6	13.0	11.9	12.0	12.1
HCC Total		**499.7**	**446.4**	**533.8**	**517.6**	**623.0**	**385.9**	**499.8**	**332.5**	**306.8**	**440.0**	**344.3**	**410.6**	**445.0**
ROR Total		**180.1**	**184.7**	**162.4**	**193.1**	**281.4**	**290.7**	**275.0**	**198.5**	**204.6**	**187.5**	**175.5**	**178.6**	**209.3**
Total		**679.8**	**631.1**	**696.2**	**710.7**	**904.4**	**676.6**	**774.8**	**531.0**	**511.4**	**627.5**	**519.8**	**589.2**	**654.4**

*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*	212.0	197.8	232.9	226.0	273.6	168.1	222.3	141.5	131.5	192.2	148.6	178.8	193.8
Oxbow	HCC	89.8	84.8	100.3	96.5	115.7	72.7	93.8	64.4	59.0	83.4	65.8	78.0	83.7
Hells Canyon	HCC	177.5	168.5	203.1	196.5	237.1	147.5	184.3	126.7	116.2	164.1	130.7	153.9	167.2
American Falls	ROR	0.0	0.0	0.0	29.6	70.0	87.7	87.1	56.5	28.5	8.7	0.0	0.0	30.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	33.3	33.5	32.0	32.5	38.1	36.3	34.0	26.9	35.4	36.2	33.7	33.7	33.8
C .J. Strike	ROR	42.2	42.1	41.4	41.1	43.4	39.6	32.0	29.5	39.1	43.1	42.5	41.8	39.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	21.1	21.3	19.4	20.1	25.6	24.4	22.0	15.1	22.1	23.0	21.2	21.2	21.4
Milner	ROR	0.0	3.1	0.0	0.0	9.7	9.6	6.4	0.0	0.0	0.0	0.0	0.0	2.4
Shoshone Falls	ROR	9.2	10.8	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	6.6	9.1	8.3
Swan Falls	ROR	14.4	14.4	14.2	14.2	14.8	13.6	11.7	10.4	13.9	14.9	14.6	14.3	13.8
Twin Falls	ROR	5.6	6.9	0.0	0.0	12.4	12.6	10.3	0.0	0.0	0.0	0.0	5.5	4.4
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.5	12.8	11.4	12.0	16.2	15.1	13.3	8.1	13.3	13.8	12.4	12.5	12.8
Upper Salmon 3&4	ROR	11.9	12.1	11.0	11.5	15.1	14.1	12.6	8.2	12.6	13.0	11.8	11.9	12.2
HCC Total		**479.3**	**451.1**	**536.3**	**519.0**	**626.4**	**388.3**	**500.4**	**332.6**	**306.6**	**439.7**	**345.1**	**410.7**	**444.6**
ROR Total		**177.4**	**184.6**	**162.1**	**193.7**	**287.5**	**295.9**	**274.9**	**198.7**	**205.9**	**188.3**	**170.2**	**177.2**	**209.7**
Total		**656.7**	**635.7**	**698.4**	**712.7**	**913.9**	**684.2**	**775.3**	**531.3**	**512.4**	**628.0**	**515.3**	**587.9**	**654.3**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2019**	**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*	209.6	202.3	231.5	226.6	274.5	168.3	222.5	141.6	129.8	192.6	149.3	178.1	193.9
Oxbow	HCC	88.8	86.7	99.7	96.7	116.1	72.7	93.9	64.5	58.1	83.4	66.1	77.7	83.7
Hells Canyon	HCC	175.5	172.3	201.9	197.0	237.9	147.6	184.5	126.8	114.6	164.1	131.2	153.3	167.2
American Falls	ROR	0.0	0.0	0.0	29.4	70.0	87.7	87.1	56.2	28.7	8.8	0.0	0.0	30.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.9	33.3	32.0	32.5	38.3	36.7	34.1	27.0	35.3	36.2	33.5	33.2	33.8
C .J. Strike	ROR	41.4	41.5	41.5	41.4	43.8	40.6	32.1	29.6	39.0	43.1	42.0	41.3	39.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.6	20.9	19.4	20.2	26.1	24.5	22.1	15.1	22.1	23.0	20.8	20.7	21.3
Milner	ROR	0.0	0.0	0.0	0.0	10.3	10.2	6.4	0.0	0.0	0.0	0.0	0.0	2.2
Shoshone Falls	ROR	7.1	8.7	4.2	4.3	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.0	7.7
Swan Falls	ROR	14.2	14.3	14.2	14.2	14.9	13.9	11.7	10.4	13.9	14.8	14.4	14.2	13.8
Twin Falls	ROR	3.7	5.1	0.0	0.0	13.0	13.1	10.3	0.0	0.0	0.0	0.0	0.0	3.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.1	12.4	11.4	12.1	16.6	15.2	13.3	8.2	13.3	13.8	12.1	12.2	12.7
Upper Salmon 3&4	ROR	11.5	11.8	11.0	11.6	15.4	14.2	12.6	8.2	12.6	13.0	11.6	11.6	12.1
HCC Total		**473.9**	**461.3**	**533.1**	**520.3**	**628.5**	**388.6**	**500.9**	**332.9**	**302.5**	**440.1**	**346.6**	**409.1**	**444.8**
ROR Total		**170.7**	**175.6**	**162.2**	**194.4**	**290.6**	**299.0**	**275.2**	**198.7**	**205.9**	**188.3**	**167.2**	**167.4**	**207.9**
Total		**644.6**	**636.9**	**695.3**	**714.7**	**919.1**	**687.6**	**776.1**	**531.6**	**508.3**	**628.4**	**513.8**	**576.5**	**652.7**

*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*	209.7	196.6	231.5	226.7	274.9	168.1	222.4	141.5	129.4	192.5	149.2	178.0	193.4
Oxbow	HCC	88.8	84.3	99.7	96.8	116.2	72.7	93.9	64.4	58.0	83.3	66.0	77.6	83.5
Hells Canyon	HCC	175.6	167.4	201.9	197.1	238.2	147.5	184.4	126.6	114.3	164.0	131.1	153.2	166.8
American Falls	ROR	0.0	0.0	0.0	29.3	70.0	87.7	87.1	56.7	28.8	8.8	0.0	0.0	30.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.9	32.1	32.0	32.5	38.2	36.2	34.0	26.9	35.2	36.1	33.4	33.3	33.6
C .J. Strike	ROR	41.4	40.1	41.5	41.7	44.0	40.3	32.1	29.5	38.9	43.1	41.9	41.6	39.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.6	20.1	19.4	20.2	25.9	24.5	22.0	15.1	22.0	23.0	20.7	20.7	21.2
Milner	ROR	0.0	0.0	0.0	0.0	10.0	9.9	6.4	0.0	0.0	0.0	0.0	0.0	2.2
Shoshone Falls	ROR	7.2	8.4	4.2	4.3	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.0	7.6
Swan Falls	ROR	14.2	13.8	14.2	14.3	15.0	13.8	11.7	10.4	13.9	14.8	14.4	14.2	13.7
Twin Falls	ROR	3.7	4.9	0.0	0.0	12.6	13.0	10.3	0.0	0.0	0.0	0.0	0.0	3.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.1	12.0	11.4	12.1	16.5	15.1	13.3	8.1	13.2	13.8	12.1	12.2	12.7
Upper Salmon 3&4	ROR	11.6	11.4	11.0	11.6	15.3	14.2	12.6	8.2	12.5	13.0	11.5	11.6	12.0
HCC Total		**474.1**	**448.3**	**533.1**	**520.6**	**629.3**	**388.3**	**500.7**	**332.5**	**301.7**	**439.8**	**346.3**	**408.8**	**443.6**
ROR Total		**170.9**	**170.3**	**162.2**	**194.7**	**289.7**	**297.6**	**275.0**	**198.9**	**205.5**	**188.2**	**166.8**	**167.8**	**207.3**
Total		**645.0**	**618.6**	**695.3**	**715.3**	**919.0**	**685.9**	**775.7**	**531.4**	**507.1**	**628.0**	**513.1**	**576.6**	**650.9**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2021**	**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*	210.0	202.6	231.5	227.1	275.5	168.1	222.4	141.4	128.7	192.7	149.4	177.0	193.9
Oxbow	HCC	88.9	86.8	99.7	96.9	116.5	72.7	93.9	64.3	57.7	83.4	66.2	77.2	83.7
Hells Canyon	HCC	175.8	172.6	202.0	197.4	238.7	147.5	184.4	126.6	113.7	164.1	131.3	152.4	167.2
American Falls	ROR	0.0	0.0	0.0	29.4	69.9	87.7	87.1	56.6	28.7	8.8	0.0	0.0	30.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.8	33.0	32.2	32.6	38.2	36.2	34.0	26.9	35.1	36.1	33.4	33.0	33.6
C .J. Strike	ROR	41.1	41.5	41.7	41.8	44.0	40.1	32.1	29.5	38.9	43.0	41.9	41.3	39.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.4	20.6	19.5	20.3	25.9	24.4	22.0	15.0	21.9	22.9	20.7	20.5	21.2
Milner	ROR	0.0	0.0	0.0	0.0	9.7	9.6	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	6.0	7.6	4.2	4.3	12.0	12.0	12.0	6.5	6.5	6.2	5.4	5.9	7.4
Swan Falls	ROR	14.1	14.3	14.3	14.3	15.0	13.7	11.7	10.4	13.8	14.8	14.4	14.2	13.8
Twin Falls	ROR	0.0	4.0	0.0	0.0	12.4	12.8	10.3	0.0	0.0	0.0	0.0	0.0	3.3
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.0	12.3	11.5	12.2	16.5	15.1	13.3	8.1	13.1	13.7	12.0	11.9	12.6
Upper Salmon 3&4	ROR	11.4	11.7	11.0	11.6	15.3	14.1	12.6	8.1	12.4	12.9	11.5	11.4	12.0
HCC Total		**474.7**	**462.0**	**533.2**	**521.4**	**630.7**	**388.3**	**500.7**	**332.3**	**300.1**	**440.2**	**346.9**	**406.6**	**444.8**
ROR Total		**165.0**	**172.6**	**162.9**	**195.2**	**289.1**	**296.6**	**275.0**	**198.6**	**204.9**	**187.8**	**166.7**	**165.4**	**206.6**
Total		**639.7**	**634.6**	**696.1**	**716.6**	**919.8**	**684.9**	**775.7**	**530.9**	**504.9**	**628.0**	**513.6**	**572.0**	**651.4**

*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*	210.4	202.9	231.8	224.7	275.9	167.9	222.1	141.1	128.2	192.5	149.3	178.0	193.7
Oxbow	HCC	89.1	86.9	99.8	95.9	116.7	72.6	93.8	64.2	57.4	83.3	66.1	77.7	83.6
Hells Canyon	HCC	176.1	172.8	202.2	195.5	239.0	147.3	184.2	126.3	113.2	164.0	131.2	153.3	167.1
American Falls	ROR	0.0	0.0	0.0	30.5	70.1	87.4	86.7	56.0	28.6	8.6	0.0	0.0	30.7
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	33.0	33.2	32.1	32.6	38.4	36.2	34.0	26.8	35.0	36.0	33.4	33.4	33.7
C .J. Strike	ROR	41.7	41.7	41.6	41.2	43.9	39.1	32.0	29.4	38.8	43.0	41.8	41.8	39.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.8	21.0	19.4	20.3	26.0	24.2	21.9	14.9	21.8	22.8	20.7	20.9	21.2
Milner	ROR	0.0	0.0	0.0	0.0	9.6	9.5	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	7.6	9.1	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.5	7.8
Swan Falls	ROR	14.3	14.3	14.2	14.1	15.0	13.4	11.6	10.3	13.8	14.8	14.4	14.2	13.7
Twin Falls	ROR	4.0	5.5	0.0	0.0	12.3	12.6	10.3	0.0	0.0	0.0	0.0	3.9	4.1
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.2	12.5	11.4	12.2	16.6	14.9	13.2	8.0	13.0	13.6	12.0	12.3	12.7
Upper Salmon 3&4	ROR	11.7	11.9	11.0	11.6	15.4	14.0	12.5	8.1	12.3	12.9	11.5	11.7	12.1
HCC Total		**475.6**	**462.6**	**533.8**	**516.1**	**631.6**	**387.8**	**500.1**	**331.6**	**298.8**	**439.8**	**346.6**	**409.0**	**444.4**
ROR Total		**172.5**	**176.8**	**162.4**	**195.2**	**289.5**	**294.2**	**274.1**	**197.5**	**204.2**	**187.3**	**166.6**	**172.9**	**207.8**
Total		**648.1**	**639.4**	**696.2**	**711.3**	**921.1**	**682.0**	**774.2**	**529.1**	**503.0**	**627.1**	**513.2**	**581.9**	**652.2**

*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*	210.1	203.2	231.5	224.6	276.1	167.6	221.8	140.7	126.9	192.6	148.8	178.1	193.5
Oxbow	HCC	89.0	87.1	99.7	95.9	116.7	72.5	93.6	64.0	56.8	83.3	65.9	77.7	83.5
Hells Canyon	HCC	175.9	173.0	202.0	195.3	239.2	147.1	183.9	126.0	112.1	164.0	130.8	153.4	166.9
American Falls	ROR	0.0	0.0	0.0	30.5	70.1	87.4	86.7	56.0	28.6	8.5	0.0	0.0	30.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	33.0	33.2	32.0	32.6	38.4	36.1	33.9	26.7	34.9	35.9	33.2	33.4	33.6
C .J. Strike	ROR	41.6	41.6	41.5	41.2	43.9	38.9	31.9	29.2	38.8	43.0	41.7	41.7	39.6
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.7	20.9	19.3	20.3	26.0	24.0	21.9	14.8	21.6	22.7	20.6	20.8	21.1
Milner	ROR	0.0	0.0	0.0	0.0	9.5	9.4	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	7.6	9.1	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.5	7.8
Swan Falls	ROR	14.2	14.3	14.2	14.1	15.0	13.4	11.6	10.3	13.8	14.7	14.3	14.2	13.7
Twin Falls	ROR	4.0	5.5	0.0	0.0	12.2	12.4	10.3	0.0	0.0	0.0	0.0	3.9	4.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.2	12.5	11.4	12.1	16.5	14.8	13.2	8.0	12.9	13.6	11.9	12.2	12.6
Upper Salmon 3&4	ROR	11.6	11.9	10.9	11.6	15.4	13.8	12.5	8.0	12.2	12.8	11.4	11.7	12.0
HCC Total		**475.0**	**463.3**	**533.2**	**515.8**	**632.0**	**387.2**	**499.3**	**330.7**	**295.8**	**439.9**	**345.5**	**409.2**	**443.9**
ROR Total		**172.1**	**176.6**	**162.0**	**195.1**	**289.2**	**293.1**	**273.9**	**197.0**	**203.7**	**186.8**	**165.9**	**172.6**	**207.3**
Total		**647.1**	**639.9**	**695.2**	**710.9**	**921.2**	**680.3**	**773.2**	**527.7**	**499.5**	**626.7**	**511.4**	**581.8**	**651.2**

*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*	209.8	193.2	231.2	224.4	276.3	167.3	221.5	140.3	125.5	192.3	149.2	177.9	192.4
Oxbow	HCC	88.9	82.8	99.6	95.8	116.8	72.3	93.5	63.9	56.2	83.1	66.0	77.6	83.0
Hells Canyon	HCC	175.7	164.6	201.7	195.2	239.3	146.8	183.6	125.6	110.9	163.6	131.0	153.1	165.9
American Falls	ROR	0.0	0.0	0.0	30.4	70.1	87.4	86.7	56.0	28.5	8.5	0.0	0.0	30.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.9	32.0	31.9	32.6	38.5	36.1	33.8	26.6	34.7	35.7	33.1	33.3	33.4
C .J. Strike	ROR	41.5	40.2	41.4	41.2	43.9	38.8	31.8	29.1	38.7	42.9	41.6	41.4	39.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.7	20.1	19.3	20.2	26.0	23.8	21.8	14.7	21.5	22.6	20.5	20.7	21.0
Milner	ROR	0.0	0.0	0.0	0.0	9.3	9.2	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	7.6	8.8	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.5	7.7
Swan Falls	ROR	14.2	13.8	14.2	14.1	15.0	13.3	11.6	10.2	13.8	14.7	14.3	14.2	13.6
Twin Falls	ROR	4.0	5.3	0.0	0.0	12.0	12.3	10.3	0.0	0.0	0.0	0.0	3.9	4.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.1	12.0	11.3	12.1	16.5	14.6	13.1	7.9	12.8	13.5	11.9	12.2	12.5
Upper Salmon 3&4	ROR	11.6	11.4	10.9	11.6	15.4	13.7	12.4	8.0	12.1	12.7	11.3	11.6	11.9
HCC Total		**474.4**	**440.7**	**532.5**	**515.4**	**632.4**	**386.4**	**498.6**	**329.8**	**292.5**	**439.0**	**346.2**	**408.6**	**441.4**
ROR Total		**171.8**	**171.0**	**161.7**	**194.9**	**288.9**	**292.1**	**273.4**	**196.5**	**203.1**	**186.2**	**165.5**	**172.0**	**206.4**
Total		**646.2**	**611.7**	**694.2**	**710.3**	**921.3**	**678.5**	**772.0**	**526.3**	**495.6**	**625.2**	**511.7**	**580.6**	**647.8**

*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*	209.6	195.7	230.9	224.2	276.4	167.0	221.0	139.9	124.1	192.2	149.1	177.5	192.3
Oxbow	HCC	88.8	83.9	99.4	95.7	116.9	72.2	93.3	63.7	55.5	83.0	65.9	77.4	83.0
Hells Canyon	HCC	175.4	166.8	201.4	195.0	239.4	146.5	183.3	125.3	109.6	163.4	130.9	152.9	165.8
American Falls	ROR	0.0	0.0	0.0	30.3	69.8	87.3	86.7	56.0	28.4	8.4	0.0	0.0	30.6
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.8	33.0	31.8	32.5	38.5	36.0	33.7	26.5	34.5	35.6	33.0	33.2	33.4
C .J. Strike	ROR	41.4	41.5	41.2	41.1	44.0	38.6	31.6	28.9	38.6	42.8	41.5	41.3	39.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.5	20.7	19.2	20.2	25.9	23.6	21.7	14.6	21.3	22.4	20.3	20.6	20.9
Milner	ROR	0.0	0.0	0.0	0.0	9.2	9.1	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	7.6	9.1	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.5	7.8
Swan Falls	ROR	14.2	14.2	14.2	14.1	15.0	13.3	11.5	10.2	13.8	14.6	14.2	14.1	13.6
Twin Falls	ROR	4.0	5.5	0.0	0.0	11.9	12.3	10.3	0.0	0.0	0.0	0.0	4.0	4.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.0	12.4	11.3	12.1	16.5	14.4	13.0	7.8	12.7	13.4	11.8	12.1	12.5
Upper Salmon 3&4	ROR	11.5	11.8	10.8	11.5	15.3	13.6	12.3	7.9	12.0	12.6	11.3	11.5	11.8
HCC Total		**473.8**	**446.4**	**531.7**	**514.9**	**632.7**	**385.7**	**497.6**	**328.9**	**289.2**	**438.6**	**345.9**	**407.8**	**441.1**
ROR Total		**171.2**	**175.8**	**161.2**	**194.5**	**288.3**	**291.1**	**272.7**	**195.9**	**202.2**	**185.4**	**164.9**	**171.5**	**206.2**
Total		**645.0**	**622.2**	**692.9**	**709.4**	**921.0**	**676.8**	**770.3**	**524.8**	**491.4**	**624.0**	**510.8**	**579.3**	**647.3**

*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*	209.2	192.4	230.5	223.9	276.5	166.8	220.7	139.5	121.6	192.7	149.5	177.1	191.7
Oxbow	HCC	88.6	82.4	99.2	95.5	116.9	72.1	93.2	63.4	54.4	83.1	66.1	77.3	82.7
Hells Canyon	HCC	175.1	164.0	201.1	194.7	239.5	146.4	183.0	124.9	107.4	163.5	131.2	152.5	165.3
American Falls	ROR	0.0	0.0	0.0	30.3	69.5	87.0	86.7	56.0	28.1	8.3	0.0	0.0	30.5
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.7	32.9	31.7	32.5	38.3	35.7	33.6	26.3	34.3	35.4	32.9	33.1	33.3
C .J. Strike	ROR	41.1	41.5	41.1	41.0	44.0	38.4	31.5	28.8	38.6	42.7	41.5	41.2	39.3
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.4	20.6	19.1	20.1	25.9	23.4	21.6	14.5	21.1	22.3	20.2	20.6	20.8
Milner	ROR	0.0	0.0	0.0	0.0	9.2	9.1	6.4	0.0	0.0	0.0	0.0	0.0	2.1
Shoshone Falls	ROR	7.6	9.2	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.5	7.8
Swan Falls	ROR	14.1	14.1	14.2	14.1	15.0	13.2	11.5	10.1	13.7	14.6	14.2	14.1	13.6
Twin Falls	ROR	4.0	5.5	0.0	0.0	11.9	12.3	10.3	0.0	0.0	0.0	0.0	4.0	4.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	12.0	12.3	11.2	12.0	16.5	14.4	13.0	7.7	12.5	13.3	11.7	12.0	12.4
Upper Salmon 3&4	ROR	11.4	11.7	10.8	11.5	15.3	13.5	12.3	7.8	11.9	12.5	11.2	11.5	11.8
HCC Total		**472.9**	**438.8**	**530.8**	**514.1**	**632.9**	**385.3**	**496.9**	**327.8**	**283.3**	**439.3**	**346.8**	**406.9**	**439.7**
ROR Total		**170.5**	**175.4**	**160.8**	**194.2**	**287.8**	**289.9**	**272.4**	**195.2**	**201.2**	**184.7**	**164.5**	**171.2**	**205.6**
Total		**643.4**	**614.2**	**691.6**	**708.3**	**920.7**	**675.2**	**769.3**	**523.0**	**484.5**	**624.0**	**511.3**	**578.1**	**645.3**

*HCC=Hells Canyon Complex, **ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2027**	**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*	208.8	192.0	230.1	223.6	276.5	166.7	220.2	139.0	120.2	192.6	149.4	176.8	191.3
Oxbow	HCC	88.5	82.3	99.1	95.4	116.9	72.0	93.0	63.2	53.7	83.0	66.0	77.1	82.5
Hells Canyon	HCC	174.8	163.7	200.7	194.5	239.5	146.3	182.6	124.5	106.2	163.4	131.1	152.2	165.0
American Falls	ROR	0.0	0.0	0.0	30.3	69.5	86.9	86.7	56.0	27.8	8.2	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.6	32.7	31.7	32.5	38.2	35.3	33.4	26.2	34.1	35.3	32.7	33.0	33.1
C .J. Strike	ROR	41.0	41.5	41.0	40.9	44.0	38.1	31.3	28.6	38.4	42.5	41.4	41.2	39.2
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.2	20.5	19.0	20.1	25.8	23.3	21.5	14.4	21.0	22.2	20.1	20.5	20.7
Milner	ROR	0.0	0.0	0.0	0.0	8.6	8.6	6.4	0.0	0.0	0.0	0.0	0.0	2.0
Shoshone Falls	ROR	7.7	9.2	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	14.1	14.1	14.1	14.1	15.0	13.1	11.4	10.1	13.6	14.5	14.1	14.1	13.5
Twin Falls	ROR	4.1	5.5	0.0	0.0	11.4	12.3	10.3	0.0	0.0	0.0	0.0	4.0	4.0
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.8	12.2	11.1	12.0	16.4	14.3	12.9	7.6	12.4	13.1	11.6	12.0	12.3
Upper Salmon 3&4	ROR	11.3	11.6	10.7	11.5	15.2	13.4	12.2	7.7	11.8	12.4	11.1	11.4	11.7
HCC Total		**472.1**	**438.0**	**529.9**	**513.5**	**632.9**	**385.0**	**495.8**	**326.7**	**280.0**	**439.0**	**346.5**	**406.1**	**438.8**
ROR Total		**170.0**	**174.9**	**160.3**	**194.1**	**286.3**	**288.2**	**271.6**	**194.6**	**200.1**	**183.8**	**163.8**	**171.0**	**204.9**
Total		**642.1**	**612.9**	**690.2**	**707.6**	**919.2**	**673.2**	**767.4**	**521.3**	**480.1**	**622.8**	**510.3**	**577.1**	**643.7**

*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*	208.4	185.0	228.1	223.2	276.6	166.4	219.7	138.6	118.1	193.0	149.6	176.4	190.3
Oxbow	HCC	88.3	79.3	98.2	95.3	117.0	71.9	92.8	63.0	52.7	83.1	66.1	76.9	82.0
Hells Canyon	HCC	174.5	157.8	199.1	194.2	239.6	146.1	182.2	124.1	104.3	163.5	131.2	151.9	164.0
American Falls	ROR	0.0	0.0	0.0	30.3	69.3	86.8	86.7	56.0	27.7	8.2	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.5	31.5	31.6	32.5	37.8	34.9	33.3	26.1	33.9	35.1	32.6	32.9	32.9
C .J. Strike	ROR	40.9	40.0	40.9	40.8	44.0	37.9	31.2	28.4	38.2	42.4	41.3	41.1	38.9
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.1	19.7	18.9	20.0	25.6	23.2	21.4	14.3	20.8	22.0	19.9	20.4	20.5
Milner	ROR	0.0	0.0	0.0	0.0	8.3	8.2	6.4	0.0	0.0	0.0	0.0	0.0	1.9
Shoshone Falls	ROR	7.7	8.9	4.2	4.0	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.7
Swan Falls	ROR	14.1	13.7	14.1	14.0	15.0	13.0	11.4	10.0	13.5	14.4	14.1	14.1	13.5
Twin Falls	ROR	4.1	5.3	0.0	0.0	11.1	11.9	10.3	0.0	0.0	0.0	0.0	4.0	3.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.7	11.7	11.0	11.9	16.2	14.2	12.8	7.5	12.3	13.0	11.5	11.9	12.1
Upper Salmon 3&4	ROR	11.2	11.1	10.6	11.4	15.1	13.3	12.2	7.7	11.7	12.3	11.0	11.4	11.6
HCC Total		**471.2**	**422.0**	**525.4**	**512.7**	**633.2**	**384.4**	**494.7**	**325.7**	**275.0**	**439.6**	**346.9**	**405.2**	**436.3**
ROR Total		**169.5**	**169.4**	**159.8**	**193.6**	**284.6**	**286.3**	**271.2**	**194.0**	**199.0**	**183.0**	**163.2**	**170.6**	**203.7**
Total		**640.7**	**591.4**	**685.2**	**706.3**	**917.8**	**670.7**	**765.9**	**519.7**	**474.0**	**622.6**	**510.1**	**575.8**	**640.0**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	208.0	191.3	227.6	222.8	276.7	165.6	219.2	138.1	116.2	192.9	149.7	175.9	190.3
Oxbow	HCC	88.1	81.9	98.0	95.1	117.0	71.6	92.6	62.8	51.9	83.0	66.1	76.7	82.1
Hells Canyon	HCC	174.2	163.1	198.7	193.9	239.6	145.4	181.8	123.6	102.7	163.3	131.3	151.5	164.1
American Falls	ROR	0.0	0.0	0.0	30.3	69.0	86.8	86.7	56.0	27.5	8.4	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.4	32.5	31.5	32.4	37.7	34.6	33.2	25.9	33.7	34.9	32.4	32.8	32.8
C .J. Strike	ROR	40.8	41.3	40.4	40.5	43.9	37.7	31.0	28.2	37.9	42.2	41.1	40.9	38.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	20.0	20.2	18.8	19.9	25.3	23.0	21.3	14.2	20.6	21.9	19.8	20.3	20.4
Milner	ROR	0.0	0.0	0.0	0.0	8.3	8.2	6.4	0.0	0.0	0.0	0.0	0.0	1.9
Shoshone Falls	ROR	7.7	9.1	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	14.1	14.1	14.1	14.0	15.0	13.0	11.3	9.9	13.4	14.4	14.1	14.1	13.5
Twin Falls	ROR	4.1	5.4	0.0	0.0	11.1	11.8	10.3	0.0	0.0	0.0	0.0	4.0	3.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.6	12.0	11.0	11.9	16.1	14.0	12.7	7.4	12.1	12.9	11.4	11.8	12.1
Upper Salmon 3&4	ROR	11.1	11.4	10.6	11.4	14.9	13.2	12.1	7.6	11.6	12.2	10.9	11.3	11.5
HCC Total		**470.3**	**436.3**	**524.3**	**511.8**	**633.3**	**382.6**	**493.6**	**324.5**	**270.7**	**439.2**	**347.1**	**404.1**	**436.5**
ROR Total		**169.0**	**173.6**	**159.1**	**193.0**	**283.5**	**285.2**	**270.5**	**193.2**	**197.8**	**182.5**	**162.5**	**170.0**	**203.3**
Total		**639.3**	**609.9**	**683.4**	**704.8**	**916.8**	**667.8**	**764.1**	**517.7**	**468.5**	**621.7**	**509.6**	**574.1**	**639.8**

*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*	207.6	190.8	227.2	222.2	276.7	164.9	218.8	137.6	114.5	192.9	149.9	175.5	189.9
Oxbow	HCC	87.9	81.8	97.8	94.8	117.0	71.2	92.4	62.5	51.1	82.9	66.2	76.5	81.8
Hells Canyon	HCC	173.8	162.7	198.3	193.4	239.7	144.8	181.4	123.2	101.1	163.1	131.4	151.2	163.7
American Falls	ROR	0.0	0.0	0.0	30.9	69.0	86.4	86.7	56.1	27.4	8.3	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.3	32.4	31.4	32.3	37.7	34.4	33.1	25.8	33.6	34.8	32.3	32.7	32.7
C .J. Strike	ROR	40.8	41.1	40.3	40.3	43.9	37.5	30.8	28.0	37.7	42.1	40.9	40.8	38.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.9	20.2	18.7	19.9	25.3	22.8	21.2	14.0	20.5	21.7	19.7	20.2	20.3
Milner	ROR	0.0	0.0	0.0	0.0	8.2	8.1	6.4	0.0	0.0	0.0	0.0	0.0	1.9
Shoshone Falls	ROR	7.7	9.1	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	14.1	14.1	14.1	13.9	15.0	12.9	11.2	9.9	13.4	14.3	14.1	14.0	13.4
Twin Falls	ROR	4.1	5.4	0.0	0.0	11.0	11.6	10.3	0.0	0.0	0.0	0.0	4.0	3.9
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.6	11.9	10.9	11.8	16.0	13.9	12.7	7.3	12.0	12.8	11.3	11.7	12.0
Upper Salmon 3&4	ROR	11.1	11.4	10.5	11.3	14.9	13.1	12.0	7.5	11.5	12.1	10.8	11.2	11.5
HCC Total		**469.3**	**435.3**	**523.3**	**510.4**	**633.4**	**380.9**	**492.6**	**323.3**	**266.6**	**438.9**	**347.5**	**403.2**	**435.4**
ROR Total		**168.8**	**173.2**	**158.6**	**193.0**	**283.2**	**283.6**	**269.9**	**192.6**	**197.1**	**181.7**	**161.9**	**169.4**	**202.7**
Total		**638.1**	**608.5**	**681.9**	**703.4**	**916.6**	**664.5**	**762.5**	**515.9**	**463.7**	**620.6**	**509.4**	**572.6**	**638.1**

*HCC=Hells Canyon Complex, **ROR= Run of River

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*	207.2	190.4	226.7	221.8	276.7	164.4	218.3	137.1	113.9	192.3	149.6	177.7	189.7
Oxbow	HCC	87.7	81.6	97.6	94.7	117.0	71.0	92.2	62.3	50.8	82.6	66.0	77.5	81.8
Hells Canyon	HCC	173.5	162.4	197.9	193.0	239.7	144.4	181.0	122.7	100.6	162.7	131.1	153.0	163.5
American Falls	ROR	0.0	0.0	0.0	31.1	68.8	86.6	86.5	56.0	27.4	8.3	0.0	0.0	30.4
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.3	32.4	31.6	32.2	37.7	34.2	33.0	25.6	33.4	34.6	32.1	32.7	32.7
C .J. Strike	ROR	41.0	41.0	40.6	40.1	43.8	37.3	30.7	27.9	37.4	42.0	40.8	40.6	38.6
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.9	20.1	18.7	19.8	25.2	22.6	21.1	13.9	20.3	21.6	19.5	20.1	20.2
Milner	ROR	0.0	0.0	0.0	0.0	8.1	8.0	6.4	0.0	0.0	0.0	0.0	0.0	1.9
Shoshone Falls	ROR	7.7	9.2	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	14.1	14.1	14.1	13.9	15.0	12.9	11.2	9.8	13.3	14.2	14.1	14.0	13.4
Twin Falls	ROR	4.1	5.5	0.0	0.0	10.8	11.3	10.3	0.0	0.0	0.0	0.0	4.0	3.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.6	11.9	10.8	11.8	15.9	13.7	12.6	7.2	11.9	12.7	11.2	11.7	11.9
Upper Salmon 3&4	ROR	11.1	11.3	10.5	11.3	14.8	12.9	12.0	7.4	11.4	12.0	10.7	11.2	11.4
HCC Total		**468.4**	**434.4**	**522.2**	**509.5**	**633.4**	**379.8**	**491.5**	**322.1**	**265.3**	**437.6**	**346.7**	**408.2**	**434.9**
ROR Total		**169.0**	**173.1**	**159.0**	**192.8**	**282.3**	**282.4**	**269.3**	**191.8**	**196.0**	**181.0**	**161.2**	**169.1**	**202.2**
Total		**637.4**	**607.5**	**681.2**	**702.3**	**915.7**	**662.2**	**760.8**	**513.9**	**461.3**	**618.6**	**507.9**	**577.3**	**637.2**

*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*	206.6	183.4	226.3	221.4	276.8	163.8	217.8	136.5	113.8	190.2	149.7	176.5	188.6
Oxbow	HCC	87.5	78.6	97.4	94.5	117.0	70.8	91.9	62.1	50.8	81.7	66.1	77.0	81.3
Hells Canyon	HCC	173.0	156.4	197.6	192.7	239.7	143.8	180.6	122.2	100.6	160.9	131.2	152.0	162.6
American Falls	ROR	0.0	0.0	0.0	31.1	68.4	86.4	86.5	56.0	27.2	8.3	0.0	0.0	30.3
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.2	31.2	31.6	32.1	37.6	33.9	32.8	25.5	33.2	34.4	32.0	32.6	32.4
C .J. Strike	ROR	40.9	39.4	40.5	39.8	43.8	37.1	30.6	27.7	37.1	41.8	40.5	40.5	38.3
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.8	19.3	18.6	19.7	24.9	22.2	21.0	13.8	20.1	21.4	19.4	20.0	20.0
Milner	ROR	0.0	0.0	0.0	0.0	7.8	7.7	6.4	0.0	0.0	0.0	0.0	0.0	1.8
Shoshone Falls	ROR	7.7	8.9	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.7
Swan Falls	ROR	14.1	13.5	14.0	13.8	14.9	12.8	11.1	9.8	13.2	14.2	14.0	14.0	13.3
Twin Falls	ROR	4.1	5.3	0.0	0.0	10.5	11.0	10.3	0.0	0.0	0.0	0.0	4.0	3.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.5	11.4	10.8	11.7	15.7	13.4	12.5	7.1	11.7	12.6	11.0	11.6	11.7
Upper Salmon 3&4	ROR	11.1	10.9	10.4	11.2	14.7	12.7	11.9	7.3	11.2	11.9	10.6	11.1	11.3
HCC Total		**467.1**	**418.5**	**521.3**	**508.6**	**633.5**	**378.4**	**490.3**	**320.8**	**265.2**	**432.8**	**347.0**	**405.5**	**432.4**
ROR Total		**168.6**	**167.5**	**158.6**	**192.0**	**280.5**	**280.1**	**268.6**	**191.2**	**194.7**	**180.2**	**160.3**	**168.6**	**200.9**
Total		**635.7**	**585.9**	**679.9**	**700.6**	**914.0**	**658.5**	**758.9**	**512.0**	**459.9**	**613.0**	**507.3**	**574.1**	**633.3**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	206.4	189.5	225.8	221.1	276.4	163.2	217.3	136.0	113.8	188.0	149.9	175.9	188.6
Oxbow	HCC	87.4	81.2	97.2	94.4	116.9	70.5	91.7	61.8	50.8	80.8	66.1	76.7	81.3
Hells Canyon	HCC	172.8	161.7	197.2	192.5	239.4	143.4	180.2	121.8	100.6	159.1	131.3	151.5	162.6
American Falls	ROR	0.0	0.0	0.0	30.1	68.4	85.9	86.6	56.0	27.1	8.2	0.0	0.0	30.2
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	32.0	32.2	31.5	32.1	37.6	33.8	32.7	25.3	33.0	34.3	31.8	32.4	32.4
C .J. Strike	ROR	40.8	40.7	40.4	39.3	43.8	36.9	30.4	27.5	36.9	41.6	40.3	40.3	38.2
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.7	19.9	18.5	19.7	24.9	22.1	20.9	13.6	19.9	21.3	19.3	19.9	20.0
Milner	ROR	0.0	0.0	0.0	0.0	7.7	7.6	6.4	0.0	0.0	0.0	0.0	0.0	1.8
Shoshone Falls	ROR	7.7	9.2	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	14.0	14.0	14.0	13.6	14.9	12.8	11.1	9.7	13.1	14.1	13.9	13.9	13.3
Twin Falls	ROR	4.1	5.5	0.0	0.0	10.5	10.9	10.3	0.0	0.0	0.0	0.0	4.0	3.8
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.4	11.7	10.7	11.7	15.7	13.3	12.4	7.0	11.6	12.4	10.9	11.5	11.7
Upper Salmon 3&4	ROR	10.9	11.2	10.3	11.2	14.6	12.6	11.8	7.3	11.1	11.8	10.6	11.0	11.2
HCC Total		**466.6**	**432.4**	**520.2**	**508.0**	**632.7**	**377.1**	**489.2**	**319.6**	**265.2**	**427.9**	**347.3**	**404.1**	**432.5**
ROR Total		**167.8**	**172.0**	**158.1**	**190.3**	**280.3**	**278.8**	**268.1**	**190.4**	**193.6**	**179.3**	**159.6**	**167.8**	**200.5**
Total		**634.4**	**604.4**	**678.3**	**698.3**	**913.0**	**655.9**	**757.3**	**510.0**	**458.8**	**607.2**	**506.9**	**571.9**	**633.0**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	206.3	189.1	225.4	220.8	275.9	162.6	216.8	135.5	113.7	186.2	149.7	175.4	188.1
Oxbow	HCC	87.4	81.0	97.0	94.3	116.7	70.3	91.5	61.6	50.8	80.0	66.0	76.5	81.1
Hells Canyon	HCC	172.7	161.3	196.8	192.2	239.0	142.9	179.8	121.3	100.6	157.6	131.1	151.1	162.2
American Falls	ROR	0.0	0.0	0.0	30.9	68.4	85.1	86.6	56.0	26.6	8.1	0.0	0.0	30.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	31.8	32.0	31.4	31.8	37.6	33.6	32.6	25.2	32.8	34.1	31.6	32.3	32.2
C .J. Strike	ROR	40.4	40.5	40.3	39.2	43.5	36.4	30.4	27.3	36.6	41.4	40.1	40.2	38.0
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.5	19.8	18.3	19.6	24.7	21.9	20.8	13.5	19.7	21.1	19.1	19.8	19.8
Milner	ROR	0.0	0.0	0.0	0.0	7.5	7.4	6.4	0.0	0.0	0.0	0.0	0.0	1.8
Shoshone Falls	ROR	7.7	9.2	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	13.9	13.9	13.9	13.6	14.8	12.6	11.0	9.7	13.0	14.2	13.9	13.9	13.2
Twin Falls	ROR	4.1	5.5	0.0	0.0	10.2	10.7	10.3	0.0	0.0	0.0	0.0	4.0	3.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.2	11.6	10.6	11.6	15.6	13.1	12.3	6.9	11.5	12.3	10.8	11.4	11.6
Upper Salmon 3&4	ROR	10.8	11.1	10.3	11.1	14.5	12.4	11.7	7.2	11.0	11.7	10.5	11.0	11.1
HCC Total		**466.4**	**431.4**	**519.2**	**507.3**	**631.6**	**375.8**	**488.1**	**318.4**	**265.1**	**423.8**	**346.8**	**403.0**	**431.4**
ROR Total		**166.6**	**171.2**	**157.5**	**190.4**	**279.0**	**276.1**	**267.6**	**189.8**	**192.1**	**178.5**	**158.8**	**167.4**	**199.6**
Total		**633.0**	**602.6**	**676.7**	**697.7**	**910.6**	**651.9**	**755.7**	**508.2**	**457.2**	**602.3**	**505.6**	**570.4**	**631.0**

*HCC=Hells Canyon Complex, **ROR= Run of River

Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2035**	**2/2035**	**3/2035**	**4/2035**	**5/2035**	**6/2035**	**7/2035**	**8/2035**	**9/2035**	**10/2035**	**11/2035**	**12/2035**	**aMW**
Brownlee	HCC*	206.2	188.6	224.8	220.5	275.6	162.1	216.3	135.0	113.7	183.7	150.2	175.0	187.6
Oxbow	HCC	87.3	80.8	96.8	94.1	116.5	70.0	91.3	61.4	50.8	78.9	66.2	76.3	80.9
Hells Canyon	HCC	172.6	160.9	196.4	192.0	238.7	142.4	179.4	120.9	100.6	155.4	131.4	150.7	161.8
American Falls	ROR	0.0	0.0	0.0	30.9	68.4	84.9	86.6	56.0	26.4	8.1	0.0	0.0	30.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	31.7	31.9	31.3	31.7	37.4	33.4	32.4	25.0	32.5	33.9	31.4	32.1	32.1
C .J. Strike	ROR	40.3	40.4	40.1	39.1	43.0	35.7	30.3	27.1	36.3	41.2	39.9	40.0	37.8
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.4	19.7	18.2	19.5	24.5	21.7	20.7	13.4	19.5	20.9	19.0	19.7	19.7
Milner	ROR	0.0	0.0	0.0	0.0	7.2	7.1	6.4	0.0	0.0	0.0	0.0	0.0	1.7
Shoshone Falls	ROR	7.7	9.2	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.8
Swan Falls	ROR	13.9	13.9	13.9	13.6	14.7	12.5	11.0	9.6	13.0	14.1	13.8	13.8	13.2
Twin Falls	ROR	4.1	5.5	0.0	0.0	10.1	10.6	10.3	0.0	0.0	0.0	0.0	4.0	3.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.2	11.5	10.5	11.5	15.4	13.0	12.2	6.8	11.3	12.2	10.7	11.3	11.5
Upper Salmon 3&4	ROR	10.8	11.1	10.2	11.1	14.4	12.3	11.7	7.1	10.9	11.6	10.4	10.9	11.0
HCC Total		**466.1**	**430.3**	**518.0**	**506.6**	**630.8**	**374.5**	**487.0**	**317.3**	**265.1**	**418.0**	**347.8**	**402.0**	**430.3**
ROR Total		**166.3**	**170.8**	**156.9**	**190.0**	**277.3**	**274.1**	**267.1**	**189.0**	**190.8**	**177.6**	**158.0**	**166.6**	**198.7**
Total		**632.4**	**601.1**	**674.9**	**696.6**	**908.1**	**648.6**	**754.1**	**506.3**	**455.9**	**595.6**	**505.8**	**568.6**	**629.0**

*HCC=Hells Canyon Complex, **ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2036**	**2/2036**	**3/2036**	**4/2036**	**5/2036**	**6/2036**	**7/2036**	**8/2036**	**9/2036**	**10/2036**	**11/2036**	**12/2036**	**aMW**
Brownlee	HCC*	205.4	181.7	224.5	220.2	275.6	161.5	215.8	134.5	113.6	174.7	149.7	174.9	186.0
Oxbow	HCC	87.0	77.8	96.6	94.0	116.5	69.8	91.1	61.1	50.8	78.1	66.0	76.3	80.4
Hells Canyon	HCC	172.0	155.0	196.1	191.7	238.7	141.9	179.0	120.4	100.6	153.5	131.0	150.6	160.9
American Falls	ROR	0.0	0.0	0.0	31.2	68.4	84.8	86.4	55.6	26.3	8.1	0.0	0.0	30.1
1,000 Springs	ROR**	6.2	6.3	6.1	6.1	6.1	5.9	5.9	6.1	6.2	6.3	6.2	6.2	6.1
Bliss	ROR	31.6	30.7	31.2	31.6	37.2	33.3	32.3	24.9	32.3	33.7	31.3	32.0	31.8
C .J. Strike	ROR	39.9	38.8	40.0	39.0	42.7	35.0	30.3	26.9	36.1	40.9	39.7	39.8	37.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.3	1.3	1.3	1.3	3.2
Clear Lake	ROR	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.8	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.3	11.4	12.2	12.3	13.4	12.0	12.1	12.4	13.0	13.0	11.5	11.4	12.2
Lower Salmon	ROR	19.3	19.0	18.1	19.4	24.4	21.6	20.5	13.2	19.3	20.8	18.8	19.6	19.5
Milner	ROR	0.0	0.0	0.0	0.0	6.7	6.6	6.4	0.0	0.0	0.0	0.0	0.0	1.6
Shoshone Falls	ROR	7.7	8.9	4.2	3.9	12.0	12.0	12.0	6.5	6.5	6.2	5.4	7.6	7.7
Swan Falls	ROR	13.8	13.3	13.9	13.5	14.6	12.3	10.9	9.5	12.9	14.0	13.7	13.8	13.0
Twin Falls	ROR	4.1	5.3	0.0	0.0	9.8	10.5	10.3	0.0	0.0	0.0	0.0	4.0	3.7
Upper Malad	ROR	6.5	6.6	7.0	7.2	7.5	7.0	6.9	7.0	7.2	7.0	6.4	6.4	6.9
Upper Salmon 1&2	ROR	11.1	11.1	10.4	11.5	15.4	12.9	12.1	6.7	11.1	12.1	10.6	11.2	11.4
Upper Salmon 3&4	ROR	10.7	10.7	10.1	11.0	14.3	12.2	11.6	7.0	10.7	11.5	10.3	10.8	10.9
HCC Total		**464.4**	**414.5**	**517.2**	**505.9**	**630.8**	**373.2**	**485.9**	**316.0**	**265.0**	**406.3**	**346.7**	**401.8**	**427.3**
ROR Total		**165.4**	**165.4**	**156.4**	**189.8**	**275.7**	**272.1**	**266.3**	**187.8**	**189.6**	**176.7**	**157.2**	**166.0**	**197.4**
Total		**629.8**	**579.9**	**673.6**	**695.7**	**906.5**	**645.3**	**752.2**	**503.8**	**454.6**	**583.0**	**503.9**	**567.8**	**624.7**

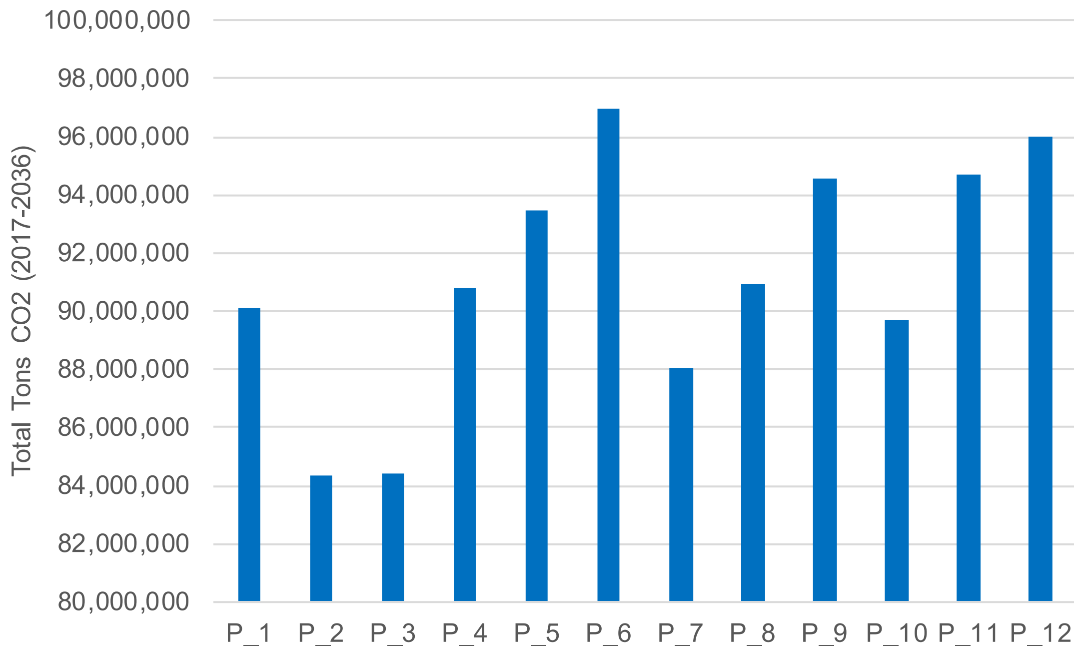
*HCC=Hells Canyon Complex, **ROR= Run of River

Portfolio Analysis, Results, and Supporting Documentation

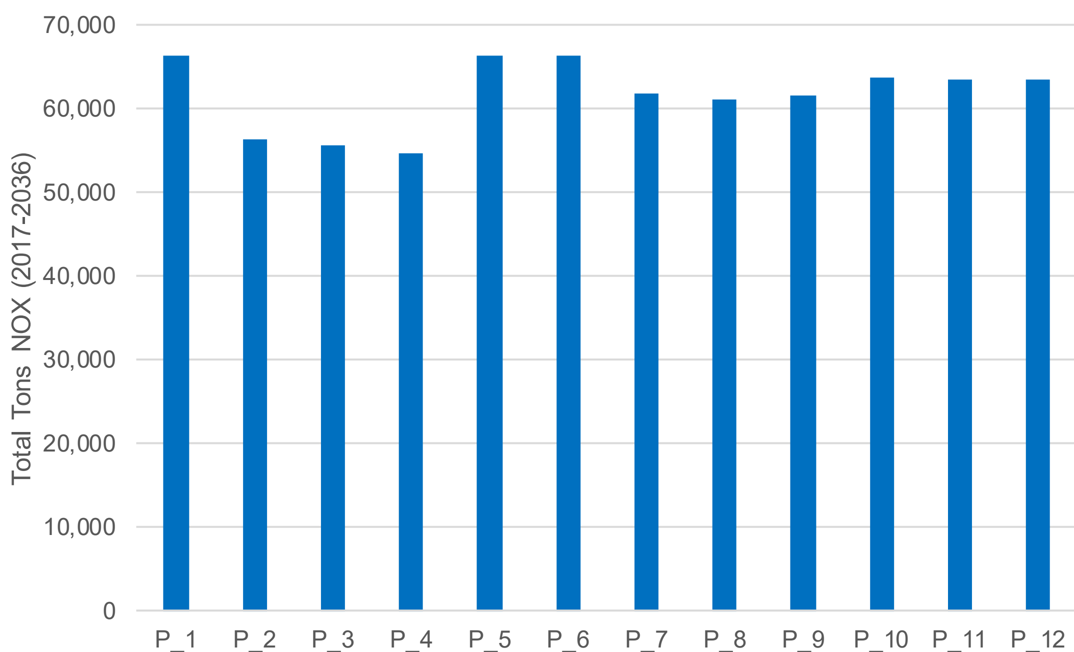
Portfolio Emissions

IPC Emissions

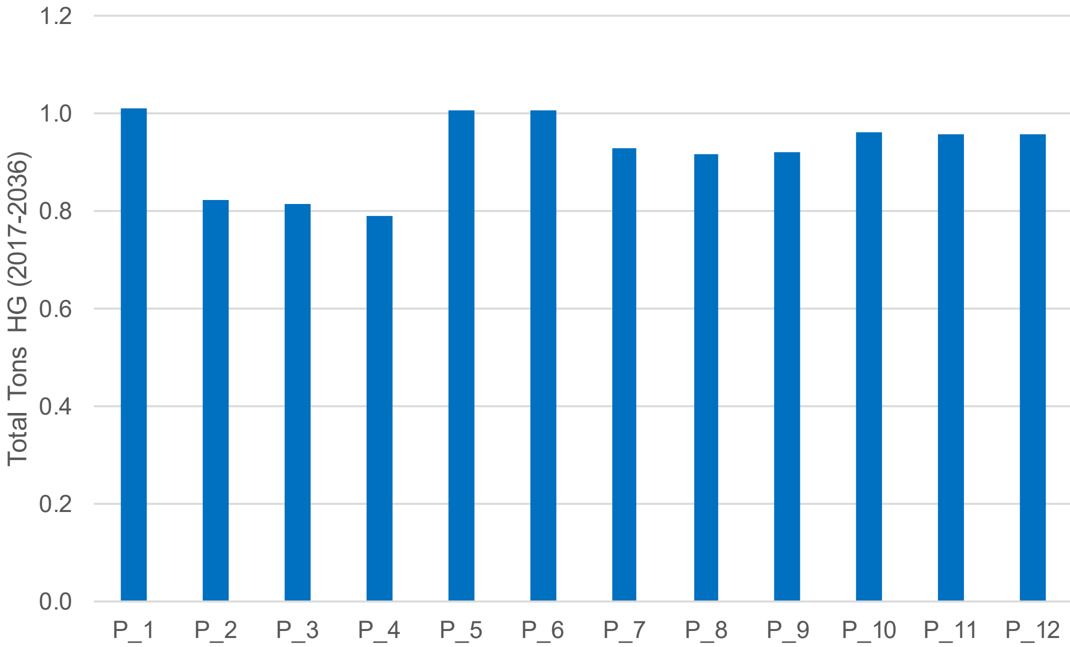
CO_2 Emission



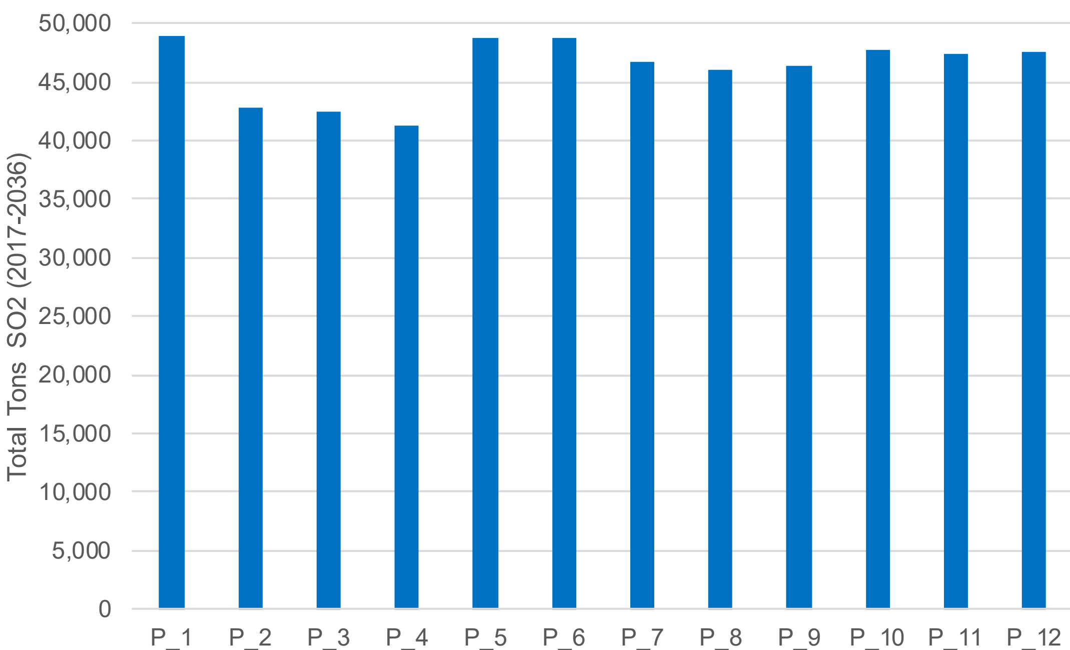
NOx Emission



HG Emission



SO_2 Emission



COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

Guideline 1: Substantive Requirements

a. All resources must be evaluation 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.

Idaho Power response:

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 3. Idaho Power Today—Existing Supply-side Resources*; demand-side options for are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning—Existing Transmission System*.

New resource options including fuel types, technologies, lead times, in-service dates, durations and locations are described in *Chapter 4. Future Supply-side Generation and Storage Resources*, *Chapter 5. Demand-Side resources*, *Chapter 6. Transmission Planning*, and *Chapter 7. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and *Chapter 9. Modeling Analysis and Result—Planning Case Portfolio Analysis*.

The WACC rate used to discount all future resource costs is stated in *Chapter 9. Modeling Analysis and Results* Table 9.1 Financial Assumptions.

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.

Idaho Power response:

Electric utility risk and uncertainty factors (load, NG and water conditions) for resource portfolios are considered in *Chapter 9b Modeling Analysis and Results—Stochastic Risk Analysis*. Plant forced outages are modeled in Aurora on a unit basis and is shown in the Technical Appendix, *Existing Resource Data—Hydroelectric and Thermal Plant Data*.

Additional sources of risk and uncertainty are discussed in *Chapter 9. Modeling Analysis and Results*.

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 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:
  a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
  b. 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.

Idaho Power response:

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. Summary—Introduction*.

Modeling 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 is discussed in *Chapter 9. Modeling Analysis and Results*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis and Risk*. Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1a. Summary—Introduction*.

Idaho Power's plan is presented in *Chapter 1g. Summary—Action Plan* and in more detail in *Chapter 10. Preferred Portfolio and Action Plan.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Idaho Power response:

Long-run public interest issues are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*.

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.

Idaho Power response:

The IRP Advisory Council meetings are open to the public. A roster of the IRP Advisory Council members along with meeting schedules and agendas is provided in the Technical Appendix, *IRP Advisory Council*.

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.

Idaho Power response:
Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is discussed in IRP Advisory Council meetings and found throughout the 2017 IRP, the 2017 Load and Sales Forecast and in the 2017 Technical Appendix.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Idaho Power response:
Idaho Power provided copies to members of the IRPAC on Thursday, May 11, 2017. The company requested for comments to be provided no later than Friday, June 12, 2017.

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.

Idaho Power response:
The OPUC acknowledged Idaho Power's 2015 IRP on April 28, 2016 in Order 16-160. The Idaho Power 2017 IRP will be filed by June 30, 2017.

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.

Idaho Power response:
Idaho Power will schedule a public meeting at the OPUC following the June 30, 2017 filing of the 2017 IRP.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

Idaho Power response:
No response needed.

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.

Idaho Power response:
No response needed.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

Idaho Power response:
No response needed.

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.

Idaho Power response:
In Order No. 16-160, the OPUC waived for Idaho Power the requirement to file an annual update to the 2015 IRP.

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.

Idaho Power response:
No response needed.

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;

Idaho Power response:
Idaho Power provides information on how the company met each requirement in a table is presented in the Technical Appendix and will be provided to the OPUC staff in an informal letter.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

Idaho Power response:
High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in *Chapter 7. Planning Period Forecasts*. Stochastic load risk analysis is discussed in *Chapter 9. Modeling Analysis and Results—Stochastic Risk Analysis*. Major assumptions are discussed in *Chapter 7. Planning Period Forecasts* and *Chapter 9a. Modeling Analysis and Results—Planning Case Portfolio Analysis*.

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;

Idaho Power response:
Peaking capacity and energy capability for each year of the plan for existing resources is discussed in *Chapter 7. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Sales and Load Forecast Data* and *Chapter 10. Existing Resource Data*, and *Chapter 5. Load and Resource Balance Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 8. Portfolios*.

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;

Idaho Power response:
Not applicable.

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

Idaho Power response:
Supply-side resources are discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources*. Demand-side resources are discussed in Chapter 5-Demand-Side Resources. Resource costs are discussed in *Chapter 7. Planning Period Forecasts – Resource Costs* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*. Demand-side resources and their levelized costs and technologies are covered in *Chapter 5. Demand-Side Resources* and in the Technical Appendix, *Demand-Side Resource Data*.

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

Idaho Power response:
Resource reliability is covered in *Chapter 9. Modeling Analysis and Results*

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

Idaho Power response:
Key Assumptions including the natural gas price forecast are discussed in *Chapter 7. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*. Compliance alternatives to SCR installation at Jim Bridger Units 1 and 2 are considered using portfolios with varying retirement dates of Jim Bridger Units 1 and 2 and are discussed in *Chapter 8 Portfolios*.

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;

Idaho Power response:
Resource portfolios considered for the 2017 IRP are described in *Chapter 8. Portfolios*. Resource portfolios were developed using resources from the resource stack provided in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and with guidance from the IRP Advisory Council and public participants.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

Idaho Power response:
Evaluation of the portfolios over a range of risks and uncertainties is discussed in *Chapter 9. Modeling Analysis and Results*.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

Idaho Power response:
Portfolio cost, risk results, interpretations and the selection of the preferred portfolio are provided in *Chapter 9. Modeling Analysis and Results*.

k. Analysis of the uncertainties associated with each portfolio evaluated;

Idaho Power response:
The quantitative and qualitative uncertainties associated with each portfolio are evaluated in *Chapter 9. Modeling Analysis and Results*.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

Idaho Power response:
The preferred resource portfolio is identified in *Chapter 10. Preferred Portfolio and Action Plan*.

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

Idaho Power response:
Portfolio risk associated with the successful permitting to operate Jim Bridger Units 1 and 2 beyond their regional haze compliance dates without installation of SCR retrofits is discussed in *Chapter 9 Modeling Analysis and Results*.

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.

Idaho Power response:
An action plan is provided in *Chapter 1. Summary—Action Plan* and in *Chapter 10 Preferred Portfolio and Action Plan.*

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.

Idaho Power response:
The fuel transportation and electric transmission required for each resource being considered is presented in the Technical Appendix, *Cost Inputs and Operating Assumptions*. Transmission assumptions for supply-side resources considered are included in *Chapter 6. Transmission Planning—Transmission assumptions in IRP portfolios*. Transportation for natural gas is discussed in *Chapter 7. Planning Period Forecasts—Natural Gas Price Forecast*.

Guideline 6: Conservation

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.

Idaho Power response:
Applied Energy Group (AEG) conducted a study for the 2017 IRP and is described in *Chapter 5 Demand-Side Resources*.

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.

Idaho Power response:
A forecast for energy efficiency effects in five-year blocks is provided in Cha*pter 5. Demand-Side Resources—Committed EE forecast*. Detailed monthly forecast values are a line item in the Technical Appendix, *Load and Resource Balance Data.*

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.

Idaho Power response:

Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Chapter 5. Demand-Side Resources*. NEEA savings are included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.

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).

Idaho Power response:

Demand response resources are evaluated in *Chapter 5. Demand-Side Resources*. Additional demand response above baseline levels is considered in select portfolios and discussed in *Chapter 5. Demand-Side Resources—Additional DR*.

Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO2 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 response:

Compliance with existing environmental regulation is discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio is shown in the Technical Appendix, *Portfolio Analysis, Results, and Supporting Documentation*.

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.

Idaho Power response:

Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads.

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 response:

Idaho Power's analysis was performed on an integrated-system basis discussed in *Chapter 9. Modeling Analysis and Results*. Idaho Power will file the 2017 IRP in both the Idaho and Oregon jurisdictions.

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.

Idaho Power response:

The capacity planning margin is discussed in *Chapter 9. Modeling Analysis and Results—Capacity Planning Margin* followed by the discussion of flexible resource needs assessment at *Chapter 9g. Modeling Analysis and Results—Flexible Resource Needs Assessment* and the loss of load probabilities at *Chapter 9h. Modeling Analysis and Results—LOLE*.

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 response:

Idaho Power evaluated utility scale solar PV combined with reciprocating engines as resource options in four portfolios. In four other portfolios, reciprocating engines were paired with CCCT gas turbines. These portfolios are discussed in *Chapter 8. Portfolios*.

Other distributed generation technologies were evaluated in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis*. Utility-scale solar and reciprocating engines were selected for further portfolio analysis based on their low-cost, scalability, and efficiency. As shown in our load and resource balance, resource need is beyond the immediate action plan. While utility scale solar and reciprocating engines are currently the low-cost choices, these future energy needs will continually be reevaluated.

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.

Idaho Power response:

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 No. 14-149 issued on April 30, 2014.

Idaho Power discusses asset ownership in *Chapter 10b. Preferred Portfolio and Action Plan—Action Plan (2017–2020).*

Idaho Power's action plan includes ongoing permitting, planning studies, and regulatory filings associated with the Boardman to Hemingway transmission line.

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 response:

Not applicable.

Compliance with EV Guidelines

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;

Idaho Power response:
A discussion of the 2017 IRP's analysis for the flexibility guideline is provided in *Chapter 9. Modeling Analysis and Results—Flexible Resource Needs Assessment*.

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;

Idaho Power response:
A discussion of the 2017 IRP's analysis for the flexibility guideline is provided in *Chapter 9. Modeling Analysis and Results—Flexible Resource Needs Assessment*.

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.

Idaho Power response:
The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast, *Company System Load—Electric Vehicles*

State Of Oregon Action Items Regarding Idaho Power's 2015 IRP

Action Item 1: B2H Transmission Line

Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.

Idaho Power response:
Discussion specific to B2H is found in *Chapter 6. Transmission Planning—Boardman to Hemingway.* Portfolio design for the 2017 IRP provides a comparison of portfolios having B2H as a resource to portfolios not having B2H. A tabulation of resource portfolios with respect to B2H inclusion is provided in *Chapter 8. Portfolios*.

Action Item 2: Gateway West Transmission Line

Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.

Idaho Power response:
Discussion specific to Gateway West is found in Chapter 6e. Transmission Planning—Gateway West.

Action Item 3: Energy Efficiency

Idaho Power will continue the pursuit of cost-effective energy efficiency—the forecast reduction for the 2015–2019 programs is 84 average megawatts (MW) for energy demand and 126 MW for peak demand.

Idaho Power response:
Discussion specific to energy efficiency is found in *Chapter 5. Demand-Side Resources*. All portfolios contain achievable energy efficiency. The monthly forecast is provided in the Technical Appendix, *Load and Resource Balance Data*.

Action Item 4: Section 111(d)

Idaho Power will coordinate with government agencies on implementation planning for Section 111 (d).

Idaho Power response:
All portfolios meet current regulatory requirements. Portfolio Emissions are shown in the Technical Appendix, *Portfolio Emissions Graphs*.

Action Item 5: Shoshone Falls License Amendment

Idaho Power will file to amend the FERC license regarding the 50-MW expansion.

Idaho Power response:
In April 2017, Idaho Power filed with FERC to amend the FERC's July 2010 License Order which authorized Idaho Power to upgrade the Shoshone Falls hydroelectric project changing the approved installed capacity from 50MW to 3.2MW.

Action Item 6: Jim Bridger Unit 3

Idaho Power will complete the installation of selective catalytic reduction (SCR) emission-control technology.

Idaho Power response:
Installation of selective catalytic reduction emission-control technology was completed on Jim Bridger Unit 3 in November 2015.

Action Item 7: Shoshone Falls Upgrades Study

Idaho Power will study options for smaller upgrades ranging in size up to approximately 4MW.

Idaho Power response:
In early 2016, Idaho Power explored a variety of smaller upgrade options. The most cost effective option was to replace units 1 and 2 with a single 3.2 MW unit.

Action Item 8: Jim Bridger Unit 4

Idaho Power will complete installation of SCR emission-control technology.

Idaho Power response:
Installation of selective catalytic reduction emission-control technology was completed on Jim Bridger Unit 3 in November 2016.

Action Item 9: North Valmy Units 1 and 2

Idaho Power will continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations.

Idaho Power response:
In October and November 2016, Idaho Power filed applications with the IPUC an OPUC, respectively, requesting authorization to accelerate depreciation for the North Valmy coal-fired power plant. The approved settlement stipulations in both Idaho and Oregon agreed to an early shutdown of year-end 2019 for Unit 1 and year-end 2025 for Unit 2.

Action Item 10: Shoshone Falls 2017 Upgrade

Idaho Power will commence construction of a smaller upgrade.

Idaho Power response:
The upgrade of Shoshone Falls is currently scheduled from May 2018 through June 2019

Action Item 11: Jim Bridger Units 1 and 2

Idaho Power will evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP.

Idaho Power response:
The 2017 IRP focuses on evaluating the installation of SCR technology for units 1 and 2 at Jim Bridger. The discussion of portfolios is in Chapter 8 Portfolios and the results are in *Chapter 9. Modeling Analysis and Results*. The preferred portfolio and action plan, discussed in Chapter 10 does not include the installation of SCR equipment; rather it contemplates early shut down for the units in lieu of installing the SCRs.

Action Item 12: Shoshone Falls 2019 On-Line Date

Idaho Power will place the smaller upgrade on-line.

Idaho Power response:
The upgrade of Shoshone Falls is currently scheduled from May 2018 through June 2019.

Other Issues

Selection of Preferred Portfolio—Staff agrees with Idaho Power's position that the Commission should acknowledge Idaho Power's 2015 IRP Action Plan.

Idaho Power response:
No action needed.

Qualitative Risk Analysis: Staff recommends Idaho Power include a more systematic evaluation of the qualitative benefits of the resource portfolios in the 2017 IRP.

Idaho Power response:
Qualitative Risk Analysis is evaluated in *Chapter 10d. Modeling Analysis and Results—Qualitative Risk Analysis*.

2015 IRP Update Waiver: Staff agrees and recommends the Commission waive Idaho Power's obligation to file a 2015 IRP Update.

Idaho Power response:
No action needed.

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